Disclaimer [Meaghan McConnell to provide disclaimer once study is close to completion]

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Table of Contents [BC]

List of Figures [BC]

List of Tables [BC]

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Executive Summary [Communications]

- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X billion, and initiate work immediately for the development X, Y, Z

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Chapter 1: Introduction

Study motivation [Communications]

- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.

- Such an undertaking would require a comprehensive plan to develop and invest in suitable replacement supply and reorient the system around the new supply mix in order to maintain the reliability of the system.

Objectives of the study [Communications]

- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered

Report contents [Communications]
Describe how the report is organized

Chapter 2: Background and Context Setting

Role of natural gas [MTI]

- How we expect gas will support future reliable electricity system operation (e.g. capacity, energy, operability), including the technical characteristics of Ontario’s gas fleet

The focus of the analysis will be on the reliability, cost, wholesale market, operability, and timing impacts that need to be addressed should the phase out of natural gas be considered. To do that, it is important to recognize the role that natural gas currently plays in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity and about 7% of total energy in the province, as shown in Figure X.

Figure X: 2022 Installed Capacity and Energy of Natural Gas

[Insert 2022 pie chart – Installed Capacity and Energy Production].

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable supply, including X MW of wind and X MW of solar, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as they are not energy limited. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial as well as frequency response which aids in system recovery following a contingency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

[Operations: add in additional context of operability characteristics of gas]

Electricity emissions projection of base case [SK]

As outlined in the 2020 Annual Planning Outlook, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO₂ e by 2030, still well below 2005 levels. This expected
increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the outlook assumes that natural gas will fill in system capacity needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

Summary of current government policy and emissions targets [SK]

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing GHG emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 t/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/t of carbon dioxide emissions and increasing to $170/t by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

Challenges to be considered if phasing out gas generation

- Gas plants are under contract [SK]

Much of Ontario’s current natural gas-fired generation is under contract. The IESO's generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.
The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. Resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

- Locational importance of the gas fleet [JL]
  - During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in strategic locations to reduce the reliance on the transmission system to bring power into the load centres. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by being located where they are, they also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.
  - Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO's 2015 NUG Framework Assessment Report.
  - These gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. This was not a concern when coal-fired generation with gas-fired generation. Without the gas-fired generation, transmission or reactive power source may be required. An example of this is the Toronto area. The peak load in the area may not be supplied reliably without the local gas-fired generation.

- Ramping capability
  - During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. Conversely, when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

- Inertial and frequency response
  - In the event of a large loss of generation, inertial and frequency response is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of
both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

- **Restoration path**
  - Today, we have black start units that are able to generate without any supply of electricity. This is necessary to prepare the system following a black out. A restoration path requires strategically placed generating units with significant load pickup capability and significant MX absorbing capability to be operable. Currently gas plants are serving that purpose. In the absence of gas, a suitable replacement for this purpose will be required.

- **Visibility and Control**
  - The bulk of our gas-fired generation fleet is not only visible to the IESO but also dispatchable. If our gas-fired generation fleet were replaced with resources on the distribution system, we would lose visibility and control of a significant amount of MW. This could not only increase complexity of operation but also increase the need for additional services.

- **Volume of Resources/Market Participants**
  - A large increase in the number of resources and market participants providing capacity to Ontario would create increased workload in the control room. This could potentially distract from other tasks which increased the risk of human error.

- **Contingencies**
  - In the event the gas fleet is replaced with distributed energy resources, consideration will have to be taken to the amount of sympathetic loss of those resources. Our single largest contingency assessment will need to take into account not only the loss of a generator, but also the assumed amount of sympathetic loss that would also result

- **Lessons learned from off coal [JL]**

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fire generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation outputs in addition to dealing with constant demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all.
There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. One important aspect to keep in mind is the variability of wind generation output tends to be seasonal. This poses even greater challenge for storage facilities to complement variable generation in providing what gas generation can provide.

**Opportunities and benefits for phasing out gas generation**

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability:

- Where IESO has needed to procure more supply it has been procuring increasing quantities of these types of resources through IESO’s former DR auction, which has evolved to a capacity auction open to various types of resources including storage and DR.

- The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (also known as Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

- In the event we have an increase to the number of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load generation in key areas where it is needed to help control flows for system limits. This would also help keep things balanced if a unit was lost since it wouldn’t have as much of a large scale impact on the grid. Having multiple units could benefit voltage post contingency with them being situated in key areas and able to respond to dynamic grid changes.

As these new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.

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**Chapter 3: Scope of Study**

- Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

**Scenario development** [RM, VV, DR, SK, JP, JL]
**Base Case**

This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^1\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO2e.

The underlying forecast used for the off-gas scenarios is the 2020 APO Scenario 1 (Base Case) load forecast whereby demand commences at 141 TWh to 174 TWh, increasing at an annual rate of x\% per year with conservation energy savings embedded at 3 – 16 TWh. The demand forecast assumes the expected recovery from the COVID-19 pandemic downturn recovers to 2019 levels by the end of 2022. The carbon cost is based on the assumption of a benchmark of 330 t CO2/GWh and $50/t carbon price. This carbon cost assumption is used in Scenario 1 and 3. For the Scenario 2, the carbon benchmark is projected to decline to 0 t CO2/GWh and a carbon price of $170/t by 2030.

**Potential Pathways**

This study examines potential pathways to lower emissions through an illustration of complete gas phase out and maintaining stable emissions at current levels:

[Make the 3 Scenarios to something more visual]

1) **Scenario 1** - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

2) **Scenario 2** - Market based approach that examines higher gas prices and lowered benchmark to reduce utilization of gas to reduce emissions by 2030 to current levels

3) **Scenario 3** - Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels

Scenario 1 and 3 uses a supply mix based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliability system in Ontario. Increased shares from any one type of replacement comes with increased risks pertaining to that single source, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix based approach will consider demand-side and supply-side options.

In considering the candidate options, the study considers possible replacement technologies that are established and feasible today. As the reliability coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale.

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\(^1\) 2017 was a low demand year, and as a result, emissions were lower as the gas fleet ran less.
scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization that selects resource build-out over the 20 year planning period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO2 emissions at or below annual emissions target
- Sufficient flexible resource to meet system operability requirements, mostly related to ramp rates and integration of variable resources

Cost and performance assumptions for each considered resource are given in Table X. Associated transmission cost assumptions with each resource are provided in Table Y. It should be noted that it is very difficult to determine the required transmission investments without knowing where new generation would be located. Such determination would require much more extensive consideration working with generation developers which cannot be completed within the time allowed for this report. For example, for wind generation, it is recognized that much of the easier locations in the transmission system to incorporate wind generation have already been used to connect the existing wind generation through the past wind generation acquisition processes. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations.

A set of nominal costs was assumed to allow this portfolio analysis to be carried out.

**Table X:** Candidate Options for Replacement Supply for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC ($2020/MWh)</th>
<th>Capacity Cost ($2020/kw-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td></td>
<td>39%</td>
<td>Cost projection based on average of industry capital cost projections²</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td></td>
<td>17%</td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>Cost Curve</td>
<td></td>
<td>50%</td>
<td>Cost curve from <a href="http://example.com">Hatch Acres</a> hydro potential study adjusted to reflect recent hydroelectric project costs</td>
</tr>
<tr>
<td>Small Modular</td>
<td>NA</td>
<td></td>
<td>85%</td>
<td></td>
</tr>
</tbody>
</table>

² Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)
Reactors

| Firm Imports | 150 | NA | Variable | Cost assumption based on requirement of new build hydroelectric capacity in Quebec to provide year-round firm capacity |

Energy Efficiency

| Four achievable potential scenarios from the 2019 Achievable Potential Study were made available to the model with seasonal energy and capacity reductions and annual program costs |

Demand Response

| NA | 67 | NA | Cost based on recent capacity auctions |

Table Y: Transmission Assumptions for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2020M)</th>
<th>O&amp;M Cost ($2020M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports  (&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>Firm Imports  (&lt;= 3,300 MW)</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the optimization model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

Portfolios are modeled seasonally (summer and winter) over 20 years. In each year, the resource portfolios are required to meet the capacity, energy, emissions, and operability requirements referenced above. Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

Consistent with the project scope details provided in the stakeholder engagement sessions in advance of this study, all supply scenarios include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

The resulting portfolios developed using the least-cost optimization model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one
path. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

Two laminations of the replacement supply mix were considered, an unconstrained replacement resource mix assuming no barriers on supply resource, regulatory hurdles, land use and other barriers that may limit the amount of resources we can feasibly take up by 2030; and another where constraints were placed.

Scenario 2 is a market based approach that examines higher gas prices to reduce the utilization of gas and its corresponding emissions by 2030. The 2020 APO Scenario 1 is augmented to assume a linear increase to the cost of carbon from $xx/tonne in 20xx to $170/tonne by 2030 plus a linear decline to the benchmark for all natural gas facilities from 370 tonne/GWh in 2021 to zero by 2030. The demand, conservation, transmission and economic outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

An energy production assessment is conducted that includes the economic imports and exports between Ontario and its neighbouring jurisdictions. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability and emissions. The result of the energy assessment is a reduction in gas generation for exports and an increase in imports to meet domestic consumption needs, based on the economics of the higher cost of natural gas from increased cost of carbon and the elimination of the natural gas facility benchmark by 2030.

[Insert figure of modelling approach flow chart]

- [DR: Outline the assumptions and methodology used for Scenario 1 and 3].

**Areas of study**

The three scenarios described above will be examined from various lenses, including areas of reliability, costs and wholesale market impacts, operability and timing to the electricity system.

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>• Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>• Locational requirements for siting resources, or transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>• Ancillary Services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale</td>
<td>• Lowest net present value replacement supply mix cost</td>
</tr>
<tr>
<td>Market</td>
<td>• A coarse range of potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>• The assessment will use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>• Impact on wholesale market pricing how market value of system needs may change</td>
</tr>
<tr>
<td>Operability</td>
<td>• Operability and impact to wholesale market design (e.g. day-ahead and real-time energy, Operating Reserve, and Ancillary Services) and confirmation that the market can operate the supply mix</td>
</tr>
<tr>
<td>Timing</td>
<td>• Typical timelines associated with construction of generation</td>
</tr>
</tbody>
</table>
Areas of study that is out of scope [BC]

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in Chapter 3. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.

Chapter 4: Study Findings

Study Findings: Scenario 1 - Complete gas phase-out by 2030

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Reference scenario to understand which factors are the largest drivers of ratepayer costs.
- Import/Export [RM, VV, SK]
Operability impacts [MTI]

Emission projections [SK]

Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply required to completely replace natural gas generation by 2030 is shown in Figure x. In addition to this resource mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix. Two supply portfolios are shown: one with no resource limitations other than demand response, and the other with resource limits of 6,000 MW on wind, solar and storage.

Figure x: 2030 Incremental Installed Capacity, Scenario 1

The complete phase-out of gas by 2030 with replacement by a diverse mix of primarily variable renewable energy and storage resources would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” outlined in Chapter 4.

Energy Efficiency
Besides those energy efficiency savings considered in the most recent Annual Planning Outlook published in December 2020 and this study, there are potential opportunities to achieve greater electricity savings as identified in the Achievable Potential Study (APS). The most recent APS, which was the first integrated electricity and natural gas achievable potential study, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the reference case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

**Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030**

The market based approach relies on an energy production assessment that includes economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs. As indicated above this scenario assumes an increase to cost of carbon from $x /tonne in 2022 to $170/tonne by 2030 and an elimination of the natural gas benchmark of 370 t/GWh in 2022 to zero by 2030. With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for Scenario 2. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions will result in an increase to the market clearing prices for Ontario, making Ontario electricity production into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will also off setting more Ontario natural gas production. The change to natural gas production, imports and exports relative to the base case is provided in the figure below.

Figure x: Natural Gas, Imports and Exports TWh comparison.

The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO case analysis. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.
The reduced natural gas production results in GHG emissions remain around 4 MegaTonnes with the market based approach which is consistent to the 2016 to 2020 historical level and declining to 3 Megatonnes by 2030.

Figure x: Emission forecast for Scenario 2 and the 2020 APO Base Case

The cost implications of Scenario 2 relative to the Base Case is x.

Other considerations: The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.
The incremental supply required to stabilize 2030 greenhouse gas emissions at 2016-2020 levels is shown in Figure Z. In addition to this supply mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix.

Figure Z: 2030 Incremental Installed Capacity, Scenario 3

The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, the need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected, as this energy is required to displace natural gas generation from an energy perspective.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity were sufficient to meet the supply needs of the system.

Energy Efficiency

[Same discussions as Scenario 1]

Wholesale Market Impacts [Market Development & Resource Procurement]

Background / Introduction:

The Wholesale Market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of wholesale market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to a new pricing patterns influenced by the characteristics of the replacement
resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several "bounding" or "bookend" cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario's existing gas fleet. Along these lines, a "High Base-Load Case" and a "High Capacity Case" were developed in which a fleet of resources with specific attributes were used to replace Ontario's gas-fired generators. These were compared with a "Base Case" in which the gas fleet continues to operate.

