Electricity Markets in Ontario

An Examination of Mismatched Conditions and Options for Future Competitive Procurements

Final Report

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STRATEGIC POLICY ECONOMICS

Executive Summary

Ontario has been preparing long term procurement strategies to address the electricity capacity shortfall that will emerge over the next 5 to 10 years. Due to aging facilities and the expiration of contracted supply agreements, the province must renew or replace 50% of its existing capacity. This presents Ontario with an opportunity to review its: high-cost supply mix; approach to procuring new supply; and the social imperative for achieving a low-emission electricity system.

Ontario's Independent Electricity System Operator (IESO) is responsible for planning and procuring electricity supply and is actively advancing new approaches to managing these obligations through its Market Renewal and Capacity Auction initiatives. These approaches prioritize greater deregulation and competitive markets as the drivers of change. The IESO forecasts that these approaches will result in the capacity shortfall being addressed by natural gas-fired generation procurements. The consequence of which will include increased emissions and unquantified cost implications in the future that may arise from the increasing demand for natural gas and the potential advent of carbon pricing in North America. Ontario must determine whether this market approach best meets the province's needs.

This report examines two important considerations: the effectiveness of the IESO's planned competitive market mechanisms for meeting Ontario's electricity system needs; and better suited alternative procurement approaches. The four-part examination considers:

1. The theory and effectiveness of electricity markets for achieving efficiencies, managing and sharing risks, and accommodating other public policy objectives;
2. A historical look at how the electricity markets in Ontario have fared against these criteria;
3. The nature of demand that the electricity system in Ontario must supply and the characteristics of the foreseeable low emission options available to supply it; and,
4. Simulations of how market mechanisms would accommodate these low-emitting supply options.

The analysis shows that Ontario's "lessons learned" are indicative of global electricity market challenges, especially with respect to reducing emissions. These lessons reflect the consequences of Ontario's pursuit of electricity markets that are predicated on fossil-fuel dominated U.S. market models. Specifically, this study finds that:

1. Capacity and energy markets pioneered in the U.S. are unable to meet Ontario needs;
2. Ontario's previous attempt at deregulated markets resulted in high costs and, eventual failure;
3. Electricity demand in Ontario occurs in three distinct forms, each requiring a separate procurement solution, which the planned capacity and energy markets cannot provide; and,
4. Procurements targeted at Ontario's specific policy and energy system needs will yield better results.

In conclusion, this report recommends that Ontario adopt a targeted and competitive Request for Proposal (RFP) process to achieve the objectives of fostering competition, providing broader options that best meet Ontario's needs, and avoiding long term commitments to high emission natural gas-fired generation.

Detailed findings

Finding #1: Capacity and energy markets are not able to acquire what Ontario needs

Ontario's electricity system is not a natural commodity market that is suited to how electricity markets are designed. The underlying assumption is that market solutions will improve the efficiency of procurement transactions for energy, capacity, and other services. However, to make an electricity market function requires several artificial accommodations that remain insufficient to respond efficiently to system needs. Efficiency and performance shortfalls occur in two ways:

a) Shorter procurement contract lengths typical of markets will raise costs

Building out electricity infrastructure involves large capital spending and prudent management of the cost risks. Market mechanisms are intended to help manage these risks by incentivizing the procurement of adequate supply to meet both short-run efficiency (supplying the minute to minute demand variations) and long-run efficiency (ensuring that adequate and appropriate capacity is available to meet reliability requirements and any mandatory government environmental requirements). System planners engage in both short-term and long-term contracting approaches to help manage these efficiency objectives, which balances the different risk implications shown in Figure ES-1.

ES-1: Risk Implications of Contract Length

	Risk Implication	Short-term Contracts	Long-term Contracts
a	Length of procurement contract varies by market models and procurement mechanism	Short-term contracts lead to lower planning risk	Long-term contracts lead to lower investor risk
b	Who bears the risks inherent in procurement varies by contract length	Risk is shifted to investors	Risk is shifted to operators
c	Risk premiums are eventually passed onto ratepayers in the form of costs	Ratepayers bear the cost of increased investor risk premiums	Operators can lower risk premiums and reduce the cost for ratepayers

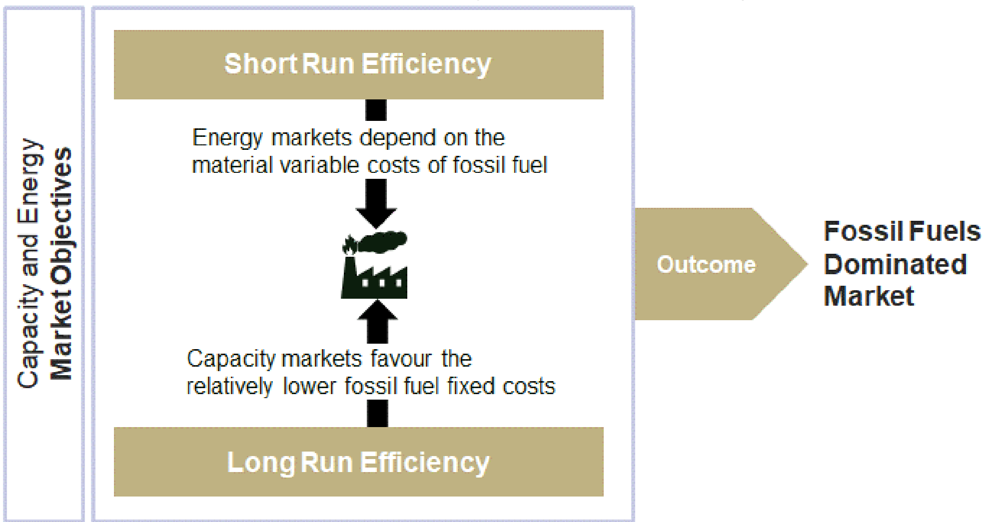
Source: Cramton et al., Haririan M., IESO, Strapolec Analysis

Short-term contracts appeal to system planners. They help avoid long-term procurement commitments when meeting uncertain forecasts and provide flexibility to address emerging demand realities. However, the cost of this risk is simply shifted to investors. With uncertainty in long term revenue expectations, investors will naturally require higher risk premiums in return, which in turn are ultimately passed onto ratepayers.

b) Fossil fuel-fired generation is well suited to US-style capacity and energy markets and will dominate supply outcomes absent out-of-market interventions

Electricity market shortcomings are addressed by two primary electricity market mechanisms: energy markets, which have devolved to recovering the variable costs of production; and capacity markets, which were created to help recover the fixed costs of generating assets required to meet NERC reliability requirements. The total costs of generation must be recovered by the separate revenue streams from these two markets. The designs of both markets emerged from jurisdictions with high fossil fuel-fired generation in their supply mixes. Figure ES-2 shows that these markets are ideally suited for procuring fossil fuel-fired generation to address short run efficiencies that mitigate demand risks and long-run efficiencies that mitigate planning risks. Fossil fuel-fired generation has relatively high marginal costs, driven for example by the price of natural gas, that allows rational and predictable settlement of the energy markets. It also has relatively low fixed costs that give it an advantage in capacity markets. Non-emitting resources, in contrast, have low variable costs and high fixed costs, making them incongruous with market designs. These factors lead to fossil fuels dominating the supply outcomes of these markets, absent out-of-market interventions.

ES-2: Fossil Fuels Ideally Suited to Market Objectives



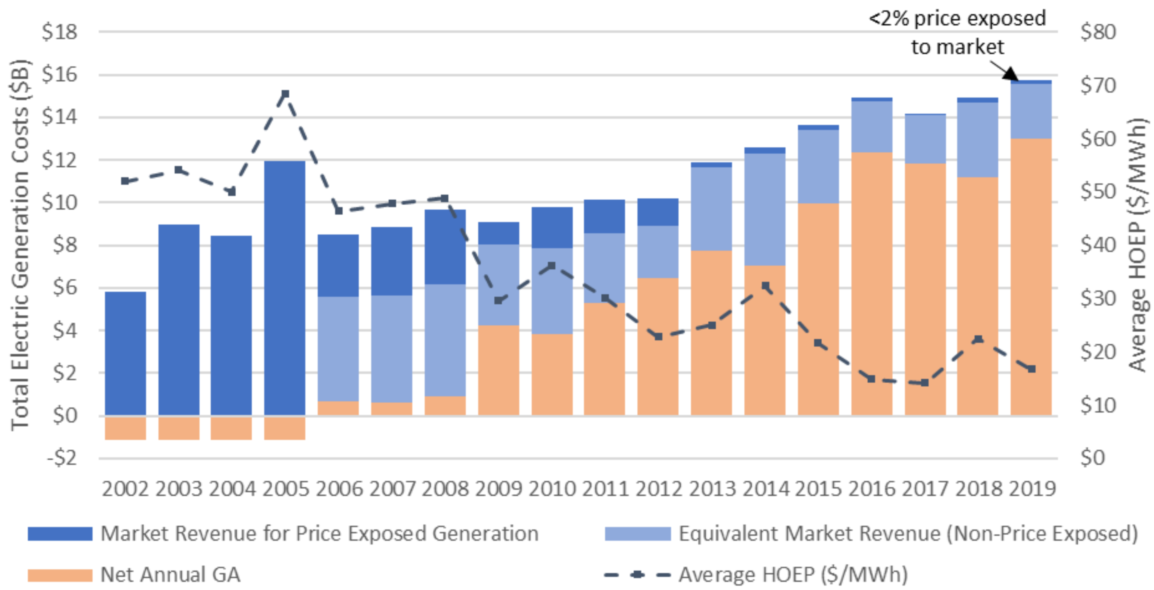
Sources: Strapolec Analysis

The failure of markets to adequately share planning and demand risk, coupled with a structure that is suited to fossil fuel-fired generation results in increased costs for ratepayers, continued dependence on GHG emitting generation, and an inability to address broader electricity system challenges. The underpinnings of these markets also clash with the prevailing evolution of policy objectives in North America. Relying solely on market mechanisms could result in adverse outcomes for Ontarians.

Finding #2: Ontario's previous attempt at deregulated markets resulted in high costs and, eventually, failure.

Ontario has been experimenting with deregulation for some time, which has resulted in higher costs and ultimately market failure. In turn, this failure resulted in the need for the Global Adjustment (GA) mechanism and the Regulated Price Plan (RPP). In response to the challenges of the markets themselves, Ontario gradually added non-market mechanisms to create a hybrid market. With minimal generation exposed to market price signals as shown Figure ES-3, there is limited economic influence from the investment in the markets. Rather the market rules have been "patched" with features to enable it to achieve desired physical resource dispatching capabilities. Having come full circle, Ontario is now attempting to shift back to deregulated markets with the introduction of capacity auctions, despite its supply mix being poorly suited to such a market structure and in the face of opposition from key stakeholders.

ES-3: Market Revenue Share of Price Exposed Generation in Ontario
($B, $/MWh by Year)



Source: IESO, Strapolec Analysis

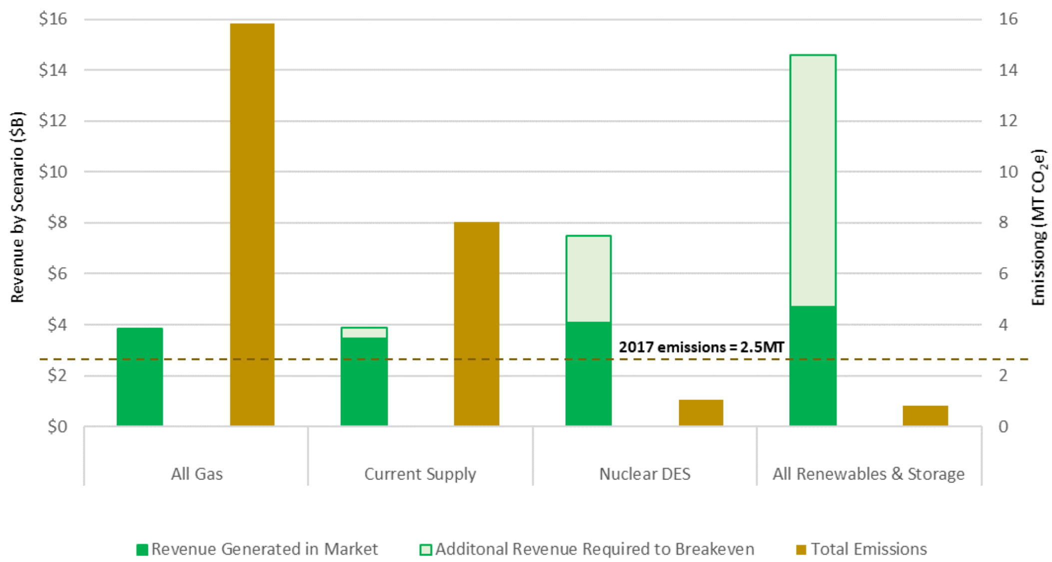
Finding #3: Electricity demand in Ontario arises in three distinct forms and each requires a separate procurement solution, which the planned capacity and energy markets cannot provide.

Capacity and energy markets rely on procuring a simply defined capacity product that cannot provide an optimal cost-effective, low-emissions solution encompassing the different needs of Ontario's electricity system. The needs of the electricity system are not simple and uniform but rather characterized by three forms of demand: Baseload; Intermediate; and Peak. Each form has distinct characteristics and is best met by a different type of generation. Satisfying all three requires an optimal mix of supply components, which has proven to be difficult to procure via markets.

Simulations of how market dynamics will respond to Ontario's anticipated electricity generation procurement needs show that capacity and energy market models do not allow non-emitting resources to be economically feasible. Several scenarios were conducted to examine the interplay of the various generation types within the market models. Figure ES-4 illustrates the results-- markets cannot procure non-emitting resources without significant out-of-market subsidies to provide the required additional revenue to make the assets economic.

The IESO's proposed market models will procure only natural gas-fired generation unless out-of-market subsidies are provided. In fact, the more non-emitting resources that are sought to reduce emissions, the greater the required out-of-market mechanism subsidies will be. Furthermore, supplying the needed out-of-market subsidies will distort the market and create other negative consequences requiring management and special market rules.

ES-4: Revenue Requirements and Emissions in Markets – By Resource
($B, MT CO_2e; Selected Scenarios)

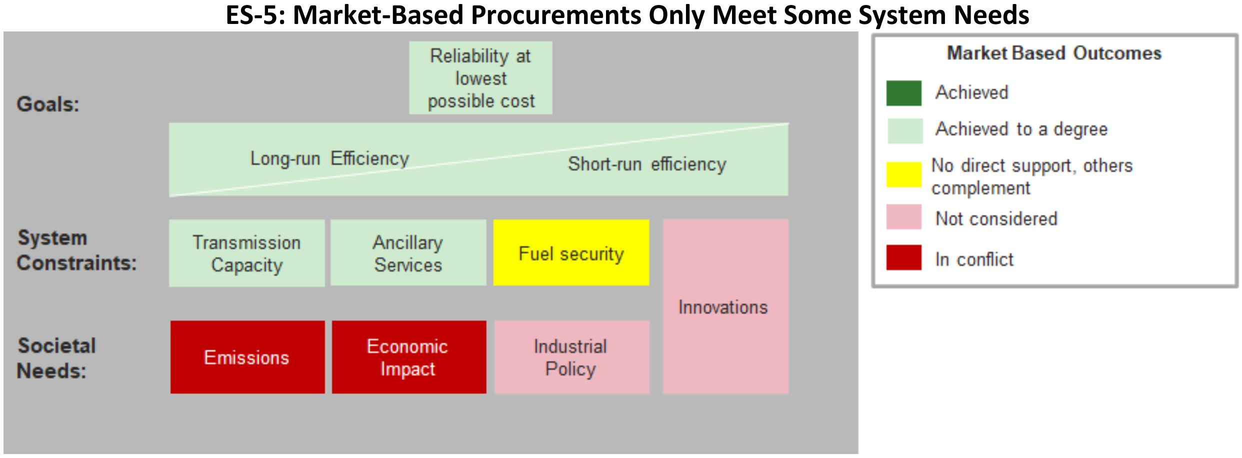


Sources: IESO, EIA, Strapolec Analysis

Finding #4: Procurements targeted at Ontario's specific policy and energy system needs will yield better results.

Electricity systems fulfill many functions beyond just providing reliable low-cost electricity that is optimized for the short and long-run. Figure ES-5 highlights the many requirements that market-based procurements do not adequately address. Solutions must consider system constraints such as transmission capacity, ancillary services, and fuel security. Also, it is increasingly evident that societal needs, such as climate change related emission reductions, domestic jobs and revenue objectives, ongoing innovation and economic/industrial/trade policy objectives are imperative considerations for securing optimal procured solutions for Ontario.

ES-5: Market-Based Procurements Only Meet Some System Needs



Sources: Strapolec Analysis

To optimize the benefit of the electricity system for ratepayers, taxpayers, and the economy, targeted procurements are required. This approach would involve specifying the need to procure energy solutions matched to the demand forms they must supply. Understanding the demand forms can greatly mitigate planning risks, reducing risk premiums, and lowering costs. Procurements should also be conducted with a clear understanding of the policy and economic objectives that the electricity system can help advance for the province. This targeted procurement approach will enable solution providers to strive for innovative, custom solutions that are well-matched to Ontario's needs.

Closing

Ontario would benefit from taking a broader approach in addressing its long-term procurement needs to renew or replace 50% of its existing electricity capacity. Ontario has the opportunity to move forward with a more integrated approach to specifically: address its high-cost supply mix; determine the best approach for procuring new, low-cost, low-carbon supply; and, enable viable synergies with other provincial economic and environmental objectives. The pitfalls of electricity markets should be carefully considered against the benefits of undertaking targeted procurements that are better matched to Ontario's needs and still achieve the objectives of fostering competition and avoiding long term commitments to high emission natural gas-fired generation.

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1.0 Introduction

Ontario has been preparing long term procurement strategies to address the emerging electricity capacity shortfall over the next 5 to 10 years. Due to aging facilities and the expiration of contracted supply agreements, the province must renew or replace 50% of its existing capacity. This presents Ontario with an opportunity to review its: high-cost supply mix; approach to procuring new supply; and the social imperative for achieving a low-emission electricity system.

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This report examines two important considerations: the effectiveness of the IESO's planned competitive market mechanisms for meeting Ontario's electricity system needs; and, presents better suited alternative procurement approaches. The four-part examination considers:

1. The theory and effectiveness of electricity markets for achieving efficiencies, managing and sharing risks, and accommodating other public policy objectives;
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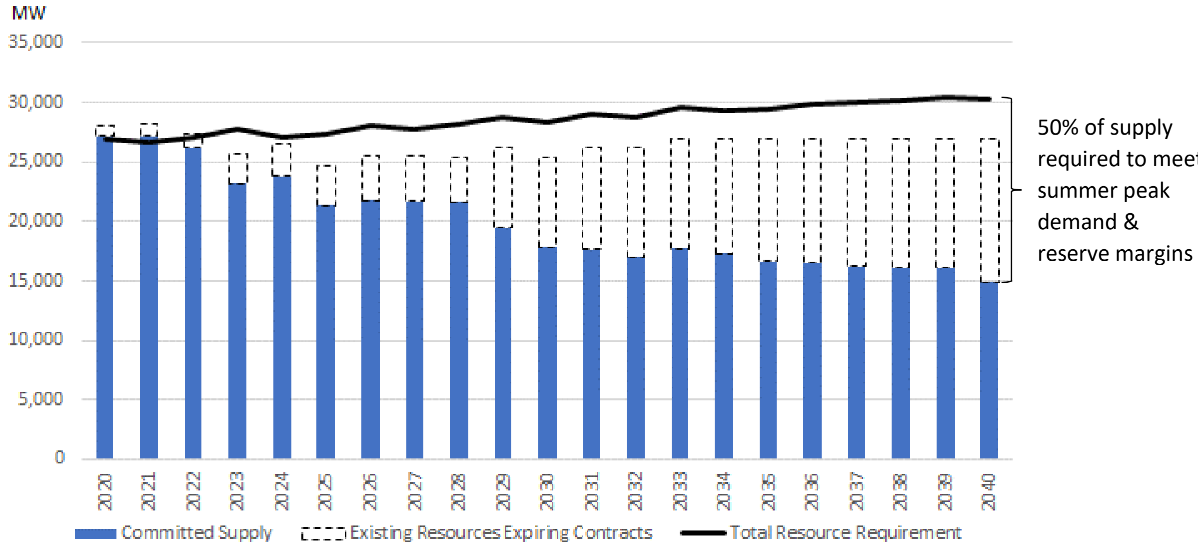
1.1 Context – Ontario needs to procure 50% of its capacity

Ontario's electricity system will have to contend with several supply and demand challenges over the next twenty years, which by 2040 will result in a summer peak capacity shortfall of 15,000 MW, or 50% of Ontario's capacity needs, as shown in Figure 1.[1] Meanwhile, the IESO expects Ontario to be energy adequate going forward by assuming that all expiring contracts will be renewed and that additional capacity requirements will be limited to a few hours each year or will serve as a backstop in case of unlikely events. This additional need is expected to be met through Demand Response (DR), energy efficiency, imports, uprates, and Distributed Energy Resources (DER).[2] These assumptions limit potential supply options and may cause insufficient supply, higher emissions, and/or increased costs.