For the High Base-Load Case, it has been assumed that a fleet of somewhat inflexible resources has been added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide very flexible output or stand by energy such as operating reserves. Similarly, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario's gas fleet. It was also assumed that the intermittent resources would comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources look to maximize profit through energy arbitrage and operating reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario's wholesale power-markets market could be impacted if resources on two opposite ends of a spectrum of attributes were chosen to replace Ontario's gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

**The High Base-Load Case**

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario's electricity system. These new base-load resources offer into the energy market at low to zero prices, and since they replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy, meaning the availability of energy above that needed to meet the province's energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the
ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, for a relatively small fraction of the year energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for a small number of hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydro availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, the the impacts to impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure below. (Note: graph annotation still needed, showing how prices become more flat and/or variable)
Market Impacts Discussion

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and that a broad range of potential different outcomes could result across Ontario’s markets. This occurs because the current gas fleet has a unique mix of costs, emissions, and attributes that it supplies to Ontario’s grid, and there is currently no like-for-like but emissions free replacement technology for this gas fleet. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

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Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.
Available Alternatives and Considerations: Hydro Quebec Imports

Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years. Import from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The interconnections in northern Ontario are these type of connections with limited capacities. The interconnection at Bauharnois near St. Lawrence is a same type of interconnection but with a capacity to connect up to 800 MW of generation into Ontario. With the intent to allow dynamic power transactions between Ontario and Quebec, the 1250 MW tie in the Ottawa area was added. It includes an ac-to-dc-to-ac conversion facilities to address the system issue.

Also due to the nature of the system in Ontario near Ottawa, the 1250 MW tie and the 800 MW tie cannot be operated at the combined total level of 2050 MW in summer peak periods. The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. A firm import capability of 1650MW can be obtained with this upgrade. For a firm import capacity beyond 1650 MW would require significant transmission investments. The scope and cost of such investment is not known without discussions/negotiations with Quebec. A nominal cost based on past consideration was used in the development of the portfolios.

Quebec’s electricity demand is projected to grow over the next decade, decreasing its surplus, and exports are generally curtailed during winter peaks, as more than 80% of Québec households use electric heating. Quebec is expected to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. While Quebec is building more wind capacity, this capacity will be energy limited and their ability to export to Ontario will also be limited.

Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030) [RM, VV, DR, SK, JP, JL, DCP]

- In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030

- This section aims to help frame discussions around longer term government targets to reduce economy-wide emissions where electricity could play a significant role.

- Role of demand-side options (e.g. additional EE)
Hydrogen

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may be come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

Carbon Capture Utilization and Storage

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO2 to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

Distributed Energy Resources

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Broader Planning and Coordination

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 MT/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less
economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.

Chapter 5: Conclusion

- Key takeaways [Communications]
1. Considerations for Phasing Out Natural Gas in the Electricity System
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Disclaimer

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Executive Summary

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Key Findings
The following key findings provide insights into the opportunities and challenges the sector has to consider under future pathways for lowered emissions.

E.g. To lower emissions by 2030 to 2016-2020 levels, it is expected to cost $X-Y billion, and these are the things that have to happen for that to work. These are the challenges expected for the three scenarios.
Introduction

Study Motivation
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Objectives of Study
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Background and Context

Role of Natural Gas

The focus of this study will investigate the impacts that need to be addressed should the phase out of natural gas be considered. To do that, it is important to recognize the role that natural gas currently plans in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity and about 7% of total energy in the province, as shown in Figure 1.

Figure 1 | 2022 Installed Capacity and Energy of Natural Gas

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable and intermittent supply, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as there is they are not energy limited. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial as well as frequency response which aids in system recovery following a contingency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

Electricity Emissions Projection in 2020 Annual Planning Outlook

As outlined in the 2020 Annual Planning Outlook (APO), the electricity sector emissions are forecast to increase to 12.2 megatonnes CO₂ e by 2030, still well below 2005 levels. This expected increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the 2020 APO assumes that existing natural gas will fill in system energy needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency and non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Current Government Emissions Policy and Emissions Targets

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing greenhouse gas (GHG) emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 tonne/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/tonne of carbon dioxide emissions and increasing to $170/tonne by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

Challenges to be Considered if Phasing Out Gas Generation

Gas Under Contract

Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.

Eliminates Competition

The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

Locational Importance
During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in locations to minimize transmission investments needed to incorporate the resource into the system. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by virtue of where they are located, also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.

Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.

**Synchronous Generators**

Gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. This was not a concern when coal-fired generation was replaced with gas-fired generation. Without the gas-fired generation, transmission or reactive power source may be required. An example of this is the Toronto area. The peak load in the area may not be supplied reliably without the local gas-fired generation.

**Ramping Requirements**

During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. Conversely, when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

**Inertial and Frequency Response**

In the event of a large loss of generation, inertial and frequency response is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

**Restoration Path**

Today, the system has black start units that are able to generate without any supply of electricity. This is necessary to prepare the system following a black out. A restoration path requires strategically placed generating units with significant load pickup capability and significant MX absorbing capability to be operable. Currently gas plants are serving that purpose. In the absence of gas, a suitable replacement for this purpose will be required.

**Visibility and Control**
The bulk of our gas-fired generation fleet is not only visible to the IESO but also dispatchable. Should the gas-fired generation fleet be replaced with resources on the distribution system, the IESO would lose visibility and control of a significant amount of MWs. This could increase complexity of operation and thereby increase the need for additional services.

**Volume of Resource and Market Participants**

A large increase in the number of resources and market participants providing capacity to Ontario would create increased workload in the control room. This could potentially distract from other tasks which increased the risk of human error.

**Contingencies**

In the event the gas fleet is replaced with distributed energy resources, consideration will have to be taken to the amount of sympathetic loss of those resources. Our single largest contingency assessment will need to take into account not only the loss of a generator, but also the assumed amount of sympathetic loss that would also result.

**Lessons Learned from Off Coal**

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fired generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation outputs in addition to dealing with constant demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all.

**Opportunities and Benefits for Phasing Out Gas Generation**

There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. With wind resources, variability of generation output tends to be seasonal. This seasonality poses greater challenges for storage facilities to complement variable generation in providing what gas generation can provide.

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability.
Where IESO has needed to procure more supply it has been procuring increasing quantities of these types of resources through IESO’s former Demand Response auction, which has evolved to a capacity auction open to various types of resources including storage and Demand Response.

The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (also known as Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

In the event the amount of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load generation in key areas where it is needed to help control flows for system limits. Large number of resources can minimize loss of generation risk considering a loss of unit would not have as much of a large scale impact on the grid. Having multiple units could benefit voltage post contingency with them being situated in key areas and able to respond to dynamic grid changes.

As new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.
Scope of Study

Background
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Scenario Development

Base Case
This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The carbon cost is based on the assumption of a benchmark of 370 tonne CO\(_2\)/GWh allowance for existing natural gas generation and $50/tonne carbon price in 2022 and held constant thereafter.

Potential Pathways
This study examines potential pathways to lower emissions through an illustration of complete gas phase out (Scenario 1) and maintaining lowered emissions at current levels (Scenario 2 and 3), as illustrated in Figure 2. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^1\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO\(_2\)e. The purpose of developing these Scenarios was not to create estimates of likely outcomes, but to allow the IESO to provide insights gleaned from the range of potential pathways.

Figure 2 | Pathway Description

<table>
<thead>
<tr>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030</td>
<td>Market based approach where increased carbon cost and decreased benchmark reduce the utilization of gas to reduce emissions by 2030 to current levels</td>
<td>Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels</td>
</tr>
</tbody>
</table>

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\(^1\) 2017 was a low demand year, and as a result, emissions were lower as the gas fleet ran less.

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
**Scenario 1 and Scenario 3** uses a supply mix based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliability system in Ontario. Increased shares from any one type of replacement comes with increased risks pertaining to that single source, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix based approach will consider demand-side and supply-side options. Scenario 2 considers a tightening of carbon policy to drive changes, and did not apply a supply mix based approach.

In considering the candidate options, the study considers possible replacement technologies that are established and feasible today. As the reliability coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. It is difficult to predict technology innovations, policy developments, and grid evolutions that could manifest in the study time frame – factors that could result in alternate supply mixes. The IESO aimed to provide a set of reasonable forward looking lowest cost estimates given professional judgement and the current information available. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization that selects resource build-out over the 20 year planning period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO₂ emissions at or below annual emissions target
- Sufficient flexible resource to meet system operability requirements, as it relates to ramp rates and integration of variable resources.

Cost and performance assumptions for each considered resource are given in Table 1. Associated transmission cost assumptions with each resource are provided in Table 2. It should be noted that it is very difficult to determine the required transmission investments without knowing where new generation would be located. Such determination would require much more extensive consideration working with generation developers which cannot be completed within the time allowed for this report. For example, it is recognized that much of the easier locations in the transmission system to incorporate wind generation, for example, have already been used to connect the existing wind generation through the past wind generation acquisition processes. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations.

A set of nominal costs was assumed to allow this portfolio analysis to be carried out.

**Table 1 | Candidate Options for Replacement Supply for Scenario 1 and 3**

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC ($2020/MWh)</th>
<th>Capacity Cost ($2020/kw-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td></td>
<td>39%</td>
<td>Cost projection based on</td>
</tr>
</tbody>
</table>

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Table 2 | Transmission Assumptions for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2020M)</th>
<th>O&amp;M Cost ($2020M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1,500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 3,300 MW)</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the optimization model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

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2 Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)

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Portfolios are modeled seasonally (summer and winter) over 20 years. In each year, the resource portfolios are required to meet the capacity, energy, emissions, and operability requirements referenced above. Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

Consistent with the project scope details provided in the stakeholder engagement sessions in advance of this study, all supply scenarios include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

The resulting portfolios developed using the least-cost optimization model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

Two laminations of the replacement supply mix were considered, an unconstrained replacement resource mix assuming no barriers on supply resource, regulatory hurdles, land use, and other barriers that may limit the amount of resources we can feasibly take up by 2030; and another where constraints were placed.

**Scenario 2** is a market based approach where increased carbon cost and decrease benchmark reduce the utilization of gas and its corresponding emissions by 2030. The carbon cost assumes a linear increase from $50/tonne in 2022 to $170/tonne by 2030 and the benchmark for all natural gas facilities linearly decline from 370 tonne/GWh in 2021 to 0 tonne/GWh by 2030. The demand, conservation, transmission and economic outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

These scenarios were also informed by the multitude of input from the public webinars, stakeholders and communities feedback – written feedback can be found on the IESO website.

An economic hourly dispatch model was used to determine the outcomes of the three scenarios. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability, emissions and imports and exports. Figure 3 illustrates the modelling approach for the three Scenarios.

**Figure 3 | Modelling Approach for Scenario 1, 2 and 3**

**Areas of Study**

The three scenarios was examined from various lenses, including areas of reliability, costs, wholesale market impacts, operability and timing to the electricity system, as shown in Table 3.

**Table 3 | Areas of Study**

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>Locational requirements for siting resources, or transmission</td>
</tr>
</tbody>
</table>

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
### Areas of Study Not Considered

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in Chapter 3. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.

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**Considerations for Phasing Out Natural Gas in the Electricity System | Public**
Study Findings

Scenario 1 - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

The incremental supply above the Base Case required to completely replace natural gas generation by 2030 is shown in Figure 4. In addition to this resource mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix. Two supply portfolios are shown: one with no resource limitations other than Demand Response, and the other with resource limits of 6,000 MW on wind, solar and storage.

Figure 4 | 2030 Incremental Installed Capacity, Scenario 1

The complete phase-out of gas by 2030 with replacement by a diverse mix of primarily variable renewable energy and storage resources would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later.

Considerations for Phasing Out Natural Gas in the Electricity System | Public
Besides those energy efficiency savings considered in the 2020 APO, there are potential opportunities to achieve greater electricity savings as identified in the Achievable Potential Study (APS). The most recent APS, which was the first integrated electricity and natural gas achievable potential study, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the Base Case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.

While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Base Case to understand which factors are the largest drivers of ratepayer costs.

Scenario 2 - Market based approach where increased carbon cost and decreased benchmark reduce the utilization of gas to reduce emissions by 2030 to current levels

The market based approach relies economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs and lowered carbon benchmark. As indicated above this scenario assumes an increase to cost of carbon from $50/tonne in 2022 to $170/tonne by 2030 and a decline of the natural gas benchmark of 370 tonne/GWh in 2022 to 0 tonne/GWh by 2030. With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for Scenario 2. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions is expected to increase to the market clearing prices for Ontario, making Ontario electricity production into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will offset Ontario natural gas production. The change to natural gas production, imports and exports relative to the Base Case is provided in Figure 5 below.

Figure 5 | Natural Gas, Imports and Exports Relative to the Base Case
The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO Base Case. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.

The reduced natural gas production results in GHG emissions remain around 4 megatonnes in Scenario 2 which is consistent to the 2016 to 2020 historical level and declining to 3 megatonnes by 2030, as shown in Figure 6.

**Figure 6 | Emission Forecast for Scenario 2 and the 2020 APO Base Case**

The cost implications of Scenario 2 relative to the Base Case is x.

The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

**Scenario 3 - Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels**

The incremental supply above the Base Case required to maintain 2030 greenhouse gas emissions at 2016-2020 levels is shown in Figure 7. In addition to this supply mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix.

**Figure 7 | 2030 Incremental Installed Capacity, Scenario 3**
The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, the need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected in the resource portfolio optimizer, as this energy is required to displace natural gas generation from an energy perspective.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity were sufficient to meet the supply needs of the system.

**Hydro Quebec Imports Considerations**

Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years. Import from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The interconnections in northern Ontario are these type of connections with limited capacities. The interconnection at Bauharnois near St. Lawrence is a same type of interconnection but with a capacity to connect up to 800 MW of generation into Ontario. With the intent to allow dynamic power transactions between Ontario and Quebec, the 1250 MW tie in the Ottawa area was added. It includes an ac-to-dc-to-ac conversion facilities to address the system issue.

Also due to the nature of the system in Ontario near Ottawa, the 1,250 MW tie and the 800 MW tie cannot be operated at the combined total level of 2050 MW in summer peak periods. The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. A firm import capability of 1,650 MW can be obtained with this upgrade. For a firm import capacity beyond 1650 MW would require significant transmission investments. The scope and cost of such investment is not known without discussions/negotiations with Quebec. A nominal cost based on past consideration was used in the development of the portfolios.

Quebec's electricity demand is projected to grow over the next decade, decreasing its surplus, and exports are generally curtailed during winter peaks, as more than 80% of Quebec households use electric heating. Quebec is expected to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. While Quebec is building more wind capacity, this capacity will be energy limited and their ability to export to Ontario will also be limited.

**Wholesale Market Impacts**
Context

The wholesale market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of wholesale market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to a new pricing patterns influenced by the characteristics of the replacement resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with the “Base Case” in which the gas fleet continues to operate.

The High Base-Load Case assumed that a fleet of somewhat inflexible resources is added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide very flexible output or stand by energy such as operating reserves. Similarly, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources look to maximize profit through energy arbitrage and operating reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power-markets market could be impacted if resources on two opposite ends of a spectrum of attributes were chosen to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

The High Base-Load Case

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources offer into the energy market at low to zero prices, and since they replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy,
meaning the availability of energy above that needed to meet the province's energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, for a relatively small fraction of the year energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for a small number of hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydroelectric availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure 8 below. (Note: graph annotation still needed, showing how prices become more flat and/or variable)

**Figure 8 | Illustrative Energy Prices versus Percentage of Time**
Market Impacts

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and that a broad range of potential different outcomes could result across Ontario’s markets. This occurs because the current gas fleet has a unique mix of costs, emissions, and attributes that it supplies to Ontario’s grid, and there is currently no like-for-like but emissions free replacement technology for this gas fleet. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

Opportunities to Move Towards an Emission-Free System in the Longer Term

Hydrogen
There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may be come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

**Carbon Capture Utilization and Storage**

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO2 to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

**Increasing Hydroelectric Flexibility**

Place content here – to be provided by Paul Norris/OWA – revisiting the social, environment, cultural, ecological restrictions to now also consider climate change/electricity to see if we can increase operational flexibility in hydroelectric fleet.

**Distributed Energy Resources**

Place content here

**Broader Planning and Coordination**

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 MT/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.
Conclusion

Comms - Place content here
Appendices

Place content here
Disclaimer [Meaghan McConnell to provide disclaimer once study is close to completion]

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Table of Contents [BC]

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Executive Summary [Communications]

- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X billion, and initiate work immediately for the development X, Y, Z

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Chapter 1: Introduction

Study motivation [Communications]

- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.

- Such an undertaking would require a comprehensive plan to develop and invest in suitable replacement supply and reorient the system around the new supply mix in order to maintain the reliability of the system.

Objectives of the study [Communications]

- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered.

Report contents [Communications]
Describe how the report is organized

Chapter 2: Background and Context Setting

Role of natural gas [MTI]

- How we expect gas will support future reliable electricity system operation (e.g. capacity, energy, operability), including the technical characteristics of Ontario’s gas fleet

The focus of the analysis will be on the reliability, cost, wholesale market, operability, and timing impacts that need to be addressed should the phase out of natural gas be considered. To do that, it is important to recognize the role that natural gas currently plans in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity and about 7% of total energy in the province, as shown in Figure X.

Figure X: 2022 Installed Capacity and Energy of Natural Gas

[Insert 2022 pie chart – Installed Capacity and Energy Production].

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable supply, including X MW of wind and X MW of solar, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as there is they are not energy limited. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial as well as frequency response which aids in system recovery following a contingency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

[Operations: add in additional context of operability characteristics of gas]

Electricity emissions projection of base case [SK]

As outlined in the 2020 Annual Planning Outlook, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO₂ e by 2030, still well below 2005 levels. This expected
increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the outlook assumes that natural gas will fill in system capacity needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

Summary of current government policy and emissions targets [SK]

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing GHG emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (I.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 t/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/t of carbon dioxide emissions and increasing to $170/t by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

Challenges to be considered if phasing out gas generation

- Gas plants are under contract [SK]

Much of Ontario’s current natural gas-fired generation is under contract. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.
The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. Resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

- Locational importance of the gas fleet [JL]
  - During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in strategic locations to reduce the reliance on the transmission system to bring power into the load centres. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by being located where they are, they also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.
  - Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO's 2015 NUG Framework Assessment Report.
  - These gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. This was not a concern when coal-fired generation with gas-fired generation. Without the gas-fired generation, transmission or reactive power source may be required. An example of this is the Toronto area. The peak load in the area may not be supplied reliably without the local gas-fired generation.

- Ramping capability
  - During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. Conversely, when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

- Inertial and frequency response
  - In the event of a large loss of generation, inertial and frequency response is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of
both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

- Restoration path
  - Today, we have black start units that are able to generate without any supply of electricity. This is necessary to prepare the system following a black out. A restoration path requires strategically placed generating units with significant load pickup capability and significant MX absorbing capability to be operable. Currently gas plants are serving that purpose. In the absence of gas, a suitable replacement for this purpose will be required.

- Visibility and Control
  - The bulk of our gas-fired generation fleet is not only visible to the IESO but also dispatchable. If our gas-fired generation fleet were replaced with resources on the distribution system, we would lose visibility and control of a significant amount of MW. This could not only increase complexity of operation but also increase the need for additional services.

- Volume of Resources/Market Participants
  - A large increase in the number of resources and market participants providing capacity to Ontario would create increased workload in the control room. This could potentially distract from other tasks which increased the risk of human error.

- Contingencies
  - In the event the gas fleet is replaced with distributed energy resources, consideration will have to be taken to the amount of sympathetic loss of those resources. Our single largest contingency assessment will need to take into account not only the loss of a generator, but also the assumed amount of sympathetic loss that would also result.

- Lessons learned from off coal [JL]

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fire generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation outputs in addition to dealing with constant demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all.
There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. One important aspect to keep in mind is the variability of wind generation output tends to be seasonal. This poses even greater challenge for storage facilities to complement variable generation in providing what gas generation can provide.

**Opportunities and benefits for phasing out gas generation**

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability:

- Where IESO has needed to procure more supply it has been procuring increasing quantities of these types of resources through IESO’s former DR auction, which has evolved to a capacity auction open to various types of resources including storage and DR
- The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (also known as Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.
- In the event we have an increase to the number of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load generation in key areas where it is needed to help control flows for system limits. This would also help keep things balanced if a unit was lost since it wouldn’t have as much of a large scale impact on the grid. Having multiple units could benefit voltage post contingency with them being situated in key areas and able to respond to dynamic grid changes.

As these new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.

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**Chapter 3: Scope of Study**

- Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

**Scenario development** [RM, VV, DR, SK, JP, JL]
**Base Case**

This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^1\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO\(_2\)e.

The underlying forecast used for the off-gas scenarios is the 2020 APO Scenario 1 (Base Case) load forecast whereby demand commences at 141 TWh to 174 TWh, increasing at an annual rate of \(x\%\) per year with conservation energy savings embedded at 3 – 16 TWh. The demand forecast assumes the expected recovery from the COVID-19 pandemic downturn recovers to 2019 levels by the end of 2022. The carbon cost is based on the assumption of a benchmark of 370 t CO\(_2\)/GWh and $50/t carbon price. This carbon cost assumption is used in Scenario 1 and 3. For the Scenario 2, the carbon benchmark is projected to decline to 0 t CO\(_2\)/GWh and a carbon price of $170/t by 2030.

**Potential Pathways**

This study examines potential pathways to lower emissions through an illustration of complete gas phase out and maintaining stable emissions at current levels:

[Make the 3 Scenarios to something more visual]

1) **Scenario 1** - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

2) **Scenario 2** - Market based approach that examines higher gas prices and lowered benchmark to reduce utilization of gas to reduce emissions by 2030 to current levels

3) **Scenario 3** - Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels

Scenario 1 and 3 uses a supply mix based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliability system in Ontario. Increased shares from any one type of replacement comes with increased risks pertaining to that single source, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix based approach will consider demand-side and supply-side options.

In considering the candidate options, the study considers possible replacement technologies that are established and feasible today. As the reliability coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale.

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\(^1\) 2017 was a low demand year, and as a result, emissions were lower as the gas fleet ran less.
scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization that selects resource build-out over the 20 year planning period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO2 emissions at or below annual emissions target
- Sufficient flexible resource to meet system operability requirements, mostly related to ramp rates and integration of variable resources

Cost and performance assumptions for each considered resource are given in Table X. Associated transmission cost assumptions with each resource are provided in Table Y. It should be noted that it is very difficult to determine the required transmission investments without knowing where new generation would be located. Such determination would require much more extensive consideration working with generation developers which cannot be completed within the time allowed for this report. For example, for wind generation, it is recognized that much of the easier locations in the transmission system to incorporate wind generation have already been used to connect the existing wind generation through the past wind generation acquisition processes. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations.

A set of nominal costs was assumed to allow this portfolio analysis to be carried out.

Table X: Candidate Options for Replacement Supply for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC ($2020/MWh)</th>
<th>Capacity Cost ($2020/kw-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td></td>
<td>39%</td>
<td>Cost projection based on average of industry capital cost projections²</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td></td>
<td>17%</td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>Cost Curve</td>
<td></td>
<td>50%</td>
<td>Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs</td>
</tr>
<tr>
<td>Small Modular</td>
<td>NA</td>
<td></td>
<td>85%</td>
<td></td>
</tr>
</tbody>
</table>

² Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)
Reactors

Firm Imports 150 NA Variable Cost assumption based on requirement of new build hydroelectric capacity in Quebec to provide year-round firm capacity

Energy Efficiency

Four achievable potential scenarios from the 2019 Achievable Potential Study were made available to the model with seasonal energy and capacity reductions and annual program costs

Demand Response

NA 67 NA Cost based on recent capacity auctions

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2020M)</th>
<th>O&amp;M Cost ($2020M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 3,300 MW)</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the optimization model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

Portfolios are modeled seasonally (summer and winter) over 20 years. In each year, the resource portfolios are required to meet the capacity, energy, emissions, and operability requirements referenced above. Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

Consistent with the project scope details provided in the stakeholder engagement sessions in advance of this study, all supply scenarios include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

The resulting portfolios developed using the least-cost optimization model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one
path. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

Two laminations of the replacement supply mix were considered, an unconstrained replacement resource mix assuming no barriers on supply resource, regulatory hurdles, land use and other barriers that may limit the amount of resources we can feasibly take up by 2030; and another where constraints were placed.

Scenario 2 is a market based approach that examines higher gas prices to reduce the utilization of gas and its corresponding emissions by 2030. The 2020 APO Scenario 1 is augmented to assume a linear increase to the cost of carbon from $xx/tonne in 20xx to $170/tonne by 2030 plus a linear decline to the benchmark for all natural gas facilities from 370 tonne/GWh in 2021 to zero by 2030. The demand, conservation, transmission and economic outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

An energy production assessment is conducted that includes the economic imports and exports between Ontario and its neighbouring jurisdictions. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability and emissions. The result of the energy assessment is a reduction in gas generation for exports and an increase in imports to meet domestic consumption needs, based on the economics of the higher cost of natural gas from increased cost of carbon and the elimination of the natural gas facility benchmark by 2030.

[Insert figure of modelling approach flow chart]

- [DR: Outline the assumptions and methodology used for Scenario 1 and 3].

Areas of study

The three scenarios described above will be examined from various lenses, including areas of reliability, costs and wholesale market impacts, operability and timing to the electricity system.

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>• Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>• Locational requirements for siting resources, or transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>• Ancillary Services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale</td>
<td>• Lowest net present value replacement supply mix cost</td>
</tr>
<tr>
<td>Market</td>
<td>• A coarse range of potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>• The assessment will use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>• Impact on wholesale market pricing how market value of system needs may change</td>
</tr>
<tr>
<td>Operability</td>
<td>• Operability and impact to wholesale market design (e.g. day-ahead and real-time energy, Operating Reserve, and Ancillary Services) and confirmation that the market can operate the supply mix</td>
</tr>
<tr>
<td>Timing</td>
<td>• Typical timelines associated with construction of generation</td>
</tr>
</tbody>
</table>
or transmission (e.g. environmental assessments, regulatory proceedings, construction, commissioning, etc.)

Areas of study that is out of scope [BC]

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in Chapter 3. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.