[1] This shortfall results from a loss of capacity due to Pickering Nuclear Generating Station retirement (by 2025), the expected growth in total resource requirement (the total of peak demand and reserve margins) and, a number of resource contracts expiring by 2040.

[2] IESO Annual Planning Outlook does not identify new build resources as an option.

Figure 1: Ontario Summer Resource Requirement Forecast
(MW by Year)



Sources: IESO, Strapolec Analysis

1.1.1 Ontario is focusing on a markets approach to electricity generation procurement

In the past, the IESO has used long-term contracts to procure capacity, often in response to political imperatives.[3] More recently, the IESO began developing an Incremental Capacity Auction (ICA) which would use yearly auctions to procure the forecasted incremental need for supply. Due to stakeholder pushback on the complexity of developing the new system, the ICA was cancelled in the summer of 2019. In response, the IESO has chosen to move forward with a similar capacity market policy, but in the form of an enhanced version of its existing DR auction.

The IESO's new DR-based capacity auction model was slated to commence on December 2019.[4] Like the ICA, it was designed to secure needed near term supply with the least costly capacity available. However, new build capacity is not allowed to participate, with only existing natural gas-fired generators and DR resources being permitted.[5]

[3] The Green Economy Act, for example, mandated quantities of renewables procurements that were not driven by demand nor adjusted for it when it changed as a result of the 2008/2009 recession.
[4] The 2019 Capacity Auction was delayed due to a motion to stay issued by the Ontario Energy Board (OEB) in response to the Association of Major Power Consumers in Ontario (AMPCO) Application to Review Amendments to the Market Rules made by the IESO. This consultation concluded in January 2020 and the IESO was allowed to continue with their market rules amendments to evolve the DR auction into the Capacity Auction. The IESO planned to hold the June 2020 auction with expanded participation by gas generators, energy storage resources, and imports, but this was delayed due to COVID-19.
[5] The IESO planned to progressively open up participation to different resources with each subsequent auction starting with only dispatchable gas generators in the December 2019 auction. However, existing Solar and Wind resources, and New Build resources were not included in IESO's list of resources that could participate in future auctions, and it is unclear if it was part of the IESO's plan to allow these resources to compete eventually. At this time, the IESO has not explained how they would procure these resources but has initiated a Resource Adequacy engagement that has subsequently been postponed.

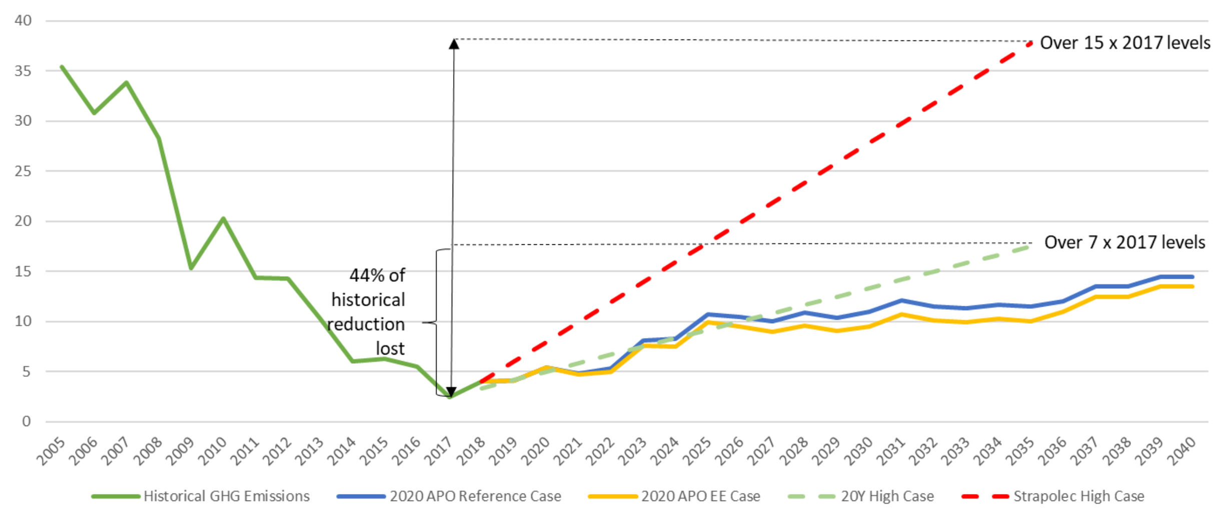
Electricity markets are based on the principle of lowest cost being the determining criterion. This singular focus for the IESO's proposed capacity auctions facilitates an increase in natural gas-fired generation. The IESO forecasts natural gas usage in Ontario will increase from 8 TWh in 2020 (6% of supply mix) to 29 TWh (17% of supply mix) by 2040[6]. These forecasts assume existing renewables are going to be re-procured, however it remains unclear as to the extent that these assets will be able to generate electricity post-contract expiry. Renewables have had trouble competing in several electricity markets in the U.S., including the ISO-NE[7] and PJM,[8]. Should Ontario's existing renewables not be re-procured in the future capacity market, natural gas-fired generation will be used to fill this gap, increasing their output to 48 TWh (28% of supply).

1.1.2 The IESO's forecast natural gas-fired generation uptake will increase Ontario's emissions

New investments in natural gas-fired generation will leave Ontario with an emissions legacy for decades. As natural gas-fired generation's share of Ontario's electricity generation mix increases, the IESO forecasts that emissions could rise to approximately 12 MT by 2035, assuming that all existing renewables are re-procured in some manner. If the renewables assumptions for Ontario's supply mix are not realized, the rise in emissions could be approximately 17MT or seven times 2017 levels, as shown in Figure 2.

Figure 2: Ontario Electricity Sector Emissions Expected to Rise

(GHG Emissions in Megatonnes CO_2e)



Source: IESO, Strapolec Analysis

Notably, the IESO's demand forecast assumes little additional electrification will occur as a result of Ontario's climate change policies. Pro climate change and electrification policies could increase Ontario's energy demand by an additional 71 TWh/year (~43% increase) above the IESO's 2035 forecast.[9] Contributing factors include:

[6] IESO, Annual Planning Outlook, 2020.
[7] Renewables contribution to total electric energy has grown from only 6% to 9% in the last 20 years (4% to 5% on a capacity basis), ISO-NE, "Resource Mix", 2020.
[8] S&P Global Intelligence, "Overpowered: PJM market rules drive an era of oversupply", 2019.
[9] Strategic Policy Economics, Emissions and the LTEP, 2016.

- New electricity demand for water and space heating in buildings, and for industrial use;
- Fuel shifting from fossil fuels to electricity for transportation; and,
- Production and use of hydrogen as an important element of decarbonization in other sectors.

This additional electricity demand will require more generation and capacity than has been currently forecast. If this demand is met by new natural gas-fired generation, Ontario's electricity emissions could increase by as much as 38 MT or 15 times the 2017 emissions levels. This would reverse the significant progress Ontario achieved lowering its electricity sector emissions by closing the coal-fired generating stations in the province.

Procuring an equivalent amount of energy to close a 50% capacity gap could represent up to $7-8B/year of future electricity cost commitments.[10] This represents a large procurement with significant implications for Ontarians and therefore warrants careful and transparent consideration of whether capacity markets will actually provide the best long-term electricity system supply and cost outcomes. This report examines this question.

1.2 Structure of the report

This report is structured into sections that taken together present the case that deregulated markets may, in large part, be ill-suited to the prevalent conditions and electricity needs of Ontario.

Section 2 provides an overview of the methodology used to research prevailing market mechanisms, case studies, potential costs, and forecast demand in order to model scenarios for the use of capacity markets in Ontario.

Section 3 discusses the theory and effectiveness of electricity markets for achieving efficiencies, managing and sharing risks, and accommodating other public policy objectives. This section examines: how the electricity market's efficiencies fall short; how the risks of acquiring adequate capacity drive up costs; the inherent bias of electricity markets to fossil fuels; and, how auctions have consequences and do not respond to public policy imperatives. These characteristics of markets demonstrate that they are unable to meet Ontario's needs and create potential adverse outcomes for Ontarians.

Section 4 provides the genesis of market mechanisms in Ontario and how Ontario's experiment with deregulated markets has evolved to the point of abandonment today.

Section 5 delves into the nature of electricity demand, outlines supply scenarios to meet it, and assesses the economics of electricity markets and their impact on Ontario's supply options. This section tests the premise that Ontario's capacity markets will almost exclusively procure natural gas-fired generation.

Section 6 explores how alternative targeted procurement mechanisms could provide Ontario with more efficient and balanced procurements that best reflect public policy goals while lowering costs and emissions.

Finally, **Section 7** summarizes the conclusions of this report.

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[10] Generation costs in Ontario forecast for 2019 were approximately $14B per IESO 2018 Technical Planning Conference; Strategic Policy Economics estimates GA and HOEP revenues in 2019 were $15.5B according to IESO Power Data.

2.0 Methodology

Four research areas are explored to help illuminate the implications for Ontario continuing its pursuit of developing electricity markets:

1. The theory and effectiveness of electricity markets for achieving efficiencies, managing and sharing risks, and accommodating other public policy objectives;
2. A historical look at how the electricity markets in Ontario have fared against these criteria;
3. The nature of demand that the electricity system in Ontario must supply and the characteristics of the potential low emission options available to supply it; and,
4. Simulations of how market mechanisms would accommodate these low-emitting supply options.

Each of these areas of investigation involved secondary research using online resources that are cited throughout the report, as well as specific considerations, analyses, and assumptions.

The theory and effectiveness of electricity markets is assessed in Section 3. The supporting research was conducted in two parts:

- Part 1 involved a scan of general market-related research on the driving design considerations and motivations for electricity markets and on the lessons learned from experiences. The sources used were primarily scholarly articles and research papers.
- Part 2 involved specific research that contrasted how eight jurisdictions procured resources using four different market models. This provided real-world examples of the performance of each market model. Sources used were primarily system operator websites, research papers, and news articles.

The historical look at electricity markets in Ontario and how they have fared is provided in Section 4. The analysis leveraged data from the IESO to quantify the role of markets and researched news articles and publications to capture the historical conditions under which market decisions were developed and made.

The nature of demand and the simulation of electricity market mechanisms is described in Section 5. The assessments required the development of an analytical model to understand how various supply mixes would perform financially in capacity and energy markets. The model is comprised of four components:

1) Future demand forecast:

A demand forecast was developed using the IESO's 2015-2017 supply and demand data, and demand growth assumptions to 2035 from the 2017 Long-term Energy Plan (LTEP). Starting with hourly Ontario grid demand data for each year, the 2017 LTEP assumptions were applied to forecast the hourly net demand 20 years into the future, for the years 2035-2037. The hourly committed supply generation (primarily hydro and nuclear) was assumed to stay the same and was removed from future net demand to show how much incremental demand would need to be procured in the future. Demand was segregated into three different supply types which also serve to help characterize the three different forms of demand:

- **Baseload:** This type of supply meets demand that is present almost all of the time. Baseload supply should be set at a level that ensures full utilization most of the time and was defined as Ontario's committed supply of hydro and nuclear assets with an additional 2,250 MW[11] to account for part of the lost capacity from the retirement of the Pickering Nuclear Generation Station. This number was chosen after an analysis of the hourly demand profile over three years showed demand was over this level for 98% of the time or approximately 8,560 hours in a year. This baseload capacity will get fully utilized 98% of the time.
- **Peak:** This supply type is rarely required to operate and is procured to meet the few hours of the year when demand increases greatly due to extreme weather and/or tight supply conditions. It is essentially the opposite of baseload, in that peak supply capacity is rarely used at all. For this report, the peak supply capacity required under normal conditions was sized to provide 3,000 MW which would only be needed to meet the highest 200 demand hours of the year or approximately 2% of the time. While reserve margin requirements are included in the IESO's forecast resource requirement, they are not included in this model.
- **Intermediate:** This form of supply was defined as that which is required to meet the remaining demand after the use of baseload and before peak requirements are dispatched. The primary characteristic of intermediate demand is that it rises from low usage levels at night to meet the normal daytime needs of the system.

2) Supply scenarios

Four different supply scenario categories were created based on the possible options available to meet Ontario's baseload and intermediate demand above committed supply. These supply scenarios help illustrate the respective economic implications of their procurement using electricity market mechanisms:

1. **Gas only:** Meeting all future demand needs with natural gas-fired generation;
2. **Re-procuring wind & solar: The** IESO's assumption that all existing wind and solar supply will be re-procured;
3. **Nuclear Distributed Energy Storage (DES):** Using nuclear combined with distributed storage resources to supply the intermediate demand; and,
4. **Renewable DER:** A combination of solar and wind resources paired with co-located distributed storage assets that, as a portfolio, would dependably supply the intermediate demand.

Sub-scenarios were developed for Scenarios 2 and 4, resulting in a total of seven differentscenarios. Scenario 2 covers three sub-scenarios:

- 2a: Natural gas-fired generation to supply baseload demand needs and accommodate renewables without curtailment;
- 2b: Nuclear providing baseload with any excess renewable supply being curtailed to maximize nuclear production; and

[11] This is an average number, the actual additional baseload supply that was modelled was underpinned by a nuclear profile and varied slightly throughout the year. This was chosen as it best suits the hourly profile of demand above committed baseload.

- 2c: Same as scenario 2b with scaled down renewables capacity to limit curtailment and meet remaining needs with natural gas-fired generation.

Scenario 4 consisted of two sub-scenarios:

- 4a: Nuclear providing baseload demand with any excess “un-storable” renewable supply curtailed to maximize nuclear production; and
- 4b: Same as scenario 4a with scaled down renewables capacity to limit curtailment and meet remaining needs with natural gas-fired generation.

3) *Market revenue*

Estimates for Capacity and Energy market prices were determined using available data from the IESO, the U.S. Energy Information Administration (EIA), and a custom algorithm for estimating real-time prices. These were used to calculate the annual revenue each resource would earn by participating in these markets.

A regression analysis of the Hourly Ontario Energy Price (HOEP) was developed from current prices, renewable curtailment, and natural gas-fired generation capacity to develop a relationship that could predict the HOEP in the future under the market conditions and resource availability defined by the scenarios. An 8,760-hour model was then developed for each scenario that calculated energy market revenue earned by each resource for each hour.

The capacity auction reference price for each 6-month period was calculated based on IESO data and the revenue earned by each resource was calculated based on the resource’s effective dependable de-rated capacity.

Finally, the total annual revenue for each resource was calculated by adding the capacity and energy market revenues. This was compared to the EIA’s cost of resources required for procurement and the IESO’s estimated re-contracting costs. If the revenue earned by a resource fell below the cost of that resource, it was deemed economically non-viable, and a shortfall was calculated.

4) *Emissions and economic viability*

The emission outputs for each supply scenario were also calculated. The emissions and revenue requirements of each scenario were then compared to show the economic viability of a scenario including the emissions output. This provides an illustrative calculation of the cost of reducing emissions with different resources.

3.0 Fundamentals of electricity markets

This section explores the objectives that underpin electricity markets in general and capacity markets in particular. The areas of investigation include: the extent to which markets have improved efficiency and risk sharing; their evolution; and, the lessons learned.

Despite the prevalence of electricity market models, the findings show that electricity is not a natural commodity well suited to markets. As a result, existing electricity markets include “artificial” accommodations to help them function. In spite of these modifications, designed electricity markets remain unable to respond efficiently to system needs. There is also a clash between these markets and the evolution of other societal policy objectives across North America. These circumstances show that relying on market mechanisms could create undesirable outcomes for Ontarians.

This section examines the objectives of electricity markets and the challenges that compromise them. It then reviews key electricity system risks and their mitigation. The section then discusses how the economics that underpin capacity and energy markets are inherently biased towards natural gas-fired generation. It then presents challenges associated with capacity auctions. The section concludes with a discussion of the conflict between electricity markets and other public policy objectives, and a summary of the implications for Ontario.

3.1 Electricity markets are failing to achieve efficiencies

Since electricity sector deregulation began in the U.S. in the late 1990s, many jurisdictions have adopted a market approach for procuring electricity resources. This transition has been complicated by treating electricity as a commodity and applying market theory to the sector.

This sub-section examines: the premise that markets deliver efficiencies; how various electricity market models achieve system objectives; why electricity is a unique commodity that gives rise to inefficiencies in electricity markets; and, how, in practice, capacity and energy markets have achieved limited success.

3.1.1 The ability of markets to gain efficiencies is impacted by real world imperfections

In perfect markets, many buyers and sellers interact such that no single buyer or seller can control the price. In such markets, the law of supply and demand holds that with all else being equal, the price of a good rises and falls in proportion to demand and supply. These markets are characterized by:[12]

- Products that are homogenous, portable, substitutable, and have cheap and efficient means of transport; and,
- Many buyers and sellers competing for the product, no barriers to entry or exit, and buyers with complete information on prices and products.

As a result, when supply and demand are in balance, the prices in these markets can be at equilibrium (close to marginal cost) and markets are fully efficient.

However, in the real world, markets are impacted by inherent imperfections. Products are differentiated, goods cannot be substituted, expectations can differ, information does not flow easily,

[12] Investopedia, “Perfect Competition”, 2020.

and transactions can be costly. While most of these imperfections do not create large inefficiencies, some can result in considerable market inefficiencies:

1. **Too much power for the buyer/seller:** Well-functioning markets, in general, require many different buyers and sellers so that neither has too much power over the other (e.g., if there are only a few sellers then a monopoly or an oligopoly can occur);
2. **The inability of buyers and sellers to adjust quickly**: Well-functioning markets effectively adjust to changing market conditions. If market players can respond to changes in conditions in real-time, then prices can be reduced to as close to the marginal cost of production as possible;
3. **Prices do not take all factors of production into account:** In well-functioning markets, prices are based on all production factors. However, this is not always the case (e.g. some companies may freely pollute but not include the cost of this externality in the cost of goods sold); and,
4. **Transaction costs create economic inefficiency:** Any trade or transaction in a market has a cost and depending on the market structure, these costs can range from minimal to significant.

3.1.2 Electricity market models

There are two basic objectives for electricity markets: short-run efficiency (i.e. turning generation on and off during the day to efficiently serve demand); and, long-run efficiency (i.e. having enough capacity to meet demand at all times including in the longer run).[13] Both objectives aim to ensure reliable supply at the least possible cost, but the features of electricity and the structure of markets have made it difficult to concurrently achieve the two objectives. Markets attempt to achieve efficiencies by:

1. **Achieving short-run efficiency** – Markets try to efficiently coordinate the dispatch of generation by matching buyers (intermediaries and some end-consumers) and sellers (generators). In this way, an attempt is made to achieve the goal of short-run efficiency by finding an equilibrium for supply and demand, without wasting resources and optimizing the price; and,
2. **Achieving long-run efficiency –** Long-run efficiency presents the challenge of ensuring that new generation is incentivized so that long-term electricity needs can be met. Markets have the task of addressing long-run efficiency by properly incentivizing generators to build new generation.

Table 1 show how markets attempt to achieve these objectives through four market model approaches.