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Chapter 4: Study Findings

Study Findings: Scenario 1 - Complete gas phase-out by 2030

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Reference scenario to understand which factors are the largest drivers of ratepayer costs.
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply required to completely replace natural gas generation by 2030 is shown in Figure x. In addition to this resource mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix. Two supply portfolios are shown: one with no resource limitations other than demand response, and the other with resource limits of 6,000 MW on wind, solar and storage.

Figure x: 2030 Incremental Installed Capacity, Scenario 1

The complete phase-out of gas by 2030 with replacement by a diverse mix of primarily variable renewable energy and storage resources would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” outlined in Chapter 4.

Energy Efficiency
Besides those energy efficiency savings considered in the most recent Annual Planning Outlook published in December 2020 and this study, there are potential opportunities to achieve greater electricity savings as identified in the Achievable Potential Study (APS). The most recent APS, which was the first integrated electricity and natural gas achievable potential study, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the reference case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

**Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030**

The market based approach relies on an energy production assessment that includes economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs. As indicated above this scenario assumes an increase to cost of carbon from $x /tonne in 2022 to $170/tonne by 2030 and an elimination of the natural gas benchmark of 370 t/GWh in 2022 to zero by 2030. With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for Scenario 2. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions will result in an increase to the market clearing prices for Ontario, making Ontario electricity production into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will also off setting more Ontario natural gas production. The change to natural gas production, imports and exports relative to the base case is provided in the figure below.

Figure x: Natural Gas, Imports and Exports TWh comparison.

The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO case analysis. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.
The reduced natural gas production results in GHG emissions remain around 4 MegaTonnes with the market based approach which is consistent to the 2016 to 2020 historical level and declining to 3 Megatonnes by 2030.

Figure x: Emission forecast for Scenario 2 and the 2020 APO Base Case

The cost implications of Scenario 2 relative to the Base Case is x.

Other considerations: The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.
The incremental supply required to stabilize 2030 greenhouse gas emissions at 2016-2020 levels is shown in Figure Z. In addition to this supply mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix.

Figure Z: 2030 Incremental Installed Capacity, Scenario 3

The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, the need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected, as this energy is required to displace natural gas generation from an energy perspective.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity were sufficient to meet the supply needs of the system.

Energy Efficiency

[Same discussions as Scenario 1]

Market Impacts [Market Development & Resource Procurement]

Background / Introduction:

Market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to a new and likely persistent pricing patterns influenced by the characteristics of the
replacement resources and their ability to supply key services. This section explores in more
detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas
generation resources, the IESO developed several “bounding” or “bookend” cases that describe,
in an illustrative way, what could happen to market prices if technologies with specific sets of
uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High
Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with
specific attributes were used to replace Ontario’s gas-fired generators. These were compared
with a “Base Case” in which the gas fleet continues to operate.

For the High Base-Load Case, it has been assumed that a fleet of somewhat inflexible resources
has been added to the grid to replace the existing gas fleet. The key distinguishing
characteristics of these resources are that they are not energy-limited, typically operate near
full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to
provide very flexible output or stand by energy such as operating reserves. Similarly, for the
High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby
resources, in combination with intermittent resources, were added to the grid to replace
Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of
renewables that typically offer into the energy market at low to zero prices while the energy-
limited or standby resources look to maximize profit through energy arbitrage and operating
reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes,
but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale
power-markets market could be impacted if resources on two opposite ends of a spectrum of
attributes were chosen to replace Ontario’s gas fleet. More diverse replacement resource supply
mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios
outlined earlier in the report fall within these bookends. Simulations were used to investigate
the potential impact on energy prices, net exports, operating reserve prices, and curtailed
energy. The observations are described below.

The High Base-Load Case

The High Base-Load Case represents a significant build-out of new non-emitting base-load
capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-
load resources offer into the energy market at low to zero prices, and since they replace gas
resources that offer into the energy market at higher prices there is a corresponding decrease
and flattening of energy market prices compared to the Base Case where the gas fleet
continues to operate. As the replacement resources increase the baseload of the supply mix the
occurrence of surplus energy, meaning the availability of energy above that needed to meet the
province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the
persistent decrease in energy market prices in the High Base-Load Case traders are incentivized
to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result,
Ontario could potentially see net exports approximately doubling compared to the Base Case. At
the same time, since the new base-load capacity does not offer operating reserves in the
ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

The High Capacity Case

The High Capacity Case represents a contrasting set of outcomes. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, for a relatively small fraction of the year energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for a small number of hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydro availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, the the impacts to impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure below. (Note: graph annotation still needed, showing how prices become more flat and/or variable)
Market Impacts Discussion

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and that a broad range of potential different outcomes could result across Ontario’s markets. This occurs because the current gas fleet has a unique mix of costs, emissions, and attributes that it supplies to Ontario’s grid, and there is currently no like-for-like but emissions free replacement technology for this gas fleet. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

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Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.
Available Alternatives and Considerations: Hydro Quebec Imports

Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years. Import from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The interconnections in northern Ontario are these type of connections with limited capacities. The interconnection at Bauharnois near St. Lawrence is a same type of interconnection but with a capacity to connect up to 800 MW of generation into Ontario. With the intent to allow dynamic power transactions between Ontario and Quebec, the 1250 MW tie in the Ottawa area was added. It includes an ac-to-dc-to-ac conversion facilities to address the system issue.

Also due to the nature of the system in Ontario near Ottawa, the 1250 MW tie and the 800 MW tie cannot be operated at the combined total level of 2050 MW in summer peak periods. The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. A firm import capability of 1650MW can be obtained with this upgrade. For a firm import capacity beyond 1650 MW would require significant transmission investments. The scope and cost of such investment is not known without discussions/negotiations with Quebec. A nominal cost based on past consideration was used in the development of the portfolios.

Quebec’s electricity demand is projected to grow over the next decade, decreasing its surplus, and exports are generally curtailed during winter peaks, as more than 80% of Québec households use electric heating. Quebec is expected to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. While Quebec is building more wind capacity, this capacity will be energy limited and their ability to export to Ontario will also be limited.

Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030) [RM, VV, DR, SK, JP, JL, DCP]

- In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030
- This section aims to help frame discussions around longer term government targets to reduce economy-wide emissions where electricity could play a significant role.
- Role of demand-side options (e.g. additional EE)
Analysis will outline opportunities and barriers that will need to be addressed including how emerging technologies may participate in the future (e.g. CCUS, hydrogen, etc.)

Hydrogen

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may be come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

Carbon Capture Utilization and Storage

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO2 to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

Distributed Energy Resources

Broader Planning and Coordination

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 MT/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less
economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.

Chapter 5: Conclusion

- Key takeaways [Communications]
Disclaimer [Legal Resources and Corporate Governance]

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Table of Contents [BC]

List of Figures [BC]

List of Tables [BC]

Executive Summary [Communications]

- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X billion, and initiate work immediately for the development X, Y, Z

Chapter 1: Introduction

Study motivation [Communications]

- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.
- Such an undertaking would require a comprehensive plan to develop and invest in suitable replacement supply and reorient the system around the new supply mix in order to maintain the reliability of the system.

Objectives of the study [Communications]

- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered

Report contents [Communications]
• Describe how the report is organized

>>>>>>

Chapter 2: Background and Context Setting

Role of natural gas [RM, VV, MTI]
• How we expect gas will support future reliable electricity system operation (e.g. capacity, energy, operability), including the technical characteristics of Ontario’s gas fleet

Electricity emissions projection of base case [SK]

Summary of current government policy and emissions targets [SK]

Challenges to be considered if phasing out gas generation
• Gas plants are under contract [SK]
• Lots of useful economic life remaining in the gas fleet [SK]
• Much of what we expect could be replacement supply are not developed or unproven at this scale; including effort and timing [RM, VV]
• Locational importance of the gas fleet [JL]
• Lessons learned from off coal [JL]

Opportunities and benefits for phasing out gas generation [RM, VV, DR, SK, JP, JL]
• Emerging technologies, lowered emissions, others

>>>>>>

Chapter 2: Scope of Study

• Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

Scenario development [RM, VV, DR, SK, JP, JL]
• 2020 APO
  o Identify the base case assumptions
    • Base case for demand, supply, transmission, economics, GHG outlook, import/export, etc. is 2020 APO
    • Describe assumptions on benchmark of 370 t CO2/GWh and $50/t carbon price assumed in 2020 APO
• Scenario 1 - Complete gas phase-out by 2030
Identify the assumptions, approach, methodology

- Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030
  - Identify the assumptions, approach, methodology

- Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs
  - Identify the assumptions, approach, methodology

**Areas of study** [RM, VV, DR, SK, JP, JL]

- Discuss the areas of study will include reliability, cost and wholesale market, operability, timing, emissions, others?

**Areas of study that is out of scope** [BC]

- Recommendations for policy decisions
- Demand impacts from decarbonization of the economy
- Consider emission impacts resulting from other jurisdictions

Chapter 3: Study Findings

**Study Findings: Scenario 1 - Complete gas phase-out by 2030**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
• Cost [SK, JP]
• Import/Export [RM, VV, SK]
• Operability impacts [MTI]
• Emission projections [SK]
• Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  o Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs**

• Discussion of reliability impacts [RM, VV, DR]
• Lead times [RM, VV, DR, JL]
• Cost [SK, JP]
• Import/Export [RM, VV, SK]
• Operability impacts [MTI]
• Emission projections [SK]
• Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  o Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Market Impacts** [Market Development & Resource Procurement]

• Qualitative description of market impacts of two bookend scenarios (replacement resource is baseload type resource vs. highly flexible resource); while the three specific scenarios outline above will likely fall within this bookend

**Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030)** [RM, VV, DR, SK, JP, JL]

• In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030
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• Analysis will outline opportunities and barriers that will need to be addressed including how emerging technologies may participate in the future (e.g. CCUS, hydrogen, etc.)
Chapter 4: Conclusion

- Key takeaways [Communications]
Disclaimer [Meaghan McConnell to provide disclaimer once study is close to completion]

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- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.
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Objectives of the study [Communications]

- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered

Report contents [Communications]
Describe how the report is organized

Chapter 2: Background and Context Setting

Role of natural gas [MTI]

- How we expect gas will support future reliable electricity system operation (e.g. capacity, energy, operability), including the technical characteristics of Ontario’s gas fleet

The focus of the analysis will be on the reliability, cost, wholesale market, operability, and timing impacts that need to be addressed should the phase out of natural gas be considered. To do that, it is important to recognize the role that natural gas currently plans in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity and about 7% of total energy in the province, as shown in Figure X.

Figure X: 2022 Installed Capacity and Energy of Natural Gas

[Insert 2022 pie chart – Installed Capacity and Energy Production].

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable supply, including X MW of wind and X MW of solar, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as there is no energy limited. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial as well as frequency response which aids in system recovery following a contingency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

[Operations: add in additional context of operability characteristics of gas]

Electricity emissions projection of base case [SK]

As outlined in the 2020 Annual Planning Outlook, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO₂ e by 2030, still well below 2005 levels. This expected
increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the 2020 APO outlook assumes that existing natural gas will fill in system capacity energy needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

**Summary of Current government emissions policy and emissions targets**

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing greenhouse gas (GHG) emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 tonne/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/tonne of carbon dioxide emissions and increasing to $170/tonne by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

**Challenges to be considered if phasing out gas generation**

- **Gas plants are under contract**

**Gas under contract**

Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to
quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.

<table>
<thead>
<tr>
<th>Remove competition</th>
</tr>
</thead>
<tbody>
<tr>
<td>The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. Resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.</td>
</tr>
</tbody>
</table>

- Locational importance of the gas fleet [JL]
  - During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in strategic locations to reduce the reliance on the transmission system to bring power into the load centres. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by being located where they are, they also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.
  - Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.
  - These gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. This was not a concern when coal-fired generation with gas-fired generation. Without the gas-fired generation, transmission or reactive power source may be required. An example of this is the Toronto area. The peak load in the area may not be supplied reliably without the local gas-fired generation.

- Ramping capability
  - During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. Conversely, when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

- Inertial and frequency response
In the event of a large loss of generation, inertial and frequency response is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

- Restoration path
  - Today, we have black start units that are able to generate without any supply of electricity. This is necessary to prepare the system following a black out. A restoration path requires strategically placed generating units with significant load pickup capability and significant MX absorbing capability to be operable. Currently gas plants are serving that purpose. In the absence of gas, a suitable replacement for this purpose will be required.

- Visibility and Control
  - The bulk of our gas-fired generation fleet is not only visible to the IESO but also dispatchable. If our gas-fired generation fleet were replaced with resources on the distribution system, we would lose visibility and control of a significant amount of MW. This could not only increase complexity of operation but also increase the need for additional services.

- Volume of Resources/Market Participants
  - A large increase in the number of resources and market participants providing capacity to Ontario would create increased workload in the control room. This could potentially distract from other tasks which increased the risk of human error.

- Contingencies
  - In the event the gas fleet is replaced with distributed energy resources, consideration will have to be taken to the amount of sympathetic loss of those resources. Our single largest contingency assessment will need to take into account not only the loss of a generator, but also the assumed amount of sympathetic loss that would also result

- Lessons learned from off coal [JL]

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fire generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation outputs in addition to dealing
with constant demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all.

There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. One important aspect to keep in mind is the variability of wind generation output tends to be seasonal. This poses even greater challenge for storage facilities to complement variable generation in providing what gas generation can provide.

**Opportunities and benefits for phasing out gas generation**

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability:

- Where IESO has needed to procure more supply it has been procuring increasing quantities of these types of resources through IESO’s former DR auction, which has evolved to a capacity auction open to various types of resources including storage and DR
- The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (also known as Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.
- In the event we have an increase to the number of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load generation in key areas where it is needed to help control flows for system limits. This would also help keep things balanced if a unit was lost since it wouldn’t have as much of a large scale impact on the grid. Having multiple units could benefit voltage post contingency with them being situated in key areas and able to respond to dynamic grid changes.

As these new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.

>>>>>>

**Chapter 3: Scope of Study**
Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

**Scenario development** [RM, VV, DR, SK, JP, JL]

**Base Case**

This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^1\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO2e.

The underlying forecast used for the off-gas scenarios is the 2020 APO Scenario 1 (Base Case) load forecast whereby demand commences at 141 TWh to 174 TWh, increasing at an annual rate of \(x\)% per year with conservation energy savings embedded at 3 – 16 TWh. The demand forecast assumes the expected recovery from the COVID-19 pandemic downturn recovers to 2019 levels by the end of 2022. The carbon cost is based on the assumption of a benchmark of 370 t CO2/GWh and \$50/t carbon price. This carbon cost assumption is used in Scenario 1 and 3. For the Scenario 2, the carbon benchmark is projected to decline to 0 t CO2/GWh and a carbon price of \$170/t by 2030.

**Potential Pathways**

This study examines potential pathways to lower emissions through an illustration of complete gas phase out and maintaining stable emissions at current levels:

[Make the 3 Scenarios to something more visual]

1) Scenario 1 - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

2) Scenario 2 - Market based approach that examines higher gas prices and lowered benchmark to reduce utilization of gas to reduce emissions by 2030 to current levels

3) Scenario 3 - Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels

Scenario 1 and 3 uses a supply mix based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliability system in Ontario. Increased shares from any one type of replacement comes with increased risks pertaining to that single source, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited

\(^{1}\) 2017 was a low demand year, and as a result, emissions were lower as the gas fleet ran less.
pool of resources. The supply mix based approach will consider demand-side and supply-side options.

In considering the candidate options, the study considers possible replacement technologies that are established and feasible today. As the reliability coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization that selects resource build-out over the 20 year planning period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO2 emissions at or below annual emissions target
- Sufficient flexible resource to meet system operability requirements, mostly related to ramp rates and integration of variable resources

Cost and performance assumptions for each considered resource are given in Table X. Associated transmission cost assumptions with each resource are provided in Table Y. It should be noted that it is very difficult to determine the required transmission investments without knowing where new generation would be located. Such determination would require much more extensive consideration working with generation developers which cannot be completed within the time allowed for this report. For example, for wind generation, it is recognized that much of the easier locations in the transmission system to incorporate wind generation have already been used to connect the existing wind generation through the past wind generation acquisition processes. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations.

A set of nominal costs was assumed to allow this portfolio analysis to be carried out.

**Table X**: Candidate Options for Replacement Supply for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC ($2020/MWh)</th>
<th>Capacity Cost ($2020/kw-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td></td>
<td>39%</td>
<td>Cost projection based on average of industry capital cost projections²</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td></td>
<td>17%</td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
</tbody>
</table>

² Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)
Hydroelectric Cost Curve

50% Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs

Small Modular Reactors

NA 85%

Firm Imports

150 NA Variable Cost assumption based on requirement of new build hydroelectric capacity in Quebec to provide year-round firm capacity

Energy Efficiency

Four achievable potential scenarios from the 2019 Achievable Potential Study were made available to the model with seasonal energy and capacity reductions and annual program costs

Demand Response

NA 67 NA Cost based on recent capacity auctions

Table Y: Transmission Assumptions for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2020M)</th>
<th>O&amp;M Cost ($2020M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind Solar</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 3,300 MW)</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the optimization model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

Portfolios are modeled seasonally (summer and winter) over 20 years. In each year, the resource portfolios are required to meet the capacity, energy, emissions, and operability requirements referenced above. Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.
Consistent with the project scope details provided in the stakeholder engagement sessions in advance of this study, all supply scenarios include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

The resulting portfolios developed using the least-cost optimization model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

Two laminations of the replacement supply mix were considered, an unconstrained replacement resource mix assuming no barriers on supply resource, regulatory hurdles, land use and other barriers that may limit the amount of resources we can feasibly take up by 2030; and another where constraints were placed.

Scenario 2 is a market based approach that examines higher gas prices to reduce the utilization of gas and its corresponding emissions by 2030. The 2020 APO Scenario 1 is augmented to assume a linear increase to the cost of carbon from $xx/tonne in 20xx to $170/tonne by 2030 plus a linear decline to the benchmark for all natural gas facilities from 370 tonne/GWh in 2021 to zero by 2030. The demand, conservation, transmission and economic outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

An energy production assessment is conducted that includes the economic imports and exports between Ontario and its neighbouring jurisdictions. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability and emissions. The result of the energy assessment is a reduction in gas generation for exports and an increase in imports to meet domestic consumption needs, based on the economics of the higher cost of natural gas from increased cost of carbon and the elimination of the natural gas facility benchmark by 2030.

[Insert figure of modelling approach flow chart]

- [DR: Outline the assumptions and methodology used for Scenario 1 and 3].

Areas of study

The three scenarios described above will be examined from various lenses, including areas of reliability, costs and wholesale market impacts, operability and timing to the electricity system.

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
</table>
| Reliability                 | • Diversity of supply for energy and capacity  
                            • Locational requirements for siting resources, or transmission required to offer alternatives  
                            • Ancillary Services requirements                                                                                                                                                                      |
| Cost and Wholesale Market   | • Lowest net present value replacement supply mix cost  
                            • A coarse range of potential net present value of system costs  
                            • The assessment will use costs for known supply technologies and transmission  
                            • Impact on wholesale market pricing how market value of system needs may change                                                                                                                             |

10
### Areas of study that is out of scope [BC]

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in Chapter 3. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.

>>>>>>

### Chapter 4: Study Findings

#### Study Findings: Scenario 1 - Complete gas phase-out by 2030

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Reference scenario to understand which factors are the largest drivers of ratepayer costs. 

- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply required to completely replace natural gas generation by 2030 is shown in Figure x. In addition to this resource mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix. Two supply portfolios are shown: one with no resource limitations other than demand response, and the other with resource limits of 6,000 MW on wind, solar and storage.

Figure x: 2030 Incremental Installed Capacity, Scenario 1

The complete phase-out of gas by 2030 with replacement by a diverse mix of primarily variable renewable energy and storage resources would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage
resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” outlined in Chapter 4.

Energy Efficiency

Besides those energy efficiency savings considered in the most recent Annual Planning Outlook published in December 2020 and this study, there are potential opportunities to achieve greater electricity savings as identified in the Achievable Potential Study (APS). The most recent APS, which was the first integrated electricity and natural gas achievable potential study, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the reference case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030

The market based approach relies on an energy production assessment that includes economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs. As indicated above this scenario assumes an increase to cost of carbon from $x /tonne in 2022 to $170/tonne by 2030 and an elimination of the natural gas benchmark of 370 t/GWh in 2022 to zero by 2030. With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for Scenario 2. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions will result in an increase to the market clearing prices for Ontario, making Ontario electricity production into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will also off setting more Ontario natural gas production. The change to natural gas production, imports and exports relative to the base case is provided in the figure below.

Figure x: Natural Gas, Imports and Exports TWh comparison.
The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO case analysis. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.

The reduced natural gas production results in GHG emissions remain around 4 MegaTonnes with the market based approach which is consistent to the 2016 to 2020 historical level and declining to 3 Megatonnes by 2030.

Figure x: Emission forecast for Scenario 2 and the 2020 APO Base Case

The cost implications of Scenario 2 relative to the Base Case is x.

Other considerations: The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply required to stabilize 2030 greenhouse gas emissions at 2016-2020 levels is shown in Figure Z. In addition to this supply mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix.

Figure Z: 2030 Incremental Installed Capacity, Scenario 3

![Graph showing incremental installed capacity for Scenario 3]

The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, the need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected, as this energy is required to displace natural gas generation from an energy perspective.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity were sufficient to meet the supply needs of the system.

Energy Efficiency

[Same discussions as Scenario 1]

**Market Impacts** [Market Development & Resource Procurement]

**Background / Introduction:**

Market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of market prices in Ontario. These include direct influences on energy, capacity, and ancillary...
services prices, as well as indirect influences on intertie flows through trader responses to
energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run
marginal production costs, and therefore it has a relatively outsized impact on energy market
prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets,
leading to a new and likely persistent pricing patterns influenced by the characteristics of the
replacement resources and their ability to supply key services. This section explores in more
detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas
generation resources, the IESO developed several “bounding” or “bookend” cases that describe,
in an illustrative way, what could happen to market prices if technologies with specific sets of
uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High
Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with
specific attributes were used to replace Ontario’s gas-fired generators. These were compared
with a “Base Case” in which the gas fleet continues to operate.

For the High Base-Load Case, it has been assumed that a fleet of somewhat inflexible resources
has been added to the grid to replace the existing gas fleet. The key distinguishing
characteristics of these resources are that they are not energy-limited, typically operate near
full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to
provide very flexible output or stand by energy such as operating reserves. Similarly, for the
High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby
resources, in combination with intermittent resources, were added to the grid to replace
Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of
renewables that typically offer into the energy market at low to zero prices while the energy-
limited or standby resources look to maximize profit through energy arbitrage and operating
reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes,
but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale
power-markets market could be impacted if resources on two opposite ends of a spectrum of
attributes were chosen to replace Ontario’s gas fleet. More diverse replacement resource supply
mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios
outlined earlier in the report fall within these bookends. Simulations were used to investigate
the potential impact on energy prices, net exports, operating reserve prices, and curtailed
energy. The observations are described below.

The High Base-Load Case

The High Base-Load Case represents a significant build-out of new non-emitting base-load
capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-
load resources offer into the energy market at low to zero prices, and since they replace gas
resources that offer into the energy market at higher prices there is a corresponding decrease
and flattening of energy market prices compared to the Base Case where the gas fleet
continues to operate. As the replacement resources increase the baseload of the supply mix the
occurrence of surplus energy, meaning the availability of energy above that needed to meet the
province’s energy requirements for most hours of the year, also increases.
Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, for a relatively small fraction of the year energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for a small number of hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydro availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, the the impacts to impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure below. (Note: graph annotation still needed, showing how prices become more flat and/or variable)
Market Impacts Discussion

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and that a broad range of potential different outcomes could result across Ontario’s markets. This occurs because the current gas fleet has a unique mix of costs, emissions, and attributes that it supplies to Ontario’s grid, and there is currently no like-for-like but emissions free replacement technology for this gas fleet. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

//

Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.
Available Alternatives and Considerations: Hydro Quebec Imports

Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years. Import from Quebec is an option to replace gas generation. To what extend it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The interconnections in northern Ontario are these type of connections with limited capacities. The interconnection at Bauharnois near St. Lawrence is a same type of interconnection but with a capacity to connect up to 800 MW of generation into Ontario. With the intent to allow dynamic power transactions between Ontario and Quebec, the 1250 MW tie in the Ottawa area was added. It includes an ac-to-dc-to-ac conversion facilities to address the system issue.

Also due to the nature of the system in Ontario near Ottawa, the 1250 MW tie and the 800 MW tie cannot be operated at the combined total level of 2050 MW in summer peak periods. The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. A firm import capability of 1650MW can be obtained with this upgrade. For a firm import capacity beyond 1650 MW would require significant transmission investments. The scope and cost of such investment is not known without discussions/negotiations with Quebec. A nominal cost based on past consideration was used in the development of the portfolios.

Quebec’s electricity demand is projected to grow over the next decade, decreasing its surplus, and exports are generally curtailed during winter peaks, as more than 80% of Québec households use electric heating. Quebec is expected to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. While Quebec is building more wind capacity, this capacity will be energy limited and their ability to export to Ontario will also be limited.

Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030) [RM, VV, DR, SK, JP, JL, DCP]

- In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030

- This section aims to help frame discussions around longer term government targets to reduce economy-wide emissions where electricity could play a significant role.

- Role of demand-side options (e.g. additional EE)
Analysis will outline opportunities and barriers that will need to be addressed including how emerging technologies may participate in the future (e.g. CCUS, hydrogen, etc.)

Hydrogen

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may be come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

Carbon Capture Utilization and Storage

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO2 to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

Distributed Energy Resources

.....

Broader Planning and Coordination

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 MT/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less
economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.