Table 1: Market Model Descriptions

	1. Energy-only markets	2. Capacity and Energy Markets	3. Hybrid Markets	4. Regulated Markets
Short-run Efficiency Approach	Energy market	Energy market	Mix of energy markets and physical dispatch made by central authority	Dispatch decisions made by a central authority
Long-run Efficiency Approach	Scarcity pricing and high price cap	Capacity auction	Mix of market and regulatory mechanisms	The regulator ensures monopoly utility compensated for generation
Benefits (what they are designed to do)	Simple market design	Ensures sufficient capacity, mitigates price spikes	Government priorities can be implemented through regulated resources while markets can fill out the rest of the generation mix	Monopolies avoid transactions costs present in electricity markets
Example Jurisdictions	Texas, Alberta	PJM, ISO-NE, MISO	Ontario, California, UK	Quebec, BC, Saskatchewan

Sources: Cramton, Strapolec Analysis

[13] Cramton, "Electricity market design", 2017.

3.1.3 Electricity is a unique commodity

Research shows that achieving market objectives is challenged by the unique, inherent characteristics of electricity:

1. **Storage:** Electricity is a perishable good that has historically not been easily or economically stored – it must be used when generated.[14] This is unlike other typical commodities, whose shelf lives extend beyond a few milliseconds and have less transient availability. The cost of storage has inhibited the ability of consumers to build up a reserve of electricity when prices are low to hedge against the risk of higher prices. As such electricity spot prices can fluctuate by minute, hour and season, correlating mostly with the available supply and demand at the time.
2. **Substitution:** Electricity serves a necessary function without which modern societies cannot operate effectively and is not substitutable.[15] In other words, there are no other products or inputs that could be substituted for electricity that allows consumers to perform the same functions. An example of substitutable goods are coffee and tea: if coffee were to become unavailable or too expensive, consumers could easily substitute it with tea and enjoy similar benefits. Electricity, however, is essential, and the optimization of supply to meet demand is crucial to minimize the costs of electricity for society.
3. **Reliability:** Electricity delivery infrastructure is essential for the sustainability of modern society, today. It is therefore critical that the reliability of this electricity delivery system is maintained, blackouts and load shedding are avoided, and the day to day operations of society are sustained. Today, reliability is regulated in recognition of these important requirements. The North American Electric Reliability Corporation (NERC) sets stringent requirements for reliability of supply that all member jurisdictions must comply with to ensure the reliability of the grid across North America.[16]

Utilities must therefore meet end-consumer demand sufficiently with a regulated minimal chance of failure. Since general end consumers are unable to participate directly in the purchase of electricity, intermediary entities have evolved to co-ordinate and balance electricity generated by suppliers with the demand from consumers (e.g. utilities, system operators, and a market operator).

Electricity's unique characteristics and the resulting market structure cause electricity markets to differ from perfect markets and exhibit many inefficiencies:

1. **Very few buyers:** In fact, Ontario effectively only has one buyer (the IESO) for almost all electricity.[17] Local distribution companies pay the price that the IESO sets and pass those costs onto consumers, generally through rate plans approved by the Ontario Energy Board (OEB);
2. **Most end-consumers are price takers:** Most consumers in Ontario are covered by rate plans that insulate their buying patterns from real-time market price exposure.[18] This separation provides consumers with no ability or incentive to react to real-time price signals. This creates two types of inefficiencies: Consumers have almost no ability to participate in the market; and can pay a drastically different price for electricity compared to how they value it;

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[14] Cramton, Ockenfels, and Stoft, "Capacity Market Fundamentals", 2013.
[15] Cramton, Ockenfels, and Stoft, "Capacity Market Fundamentals", 2013.
[16] NERC, "2019 Long-Term Reliability Assessment", 2019.
[17] Mowatt Energy, "Background Report on the Ontario Energy Sector", 2016.
[18] Mowatt Energy, "Background Report on the Ontario Energy Sector", 2016.

3. **Market-based pricing mechanisms do not reflect all the factors of system operation:** Price mechanisms have not been sufficient to coordinate the efficient operation of different elements of the electricity system (e.g., the central market operator must separately account for transmission limitations and ancillary services); and,[19] [20]
4. **Transaction costs:** Due to the complexity of electricity systems, the necessary interactions between different electricity market actors in the generation, transmission, distribution, and retailing of electricity incur cost.[21] Such transaction costs can be minimized or absent when one actor owns and controls multiple parts of the electricity system. The cost reductions that markets can bring though competition must be weighed against the transaction costs of supporting multiple actors.

3.1.4 Markets have yielded limited benefits in practice

The move toward electricity market development was rooted in the global trend in the 80s and 90s to deregulate many economic sectors. Deregulation was intended to separate large vertically integrated companies, like utilities, into smaller independent organizations. Achieving market competition in the electricity sector was a primary objective. Despite analyses at the time that outlined the risks of market imperfections, electricity market deregulation was driven by the belief that even an imperfect market could do better than regulated regimes.[22] This sub-section examines the motivations for deregulation followed by an evaluation of the outcomes.

a) The motivation for deregulation

The high cost of electricity in the 80s and 90s created pressure for deregulation. Stakeholders saw an opportunity to reduce consumer costs arguing that the compensation for electricity generation should be determined by the spot market price of electricity rather than by a set rate that made generators whole.[23] Theoretically, this would cause generators to reduce their costs so that they could maximize profits and drive down consumer costs via competition. Large industrial customers were particularly interested in deregulation because they would be able to purchase electricity directly from the wholesale electricity market, thereby reducing their energy costs.

Pre-deregulation, an oversupply of generation was the main factor driving high electricity costs. Post-deregulation many of these assets were stranded. Deregulation provided an opportunity to

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[19] Cramton, "Electricity market design", 2017.
[20] For example, the possibility of network congestion means that just dispatching the least costly generators at any moment in time can't ensure all generation is able to get to load. Initial attempts to solve this through pricing congestion produced sub-optimal results and allowed market manipulation. This problem played a significant role in the collapse of California's market in 2000/2001. Dealing with this problem has required central market operators to take bids and offers and optimize physical dispatch given network constraints. Even as mechanisms for pricing congestion have improved (e.g., Locational Marginal Pricing) central market operators have done a better job of optimizing efficiency based on physical needs than the market has through decentralized buyers and sellers.
[21] Joskow, "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies", 1991.
[22] Joskow, "The Role of Transaction Cost Economics in Antitrust and Public Utility Regulatory Policies", 1991.
[23] NBER, "The U.S. Electricity Industry After 20 Years of Restructuring", 2015.

shift the cost of those stranded assets[24] from ratepayers to utilities. However, electricity markets would not allow utilities to recover the remaining value of these stranded assets. Realizing this challenge, utilities convinced regulators to allow them to recover the costs of stranded assets from ratepayers with above-market retail rates or surcharges on customer bills. This resulted in ratepayers having to cover almost the entire cost of these assets.

b) The measurable outcomes of deregulation

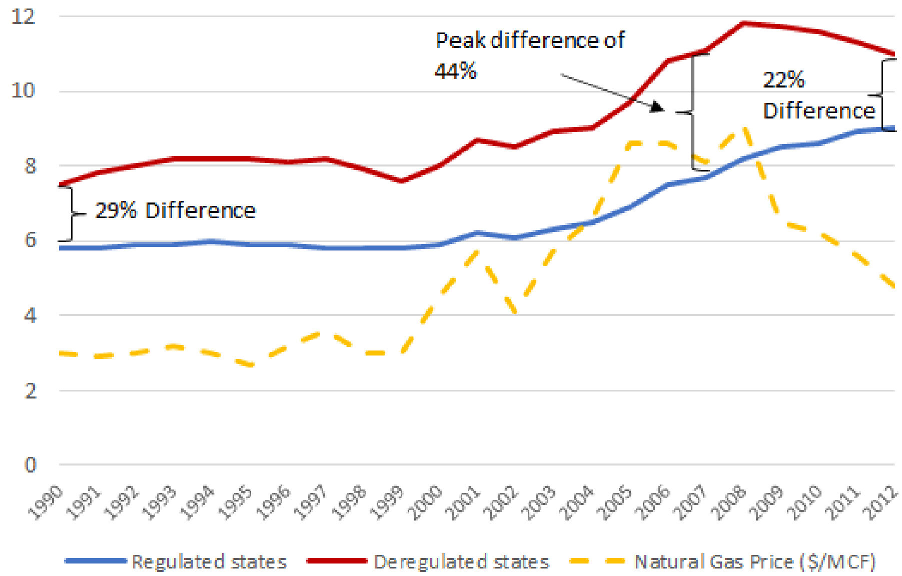
Regression analysis shows that in the years following deregulation, there was no discernible difference in prices between regulated and deregulated states when accounting for the cost of natural gas, as shown in Figure 3. This leads to the following three observations:

1. **The price of natural gas is the biggest determinant of cost difference, not whether the jurisdiction is regulated or deregulated.** Figure 3 shows that discounting the impact of higher natural gas prices in deregulated states, the difference in electricity cost between regulated states and deregulated states remained relatively consistent from 1990 to 2012. The difference in rates steadily grew as natural gas prices increased until peaking in 2007-2008, then decreasing to similar levels in 1990.
2. **Regulated states tend to be less expensive, largely due to the benefit of cheaper resources. From 1990 to 2012,** regulated states have been consistently less expensive. However, that is because those states had cheaper resources pre-dating this period (e.g., hydro in the Pacific Northwest). The higher rates in the 1990s was a key driver for states that became deregulated. It is noteworthy that regulated states saw steadily increasing rates, possibly due to lags in cost increases as compared to deregulated states.
3. **Deregulated states respond more to natural gas price changes.** Electricity costs in deregulated states are impacted more by natural gas prices than costs in regulated states as natural gas generation in those jurisdictions tends to be the marginal resource most of the time. Figure 3 illustrates prices and volatility in response to natural gas price changes have been higher in deregulated states.

Deregulated markets are more responsive to natural gas prices, show higher volatility, and achieve some plant efficiencies when compared to regulated states,[25] but in the grand scheme, the data shows that there is little to separate them from regulated markets in terms of a price advantage to ratepayers.

[24] Stranded assets are investments which are made but which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return, leaving part of the investment unrecoverable and hence stranded.
[25] Deregulated states have seen some small benefits; Some plant efficiencies have been observed at about a 10% increase in output, NERB, "The U.S. Electricity Industry 20 years After Restructuring", 2015.

Figure 3: Average Cost of Electricity in Regulated vs. Deregulated U.S. States
(Retail Electric and Citygate Gas Price Nominal ₵/kWh)



Sources: National Bureau of Economic Research (NBER)

3.2 Risks of acquiring adequate capacity are not mitigated, instead markets drive up costs

Despite uncertainty regarding the benefits of deregulation, system planners continue to consider deregulation as a way to reduce costs in the face of increasing uncertainty in demand forecasts. Like the system planners dealing with deregulation in the 80s and 90s[26], today's planners hope to shift the risks inherent in procuring generation away from themselves and onto investors and the market. While system planners are not exposed to the financial consequences of these risks, they are still held accountable for it by ratepayers and the government – a key motivator for minimizing any attribution of fault when rates increase.

This sub-section examines the risks inherent in procuring generation, how these risks shift between investors and system planners under different market models though are ultimately borne by ratepayers, and how long-term contracts provide an avenue to reduce costs to ratepayers.

3.2.1 Risk is an important determinant of costs for achieving long-run efficiency

The risks involved in planning for future demand and investing in future capacity are central to a discussion of long-run efficiency. Generation capacity is the largest driver of electricity system costs[27] and procurement risk is a large determinant of these costs, for several reasons:

1. Supplying capacity for the future means investing in large, multi-year capital projects;
2. Forecasting future demand is difficult because the inability to store electricity results in a lower margin of error, where the consequences of getting it wrong could be blackouts; and,

[26] Such as IESO, PJM, ISO-NE, etc.
[27] Ontario generation costs represent approximately $15B of the $22 B total system cost.

3. The uncertainty in electricity demand over the long-term can greatly impact the cost of capital, and therefore the financial viability of these investments.

Table 2 highlights the two types of procurement risks: planning and investor.

Planning risk occurs when procured capacity is less than or more than necessary. If capacity is under procured, reliability will be impacted, and the risk of load shedding or blackouts will increase. If it is over procured, higher than necessary costs may have to be incurred. Planning risk is borne by system planners and consumers.

Investor risk occurs when revenues are inadequate for suppliers to make a sufficient return on investment over the lifetime of the plant. It results in closures of existing generation capacity earlier than planned life (stranded assets), or new entrants not entering the market. This risk is borne by investors and consumers.

Table 2: Planning and Investor Risk

Risk	Definition	Implications
Planning	Supply and demand mismatch may result in under- or over-procurement	Accurate forecasting by system planner is integral
		Impacted by many exogenous factors
Investor	Investors may not recover investments	Investors have demand uncertainty and high cost of capital
		Higher investor risks requires higher returns, leading to higher costs

Source: Cramton et. al., Strapolec Analysis

3.2.2 Planning and investor risks cannot be eliminated

Planning and investor risks are inherent to long-run efficiency and can be shifted but not mitigated, i.e., the likelihood of the risk occurring, along with the commensurate increase in cost to the system, cannot be materially reduced. As a result, while risks can be shifted from planner to generator and vice versa, the costs in the end will still be borne by the consumer.

The primary lever for shifting these risks is the duration of the procurement contract, as discussed below:[28]

- Contract duration determines risk: In the case of *short-term contracts*, the planning risk (i.e., the risk for the planner of forecasting demand over a short horizon) is low, while the investor risk (i.e. to take the risk of investing in a capital project without long term demand security) is high. In the case of *long-term contracts,* the planning risk is higher (i.e., the planner will have to forecast demand in the long run), while the investor risk is low (i.e., since returns are more or less guaranteed)

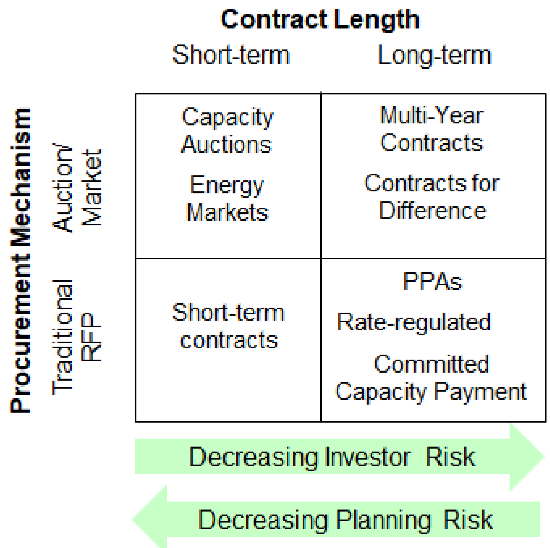
[28] Cramton et al., “Capacity Market Fundamentals”, 2013.

- System managers shift risk: Electricity system managers use short-term and long-term electricity procurement contracts as mechanisms to shift risk, but not mitigate it. By picking one type of contract over another, the risk is shifted from the planner to the investor and vice versa. The sum of the planning and investor risks are equivalent in an efficient market. The change is in who carries the risk.
- Ratepayers carry the costs: Risks have associated risk premiums, which is the cost of tolerating the risk. Notionally, the risk premium is borne by either the investor or the planner, but in reality, the end consumer bears the cost of the risk premium via their electricity bill.

3.2.3 System managers leverage different market models to shift risk

Market models provide system managers with the procurement vehicles to acquire capacity, vary contract duration, and shift risks, as illustrated in Figure 4.

Figure 4: Competitive Contracting Mechanisms Framework



Source: Strapolec Analysis

- **Short-term contracting:** All market models can provide short-term contracting mechanisms (typically 1 year),[29] but the specifics differ between energy markets, capacity auctions, and short-term contractual agreements between planners and generators. [30]

- **Long-term contracting:** Hybrid or regulated market models typically provide longer-term contracting mechanisms (typically 15-20 years). Mechanisms include Committed Capacity Payments, Power Purchase Agreements (PPAs), Multi-Year Contracts and Contracts for Difference (CfD) to create long term contractual agreements between planners and investors.[31]

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[29] Some capacity auctions have options for multi-year contract, e.g. ISO-NE, NGESO (UK grid operator).
[30] The capacity auction is the primary option being explored and developed to procure future capacity in Ontario. This document illustrates the characteristics of short-term contractual arrangements with capacity markets as an example.
[31] PPAs, rate regulated, fixed rate contracts, and committed capacity payments have been used to procure a majority of Ontario's assets. Committed capacity payments, like the ones used in procuring Ontario's gas plants,

3.2.4 Long-Term contracts can be advantageous in reducing risk premiums and costs to consumers

System planners use both short-term and long-term contracts to manage procurement risk. However, long-term contracts have an advantage as they can reduce the risks and costs to the consumers. Figure 5 shows the differences in procurement risk using the predominant mechanisms for short- and long-term contracts in Ontario (i.e., capacity markets and committed capacity payments), and outlines the advantage provided by long term contracts.

Figure 5: Implications of Contract Length

	Short-term Contracts	Long-term Contracts
a	Short-term contracts lead to lower planning risk	Long-term contracts lead to lower investor risk
b	Risk is shifted to investors	Risk is shifted to operators
c	Ratepayers bear the cost of increased investor risk premiums	Operators can lower risk premiums and reduce the cost for ratepayers

Source: Cramton et al., Haririan M., IESO, Strapolec Analysis

Short-Term Contracts: Typically, a capacity market means moving to shorter-term procurement contracts which provides planners with greater flexibility. Support for short-term contracts in Ontario has been influenced by the province's experience with long-term contracts. Over the last decade In Ontario, long-term contracts coupled with flat demand growth resulted in an overcapacity situation.

Long-Term Contracts: By comparison, longer-term contracts, involving committed capacity payments are considered less flexible, yet provide investors with demand certainty based on an effectively guaranteed price. Unlike short term contracts, investors can guarantee their return on the asset as long as the facilities can operate. This results in lower investor risk by allowing them to build capacity using lower risk premiums for the cost of capital.

Short-Term Contracts: Some proponents believe planning risk can be reduced by moving to a capacity market.[32] By providing greater flexibility to planners, capacity markets reduce planning risk but do not mitigate total risk. Investors must price the increased risk that is associated with the shorter-term contracts.

Long-Term Contracts: Committed capacity payments do not mitigate total risk either. However, they do help to shift the risk from the investor/generator to the planner resulting in decreased investor risk and increased planning risk. Planners now must rely on accurate demand forecasts over the long-term. Meanwhile, if investors can keep their

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are used as a basis to discuss long-term contracts because they directly contrast with capacity markets. While other types of long-term contracts like PPAs work in slightly different ways (e.g. on a $/MWh basis) the discussion remains valid for them as well.

[32] E.g. comments made during the IESO ICA stakeholder engagement, and MRP Update Meeting stakeholder engagements, 2019.

plants running well, they will continue to receive capacity payments, irrespective of demand fluctuations.

Ratepayers Bear Costs

Short-Term Contracts: Higher investor risk in capacity markets has a knock-on effect on ratepayers. The increased risk premium for investors means that they have a higher cost of capital that will translate into their proposed / bid pricing. These costs are then passed on to the consumers. In Ontario, higher capacity costs result in a higher Global Adjustment (GA) for ratepayer bills.

Long-Term Contracts: Higher planning risk in committed capacity payments may not result in the same increased risk premiums as would be the case for investor risk in capacity markets. Government and State-Owned Enterprises (SOE) can command lower risk premiums than generators so they can reduce the costs passed on to consumers.[33] This occurs because SOEs generally have their debt/equity guaranteed by the government, resulting in a lower cost of capital. Furthermore, SOEs can diversify their risk among a greater number of assets unlike a single generator. Therefore, SOEs have a greater capacity to absorb the risk of demand forecasts being inaccurate over the long run. By accounting for risk at a lower cost, SOEs can reduce the cost of electricity and present a better option for ratepayers.[34]

In the end, system planners are still responsible for developing the planning forecast which investors use to make go/no-go investment decisions. Therefore, investors have no greater knowledge than planners on how likely it is for demand to materialize and are unlikely to make better investment decisions. If the desired result is lower costs for the public, planners should use long-term contracts to procure the generation they know will be needed.