Chapter 5: Conclusion

- Key takeaways [Communications]
Aim for 30 pages

Disclaimer - Legal

Executive Summary - Comms

Introduction - Comms

Background and Context - Sal

Electricity Emissions in the Context of the Province

Planning and Operating the Bulk Electric System
  - High Level Planning
  - Operating Fundamentals
  - Broader Planning and Coordination

Current Supply Mix and The Role of Natural Gas

Table 1 – Current Resources vs. Reliability Attributes

Lessons Learned from Off Coal

Clean Energy Resources - Shan

Potential Pathways – Candidate options for replacement supply

Table 2 – Replacement Resources vs. Reliability Attributes
  - Incremental Energy Efficiency
  - Demand Response
  - Wind, Solar and Storage
  - Hydroelectric
  - Nuclear – Small and Large
  - Hydro Quebec
  - DER
  - Hydrogen
  - Carbon Capture

Scope of Study – Shan

Areas of study considered/not considered

Scenario Description - Conrad
Base Case 2020 APO – Demand, Supply Mix, Gas Price, Carbon/Current Emissions Policy

APO 2030 Supply Mix

Scenario Descriptions

**Cost Optimization Method and Portfolio Development - Conrad**

Screening

Model Description

Scenario Results

**Challenges to Implementation - Joyce**

Practical Considerations

Tx Plan/Buildout

  Resource connection, “Back bone” Build-Out, Enhanced Interties

Wholesale Market Impacts of the Portfolios

**What If We Wait/Potential System Evolution - TBD**

Lessons Learned from GEA

Current Direction of the System (I.e. In time, we will eventually achieve off gas)

**Conclusions and Next Steps - Comms**

Link to relevant IESO work like Enabling Resources, AAR

**Potential Appendices**

Operability in Depth

Market Impacts in Depth
Disclaimer [Meaghan McConnell to provide disclaimer once study is close to completion]

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Table of Contents [BC]

List of Figures [BC]

List of Tables [BC]

Executive Summary [Communications]

- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X billion, and initiate work immediately for the development X, Y, Z

Chapter 1: Introduction

Study motivation [Communications]

- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.
- Such an undertaking would require a comprehensive plan to develop and invest in suitable replacement supply and reorient the system around the new supply mix in order to maintain the reliability of the system.

Objectives of the study [Communications]

- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered

Report contents [Communications]

1
Describe how the report is organized

Chapter 2: Background and Context Setting

Role of natural gas [MTI]

- How we expect gas will support future reliable electricity system operation (e.g. capacity, energy, operability), including the technical characteristics of Ontario’s gas fleet

The focus of the analysis will be on the reliability, cost, wholesale market, operability, and timing impacts that need to be addressed should the phase out of natural gas be considered. To do that, it is important to recognize the role that natural gas currently plays in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity and about 7% of total energy in the province, as shown in Figure X.

Figure X: 2022 Installed Capacity and Energy of Natural Gas

[Insert 2022 pie chart – Installed Capacity and Energy Production].

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable supply, including X MW of wind and X MW of solar, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as there is they are not energy limited. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provide voltage stability. Additionally, they provide inertial as well as frequency response which aids in system recovery following a contingency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

[Operations: add in additional context of operability characteristics of gas]

Electricity emissions projection of base case [SK]

As outlined in the 2020 Annual Planning Outlook, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO₂ e by 2030, still well below 2005 levels. This expected
increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the outlook assumes that natural gas will fill in system capacity needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

**Summary of current government policy and emissions targets [SK]**

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing GHG emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 t/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/t of carbon dioxide emissions and increasing to $170/t by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

**Challenges to be considered if phasing out gas generation**

- Gas plants are under contract [SK]

Much of Ontario’s current natural gas-fired generation is under contract. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.
The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. Resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

- Locational importance of the gas fleet [JL]
  - During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in strategic locations to reduce the reliance on the transmission system to bring power into the load centres. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by being located where they are, they also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.
  - Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.
  - These gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. This was not a concern when coal-fired generation with gas-fired generation. Without the gas-fired generation, transmission or reactive power source may be required. An example of this is the Toronto area. The peak load in the area may not be supplied reliably without the local gas-fired generation.

- Ramping capability
  - During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. Conversely, when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

- Inertial and frequency response
  - In the event of a large loss of generation, inertial and frequency response is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of
both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

- Restoration path
  - Today, we have black start units that are able to generate without any supply of electricity. This is necessary to prepare the system following a black out. A restoration path requires strategically placed generating units with significant load pickup capability and significant MX absorbing capability to be operable. Currently gas plants are serving that purpose. In the absence of gas, a suitable replacement for this purpose will be required.

- Visibility and Control
  - The bulk of our gas-fired generation fleet is not only visible to the IESO but also dispatchable. If our gas-fired generation fleet were replaced with resources on the distribution system, we would lose visibility and control of a significant amount of MW. This could not only increase complexity of operation but also increase the need for additional services.

- Volume of Resources/Market Participants
  - A large increase in the number of resources and market participants providing capacity to Ontario would create increased workload in the control room. This could potentially distract from other tasks which increased the risk of human error.

- Contingencies
  - In the event the gas fleet is replaced with distributed energy resources, consideration will have to be taken to the amount of sympathetic loss of those resources. Our single largest contingency assessment will need to take into account not only the loss of a generator, but also the assumed amount of sympathetic loss that would also result

- Lessons learned from off coal [JL]

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fire generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation in addition to dealing with demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all.
There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. One important aspect to keep in mind is the variability of wind generation output tends to be seasonal. This poses even greater challenge for storage facilities to complement variable generation in providing what gas generation can provide.

**Opportunities and benefits for phasing out gas generation**

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability:

- Where IESO has needed to procure more supply it has been procuring increasing quantities of these types of resources through IESO’s former DR auction, which has evolved to a capacity auction open to various types of resources including storage and DR.
- The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (also known as Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.
- In the event we have an increase to the number of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load generation in key areas where it is needed to help control flows for system limits. This would also help keep things balanced if a unit was lost since it wouldn’t have as much of a large scale impact on the grid. Having multiple units could benefit voltage post contingency with them being situated in key areas and able to respond to dynamic grid changes.

As these new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.

>>>>

**Chapter 3: Scope of Study**

- Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

**Scenario development** [RM, VV, DR, SK, JP, JL]
**Base Case**

This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^1\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO\(_2\)e.

The underlying forecast used for the off-gas scenarios is the 2020 APO Scenario 1 (Base Case) load forecast whereby demand commences at 141 TWh to 174 TWh, increasing at an annual rate of x\% per year with conservation energy savings embedded at 3 – 16 TWh. The demand forecast assumes the expected recovery from the COVID-19 pandemic downturn recovers to 2019 levels by the end of 2022. The carbon cost is based on the assumption of a benchmark of 370 t CO\(_2\)/GWh and $50/t carbon price. This carbon cost assumption is used in Scenario 1 and 3. For the Scenario 2, the carbon benchmark is projected to decline to 0 t CO\(_2\)/GWh and a carbon price of $170/t by 2030.

**Potential Pathways**

This study examines potential pathways to lower emissions through an illustration of complete gas phase out and maintaining stable emissions at current levels:

[Make the 3 Scenarios to something more visual]

1) Scenario 1 - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

2) Scenario 2 - Market based approach that examines higher gas prices and lowered benchmark to reduce utilization of gas to reduce emissions by 2030 to current levels

3) Scenario 3 - Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels

Scenario 1 and 3 uses a supply mix based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliability system in Ontario. Increased shares from any one type of replacement comes with increased risks pertaining to that single source, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix based approach will consider demand-side and supply-side options.

In considering the candidate options, the study considers possible replacement technologies that are established and feasible today. As the reliability coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale.

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1 2017 was a low demand year, and as a result, emissions were lower as the gas fleet ran less.
scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization that selects resource build-out over the 20 year planning period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO2 emissions at or below annual emissions target
- Sufficient flexible resource to meet system operability requirements, mostly related to ramp rates and integration of variable resources

Cost and performance assumptions for each considered resource are given in Table X. Associated transmission cost assumptions with each resource are provided in Table Y.

**Table X: Candidate Options for Replacement Supply for Scenario 1 and 3**

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC ($2020/MWh)</th>
<th>Capacity Cost ($2020/kw-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td></td>
<td>39%</td>
<td>Cost projection based on average of industry capital cost projections</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td></td>
<td>17%</td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>Cost Curve</td>
<td></td>
<td>50%</td>
<td>Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs</td>
</tr>
<tr>
<td>Small Modular Reactors</td>
<td>NA</td>
<td>NA</td>
<td>85%</td>
<td></td>
</tr>
<tr>
<td>Firm Imports</td>
<td>150</td>
<td>NA</td>
<td>Variable</td>
<td>Cost assumption based on requirement of new build hydroelectric capacity in Quebec to provide year-round firm capacity</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>Four achievable potential scenarios from the 2019 Achievable Potential Study were made available to the model with seasonal energy and capacity reductions and annual program costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand</td>
<td>NA</td>
<td>67</td>
<td>NA</td>
<td>Cost based on recent capacity</td>
</tr>
</tbody>
</table>

2 Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)
Response auctions

Table Y: Transmission Assumptions for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2020M)</th>
<th>O&amp;M Cost ($2020M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelecic capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>Firm Imports</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
<tr>
<td>(&lt;= 1,800 MW)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Firm Imports</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(&lt;= 3,300 MW)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the optimization model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

Portfolios are modeled seasonally (summer and winter) over 20 years. In each year, the resource portfolios are required to meet the capacity, energy, emissions, and operability requirements referenced above. Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

Consistent with the project scope details provided in the stakeholder engagement sessions in advance of this study, all supply scenarios include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

The resulting portfolios developed using the least-cost optimization model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

Two laminations of the replacement supply mix were considered, an unconstrained replacement resource mix assuming no barriers on supply resource, regulatory hurdles, land use and other barriers that may limit the amount of resources we can feasibly take up by 2030; and another where constraints were placed.

Scenario 2 is a market based approach that examines higher gas prices to reduce the utilization of gas and its corresponding emissions by 2030. The 2020 APO Scenario 1 is augmented to
assume a linear increase to the cost of carbon from $xx/tonne in 20xx to $170/tonne by 2030 plus a linear decline to the benchmark for all natural gas facilities from 370 tonne/GWh in 2021 to zero by 2030. The demand, conservation, transmission and economic outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

An energy production assessment assessment is conducted that includes the economic imports and exports between Ontario and its neighbouring jurisdictions. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability and emissions. The result of the energy assessment is a reduction in gas generation for exports and an increase in imports to meet domestic consumption needs, based on the economics of the higher cost of natural gas from increased cost of carbon and the elimination of the natural gas facility benchmark by 2030.

[Insert figure of modelling approach flow chart]

- [DR: Outline the assumptions and methodology used for Scenario 1 and 3].

Areas of study

The three scenarios described above will be examined from various lenses, including areas of reliability, costs and wholesale market impacts, operability and timing to the electricity system.

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>• Diversity of supply for energy and capacity&lt;br&gt;• Locational requirements for siting resources, or transmission required to offer alternatives&lt;br&gt;• Ancillary Services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale Market</td>
<td>• Lowest net present value replacement supply mix cost&lt;br&gt;• A coarse range of potential net present value of system costs&lt;br&gt;• The assessment will use costs for known supply technologies and transmission&lt;br&gt;• Impact on wholesale market pricing how market value of system needs may change</td>
</tr>
<tr>
<td>Operability</td>
<td>• Operability and impact to wholesale market design (e.g. day-ahead and real-time energy, Operating Reserve, and Ancillary Services) and confirmation that the market can operate the supply mix</td>
</tr>
<tr>
<td>Timing</td>
<td>• Typical timelines associated with construction of generation or transmission (e.g. environmental assessments, regulatory proceedings, construction, commissioning, etc.)</td>
</tr>
</tbody>
</table>

Areas of study that is out of scope [BC]

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high
electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in Chapter 3. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.

Chapter 4: Study Findings

Study Findings: Scenario 1 - Complete gas phase-out by 2030

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Reference scenario to understand which factors are the largest drivers of ratepayer costs.
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.
The incremental supply required to completely replace natural gas generation by 2030 is shown in Figure x. In addition to this resource mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix. Two supply portfolios are shown: one with no resource limitations other than demand response, and the other with resource limits of 6,000 MW on wind, solar and storage.

Figure x: 2030 Incremental Installed Capacity, Scenario 1

The complete phase-out of gas by 2030 with replacement by a diverse mix of primarily variable renewable energy and storage resources would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” outlined in Chapter 4.

Energy Efficiency

Besides those energy efficiency savings considered in the most recent Annual Planning Outlook published in December 2020 and this study, there are potential opportunities to achieve greater electricity savings as identified in the Achievable Potential Study (APS). The most recent APS, which was the first integrated electricity and natural gas achievable potential study, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market...
barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the reference case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

**Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030**

The market based approach relies on an energy production assessment that includes economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs. As indicated above this scenario assumes an increase to cost of carbon from $x/tonne in 2022 to $170/tonne by 2030 and an elimination of the natural gas benchmark of 370 t/GW in 2022 to zero by 2030. With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for Scenario 2. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions will result in an increase to the market clearing prices for Ontario, making Ontario electricity production into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will also off setting more Ontario natural gas production. The change to natural gas production, imports and exports relative to the base case is provided in the figure below.

Figure x: Natural Gas, Imports and Exports TWh comparison.

The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO case analysis. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.

The reduced natural gas production results in GHG emissions remain around 4 MegaTonnes with the market based approach which is consistent to the 2016 to 2020 historical level and declining to 3 Megatonnes by 2030.

Figure x: Emission forecast for Scenario 2 and the 2020 APO Base Case

The cost implications of Scenario 2 relative to the Base Case is x.
Other considerations: The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply required to stabilize 2030 greenhouse gas emissions at 2016-2020 levels is shown in Figure Z. In addition to this supply mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix.