3.3 Capacity and energy markets are partial to fossil fuels

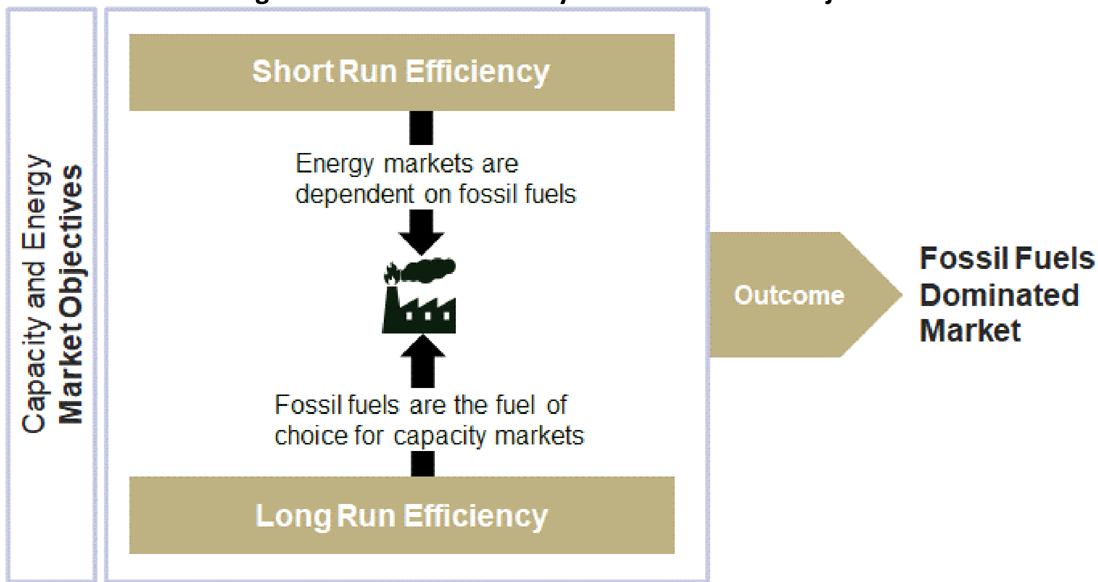
The cost structure and performance (flexibility and dependability) of fossil fuels makes them particularly well-suited to capacity and energy markets. This matchup is so intrinsic to the design of electricity markets that these markets would have trouble existing without significant fossil fuels in the supply mix. As society attempts to reduce emissions through a supply of non-emitting resources, this coupling presents challenges for system planners and policymakers alike.

The deeply symbiotic relationship between fossil fuels and electricity markets allows them to support the short-run and long-run efficiency goals of capacity and energy markets, as shown in Figure 6.

This sub-section examines the relationship of capacity and energy markets with fossil fuels and how this results in a market bias that favours fossil fuels over other forms of clean generation.

[33] Haririan, M., "State Owned Enterprises In A Mixed Economy", 1990.
[34] The recent contract review commissioned by the IESO highlighted the potential savings to ratepayers of government backed financing. IESO, "Contract Review Directive Report", 2020.

Figure 6: Fossil Fuels Ideally Suited to Market Objectives

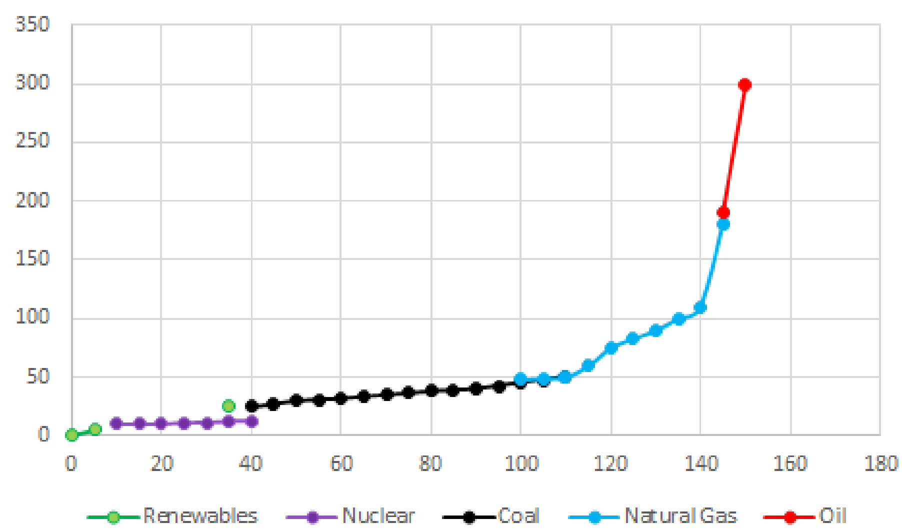


Sources: Strapolec Analysis

3.3.1 Energy markets require fossil fuels to function and meet short-run efficiency needs

The capacity and energy market model achieves short-run efficiency by ensuring that supply can meet demand and generators can be profitable. Energy markets work on basic supply/demand principles: As demand increases, more expensive generators are dispatched to supply the system, as shown in Figure 7. Generators further up in the supply price-stack que (i.e., more expensive resources) are called upon until electricity demand is fulfilled.

Figure 7: Typical PJM Generation Resource Supply Costs
(Price in $/MWh by Generation in GW)



Sources: B. Posenr, Accessed through Penn State "The Fundamentals of Electricity Markets", Strapolec Analysis

In energy markets, times of high demand are necessary for generators to be profitable since more expensive generators set the clearing price and allow other higher fixed cost and lower fuel cost generators to profit from the difference between the clearing price and their own marginal costs.

Typically, high marginal cost resources like fossil fuels have low fixed costs and higher variable costs. They can be called upon when demand increases and are not utilized when demand decreases since they do not have high fixed costs if they are unused (i.e., having extra unused capacity does not cost the system excessively).

On the other hand, lower marginal cost resources like non-emitting resources typically[35] have higher fixed costs and cannot respond well to daily demand variations.[36] These resources depend on periods of high marginal prices to earn enough revenue to offset their large fixed cost. Absent enough of these periods during the year (e.g., if there is a large supply of zero marginal cost renewables) then these resources will not be profitable.

Therefore, high marginal cost fossil fuels need to be present to make the market work effectively so that energy market prices are high enough for low marginal cost resources to recover their costs. Otherwise, market interventions, or a different type of market altogether, is needed for non-emitting resources to participate profitably.

3.3.2 Capacity markets require fossil fuels to meet long-run efficiency needs

Capacity markets utilize the auction mechanism to provide payment certainty to generators. This encourages generators to develop an adequate capacity to meet future electricity generation needs. Generators in capacity and energy markets receive two revenue streams:

- Capacity payments earned through auction ($/MW-year)
- Energy payments earned through real-time energy markets ($/MWh)

Notionally, generators can recover fixed costs through capacity payments and variable costs through energy markets. However, to be profitable, generators must ensure that they earn enough revenue to cover their total costs through a combination of the capacity and energy payments. Earning more in one market (e.g., capacity) can offset a lack of revenue in the other market (e.g., energy). It is the sum of the revenue streams against costs that ultimately determines financial viability. The design of the capacity and energy market is such that generators can vary their capacity market bids based on what they believe they could earn in the energy market and hence use capacity markets to hedge against the risk of low demand in the energy market.

Capacity markets are partial to resources with low fixed costs because these generators are the low bidders in a capacity auction, even if they have high variable costs. Resources with lower fixed costs need a lower guaranteed payment to compete in the market and so can bid low, clear the auction, and guarantee some portion of their revenue. On the contrary, resources with high fixed costs are disadvantaged because they are typically unable to get their fixed costs covered in capacity auctions and

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[35] Hydro is the only low marginal cost resource that can be called upon to respond to demand variations.

[36] If the electricity system relied on these resources to provide electricity when demand increases it would also have to absorb the fixed cost when demand is lower and generation is unused. Therefore, these are sub-optimal resources for providing capacity to deal with demand variability.

are exposed to the risk of becoming unprofitable if enough revenue is not earned in energy markets to cover total costs.

Natural gas-fired generators compete in capacity markets on the basis of their low fixed costs and can outbid others with lower capacity bids, as shown in Table 3, while non-emitting resources need to compete in the capacity market with their much higher fixed cost. Therefore, typically, natural gas-fired generators win capacity auctions ahead of non-emitting resources.

Table 3: Cost Structure for New Generation in the U.S. in 2025 (in $2019 USD)

Cost Structure for New Generation in 2025 (in $2019 USD)									
	Capacity Factor	Fixed Cost			Variable Cost			Total Cost	
		$/MWh	$/MW-year	%	$/MWh	$/MW-year	%	$/MWh	$/MW-year
Gas Resources									
Gas - CCGT	87%	$ 11.19	$ 85,281	29%	$ 26.88	$ 204,858	71%	$ 38.07	$ 290,139
Gas - Peaker Plant	30%	$ 22.29	$ 58,578	33%	$ 44.33	$ 116,499	67%	$ 66.62	$ 175,077
Non-Emitting Resources									
Nuclear	90%	$ 72.59	$ 572,300	89%	$ 9.06	$ 71,429	11%	$ 81.65	$ 643,729
Wind - Onshore	40%	$ 39.95	$ 139,985	100%	$ -	$ -	0%	$ 39.95	$ 139,985
Solar	29%	$ 35.74	$ 90,794	100%	$ -	$ -	0%	$ 35.74	$ 90,794
Hydro	59%	$ 49.72	$ 256,973	94%	$ 3.07	$ 15,867	6%	$ 52.79	$ 272,840

Sources: EIA, Strapolec Analysis

Capacity markets confer another advantage to natural gas-fired generators, by providing them with a risk hedging mechanism for fuel costs. All dispatched resources have their marginal costs covered in the energy market provided there is enough demand. If natural gas is not dispatched it does not need to cover its variable cost (since the cost is not incurred) and is still able to cover fixed costs through the capacity market. The excess revenue generated in the capacity market hedges what natural gas-fired generators need to earn in the energy market, as shown in Table 4.

Meanwhile, non-emitting resources remain exposed to the risk of low fuel prices. Low fuel prices bring down the clearing price in energy markets and reduce profitability for non-emitting resources. Since capacity markets are not able to cover their higher fixed costs, non-emitting resources are at a disadvantage. All generation resources are subject to the risk of low demand. Table 4 shows that the risk premium is lower for natural gas-fired generators compared to non-emitting resources in a capacity market.

Table 4: Cost Structure and Risk Profile of Generation Resource Options

Resource	Gas	Nuclear/Hydro	Renewables
Cost Structure	Low Capital	High Capital	High Capital
	High Variable Operating	Low Variable Operating	Negligible Variable Operating
Risk to Profitability	Low Demand	Low Demand	Low Demand
		Low Fossil Fuel Prices	Low Fossil Fuel Prices
			Intermittency
Role in Market (w/o carbon tax)	Price Setter	Price Taker	Price Taker
Risk Best Balanced By	Capacity Markets	Long-term PPAs	Long-term PPAs & storage/gas backup

Sources: Mays et al, Strapolec Analysis

The consequences are that most non-emitting resources need some sort of subsidy to compete with natural gas-fired generators.[37] U.S. nuclear plant closures in particular have primarily been in regions where there are capacity markets. Some existing nuclear plants continue to be threatened with closure unless subsidies are provided (e.g., Ohio, ISO-NE). Meanwhile, renewables in U.S. capacity markets are mostly being procured through state mandates or generous subsidies. PJM is an example of a market that has seen little renewables growth due to a lack of subsidies and the prevalence of cheap natural gas.

3.4 Capacity auction design challenges have consequences

Electricity system needs are complex and designing capacity auctions to meet those needs is difficult. Intrinsic auction design limitations create three challenges. First, auctions define capacity as a uniform product, which leads to inefficiency since it means selecting between over-specification (picking winners) and setting broad principles (possibly not meeting the desired outcomes). Second, electricity has a complex, interdependent system of power plants, generators, transmission, distribution, end-users, etc., and optimizing one part of the system through an auction does not necessarily optimize the whole. Finally, auctions are dependent on an extended chain of principal/agent relationships whose interests must be satisfied, but information flow is slow and costly which complicates auction design and product definitions. As a result, capacity auctions can create undesirable outcomes.

This sub-section discusses why electricity markets are prone to over procurement, how they are unable to address many electricity system constraints, and why they are subject to the inefficient entry and exit of resources.

3.4.1 Auctions are prone to over procurement

System planners use an auction (demand) curve to communicate requirements and procure capacity, but the curve does not necessarily reflect consumer demand.

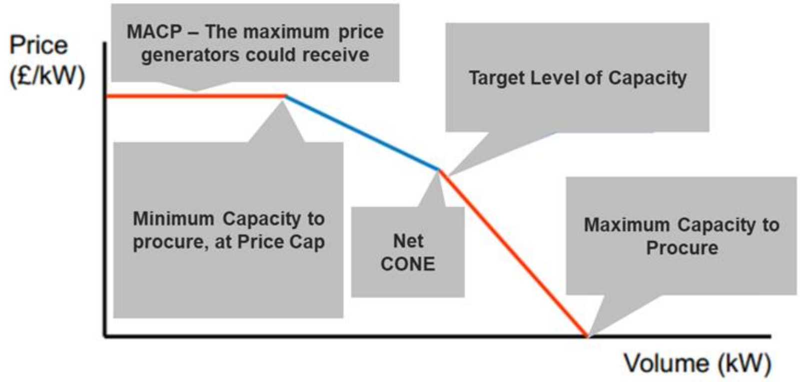
In a typical efficient market, the demand curve is a downward sloping line reflecting customer willingness to pay for different quantities of a good (for example, the improved reliability of service from the additional capacity). In capacity auctions, an administratively determined level of demand replaces consumer preferences and the curves are determined using various assumptions[38] such as target level of capacity, Maximum Auction Clearing Price (MACP), parametric multipliers, the shape of the curve, and Net Cost of New Entry (CONE)[39] as shown in Figure 8.

[37] Largely a function of geography (e.g., sunny locales can build more efficient solar that can compete with fossil fuels during the day).

[38] The modelling and calculations of these assumptions are often confidential, and the design of the curve is presented as a relative black box which presents separate issues around accountability and transparency.

[39] The Net CONE is the expected annual payment required by the generator from the capacity auction to justify proceeding with the development of a new reference resource which is the primary expected new entrant into the capacity market. Combined Cycle Gas Plants or Single Cycle Gas Plants are often the primary new entrant and chosen as the reference resource.

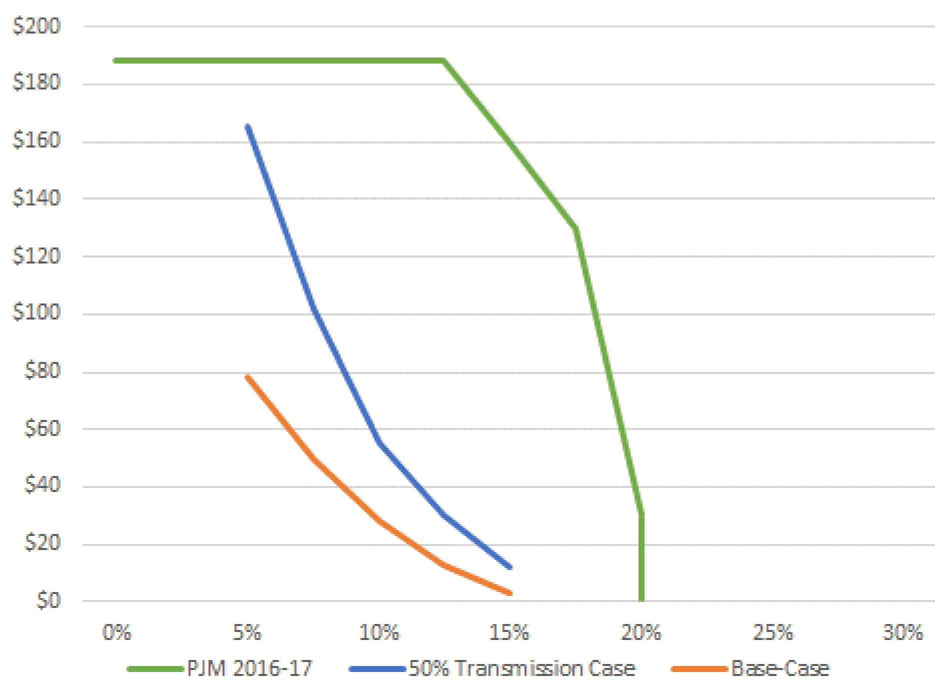
Figure 8: Simplified Auction Demand Curve for Illustration
(Price in £/kW; Volume in kW)



Sources: National Grid ESO, Strapolec Analysis

As a result, the auction curve designed by planners can value capacity differently from how consumers value it. Research shows that using a consumer value-based approach would result in substantially less capacity being procured and at lower costs, as seen in Figure 9.[40]

Figure 9: Administrative PJM Capacity Demand Curve Compared to Consumer Value-Based Curve
($/kW-Yr ICAP by Reserve Margin in %ICAP)



Source: Grid Strategies, Strapolec Analysis

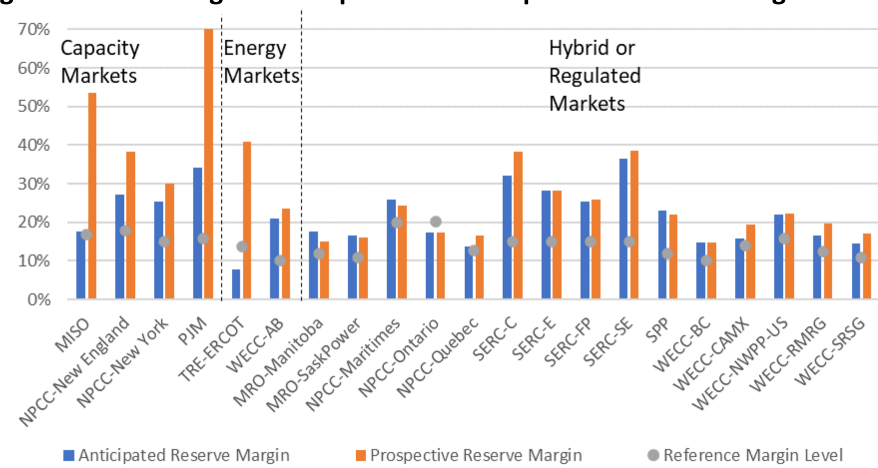
[40] Note how a curve that is lower and to the left (blue and orange lines) would intersect any supply curve at a lower price and capacity, resulting in less capacity procured for cheaper.

Since system planners must make assumptions impacting how much capacity to procure, over procurement can occur. For example, when planners:

- Overstate Net CONE by causing a shift of the demand curve up and to the right, due to outdated costs;
- Use a reference resource that does not represent most new entrants, and therefore misrepresents the Net CONE;
- Arbitrary reductions in modelled energy market revenue when calculating Net CONE; and,
- Arbitrary shifts rightward of the demand curve based on subjective risk assessments.

Evidence of over procurement can be seen in regions with capacity markets as they tend to have higher reserve margins, as shown in Figure 10. PJM, the New York ISO and the ISO New England (all capacity markets) have procured excess capacity at a combined cost of roughly $1.4 billion per year in these three markets.[41]

Figure 10: NERC Region Anticipated and Prospective Reserve Margins in 2024



Source: NERC, Strapolec Analysis

3.4.2 Auctions present an inability to address system constraints

Capacity auctions tend to be limited in their capability to ensure peak capacity, and do not account for other electricity system challenges. Auctions by design, must define a uniform product (i.e., capacity), and do not account for the other attributes a resource requires to provide electricity reliably to consumers. Once capacity is awarded, the ISO expects that it will be available when needed. However, generators do not always have control over the reliable provision of electricity due to other electricity system constraints:

- **Fuel security**: Ensuring fuel is available for resources to generate electricity depends on the supply chain of the respective fuel. Capacity auctions have not accounted for the risk that a generator may not deliver energy due to the lack of fuel. For example, PJM and the ISO-NE have experienced periods of extreme weather which have resulted in tightened natural gas supplies,

[41] Grid Strategies, "Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform", 2019.

posed a reliability risk and required out of market actions to access otherwise unavailable resources.[42]

- **Ancillary services**: Different resources have varying abilities to provide ancillary services (e.g., ensuring power quality by maintaining frequency, regulating voltage), but capacity auctions do not differentiate between the type of capacity that is contracted. For example, in California, large amounts of solar energy in the supply mix increase the need for flexible resources as the sun rises and sets (e.g. natural gas-fired generation, storage).
- **Transmission capacity**: Delivering electricity from generators to consumers requires infrastructure, and that comes at a cost, especially since transmission systems must account for the total capacity of a resource not just average capacity. These cost implications are not funded through capacity auctions and require the addition of a separate mechanism to ensure adequate supply, which doesn't always achieve desired objectives.[43] For example, in Germany, inadequate transmission capacity is limiting renewables in the north of the country because they can't deliver to load centres in the south (where most of the demand is), contributing to negative prices, curtailment, and Germany paying foreign wind farms to shut down so the renewable resources in Germany's north can export.[44]

3.4.3 Auctions create inefficient entries and exits

The auction clearing price is an investment signal for new entry and as prices increase. However, developing new infrastructure can take longer than anticipated and the retirement of resources can happen early. Furthermore, the presence of excess capacity in the market could depress prices and be a disincentive to the desired type of new generation

As an example, in the UK, capacity auction prices have continued to be low and have not incented much new generation to enter the market. This occurred in two ways:

- **Inability to incent new non-emitting generation:** Despite policy objectives to close all coal plants and reduce emissions, coal plants continue to participate in the market and are forced off only due to legislated timelines. By 2017, not a single new generation plant had been incented; and,
- **Inability to incent new reliable peaking generation:** While the UK has more than enough capacity on average, it does not have enough reliable peaking capacity. The capacity market should be able to incentivize new reliable peaking generation. However, in spite of tightening supply and demand on certain occasions, capacity market prices remain too low to incentivize new peaking capacity.

3.4.4 Case study from New England

The challenges of utilizing capacity auctions for the electricity system can be summarized in the experience of ISO-NE, which has witnessed several failings of a capacity market:

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[42] ISO-NE retains Mystic 8 & 9 plant, which has a dual fuel capability (natural gas and oil) that would otherwise be retired.

[43] Locational marginal pricing can account for transmission limitations by providing higher capacity prices in transmission constrained locations, but the cost of transmission is not explicitly considered or funded through the capacity market.

[44] Greentech Media, "Germany's Maxed-Out Grid Is Causing Trouble Across Europe", March 31, 2020.

1. **Over procurement:** Reserve margins are well above 20% for the next decade while the reference level is 18%, indicating excess procured capacity and therefore, excess costs.
2. **System challenges:** Gas pipeline constraints have left the ISO-NE with fuel insecurity in times of extreme weather. It has forced them to take out-of-market actions to retain resources that were intended to be retired. Despite taking several costly response measures, the ISO-NE has been unable to address some of the energy infrastructure constraints through electricity markets. While pipeline development is incentivized by long-term contracts that are committed to only by gas heating utilities, they are too risky for electric utilities.
3. **Inefficient entry and exit:** Over 2,500 MW of generators retired in 2018, while the ISO-NE had procured less capacity than needed in the Forward Capacity Auction (FCA#8) for the 2017/2018 period. This results in price volatility and reliability risk. The ISO-NE acknowledges that the imperfect coordination of entry and exit may lead to constraints and shortages.

Even for mature capacity markets, there are no clear solutions to the issues inherent in auction design.

3.5 Markets have been unable to allow for public policy

Markets look to drive costs down by selecting the lowest cost inputs. In the electricity system, the lowest cost input is typically natural gas-fired generation, as previously noted. However, to fight climate change, many nations and states are looking to reduce emissions through ever-stricter emission targets. This requires non-emitting resources that are more costly than natural gas-fired generation. The two objectives are at odds, a fundamental reason for questioning the utility of the electricity market mechanisms being considered for Ontario.

This sub-section reviews: the societal significance of electricity; the need for responsive integrated public policy responses; the tension between markets and other policy objectives; and, the mechanisms typically used to mitigate these challenges. The sub-section concludes with a discussion of likely outcomes from a market approach and implications of a grid dependent on natural gas-fired generation.

3.5.1 Electricity procurements must respond to public policy

Maintaining a robust and reliable electricity system for Ontario represents a $20B plus annual cost to ratepayers. This has significant impacts beyond the generation and consumption of electricity including:

- **Economic impacts:** The capital and operating funding of generation assets provide jobs and impact both domestic and foreign economies.[45] The final cost of electricity as an input for businesses affects their competitiveness in global markets.
- **Industrial policy benefits:** Governments can choose to support certain industries representing significant economic, environmental and/ or societal benefits. As an example, an industrial policy supporting a Canadian hydrogen fuel economy would impact the supply mix.
- **Energy security and independence:** Dependence on a single fuel source or on other jurisdictions for fuel related to electricity generation represents a significant risk. As an example, Europe's dependence on Russia for natural gas underscores the economic and environmental impacts that critical fuel shortages can have on a country.
- **Innovation:** The continuous growth and evolution of the electricity system requires ongoing innovation that is directed at reducing costs, emissions and related wastes.

[45] Depending on the domestic content of the resource.

- **Emissions consequences:** The climate impacts of continued use of fossil fuels are especially significant given the reduction targets set both at the federal and provincial levels.

These considerations are becoming ever more relevant to Ontarians and underscore the inextricable links between electricity supply and the public interest requiring a coordinated public policy response.

3.5.2 Markets clash with climate policy imperatives

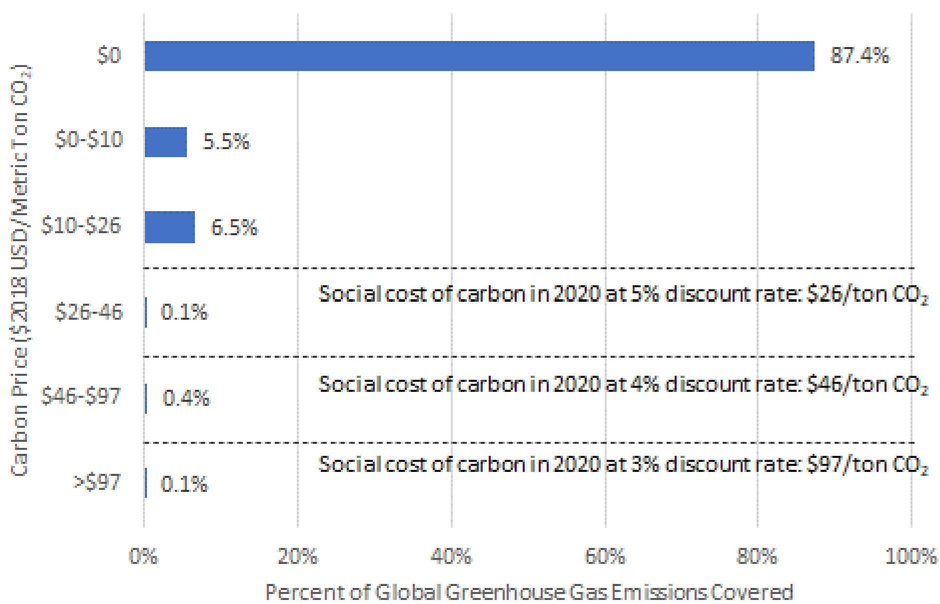
Around the world, electricity markets alone have not been able to meet the ambitious emission reduction goals that are progressively being considered an important policy goal around the world. The low cost of natural gas-fired generation coupled with a market that selects the lowest cost option mean that fossil fuels remain a mainstay in the supply mix. This has resulted in additional in and out-of-market mechanisms to achieve emission reductions.

3.5.2.1 In-market mechanism: carbon pricing is not working

In theory, a carbon price, an in-market mechanism, could elegantly reduce emissions if all the external costs of emissions from fossil fuels were included in the market cost.

In practice, carbon prices have failed to achieve public and industrial acceptance and have been unable get high enough or cover enough sources of emission to meaningfully address the social cost to the environment. 87% of global emissions are not subject to and face no carbon price and less than 1% are priced at even the lowest estimate of the social cost of carbon emissions, as shown in Figure 11.[46]

Figure 11: Comparison of Social Cost of Carbon and Carbon Prices Faced by Global GHG Emissions
(% of emissions that fall into cost category)



Source: Jenkins, Strapolec Analysis

[46] For comparison the UN "Special Report on Global Warming of 1.5 °C" estimated that a carbon price of $135–$6,050/ton (US$2010) is needed by 2030 to achieve warming below 1.5C.

For Ontario to achieve its 2030 emission targets, the required carbon price is estimated to be $120-$210/ton.[47] A minimum of a $115/ton carbon price is needed to make the cheapest non-emitting resource (nuclear) competitive with natural gas.[48] Contrasting this with the present state, Ontario's (and Canada's) Output-Based Pricing System (OBPS) heavily discounts 80% of carbon emissions from fossil fuel resources,[49] while the U.S. RGGI market prices for carbon have remained below $10/ton.[50] Current carbon prices are much lower than necessary and are unlikely in the near term to approach the price levels necessary to make an impact.

3.5.2.2 Out-of-market mechanism: State policy distorting markets

Many jurisdictions are tackling the emissions challenge through out-of-market mechanisms such as subsidies for non-emitting resources or Renewable Portfolio Standards (RPS) that mandate an amount of non-emitting supply mix.

These resources are usually contracted through PPAs or other types of long-term contracts with developers (essentially subsidizing them at above-market rates). This is independent of the capacity auction mechanism, which these resources may also be eligible to bid into. However, subsidizing the capacity cost of these resources puts downward pressure on capacity auction prices and lowers the viable revenue for other resources. Subsidies reduce market incentives for new unsubsidized non-emitting resources to enter the market due to the artificial, or policy driven, cost disadvantage.

Attempts to reduce these distortions without addressing the fundamental market rules can lead to conflict and higher rates for ratepayers. In the U.S., the Federal Energy Regulatory Commission (FERC) has implemented rules to combat state subsidies for non-emitting resources and ensure a fairer playing field.[51] The rules prevent subsidized resources from competing in the capacity auction, but subsidized resources are being developed independently in response to state mandates. As a result, ratepayers effectively pay twice for capacity: Once through government subsidies, and again through the capacity auction.

3.5.3 Markets that result in natural gas-fired generation also have other impacts

As shown in the preceding sections, leaving capacity and energy markets to operate with as little regulation or intervention as possible will result in more natural gas-fired generation being procured. This may be a low-cost option in the short-term, but a natural gas-dependent electricity grid has several disadvantages:

1. **Price volatility:** Although natural gas prices have been low for the past ten years, history shows that could change. As additional natural gas-fired generation is used in a region, natural gas prices increase because of shared pipelines.[52] The EIA predicts the cost of natural gas for

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[47] Strategic Policy Economics, "Emissions and the LTEP", 2016.
[48] Strategic Policy Economics, "Renewables-Based Distributed Energy Resources in Ontario", 2018.
[49] Environment and Climate Change Canada, "Pricing carbon pollution for large industry: backgrounder", 2018.
[50] RGGI, "Allowance Prices and Volumes", 2020.
[51] By implementing the Minimum Offer Price Rule (MOPR), FERC is mandating that any subsidized resource must bid into a capacity auction based on their unsubsidized price, effectively nullifying the point of the subsidies provided to these resources, which need subsidies to be financed and built.
[52] PJM plans to add 30,000 MW of new gas capacity by 2027, S&P Global Intelligence, "Overpowered: Why a U.S. gas-building spree continues despite electricity glut", 2019.

electricity generation will increase by 27% from $2.86/MMBtu in 2019 to $3.63/MMBtu in 2030.[53] In addition, if there is more natural gas in the supply mix then any material increase in the natural gas prices will increase electricity costs for Ontarians. The IESO is forecasting marginal electricity costs to double in the next 20 years ($17 in 2020 to $36 in 2040) because there will be more natural gas in Ontario's supply mix.[54] North American natural gas prices are currently lower than prices in other parts of the world due to a lack of natural gas export facilities and greater support for fracking in the U.S. If additional export facilities are built there will be upward pressure on North American natural gas prices.

2. **Delivery concerns:** Under certain conditions (e.g., extreme weather events), the delivery of natural gas can be interrupted and can impact electricity reliability. This happened with the 2014 Polar Vortex in the Northeast U.S. affecting in particular PJM and ISO-NE as both are dependent on natural gas.[55,56] Along with New England, Ontario was also impacted activating what is normally higher cost oil-fired generation, but the price of natural gas was so high that it made oil-fired generation economic.[57] Constrained supply in cold weather also leads to greater price volatility as previously mentioned.
3. **Commitment to emitting resources:** Markets that incent natural gas-fired generators will mean higher emissions for the 20 to 40-year economic life of the facilities.

3.6 Implications for Ontario

This preceding analysis illustrated how a capacity and energy market model for procuring generation is incompatible with several electricity system constraints and societal needs. Markets are inherently biased towards natural gas-fired generation. In turn, this results in higher emissions and higher planning risk that mean higher costs for ratepayers and conflicts with the objectives of other public policies like climate. Collectively, these factors clearly indicate that capacity and energy markets are a less compelling option for Ontario.

Ontario electricity system already has large amounts of low-carbon hydro, nuclear and renewable resources making it one of the cleanest grids in North America.[58] Shifting to more natural gas-fired generation will economically harm Ontario's domestic clean energy supply and unnecessarily increase dependence on foreign sources of energy.

[53] EIA, Annual Energy Outlook 2020, 2020.
[54] Part of this increase is also caused by many of Ontario's resources coming off long-term contracts.
[55] New England saw average natural gas and electricity prices in January 2014 go up by over 5 times than in the preceding months, ISO New England, "Oil inventory was key in maintaining power system reliability through colder-than-normal weather during winter 2013/2014" (ISO Newswire, April 4, 2014).
[56] In PJM, natural gas prices reached over $100/MMBTU in January 2014, while average wholesale electricity prices reached over $600/MWh, PJM, "Operational Events and Market Impacts January 2014 Cold Weather", May 9, 2014.
[57] Luft, Gallant, "Polar Vortex almost generates a profit for electricity exports from Ontario", 2014
[58] Over 90% of Ontario energy demand was met with non-emitting resources in 2018 and 2019. For comparison, California, which has some of the most aggressive emissions targets in North America still meets about 30% of net energy demand with fossil fuels. IESO, CAISO.

Canadians recognize the importance of tackling climate change at the global level and are increasingly supportive of climate action[59] [60] Yet, Ontario's pro-natural gas-fired generation policies will leave the province with a higher emission grid for the 20 to 40-year economic life of these facilities. A future change in legislation such as a much higher carbon tax or a ban on natural gas generation will leave Ontarians paying the bill either directly or indirectly.

In summary, electricity markets, as currently proposed, do not work well for Ontario:

- Procuring generation through short-term capacity markets will raise risk premiums and cost for ratepayers;
- The capacity auction is not a true free-market mechanism as it is administratively designed and difficult to get right. This presents a number of challenges for the electricity system, including, the inefficient entry and exit of resources requiring additional mechanisms to address system constraints;
- Markets will naturally lead to more natural gas procurement, and hence greater emissions than produced currently; and,
- A grid dependent on natural gas-fired generation is undesirable for other reasons as well, e.g., greater energy insecurity, less desirable economic benefits and assets that will likely become stranded in the inevitable shift towards non-emitting generation.

[59] Strategic Policy Economics, "2020 Green Ribbon Panel Report", 2020.

[60] Climate Action Tracker, "China going carbon neutral before 2060 would lower warming projections by around 0.2 to 0.3 degrees C", September 23, 2020.

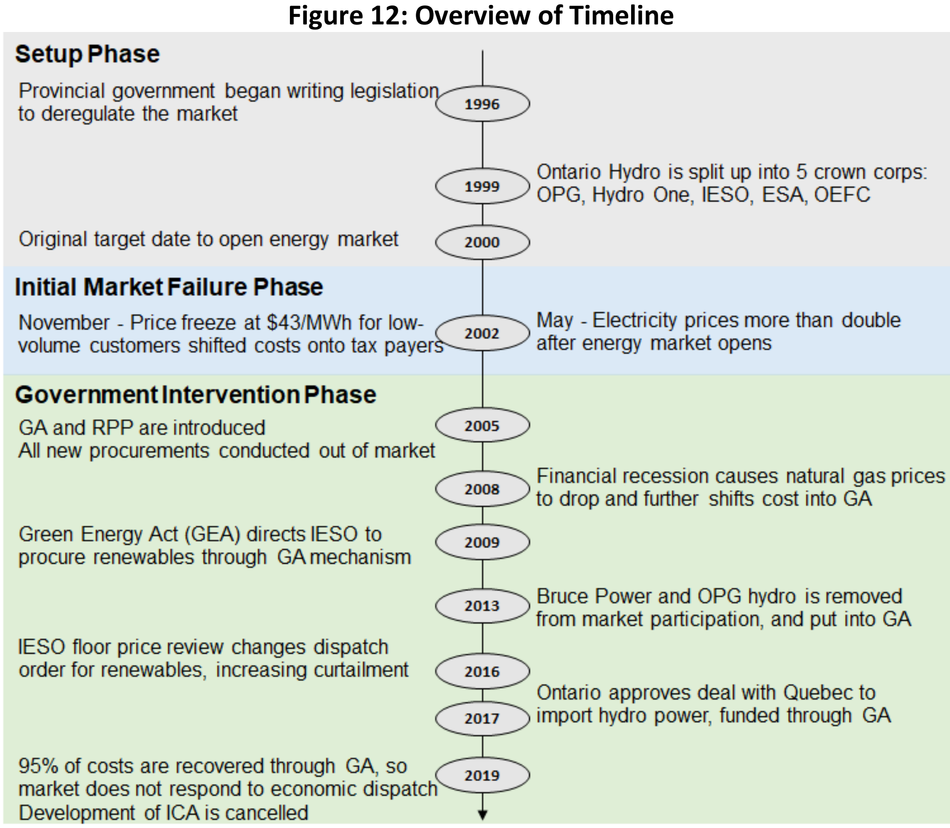
4.0 Ontario's history with markets

Ontario has a long history of operating an electricity market. This section explores how Ontario's market has worked to date.

Ontario's experience with electricity markets began in the 90s when government looked to deregulation in the U.S. as offering a solution for high cost of generation in Ontario. However, problems in energy market design became apparent from the beginning and despite attempts to address these problems, a lack of new capacity and higher costs occurred, and the market eventually failed. Ontario gradually added non-market mechanisms to mitigate some of the issues, creating a hybrid market that includes long-term PPAs, a Global Adjustment (GA) mechanism that covers most fixed costs and a Regulated Price Plan (RPP) to recover total generation costs from small retail consumers. Ontario's energy market now purposefully acts primarily as a physical resource dispatching system. The individual generators' energy market revenues are netted out from their contractually guaranteed revenues. Ontario's GA mechanism is a highly contentious legacy today.

The evolution of Ontario's markets over the past three decades is summarized in Figure 12. This section reviews the conditions present when the decision to pursue deregulation was made. This includes a description of how the market failure occurred and how the resulting high costs were managed. The analysis considers the many initiatives pursued to rectify the market failings, including how little energy is price-exposed by trading in the market today. The section concludes with a discussion about Ontario's full circle return to deregulated markets via its proposed capacity auctions.