**Figure Z: 2030 Incremental Installed Capacity, Scenario 3**
The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, the need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected, as this energy is required to displace natural gas generation from an energy perspective.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity were sufficient to meet the supply needs of the system.

Energy Efficiency

[Same discussions as Scenario 1]

**Market Impacts** [Market Development & Resource Procurement]

**Background / Introduction:**

Market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario's markets, leading to a new and likely persistent pricing patterns influenced by the characteristics of the replacement resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe,
in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with a “Base Case” in which the gas fleet continues to operate.

For the High Base-Load Case, it has been assumed that a fleet of somewhat inflexible resources has been added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide very flexible output or stand by energy such as operating reserves. Similarly, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources look to maximize profit through energy arbitrage and operating reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power-markets market could be impacted if resources on two opposite ends of a spectrum of attributes were chosen to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

The High Base-Load Case

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources offer into the energy market at low to zero prices, and since they replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy, meaning the availability of energy above that needed to meet the province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand.
and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, for a relatively small fraction of the year energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for a small number of hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydro availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, the the impacts to impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure below. (Note: graph annotation still needed, showing how prices become more flat and/or variable)
Market Impacts Discussion

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and that a broad range of potential different outcomes could result across Ontario’s markets. This occurs because the current gas fleet has a unique mix of costs, emissions, and attributes that it supplies to Ontario’s grid, and there is currently no like-for-like but emissions free replacement technology for this gas fleet. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

//

Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.
Available Alternatives and Considerations: Hydro Quebec Imports

Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years. Import from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The 1250 MW tie at with Quebec in the Ottawa area includes an ac-to-dc-to-ac conversion facilities to address this issue.

---work in progress...

The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. An import capability of 1650MW can be obtained with this upgrade. Replacing any significant part of the gas supply with imports would require new interconnection points along the border and substantial and costly transmission infrastructure projects to replace the lines currently serving gas generators.

Quebec's electricity demand is projected to grow over the next decade, decreasing its surplus, and exports are generally curtailed during winter peaks, as more than 80% of Québec households use electric heating. Quebec is expected to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. While Quebec is building more wind capacity, this capacity will be energy limited and their ability to export to Ontario will also be limited.

Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030) [RM, VV, DR, SK, JP, JL, DCP]

- In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030
- This section aims to help frame discussions around longer term government targets to reduce economy-wide emissions where electricity could play a significant role.
- Role of demand-side options (e.g. additional EE)
- Analysis will outline opportunities and barriers that will need to be addressed including how emerging technologies may participate in the future (e.g. CCUS, hydrogen, etc.)

Hydrogen

19
There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may be come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

Carbon Capture Utilization and Storage

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO2 to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

Distributed Energy Resources

......

Broader Planning and Coordination

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 MT/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.

>>>>>
Chapter 5: Conclusion

- Key takeaways [Communications]
Disclaimer [Meaghan McConnell to provide disclaimer once study is close to completion]

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>>>>

Table of Contents [BC]
List of Figures [BC]
List of Tables [BC]

>>>>

Executive Summary [Communications]
- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X billion, and initiate work immediately for the development X, Y, Z

>>>>

Chapter 1: Introduction

Study motivation [Communications]
- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.
- Such an undertaking would require a comprehensive plan to develop and invest in suitable replacement supply and reorient the system around the new supply mix in order to maintain the reliability of the system.

Objectives of the study [Communications]
- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered

Report contents [Communications]
Describe how the report is organized

Chapter 2: Background and Context Setting

Role of natural gas [MTI]

- How we expect gas will support future reliable electricity system operation (e.g. capacity, energy, operability), including the technical characteristics of Ontario’s gas fleet

The focus of the analysis will be on the reliability, cost, wholesale market, operability, and timing impacts that need to be addressed should the phase out of natural gas be considered. To do that, it is important to recognize the role that natural gas currently plays in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity and about 7% of total energy in the province, as shown in Figure X.

Figure X: 2022 Installed Capacity and Energy of Natural Gas

[Insert 2022 pie chart – Installed Capacity and Energy Production].

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable supply, including X MW of wind and X MW of solar, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial as well as frequency response which aids in system recovery following a contingency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

Electricity emissions projection of base case [SK]

As outlined in the 2020 Annual Planning Outlook, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO₂ e by 2030, still well below 2005 levels. This expected
increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the 2020 APOoutlook assumes that existing natural gas will fill in system capacity energy needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

**Summary of c**urrent government emissions policy and emissions targets [SK]

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing greenhouse gas (GHG) emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 tonnes/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/tonne of carbon dioxide emissions and increasing to $170/tonne by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

**Challenges to be considered if phasing out gas generation**

- **Gas plants are under contract [SK]**

Gas under contract

Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to
quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.

Remove competition

The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. Resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

Locational importance of the gas fleet

During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in strategic locations to minimize transmission investments to incorporate the resource into the system, reduce the reliance on the transmission system to bring power into the load centres. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by being located where they are, also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.

Some of the gas-fired non-utility generators, or "NUGs", also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.

These gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. This was not a concern when coal-fired generation with gas-fired generation. Without the gas-fired generation, transmission or reactive power source may be required. An example of this is the Toronto area. The peak load in the area may not be supplied reliably without the local gas-fired generation.

Ramping capability

During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. Conversely, when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

Inertial and frequency response

In the event of a large loss of generation, inertial and frequency response is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post
contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

Restoration path

Today, we have black start units that are able to generate without any supply of electricity. This is necessary to prepare the system following a black out. A restoration path requires strategically placed generating units with significant load pickup capability and significant MX absorbing capability to be operable. Currently gas plants are serving that purpose. In the absence of gas, a suitable replacement for this purpose will be required.

Visibility and Control

The bulk of our gas-fired generation fleet is not only visible to the IESO but also dispatchable. If our gas-fired generation fleet were to be replaced with resources on the distribution system, the IESO would lose visibility and control of a significant amount of MWs. This could not only increase complexity of operation but also increase the need for additional services.

Volume of Resources/Market Participants

A large increase in the number of resources and market participants providing capacity to Ontario would create increased workload in the control room. This could potentially distract from other tasks which increased the risk of human error.

Contingencies

In the event the gas fleet is replaced with distributed energy resources, consideration will have to be taken to the amount of sympathetic loss of those resources. Our single largest contingency assessment will need to take into account not only the loss of a generator, but also the assumed amount of sympathetic loss that would also result.

Lessons learned from off coal

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fired generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation in addition to dealing with demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all.
There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. One important aspect to keep in mind is the variability of wind generation output tends to be seasonal. This poses even greater challenge for storage facilities to complement variable generation in providing what gas generation can provide.

**Opportunities and benefits for phasing out gas generation**

There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. 

With wind resources, variability of generation output tends to be seasonal. One important aspect to keep in mind is the variability of wind generation output tends to be seasonal. This seasonality poses even greater challenges for storage facilities to complement variable generation in providing what gas generation can provide.

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability:

- Where IESO has needed to procure more supply it has been procuring increasing quantities of these types of resources through IESO’s former DR auction, which has evolved to a capacity auction open to various types of resources including storage and DR

- The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (also known as Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

- In the event the amount we have an increase to the number of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load generation in key areas where it is needed to help control flows for system limits. Large number of resources can minimize risk considering a loss of generation would not. This would also help keep things balanced if a unit was lost since it wouldn’t have as much of a large scale impact on the grid. Having multiple units could benefit voltage post contingency with them being situated in key areas and able to respond to dynamic grid changes.
As these new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.

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Chapter 3: Scope of Study

- Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

Scenario development [RM, VV, DR, SK, JP, JL]

Base Case

This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020 to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO2e.

The underlying forecast used for the off-gas scenarios is the 2020 APO Scenario 1 (Base Case) load forecast whereby demand commences at 141 TWh to 174 TWh, increasing at an annual rate of x% per year with conservation energy savings embedded at 3 – 16 TWh. The demand forecast assumes the expected recovery from the COVID-19 pandemic downturn recovers to 2019 levels by the end of 2022.

—The carbon cost is based on the assumption of a benchmark of 370 tonne CO2/GWh allowance for existing natural gas generators and $50/tonne carbon price in 2022 and held constant there after. This carbon cost assumption is used in Scenario 1 and 3. For the Scenario 2, the carbon benchmark is projected to decline to 0 t CO2/GWh and a carbon price of $170/t by 2030.

Potential Pathways

This study examines potential pathways to lower emissions through an illustration of complete gas phase out and maintaining stable emissions at current levels:

[Make the 3 Scenarios to something more visual]

1) Scenario 1 - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

2) Scenario 2 - Market based approach where increased carbon cost and decreased benchmark that examines higher gas prices and lowered benchmark to reduce the utilization of gas to reduce emissions by 2030 to current levels

1 2017 was a low demand year, and as a result, emissions were lower as the gas fleet ran less.
3) Scenario 3 - Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels

Scenario 1 and 3 uses a supply mix based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliability system in Ontario. Increased shares from any one type of replacement comes with increased risks pertaining to that single source, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix based approach will consider demand-side and supply-side options. **Scenario 2 considers a tightening of carbon policy to drive changes, and did not apply a supply mix based approach.**

In considering the candidate options, the study considers possible replacement technologies that are established and feasible today. As the reliability coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. **It is difficult to predict technology innovations, policy developments, and grid evolutions that could manifest in the study time frame – factors that could result in alternate supply mixes. The IESO aimed to provide a set of reasonable forward looking lowest cost estimates given professional judgement and the current information available.** The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization that selects resource build-out over the 20 year planning period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO2 emissions at or below annual emissions target
- Sufficient flexible resource to meet system operability requirements, mostly related as it relates to ramp rates and integration of variable resources

Cost and performance assumptions for each considered resource are given in Table X. Associated transmission cost assumptions with each resource are provided in Table Y.

**Table X: Candidate Options for Replacement Supply for Scenario 1 and 3**

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC ($2020/MWh)</th>
<th>Capacity Cost ($2020/kw-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td></td>
<td>39%</td>
<td>Cost projection based on average of industry capital</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td></td>
<td>17%</td>
<td></td>
</tr>
<tr>
<td>Resource</td>
<td>Capital Cost ($2020M)</td>
<td>O&amp;M Cost ($2020M/year)</td>
<td>Notes</td>
<td></td>
</tr>
<tr>
<td>----------</td>
<td>-----------------------</td>
<td>------------------------</td>
<td>-------</td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1,500 MW of additional wind and solar capacity</td>
<td></td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
<td></td>
</tr>
<tr>
<td>Firm Imports (&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
<td></td>
</tr>
<tr>
<td>Firm Imports (&lt;= 3,300 MW)</td>
<td>2,200</td>
<td>22</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the optimization model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

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2 Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)
Portfolios are modeled seasonally (summer and winter) over 20 years. In each year, the resource portfolios are required to meet the capacity, energy, emissions, and operability requirements referenced above. Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

Consistent with the project scope details provided in the stakeholder engagement sessions in advance of this study, all supply scenarios include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

The resulting portfolios developed using the least-cost optimization model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

Two laminations of the replacement supply mix were considered, an unconstrained replacement resource mix assuming no barriers on supply resource, regulatory hurdles, land use, suitable technical potential and other barriers that may limit the amount of resources we can feasibly take up by 2030; and another where constraints were placed.

Scenario 2 is a market based approach where increased carbon cost and decrease benchmark that examines higher gas prices to reduce the utilization of gas and its corresponding emissions by 2030. The carbon cost The 2020 APO Scenario 1 is augmented to assumes a linear increase to the cost of carbon from $50/tonne in 2022 to $170/tonne by 2030 and plus a linear decline to the benchmark for all natural gas facilities linearly deline from 370 tonne/GWh in 2021 to zero by 2030. The demand, conservation, transmission and economic outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

An economic hourly dispatch model was used to determine the outcomes of the three scenarios. An energy production assessment is conducted that includes the economic imports and exports between Ontario and its neighbouring jurisdictions. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability, and emissions and imports and exports.

- The result of the energy assessment is a reduction in gas generation for exports and an increase in imports to meet domestic consumption needs, based on the economics of the higher cost of natural gas from increased cost of carbon and the elimination of the natural gas facility benchmark by 2030.

[Insert figure of modelling approach flow chart]

[DR: Outline the assumptions and methodology used for Scenario 1 and 3].

Areas of study

The three scenarios described above will be examined from various lenses, including areas of reliability, costs and wholesale market impacts, operability and timing to the electricity system.

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
</table>

10
Reliability
- Diversity of supply for energy and capacity
- Locational requirements for siting resources, or transmission required to offer alternatives
- Ancillary services requirements

Cost and Wholesale Market
- Lowest net present value replacement supply mix cost
- A coarse range of potential net present value of system costs
- The assessment will use costs for known supply technologies and transmission
- Impact on wholesale market pricing how market value of system needs may change

Operability
- Operability and impact to wholesale market design (e.g. day-ahead and real-time energy, Operating Reserve, and Ancillary Services) and confirmation that whether the market can operate the supply mix

Timing
- Typical timelines associated with construction of generation or transmission (e.g. environmental assessments, regulatory proceedings, construction, commissioning, etc.)