Figure 12: Overview of Timeline



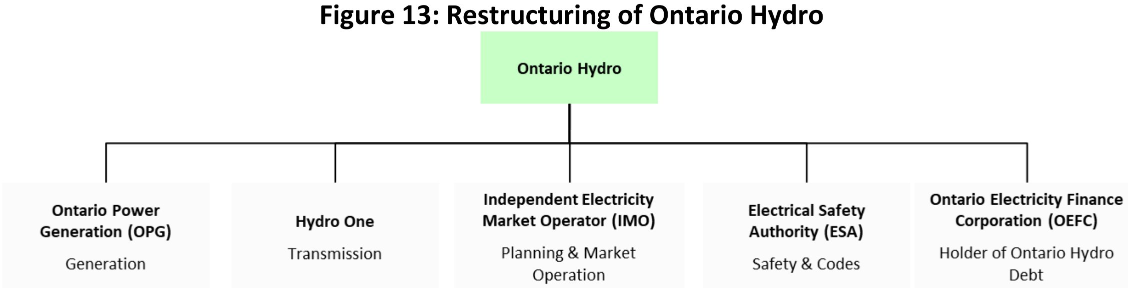
Source: Treilbock and Hrab 2005, Luft 2019, IESO, Strapolec analysis

4.1 Ontario's market setup

The financial challenges faced by Ontario's electricity system in the 70s, 80s and 90s figured prominently in the decision to bring energy markets to the province. Ontario Hydro had built out the province's electricity infrastructure[61] which led to a 30% increase in retail electricity prices, a shift perceived by ratepayers to be too high.[62] To protect Ontario consumers, the government felt compelled to intervene and in 1993 enacted a price freeze at $30/MWh.

Planning for a deregulated market began in 1996 as it became evident that the price freeze exacerbated Ontario Hydro's debt challenges by reducing its revenues and putting a considerable burden on the crown corporation. By 1999, Ontario Hydro's debt of $38.1B was one-third of provincial debt and 35% of Ontario Hydro's annual revenue went to paying down interest on the debt. Figure 13 illustrates the first step taken to deregulate the market and to restore the viability of the crown corporation's assets: Ontario Hydro was split into five separate entities by 1999 that still survive today.

Figure 13: Restructuring of Ontario Hydro



Source: IESO, Strapolec Analysis

However, simply restructuring Ontario Hydro was insufficient to address the cost issues facing the electricity system. A major objective of deregulation was to introduce an electricity market to ensure competition in electricity generation. The mandate to create the electricity market was given to the Independent Market Operator (IMO).[63]

OPG's monopoly on generation was recognized as one challenge to fostering an efficient market. The Market Power Mitigation Agreement (MPMA) was developed in response to this challenge. The agreement effectively set a revenue ceiling on OPG and disincentivized the use its monopoly pricing advantage. OPG was required to rebate customers if yearly Ontario-wide prices were above $38/MWh. This was known as the Power Mitigation Rebate (PMR). The MPMA was meant to be a temporary measure until OPG could be split up and privatized after the market was initiated, but such a split was never completed.

In May 2002, a year and a half later than originally planned, the IMO rolled out an energy market to achieve the objective to cost effectively and efficiently meet Ontario's electricity system needs.

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[61] At the time Ontario Hydro was Ontario's large vertically integrated utility.
[62] Treilbock and Hrab, "Electricity Restructuring in Ontario", 2005.
[63] The IMO was the predecessor to today's IESO.

4.2 Initial market failure

Soon after the opening of Ontario's deregulated market, prices rose, doubling from $30/MWh in May 2002 to $62/MWh by July, and reaching above $80/MWh by September. This was a shock to consumers as these prices far exceeded the historical 30% increase that had initially prompted a price freeze. There were several reasons for the price increases:

1. Prior to deregulation Ontario had under-invested in electricity generation capacity;
2. Investors lost confidence in Ontario's power sector as a result of the long delays in market opening and the continued public ownership of OPG and Hydro One; and,
3. Selected market rule and structure issues that created adverse effects (e.g., a rule that allowed for considerable price spikes when imports were required).

When Ontario faced a particularly hot summer in 2002, the first two factors led to an insufficient electricity supply at a time when resources in neighbouring jurisdictions were dealing with the same heat wave. As a result, Ontario consumers received frequent power warnings and advisories from the province's market operator. Under mounting political pressure, in November 2002, the government announced a retail price freeze at $43/MWh for low-volume customers. This out-of-market price freeze for consumers was implemented even though Ontario's market rates were similar to those in New York, New England, and Ontario's neighbouring U.S. states (currency-adjusted).

4.3 Subsequent government intervention

The government's retail price freeze intervention into the energy market gave temporary relief to low volume consumers. However, the market continued to operate in parallel. The costs of the difference between market prices and the frozen retail price were absorbed by the government's general finances and thus, ultimately borne by taxpayers. To address this situation, the government introduced new mechanisms which included:

- The RPP, retail rate plans for residential and small commercial customers who purchase electricity from local distribution companies, which provided stable and predictable pricing; and,
- The GA to collect the difference between the market energy prices and the total generation costs, such as the fixed costs of natural gas-fired generation plants. This provided an accounting mechanism to keep generators whole and a pricing mechanism that could be passed on to ratepayers.

The RPP sets rates to fully recover the total cost of electricity from ratepayers. In this way, the electricity system would be paid for primarily by ratepayers instead of taxpayers, and residential customers would be charged stable rates that do not fluctuate with the HOEP set by the market.[64]

Concurrently, the Ontario government decided to phase out coal-fired generation. This required new generation to replace the coal fleet. Given that the energy market was unable to incentivize new generation from 2005 to 2008, the Government undertook to procure generation outside of the market

[64] In 2017, the Ontario Government introduced a rebate for electricity consumers, which meant that the RPP no longer fully covered the cost of electricity for residential customers.

(using the GA mechanism). Specifically, it procured gas-fired generation capacity and contracted the restart of two mothballed nuclear units at the Bruce Power site.

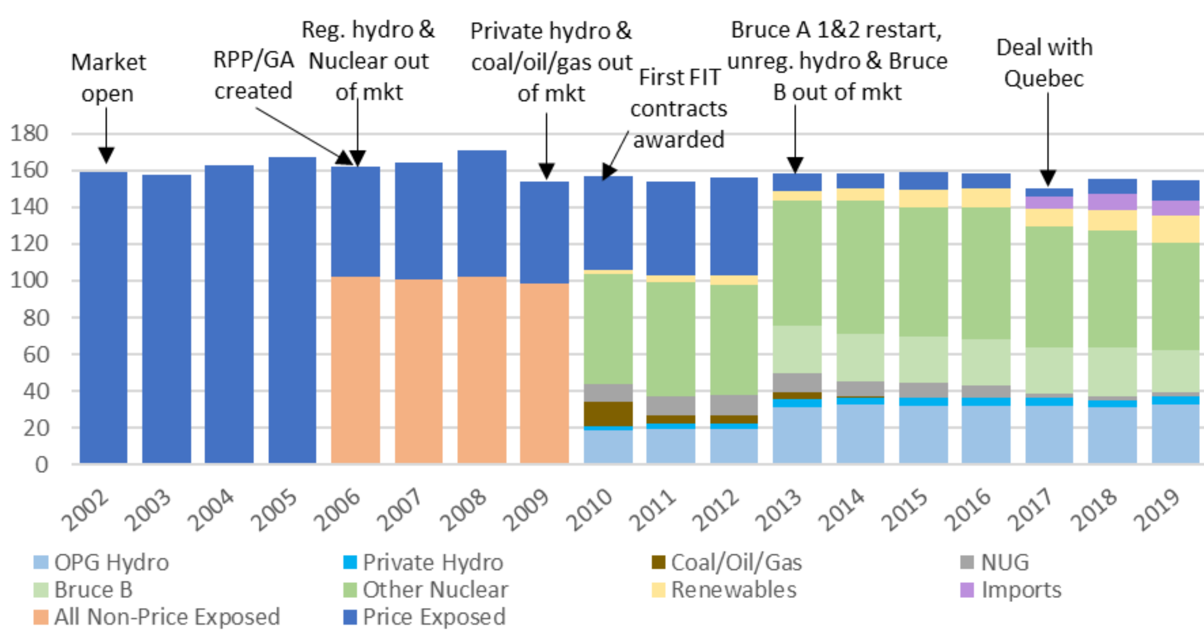
When the GA was first introduced in 2005, it resulted in a net credit to consumers due to the PMR, which was reimbursed by OPG to help reconcile financial accountings within Ontario's electricity market. However, in 2006, as generation costs increased, the GA on consumer bills started to become a minor charge.

Following the 2008 recession, the government regularly intervened in the energy market to address its electricity generation supply challenges. Four interventions involved significant amounts of generation being removed from trading in the market, as shown in Figure 14:[65]

1. OPG coal-fired generation and private hydro generation were contracted out-of-market in 2009 to sustain their financial viability as market prices declined due to low cost natural gas. [66]
2. The 2009 Green Energy Act (GEA) initiated a feed-in tariff (FIT) program for renewables as an out-of-market mechanism as the markets were incapable of supporting this policy.
3. In 2013, all of OPG's hydro and Bruce B's nuclear output that had been trading in the market was removed due to the ongoing decline in natural gas fuel prices. OPG supply was regulated and the Bruce B supply contracted.
4. Premium hydropower import arrangements with Quebec guaranteed prices in an out-of-market deal commencing in 2017.[67]

Figure 14: Price Exposed Electricity Supply in Ontario[68]

(TWh by Year)



Source: IESO, OPG, Treilbock and Hrab 2005, Luft 2019, Strapolec Analysis

[65] IESO, OPG, Treilbock and Hrab 2005, Luft 2019, Strategic Policy Economics Analysis.
[66] OEB, "Regulated Price Plan Price Report May 1, 2010 to April 30, 2011", 2010.
[67] Financial Accountability Office of Ontario, "Electricity Trade Agreement", 2018.
[68] Breakdown of the "All Non-Price Exposed" assets from 2006 to 2009 was not available in the sources consulted.

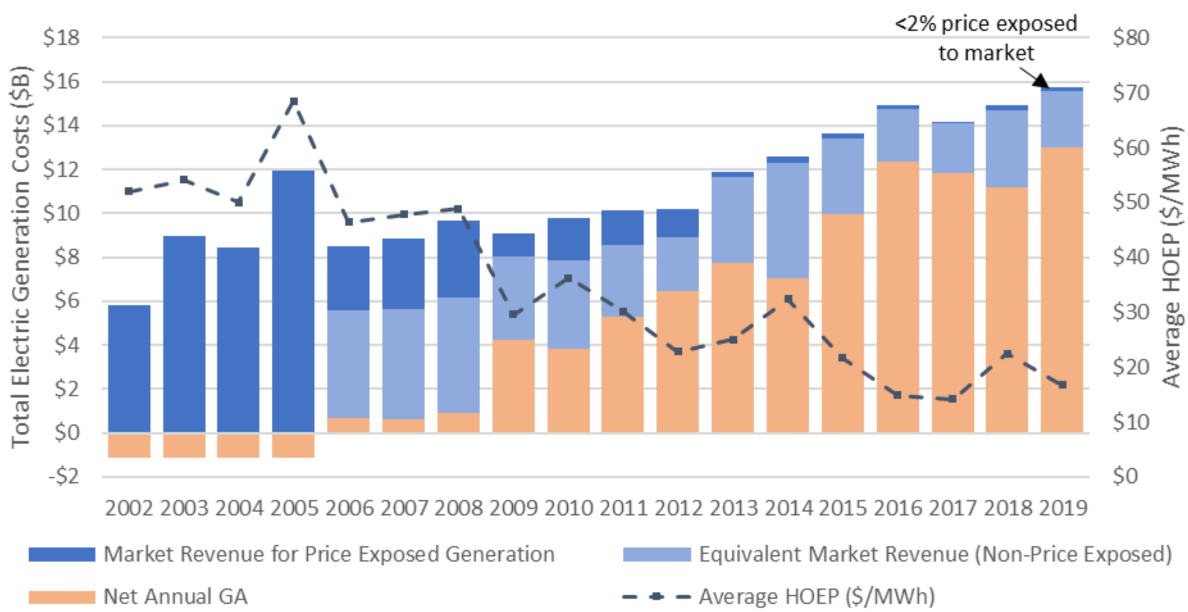
By 2019, only about 11 TWh (7%) of Ontario's energy supply was price exposed in the energy market.

These out-of-market government initiatives increased the costs covered by the GA which grew from a negligible correction factor on market prices in 2006 to represent the majority of the generation costs by 2019, as seen in Figure 15. Concurrently, HOEP determined from the Ontario Spot Market price for electricity dropped significantly due to the combined effects of the lower cost of natural gas, the oversupply of low-marginal cost renewables. However, a change in the HOEP only impacts the total cost of the price of exposed assets, while the greatest perceived impact is the shift in costs to the GA.

The GA, however, is no more than an accounting mechanism to reconcile total system costs with an allocated HOEP set by the market. This accounting practice increases the costs administered through the GA, i.e. shifting costs to the GA without changing the costs of electricity. This shift is caused by the accounting impact of a declining market price on the equivalent market price component of the non-price exposed assets (light blue area in Figure 15). As the actual costs of the assets are not impacted, the accounting allocation simply shifts from revenue for price exposed generation (light blue area) to GA revenue (orange area).

Figure 15: Share of Total Electricity Generating Costs

($B, $/MWh by Year)



Source: IESO, Strapolec Analysis

It is important to note the diminishing share of costs that are determined by Ontario's energy market. Over 98% of Ontario's generation costs are controlled through either regulation or contracts, and even the fixed costs of most of the assets that trade on the market are contracted. As a result, less than 2%[69] of the total system costs are actually price-exposed and influenced by the market (the dark blue area). The costs to ratepayers established by the regulated and contracted supplies are predetermined (sum of the orange and light blue areas).

[69] This is based on total cost of generation that is price exposed. Figure 14 shows 7% of total energy is price exposed and hence the difference.

These government interventions have fully transitioned Ontario's electricity market away from its intended function: to provide the most economic solutions for meeting Ontario's electricity system needs. Since almost all of the generation is contracted or rate-regulated, the related costs of generation are paid for and their marginal cost is zero or near zero. To ensure that generators are dispatched in the most economical order, the IESO imposes floor prices on offers into the market at a set price, which is dependent upon the type of low-emission resource. Hydro marginal cost is established by a production tax,[70] renewables and flexible nuclear costs are established by predetermined IESO parameters,[71] as is inflexible nuclear and inflexible hydro which offer in at negative $2,000/MWh, and are always dispatched first and rarely dispatched off, since they are costly to curtail.[72] The effects of this intervention were evident in 2017, when the IESO began curtailing significant amounts of variable renewable generation before curtailing flexible nuclear. Flexible hydroelectric capacity self-curtails based on energy market prices when the market price falls below the hydroelectric production tax. Effectively, flexible hydroelectric capacity is the first low emission generation type to curtail production based on low market prices during periods of low consumer demand.

Ontario now operates within a hybrid market that is essentially performing as a physical dispatching tool that is setting the price based on contracted and rate-regulated generation offers into the market. Those offers are either actual marginal costs or floor prices that reflects the order desired by the IESO to minimize electricity total commodity cost.

4.4 The IESO is pursuing an expansion of deregulated markets

The IESO launched the Market Renewal Program (MRP) in 2016 to overhaul the energy market and introduce the capacity procurement mechanism through the ICA.[73] The ICA was cancelled in the summer of 2019. During the ICA stakeholder engagement, stakeholders pointed out several issues with the ICA: it may not be appropriate for Ontario's market design; it may increase costs by shifting risks to investors; it is biased against large capital projects like hydro and nuclear; it favours natural gas-fired generation; and, it will likely result in higher emissions.[74] The capacity auction mechanism still exists as IESO is evolving the DR auction into a more broadly purposed capacity auction.[75]

Notwithstanding Ontario's previous history of failed electricity markets, it appears the capacity auction will become the IESO's primary procurement mechanism to meet system planning capacity needs.

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[70] Hydroelectric generation must pay a production tax (a gross revenue charge) to the government. This tax creates a positive marginal cost of production ranging from about $4/MWh for small hydro facilities to $14.4/MWh for the largest hydro facilities.

[71] Wind and solar offer in at negative $3/MWh while flexible nuclear (i.e. Bruce Power reactors) offers in at negative $5/MWh.

[72] Brattle Group, Modelling Ontario's Future Electricity Markets Revised Modelling Assumptions, report prepared for IESO Non-Emitting Resources Subcommittee, 2018.

[73] The ICA was forecast to bring the majority of the $2.2-5.2B savings of MRP over 10 years.

[74] IESO ICA Stakeholder Engagement, synthesized from public comments on the ICA High Level Design from Association of Major Power Consumers of Ontario (AMPCO), Capital Power, Canadian Manufacturers & Exporters (CME), and Power Workers' Union (PWU).

[75] The ICA was a complex IT project that required a business case and IESO board approval. In the middle of the process of making a business case, IESO cancelled the project. The decision to develop a much simpler Capacity Auction by expanding the DR auction did not require any board approval or oversight due to the lower capital spend.

5.0 The nature of demand and implications on procurement options

The previous section discussed how Ontario's varied supply mix has evolved in response to a number of market and policy driven factors. Since 2010, this supply mix has been pre-determined by the government and has not been well matched to Ontario's demand needs. The decision process for future supply procurements should consider the nature of the demand that must be satisfied to enable optimal solutions. This section explores how Ontario's future demand can be met by various supply options and the extent to which markets can be expected to adequately optimize that matching.

Electricity system demand comes in three forms: Baseload, Intermediate, and Peak. Cost-effectively satisfying all three requires an optimal mix of supply components, which experience shows are difficult to procure through markets. This analysis shows that capacity markets are good for procuring a "generically defined" capacity product. However, securing optimal, cost-effective solutions are difficult to achieve given the realities of the variability in demand – hourly, daily, and seasonal – and reliance on energy markets.

This section reviews the characteristics of these forms of demand, considers suitable resources to satisfy each, and uses simulations to demonstrate how electricity markets may perform in meeting Ontario's demand under various policy scenarios.

5.1 Demand has three distinct forms each with its own characteristics

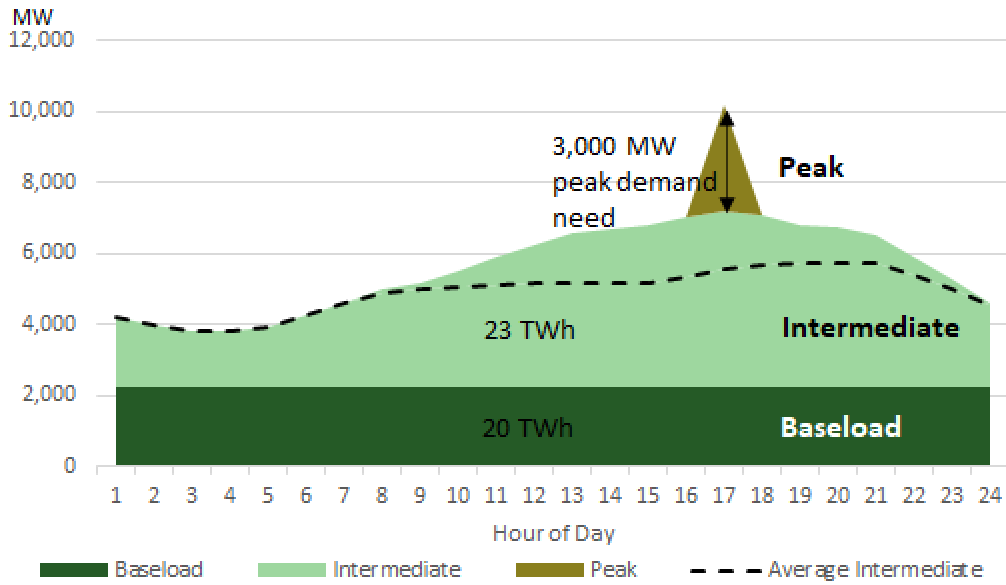
Demand for electricity varies daily reflecting business needs and residential consumption patterns, as well as throughout the year due to seasonal and weather conditions. To ensure that reliability, an important requirement of the electricity system, is achieved the IESO needs to ensure that supply is available to meet this fluctuating demand. Ontario has existing and committed resources that are expected to be available over the next few decades, specifically nuclear and hydro assets. The procurement question does not relate to the demand that those assets will supply, but to the rest of the unmet demand that will arise as supply contracts expire or when their end of economic life occurs. This change in the contracted or available assets surfaces a future incremental demand profile that will not be met by these aforenoted existing and committed assets but will have to be supplied through future procurement decisions to renew or replace those assets. There are three distinct forms of this future incremental electricity demand - baseload, intermediate, and peaking as shown in Figure 16.[76]

- **Baseload Demand:** Demand that is present always (or nearly always), 24 hours a day, 365 days a year. Ontario could have an incremental baseload demand need (above currently committed supply) of up to 2,250 MW or approximately 20 TWh.
- **Intermediate Demand:** Demand that is needed most of the time, but not the very long duration baseload nor the very short duration peak load. This form of demand can vary quite a lot day to day, season to season, and presents the most amount of variation for system planners. The average incremental demand (dotted line in Figure 16) is about 23 TWh throughout the year and almost 4,000 MW above baseload. However, intermediate demand can get even higher in late afternoon at approximately 5,750 MW above the incremental baseload.

[76] While the terms "baseload" and "peak demand" are defined in the NERC Glossary of Terms, as the minimum and maximum amount of power required in a given time, they are defined in this report as a means to clarify the intermediate form of demand.

- **Peak Demand:** Demand that is needed for a small fraction of the hours in the year, usually due to extreme weather (e.g. hot summer days causing most customers to turn their air conditioning units on or very cold winter days requiring more heating). About 3,000 MW is typically required to cover these extreme demand days. This does not include reserve supplies to accommodate generation equipment failures and for unplanned demand increases.

Figure 16: Average Daily Profile of Future Incremental Demand[77]
(MW by Hour of the Day)



Source: IESO, Strapolec Analysis

Based on the projected incremental demand, supply to satisfy each of the three forms of demand must be procured.

5.2 Each form of demand requires a different supply option

The motivation for characterizing demand in its distinct forms is to enable matching it with the optimal supply mix. Understanding the cost and system implications of matching demand with different supply resources can identify optimal options, as summarized in Figure 17.

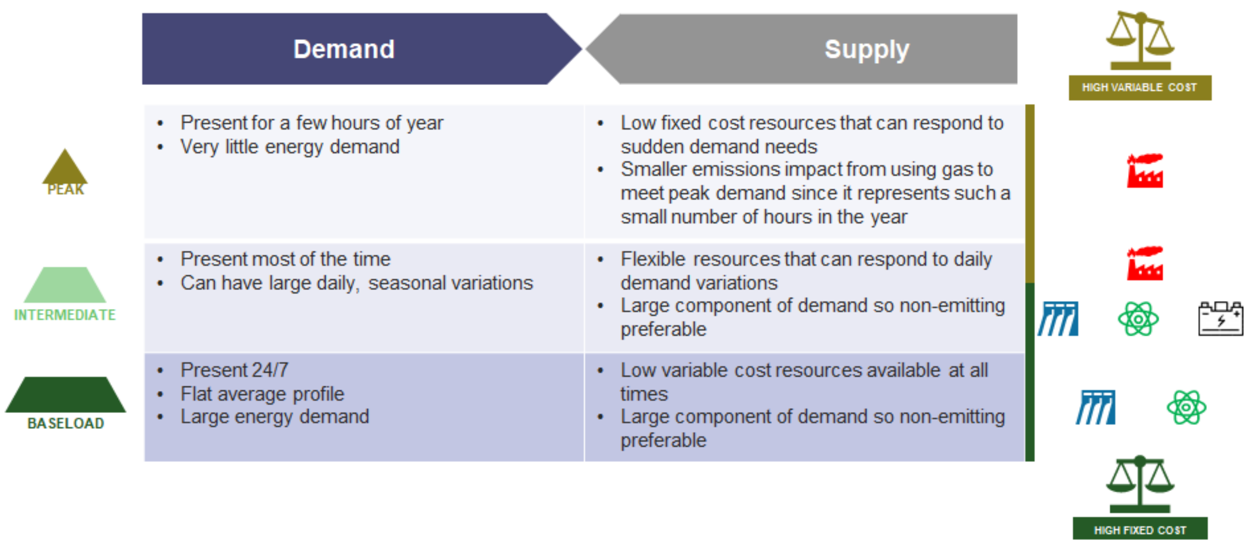
- **Baseload Supply:** Resources with a high fixed cost and a low variable cost (e.g., nuclear, hydro) are typically required to always be generating to maximize their economics and recover their fixed costs. Since baseload demand is relatively constant and does not require a resource to be flexible, highly capital-intensive resources such as nuclear and hydro generation are a good match.
- **Intermediate Supply:** Finding flexible resources to supply this demand poses the greatest challenge for Ontario, but also has the greatest number of options as a solution. Traditionally, this demand has been supplied by Ontario's low fixed-cost, high variable-cost natural gas fleet. In contrast, emerging supply resources, such as wind, solar, and storage, as well as the

[77] Chart is used to illustrate the three form of demand and shows assumptions and modelling results that will be discussed later in the section.

traditional hydro and nuclear resources, all have low variable costs and high fixed costs. These can be deployed to meet the daily variations of intermediate demand, but only moderately well. Solar and wind are intermittent, so they depend on the weather and geography. Hydro can effectively meet some of the variations of intermediate demand but is limited by the capacity of rivers and dams in the region which are also impacted by weather. Conventional nuclear assets in Ontario are being equipped with new technologies that provide additional flexibility, however these investments are most cost-effective when operating in baseload mode. All these resources can be paired with storage to improve their ability to meet intermediate demand, albeit with varying degrees of success and reliance on backup supplies.

- **Peak Supply:** Resources procured to meet these conditions are rarely called upon. These are assets that must be able to cost effectively sit idle for over 95% of the year. Peaking natural gas plants are the best match since their low fixed cost allows cost effective operations at low capacity factors.[78]

Figure 17: Demand and Supply Considerations for Each Demand Form



Source: IESO, Strapolec Analysis

5.3 Ontario electricity markets will only procure natural gas-fired generation

Competitive electricity markets generally favor natural gas-fired generation given their cost structure. To explore this bias, several supply scenarios were modeled to illustrate the competitiveness of different resources for meeting Ontario's intermediate demand via the proposed capacity and energy markets.[79] Supply scenarios for meeting peaks (and reserve margins) were not modelled as gas-fired peaking plants

[78] Note that operators must procure additional supply beyond the forecast demand to maintain reliability standards. This supply is called reserve margin and is not planned to be called upon except for in extreme weather events. Like the supply procured for peak demand, the reserve margin is supplied by assets that need to sit idle almost all the time. Therefore, the same types of supply would be suited for both.

[79] If gas is used to meet baseload demand it is assumed to be procured through the capacity auction. If nuclear is used to meet baseload demand it is assumed to be procured through long-term contracts and not through the capacity auction.

are the efficient supply option. Four broad scenario categories were explored as described in Section 2.0 and Table 5:

1. **Gas only:** Meeting all future demand needs with natural gas;
2. **Existing supply mix:** IESO's assumption that all existing wind & solar supply will be re-procured;
3. **Nuclear DES:** Using nuclear and storage for intermediate supply; and,
4. **Renewable DER:** Combined solar and wind paired with storage.

Table 5: Electricity System Scenario Overview[80]

Scenario Category	Scenario #/Name	Scenario Description		
		Baseload Supply	Intermediate Supply	Other Features
Gas Only	1 - Nominal	Gas	Gas	Meeting incremental demand with 100% gas supply
Existing Supply	2a – Gas Baseload	Gas	Gas, wind, solar	Renewing existing wind & solar supply, set to expire in 2035. This will create excess intermediate renewable supply which will not be curtailed and will instead reduce gas baseload.
	2b – Nuclear Baseload	Nuclear	Gas, wind, solar	Renewing existing wind & solar supply, set to expire in 2035. This will create excess intermediate renewable supply which will be curtailed because of the nuclear baseload.
	2c – Scaled Down	Nuclear	Gas, wind, solar	Wind and solar capacity is decreased until either are profitable. Same as scenario 2b, except letting some existing wind and solar expire. This will limit the need to curtail which will improve renewables utilization, while increasing gas supply which will raise energy market revenues.
Nuclear DES	3 - Nominal	Nuclear	Nuclear, gas, storage	Nuclear Distributed Energy Storage (DES) system sized to meet most demand, with gas supplying the rest.
Renewables & Storage	4a – Nominal	Nuclear	Wind, solar, gas, storage	Combined 50/50 wind and solar DER storage system sized to meet most demand, with gas supplying the rest.
	4b – Scaled Down	Nuclear	Wind, solar, gas, storage	Wind and solar capacity is decreased until either are profitable. Same as scenario 4a, but procuring less wind & solar to limit curtailment, while increasing gas supply which will raise energy market revenues.

Source: Strapolec Analysis

The sub-scenarios are based on the assumed baseload supply mix (e.g. gas vs nuclear) and the level of renewables penetration that could yield profitable results.

5.3.1 Results and implications

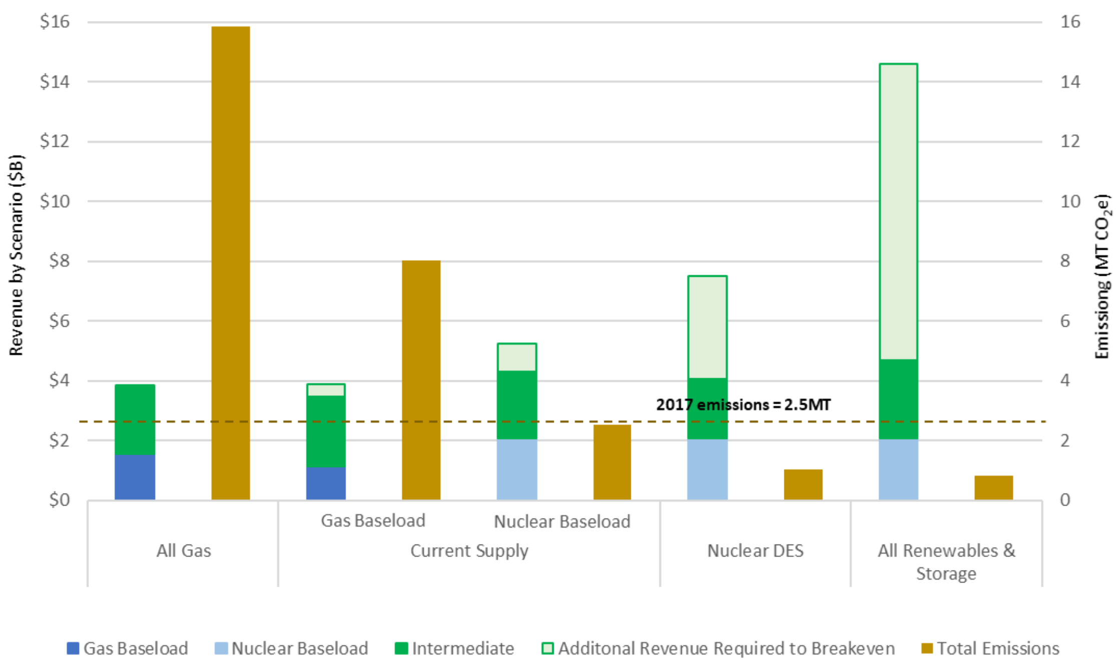
The modelling approach addressed two elements: a capacity market which assumed natural gas would set the market clearing price; and, a full-year 8,760-hour model reflecting actual demand situations in Ontario in order to compute the hourly market clearing price. The scenarios and sub-scenarios were modelled to determine the revenue that each resource could generate from the capacity and energy markets, respectively. These revenues were then compared to costs[81] to determine if the resource was profitable and would be built. If a resource is not profitable in any given scenario, the revenue required to make it profitable was calculated.

[80] Scenario 3 and 4 are based on the modelling assumptions used in Strategic Policy Economics' "Distributed Energy Resources in Ontario: A Cost and Implications Assessment" report, 2018.
[81] EIA 2020 costs were used and converted to $CAD.

Results show that all non-emitting resources are unprofitable and require subsidies in all cases, as indicated by the amount of additional revenue required to break even in Figure 18.[82] The underlying cause of the results is two-fold: (1) there is a direct policy conflict over lowering cost versus lowering emissions since natural gas is the lowest cost option, but the highest emitting; and, (2) to be profitable, natural gas-fired generation needs to operate at high capacity factors and set a high enough energy price a majority of the time for other generators. However, this leads to more emissions. On the other hand, increasing the share of non-emitting resource penetration lowers emissions, but results in a lower electricity price (on average) being bid by the near zero variable costs of these generation sources. The lower price works against these resources recovering enough revenue.

Figure 18: Markets Scenario Total Revenue, Subsidy and Emissions Outcomes

($M, MT CO_2e by Scenario)



Source: IESO, EIA, Strapolec Analysis

Scenarios 2c and 4b, shown in Table 5, considered a smaller share of renewables in the supply mix to assess the impact on their profitability. The reduced need for renewables curtailment coupled with a higher average electricity market price increased the margins. However, no share of renewables in these scenarios were profitable. As such, these scenarios are not shown in Figure 18.

The findings confirm that relying on a capacity auction in Ontario will procure mostly natural gas-fired generation to meet the province's baseload and intermediate needs, which means higher emissions. Furthermore, all scenarios result in more natural gas-fired generation supply than is currently assumed

[82] The Brattle Group modelled several scenarios of Ontario's future supply mix with procurement of non-contracted resources occurring under the then planned ICA and found renewables may be close to or at profitability under some scenarios. Yet even with favourable conditions there is little renewables capacity that is forecast to be procured, with the bulk of procurement being gas and storage. The report generally agrees with the notion that Ontario's gas use will increase under most scenarios.

by the IESO, since both existing, and any potentially new, non-emitting resources are not profitable and will be replaced by natural gas-fired generation similar to Scenario 1, resulting in a large increase in emissions.

5.4 Achieving a low emitting future requires non-market-based procurement approaches

This analysis shows that markets are inadequate for procuring the necessary supply mix to meet demand if low emissions are an objective. Alternative procurement approaches are needed to procure non-emitting resources for baseload and intermediate demand, and to reduce emissions.

Meanwhile, natural gas-fired peaking plants remain suitable resources to procure via capacity auctions to provide peak and reserve margin supply. Since this type of demand requires capacity with very little actual energy use throughout the year (i.e. few hours of operation), the choice of resource has little impact on overall system emissions.

The outstanding question is how to procure for low emission baseload and intermediate supply as well as to meet other system needs.

6.0 Targeted procurement yields better results

Market theory, Ontario's experience, and simulations of non-emitting supply mix options explored in this report all indicate that the proposed electricity markets will not adequately meet the province's needs going forward. This section explores whether other options can provide better outcomes.

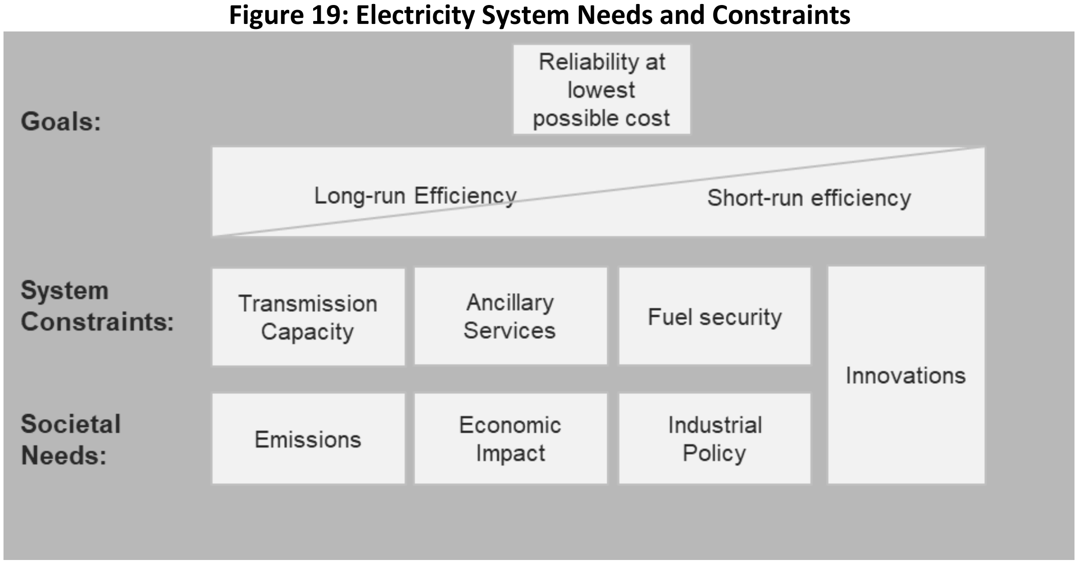
This section discusses targeted procurements and assesses how they can optimize benefits from the electricity system for ratepayers, taxpayers, and the economy. A targeted procurement approach would focus on the type of resources and the broader needs of the electricity system. This procurement approach would provide potential suppliers with a clear understanding of not only the needs of the electricity system but also other interrelated provincial policy and economic objectives. Resource providers will be better able to minimize risk while striving to provide innovative, custom solutions that are well-matched to those broader needs of the province.

The section examines the goals, constraints, and societal needs that face Ontario's electricity system, followed by assessing how electricity markets fail to deliver on these parameters. The section then evaluates the use of conventional, yet targeted procurements using the same parameters. The section concludes by assessing how a targeted portfolio procurement approach could best address the complex, interrelated policy needs impacting Ontario's electricity system.

6.1 Electricity systems have needs beyond meeting demand at low cost

System planners' primary objective is to develop an electricity system that provides reliable service at the lowest possible cost. This is characterized by the goals of optimizing short and long-run efficiency as discussed in Section 3.0. However, the importance of electricity as a public "good" means that other system and societal needs warrant consideration as summarized in Figure 19.

Figure 19: Electricity System Needs and Constraints



Source: Strapolec Analysis

System Constraints inherent in the electricity system were identified in section 3.4.2 and include the following elements:

- **Fuel security:** Electricity generation is dependent on the availability of various fuel sources, some of which (e.g. natural gas) are converted to electricity thousands of kilometers from where they are created. This introduces fuel insecurity (e.g. due to transportation disruptions) and creates a dependency risk on other nations (e.g. due to foreign policy shifts);
- **Ancillary services:** To ensure that power quality is maintained, ancillary services respond to variations in supply and demand, maintain frequency stability, and regulate voltage; and,
- **Transmission capacity:** Transmission system capacity limits how much electricity can flow between points and is generally constructed in consideration of generator capacity and location. However, as supply and demand drivers shift, transmission constraints must be considered alongside generation.

Societal Needs were outlined in 3.5.1 and highlight the inter-linkages between the energy sector and the environment and economy in general. System operations, including the relatively large cost of same, warrant co-ordination with other inter-related public policy objectives. Elements include:

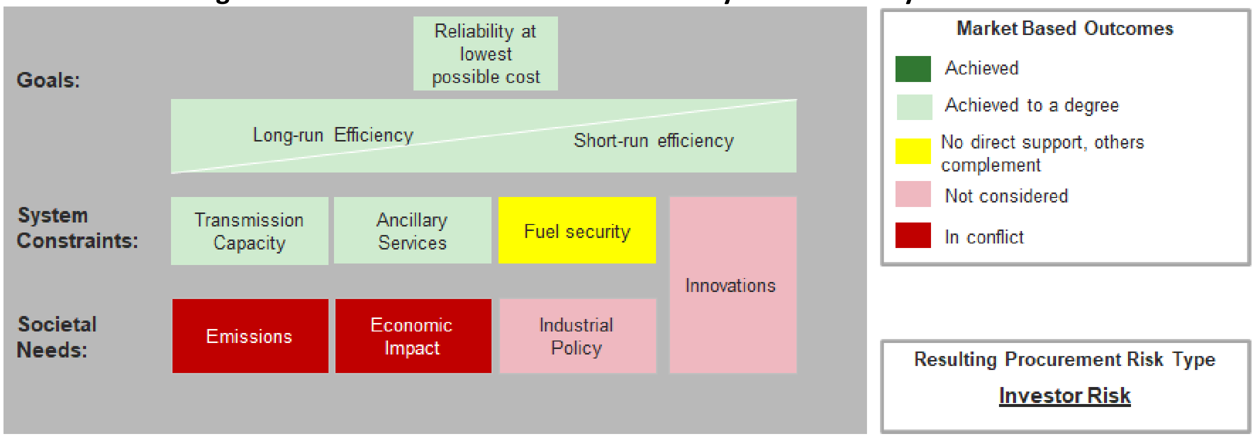
- **Climate policy and emissions:** The extensive reliance of electricity systems on natural gas and coal-fired generation contributes to increased GHG emissions. To manage increasing power consumption trends, climate policies concerned with reducing emissions must be considered by electricity planning and procurement options.
- **Economic impact:** The electricity system is a significant cost for consumers and businesses and to the degree that those costs are directed at domestic solutions, the system is a creator of jobs for the economy. A sustainable, low carbon economy requires a viable, strategically, integrated domestic electricity ecosystem that will continue to grow Ontario's global competitiveness.
- **Industrial policy:** Industry represents a major sector of Ontario's economy, and involves energy consumption and activities that generate emissions. The considerable infrastructure and investment opportunities to achieve cost-effective, optimal mitigations that address these challenges would benefit from energy planning and policy that better reflects the interrelatedness of the policy frameworks of each sector.

Innovations. Today, rapidly evolving technologies are offer more solutions for meeting Ontario's system needs. Consumers now have the option to meet their own demand, technology costs are dropping, and new technologies are being developed to meet system needs beyond capacity. Where cost-competitive, the procurement approach for system needs should encourage emerging innovative solutions to compete with traditional solutions. Planning and policies related to these new activities should employ a more "integrated" approach to ensure these solutions are cost-effective from a total system cost perspective.

6.2 Procurements through electricity markets cannot meet all of Ontario's needs

Capacity and energy markets focus primarily on the goals of short-run and long-run efficiency. Experience shows that these markets can achieve short-run and long-run efficiency only in cases where fossil fuel-fired generation is part of the supply. With complementary mechanisms, both can address some system constraints, but not all. Lastly, they do not consider, and sometimes negatively impact societal needs, as reflected in Figure 20.

Figure 20: Market-Based Procurements Only Meet Some System Needs



Source: Strapolec Analysis

Goals. Markets can achieve short- and long-run efficiency goals only in cases where the objective is to procure fossil fuel-fired generation. These market mechanisms are unable to procure other types of generation when required, as discussed in Section 3.0.

System constraints are not managed directly in capacity and energy markets. Capacity or energy is procured through the market, and other processes need to be implemented to ensure that the procured resources can operate within system constraints. Ancillary services are often procured through a separate market and procurement process, while transmission capacity is either built into markets through locational pricing and/or is managed through out-of-market mechanisms. Meeting these system needs requires a portfolio of more integrated, focused, and co-ordinated procurement decisions and markets. Fuel security cannot be addressed directly within the electricity market system, so out-of-market steps must be taken to address the associated risks.

Societal needs, even given the significant impact they can place on the electricity system, are not directly considered by electricity market structures. Conventional wisdom is that this is the purview of the government. However, Ontario's current plan to procure more natural-fired generation and the inevitable increase in provincial GHG emissions illustrates the resultant policy gap. [83] Ontario imports over 99 percent of the natural gas that is consumed by the province's electricity sector. This has a negative economic impact on the province, (e.g., lost jobs, and outflows of energy dollars creating negative trade balance). These impacts will continue to occur, as markets are focused on procuring capacity and energy at the lowest price and will require continued government intervention to achieve Ontario's longer-term strategic interests: economic, environmental, and societal objectives.

Innovation. Encouraging innovation is also not a focus in markets. Since the market procures uniform products, the motivation of providers is to innovative cost reductions on the known solutions and less on finding solutions that are customized to fit needs.

[83] A carbon price is a market mechanism that could address emissions, however as Section 3.5 described, current carbon prices are too low, and/or have too many exclusions to be effective. Additionally, carbon pricing is not part of the IESO's planning scope.

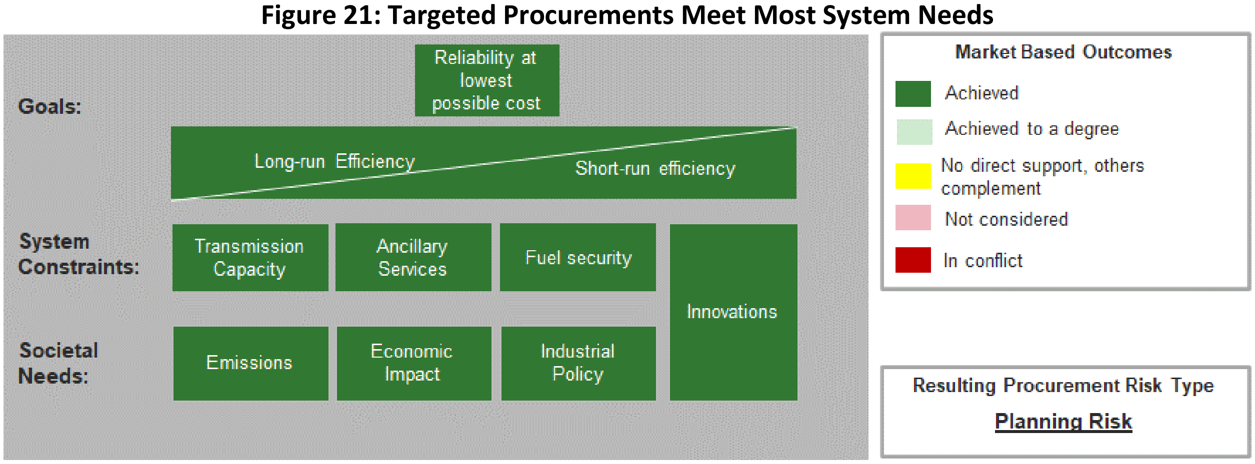
Procurement Risk. As described in section 3.2, capacity and energy markets rely on short-term contracts, thereby giving rise to investor risk, which in turn, typically leads to a higher risk premium and higher cost for ratepayers.

In summary, the design of these electricity markets is biased towards fossil fuel-fired generation procurement and would meet Ontario's future need by procuring gas-fired generation. Given the other needs of the electricity system, these markets are incorporating supplementary in-market and out-of-measures to address these constraints—and inadequately so. Despite all these measures, societal needs do not receive the focus, or the attention warranted. A broader, more integrative approach is needed to address the various system needs.

6.3 Targeted procurements can address most needs

Targeted procurement could provide an optimized, tailored solution to electricity procurement not delivered by the markets. An effective, targeted procurement approach would clearly identify all system needs and constraints and the optimal solutions to address them. The potential benefits to the system are illustrated in Figure 21.

Figure 21: Targeted Procurements Meet Most System Needs



Source: Strapolec Analysis

Goals. With targeted procurement, system planners can request more complex products than in a market system. To improve the efficiency and liquidity of the market they can seek more "uniform products". Short-run and long-run efficiency can also be ably achieved using the RFP process and by clearly addressing all forms of demand, each with different requirements, to procure the most optimized supply mix. The RFP process allows a broader based competition amongst solution providers to drive down costs.

System Constraints. Since targeted procurements allow planners to specify system constraints (e.g., transmission capacity limits, voltage regulation, and fuel security guarantees) these too can be clearly defined and integrated into the capacity procurement RFP requirements.

Societal needs can also be adequately addressed with this approach. Unlike market-based approaches that do not meet the scope of societal needs, targeted procurements allow for clear requirements outlining emissions targets, domestic economic objectives, and industrial policy.

Procurement Risk. Unlike markets, all resource types can bid competitively since their revenue would be guaranteed through long-term contracts. Long-term contracts increase planning risk, but as discussed in section 3.2, risk premiums would be lower than in markets and high fixed cost resources (i.e., non-emitting) would remain competitive.

Innovation would also be encouraged because of the lower risk to developers (due to long term contracts) and more nuanced requirements that present opportunities for novel solutions and appropriate rewards for generators.

For example, a recent U.S. study[84] analyzed future supply scenarios for the ISO-NE and their performance vis-a-vis several sustainability factors including GHG emissions, air pollution, land use, and overall LCOE. The analysis varied the amounts of natural gas, nuclear, offshore wind, and imports that could be used to meet future demand needs. Each scenario was scored on sustainability factors. The highest scoring resource portfolios for sustainability usually included increasing nuclear when compared to the status quo. However, based on the ISO-NE's forecasts, nuclear supply in their region is unlikely to increase given its inability to compete with natural gas in their markets.

To keep existing nuclear in the market, the ISO-NE is employing out-of-market subsidies. A targeted procurement approach would have enabled the ISO-NE to procure a non-emitting, low-cost supply mix without the need for out-of-market state subsidies.[85]

Targeted procurements provide a clear advantage over the capacity market approach currently being pursued by Ontario's IESO. When all system requirements are identified and shared, developers/solution providers can offer solutions based on these requirements and planners can select the most optimal solution at the least cost.

6.4 Planning risk of long-term contracts can be mitigated through portfolio management

Adopting a targeted procurement approach that includes long-term contracts as discussed in Section 3.2 could result in a higher planning risk. System planners can mitigate this risk by segregating the demand needs into a portfolio. The forecast demand can be categorized against several measures such as:

- Form (i.e. baseload, intermediate, peaking & reserve)
- Timeframe (i.e. how soon will the demand materialize?)
- Probability of materialization (i.e. what is the certainty that the demand will be needed?)

All forms of electricity demand are well understood. An examination of each form of demand, determining when and how they materialize, and the associated supply risks enables the development of different procurement strategies to minimize risks and costs.

Demand that is reasonably certain can be met with longer-term contracts to reduce risks associated with higher upfront capital costs. Conversely, where demand is more variable or less certain, some solutions may best be acquired with shorter-term contracts.

[84] Applied Energy, "Holistic multi-criteria decision analysis evaluation of sustainable electric generation portfolios: New England case study", 2019.
[85] Subsidies that now have to be discounted due to FERC's MOPR ruling, which results in higher ratepayer costs.

Two examples are provided to illustrate these concepts for Ontario: annual demand forecast uncertainty; and daily demand fluctuations and variability.

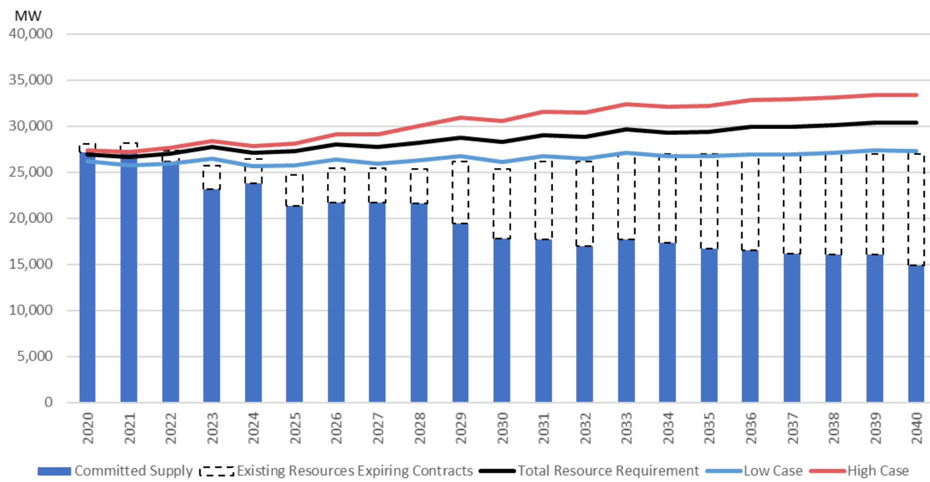
6.4.1 *Annual demand forecast uncertainty*

As mentioned in Section 1.0, current forecasts show that by 2040 Ontario will have to procure approximately 15,000 MW, either through renewal or replacement. System planners need to consider how these capacity needs will emerge over the forecast and plan when major capacity additions are needed. An example for Ontario is the capacity shortfall that will emerge in 2025 when the Pickering Nuclear Station ceases operations.

Planners could address the planning risk of these future capacity additions by examining the statistical uncertainty of the demand forecast. This could be done by producing a forecast with a reference, low, and high case. These would communicate the upper and lower bounds of any uncertainty as shown in Figure 22.[86] In 2040, this results in approximately +/-10% range of deviation from the reference case.

Figure 22: Summer and Winter Peak Demand Outlooks

(MW by Year)



Source: IESO, Strapolec Analysis

Planners could then procure all capacity within the low case with longer-term contracts since that demand is more certain to materialize. The remaining demand between the low and reference case could be procured with a mix of short- and long-term contracts, while the demand above reference case could be procured with short-term contracts at a later date, when less uncertainty around the demand needs can be expected.

6.4.2 *Daily demand fluctuations and variability*

An examination of demand uncertainty can be extended to the average daily demand profile of energy needs for each hour of the day. This can provide useful insights into the different forms of demand to be procured, as shown in Figure 23. Ontario's forecast daily demand profile in 2035 shows that of the

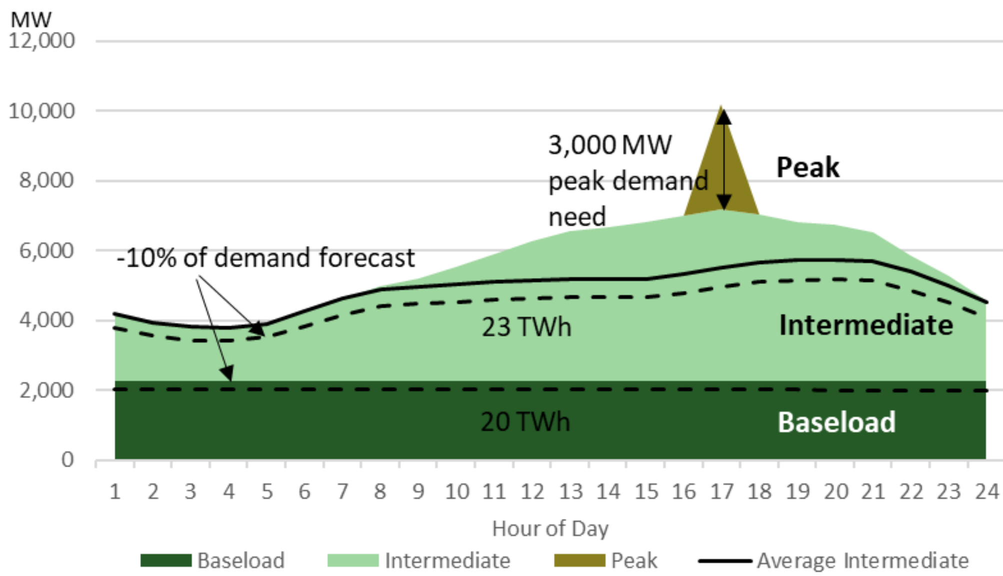
[86] Low and high case deviations from the reference case were extrapolated from IESO 2018 Technical Planning Conference, which is the last time the IESO published high and low scenarios. Data only went to 2035, so data was assumed to be similar in 2036-2040. These cases were made for illustrative purposes.

11,000 MW of capacity needed, approximately 2,250 MW is baseload, 5,750 MW is intermediate, and 3,000 MW is peak.

Applying the -10% range from the low case bound in Figure 22 onto the daily demand profile results in about 225 MW of uncertain baseload demand and about 310 MW of uncertain intermediate demand as shown in Figure 23. Short-term procurement mechanisms would be best suited for this uncertain demand. The remaining more certain demand (e.g. 2000 MW of baseload) could be procured through long-term contracts. This would minimize the risk premiums on the bulk of the supply leading to the lowest cost. As a portfolio, the resulting supply mix would represent the lowest total system cost with a minimized risk profile.

Figure 23: Average Daily Ontario Demand

(MW by Hour)



Source: IESO, Strapolec Analysis

These illustrations show by applying a portfolio management approach, system planners can acquire supply based on more nuanced forecasts and planning resulting in reduced planning risk. Targeted procurement equips planners with the necessary levers to procure for all forms of demand resources and all degrees of uncertainty related to procurement.

7.0 Conclusion

Ontario has been preparing long term procurement strategies to address the electricity capacity shortfall forecast to emerge over the next 5 to 10 years. Aging generation facilities and the expiration of contracted supply agreements will require the province to renew or replace 50% of its existing capacity. This presents Ontario with an opportunity to review its: high-cost supply mix; approach to procuring new supply; and the social imperative for achieving a low-emission electricity system.

Ontario's IESO is responsible for planning and procuring electricity supply and is actively advancing new approaches (Market Renewal and the Capacity Auction) to manage these obligations. Such approaches prioritize greater deregulation and competitive markets as the drivers of change. The IESO forecasts that these approaches will result in the capacity shortfall being addressed by natural gas-fired generation procurements which will increase emissions with unquantified cost implications in the future. Ontario must determine whether this market approach best meets the province's needs.

The analysis shows that Ontario's "lessons learned" are indicative of global electricity market challenges, especially with respect to reducing emissions. These lessons reflect the consequences of Ontario's pursuit of electricity markets that are predicated on fossil-fuel dominated U.S. market models. Specifically, this study finds that:

1. Capacity and energy markets pioneered in the U.S. are unable to meet Ontario needs;
2. Ontario's previous attempt at deregulated markets resulted in high costs and, eventual failure;
3. Electricity demand in Ontario occurs in three distinct forms, each requiring a separate procurement solution, which the planned capacity and energy markets cannot provide; and,
4. Procurements targeted at Ontario's specific policy and energy system needs will yield better results.

This report recommends that Ontario adopt a targeted and competitive Request for Proposal (RFP) process to achieve the objectives of fostering competition. Ontario would benefit from taking a broader approach in addressing its long-term procurement needs to renew or replace 50% of its existing electricity capacity. Ontario has the opportunity to move forward with a more integrated approach to specifically: address its high-cost supply mix; determine the best approach for procuring new, low-cost, low-carbon supply; and, enable viable synergies with other provincial economic and environmental objectives. The pitfalls of electricity markets should be carefully considered against the benefits of undertaking targeted procurements that are better matched to Ontario's needs and still achieve the objectives of fostering competition and avoiding long term commitments to high emission natural gas-fired generation.

Acknowledgements

This study was proposed by Strategic Policy Economics to further the understanding of how electricity markets work, the associated pros and cons and the role they should play helping to fulfill Ontario's electricity system needs and forecasted supply gap.

Overview of Strategic Policy Economics

Founded by Marc Brouillette in 2012, Strategic Policy Economics helps clients understand the implications of Ontario's energy and climate policy. The firm specializes in characterizing multi-stakeholder issues stemming from technology-based innovations in policy-driven regulated environments such as energy. Reports on Ontario's climate and energy policy have spanned across all major energy and climate issues including the implications of long-term energy planning, emissions reduction, the integration of renewables and imports from Quebec, the economic benefits of extending the life of the Pickering nuclear generating station, the challenges of integrating DER, and the pitfalls of cap and trade.

Production of this report

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The Strategic Policy Economics team hopes this report provides a constructive contribution to IESO's approach to procurement and enables Ontario to meet its future electricity system needs in the most effective manner.

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Appendix B – List of Abbreviations

AMPCO - Association of Major Power Consumers in Ontario
APO – Annual Planning Outlook
CCGT – Combined Cycle Gas Turbine
CfD – Contract for Difference
CO_2e – CO_2 equivalent
CONE – Cost of New Entry
DER – Distributed Energy Resource
DES – Distributed Energy Storage
DR – Demand Response
EIA – Energy Information Administration
ESA – Electrical Safety Authority
FCA – Forward Capacity Auction
FERC – Federal Energy Regulatory Commission
FIT – Feed in Tariff
GA – Global Adjustment
GEA – Green Energy Act
GHG – Greenhouse gas
HOEP – Hourly Ontario Energy Price
ICA – Incremental Capacity Auction
ICAP – Installed Capacity
IESO – Independent Electricity System Operator
LCOE – Levelized Cost of Electricity
MACP – Maximum Auction Clearing Price
MPMA – Market Power Mitigation Agreement
MRP – Market Renewal Program
MT – Megatonne
MW – Megawatt
NBER – National Bureau of Economic Research
NERC - North American Electric Reliability Corporation
OBPS – Output-Based Pricing System
OEB – Ontario Energy Board
OEFC – Ontario Electricity Financial Corporation
OPG – Ontario Power Generation
PMR – Power Mitigation Rebate
PPA – Power Purchase Agreements
RFP – Request for Proposal
RPP – Regulated Price Plan
RPS – Renewable Portfolio Standard
SOE – State Owned Enterprise
TWh – Terawatt hour

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