Areas of study that is out of scope [BC]

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in Chapter 3. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.
Chapter 4: Study Findings

Study Findings: Scenario 1 - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030 Complete gas phase-out by 2030

Place content here

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]

While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Reference scenario Base Case to understand which factors are the largest drivers of ratepayer costs.

- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]

  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply above the Base Case required to completely replace natural gas generation by 2030 is shown in Figure x. In addition to this resource mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix. Two supply portfolios are shown: one with no resource limitations other than demand response, and the other with resource limits of 6,000 MW on wind, solar and storage.

Figure x: 2030 Incremental Installed Capacity, Scenario 1
The complete phase-out of gas by 2030 with replacement by a diverse mix of primarily variable renewable energy and storage resources would lead to a variety of key developments in Ontario's markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario's markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” outlined later in Chapter 4.

Energy Efficiency

Besides those energy efficiency savings considered in the most recent 2020 Annual Planning Outlook published in December 2020 and similarly in this study, there are potential opportunities to achieve greater electricity savings as identified in the Achievable Potential Study (APS). The most recent APS, which was the first integrated electricity and natural gas achievable potential study, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non-energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the reference-case Base Case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.
**Firm imports**

Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.

**Study Findings: Scenario 2 - Market based approach**

The market based approach relies on an energy production assessment that includes economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs and lowered carbon benchmark. As indicated above, this scenario assumes an increase to cost of carbon from $50/tonne in 2022 to $170/tonne by 2030 and an elimination of the natural gas benchmark of 370 tonne/GWh in 2022 to 0 tonne/GWh by 2030. With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for Scenario 2. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions will result in an increase to the market clearing prices for Ontario, making Ontario electricity production into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will also offset more Ontario natural gas production. The change to natural gas production, imports and exports relative to the Base Case is provided in the figure below.

Figure X: Natural Gas, Imports and Exports TWh-comparison relative to the Base Case.

The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO Base Case analysis. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.

The reduced natural gas production results in GHG emissions remain around 4 MegaTonnes with the market-based approach in Scenario 2 which is consistent to the 2016 to 2020 historical level and declining to 3 Megatonnes by 2030, as shown in Figure X.

Figure X: Emission forecast for Scenario 2 and the 2020 APO Base Case.
The cost implications of Scenario 2 relative to the Base Case is x. 

**Other considerations:**—The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply above the Base Case required to stabilize 2030 greenhouse gas emissions at 2016-2020 levels is shown in Figure Z. In addition to this supply mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix.

Figure Z: 2030 Incremental Installed Capacity, Scenario 3
The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, the need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected in the resource portfolio optimizer, as this energy is required to displace natural gas generation from an energy perspective.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity were sufficient to meet the supply needs of the system.

Energy Efficiency

[Same discussions as Scenario 1]

Market Impacts [Market Development & Resource Procurement]

Background / Introduction:

Market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to a new and likely persistent pricing patterns influenced by the characteristics of the replacement resources and their ability to supply key services. This section explores in more detail some of these potential impacts.
In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with a “Base Case” in which the gas fleet continues to operate.

For the High Base-Load Case, it has been assumed that a fleet of somewhat inflexible resources has been added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide very flexible output or stand by energy such as operating reserves. Similarly, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources look to maximize profit through energy arbitrage and operating reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power-markets market could be impacted if resources on two opposite ends of a spectrum of attributes were chosen to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

The High Base-Load Case

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources offer into the energy market at low to zero prices, and since they replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy, meaning the availability of energy above that needed to meet the province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the
availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

The High Capacity Case

The High Capacity Case represents a contrasting set of outcomes. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much of the year. However, for a relatively small fraction of the year energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for a small number of hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydroelectric availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, the impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure below. (Note: graph annotation still needed, showing how prices become more flat and/or variable)
Market Impacts Discussion

- In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

- Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and that a broad range of potential different outcomes could result across Ontario’s markets. This occurs because the current gas fleet has a unique mix of costs, emissions, and attributes that it supplies to Ontario’s grid, and there is currently no like-for-like but emissions free replacement technology for this gas fleet. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

//

Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.
Available Alternatives and Considerations: Hydro Quebec Imports Considerations

Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years. Import from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The 1,250 MW tie at with Quebec in the Ottawa area includes an ac-to-dc-to-ac conversion facilities to address this issue.

---work in progress...

The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. An import capability of 1,650MW can be obtained with this upgrade. Replacing any significant part of the gas supply with imports would require new interconnection points along the border and substantial and costly transmission infrastructure projects to replace the lines currently serving gas generators.

Quebec’s electricity demand is projected to grow over the next decade, decreasing its surplus, and exports are generally curtailed during winter peaks, as more than 80% of Québec households use electric heating. Quebec is expected to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. While Quebec is building more wind capacity, this capacity will be energy limited and their ability to export to Ontario will also be limited.

Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030) [RM, VV, DR, SK, JP, JL, DCP]

- In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030
- This section aims to help frame discussions around longer term government targets to reduce economy-wide emissions where electricity could play a significant role.
- Role of demand-side options (e.g. additional EE)
- Analysis will outline opportunities and barriers that will need to be addressed including how emerging technologies may participate in the future (e.g. CCUS, hydrogen, etc.)

Hydrogen
There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may be come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

Carbon Capture Utilization and Storage

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO2 to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

Distributed Energy Resources

.....

**Broader Planning and Coordination**

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 MT/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.
Chapter 5: Conclusion

- Key takeaways [Communications]
Considerations for Phasing Out Natural Gas in the Electricity System

September 2021
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Scenario 2 - Market based approach where increased carbon cost and decreased benchmark reduce the utilization of gas to reduce emissions by 2030 to current levels.

Scenario 3 - Supply mix-based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels.

Developing a Transmission Plan

Delivering the Replacement Supply Mix

Maintaining Reliability Currently Provided by Strategically Located Gas Plants

Operability Considerations

Diversity

Flexibility

Ramping Considerations

Manageability

Additional Reliability Concerns and Considerations

Location

Single Largest Contingencies

System Restoration Plan

Inverter Based Resource

Rapid growth of inverter-based resources ("IBRs") add complexity to grid reliability. These include most solar and wind as well as battery storage, hybrid generation and many DER. Some inverter-based resource performance issues have been significant in recent grid disturbances, such as the tripping of a number of BPS-connected solar PV generation that occurred during the 2016 Blue Cut Fire, 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California.

Practical Considerations

Gas Under Contract

Eliminates Competition

Land Use and Siting

Variable Generation and Storage

Timing

Hydro Quebec Imports Considerations

Wholesale Market Impacts

Context

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Opportunities and Benefits for Phasing Out Gas Generation

Scope of Study

Background

Scenario Development

Base Case

Potential Pathways

Modeling Approach

Areas of Study

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Study Findings

Scenario 1 - Supply mix-based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

Scenario 2 - Market-based approach where increased carbon cost and decreased benchmark reduce the utilization of gas to reduce emissions by 2030 to current levels

Scenario 3 - Supply mix-based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels

Operability Considerations

Diversity

Flexibility

Manageability

Additional Operability Considerations

Locational Importance of the Supply Mix

Single Largest Contingencies

System Restoration Plan

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Eliminates Competition
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Executive Summary

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Key Findings

The following key findings provide insights into the opportunities and challenges the sector has to consider under future pathways for lowered emissions.

E.g. To lower emissions by 2030 to 2016-2020 levels, it is expected to cost $X-Y billion, and these are the things that have to happen for that to work. These are the challenges expected for the three scenarios.

NTD: Some initial thoughts on my key takeaways so far (Dave D). Feel free to comment/edit/add.

We can refine as the costs come in:

- Our model portfolios were intended to help us understand the likely range of costs for the proposed shift from gas.
- We have done our best to produce portfolios that are technically feasible. The mixes that we have put forward have passed our coarse tests for reliability and operability, but should not be viewed as detailed power system plans. If we were directed to implement these supply mixes, we would need to devote significant effort to refining the mix, develop tools, and operationalize the plan.
- We believe that a 2030 date for gas phase out is extremely ambitious. To develop a feasible mix for this scenario, we have relied on a number of optimistic assumptions – both technical and practical:
  - Technical:
    - Our mix assumes that large scale energy storage can be completely operationalized. At present, we have limited experience with the likely storage technologies, with the exception of pumped hydro. We believe that the storage we have modelled can provide capacity, load following and ancillary services. The limitations of our modelling raise questions about how we might address multi-day high demand events (e.g. heat wave or polar vortex).
    - We assume that a small modular nuclear reactor will be in service.
    - We assume that IESO would have full visibility of all resources on the distribution systems, and the ability to dispatch these resources. We assume that IESO systems would be upgraded to allow for continuous monitoring, dispatch, and contingency analysis.
    - We have assumed that we can leverage the existing transmission system as much as possible, siting non-emitting resources in zones to replace gas.
  - Practical:
    - Our portfolio includes a significant build-out of renewable resources. We have assumed that land use/siting is not an issue. To secure the volumes of renewables needed, off-shore wind may need to be considered.
    - We have not provided a detailed transmission plan, as the physical locations of new resources would need to be known first. We believe that it is reasonable to think that upgrades are need to enable resources in the North, increase imports from Quebec, and add to supply for the GTA.
We would require a number of enabling policies to support increased energy efficiency, fast-track construction, enable siting of resources in key electrical areas.

- **Operability:**
  - Our portfolio does not have any locational details which would be required to assess its operability. Without generation in key locations, and full visibility and control of resources placed on the distribution system, the portfolio may be difficult to operate reliably.
  - Certain characteristics provided by the existing gas fleet such as inertial and frequency response, ancillary services and voltage support will need to be replaced for reliable operation.
  - The portfolio will also need to be dispatchable and provide the flexibility of operation our gas fleet provides to ensure operability during times, particularly when ramping capability is required.
Introduction

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Background and Context

Role of Natural Gas

The focus of this study will investigate the impacts that need to be addressed should the phase out of natural gas be considered. To achieve that, it is important to recognize the role that natural gas currently plays in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW\(^1\), accounting for about 25% of total installed capacity, as shown in Figure 1, and represents about 7% of total energy in the province.

Figure 1 | 2022 Installed Capacity by Fuel Type

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable and intermittent supply, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as there are generally available at all times of the day. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial as well as fast frequency-dynamic response which aids in system recovery following a significant contingency in maintaining system frequency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

Electricity Emissions Projection in 2020 Annual Planning Outlook

As outlined in the 2020 Annual Planning Outlook (APO), the electricity sector emissions are forecast to increase to 12.2 megatonnes (Mt\(^2\)) CO\(_2\) by 2030, still well below 2005 levels. This expected increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the 2020 APO assumes that existing natural gas will fill in system energy needs. As electricity consumption

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1. Ontario’s natural gas fleet is largely connected on the transmission system.

12. Considerations for Phasing Out Natural Gas in the Electricity System | Public
increases, the rise in electricity sector emissions could be reduced by increased energy efficiency and non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

Current Government Emissions Policy and Emissions Targets

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing greenhouse gas (GHG) emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario's EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 tonnes CO\textsubscript{2}/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/tonne of CO\textsubscript{2} emissions and increasing to $170/tonne by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries. With a threshold allowance of 370 tonnes CO\textsubscript{2}/GWh, there are currently no natural gas generating units in Ontario that would receive a credit.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario's EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

Lessons Learned from Off Coal

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fired generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation outputs in addition to dealing with constant demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all. When considering which resource(s) to use in place of the natural gas fleet, there are no readily available resource types that can offer the same level of on-demand energy availability and flexibility by themselves. To replace the gas fleet, a combination of many resources would be required, including (but not limited to) variable generation, storage, imports and DR demand response.
Bringing on large numbers of generators with a different fuel-type than coal posed new administrative and operational challenges. The IESO developed new approaches to monitor and operate different forms of generation. New approaches were developed to manage variable generation, including increased visibility of current variable generation output, enhanced methods to forecast variable generation output, and processes to dispatch variable generation resources.

Further, certain coal-fired power plants were located in strategic areas that supported loads centres and ultimately reduced the reliance of power being delivered from the transmission system. For instance, the former coal-fired Hearn generating station supported Toronto and central GTA transmission systems, Lakeview supported the southwestern and western GTA. The replacement of such strategically located facilities was achieved by what has been colloquially referred to as the “smart gas strategy”, which saw adding facilities like Portlands Energy Centre, as well as Sithe Goreway and Halton Hills sited in a way to avoid the need to reinforce significant amounts of the transmission system that Hearn and Lakeview otherwise supported.

Opportunities and Benefits for Phasing Out Gas Generation

There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. With wind resources, variability of generation output tends to be seasonal. This seasonality poses greater challenges for storage facilities to complement variable generation in providing what gas generation can provide.

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability. Where IESO has needed to procure more supply, it has been procuring increasing quantities of these types of resources through IESO’s former Demand Response auction, which has evolved to a capacity auction open to various types of resources including storage and Demand Response.

The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (e.g. Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

In the event the amount of resources replacing the gas-fired generation is greater than the current number of gas-fired resources, depending on their location, there may be an increased ability to load dispatch generation, supply resources in key areas where it is needed to help control flows for system limits. Large number of resources can minimize loss of generation risk considering a loss of unit would not have as much of a large-scale impact on the grid. Having multiple units could benefit...
voltage post-contingency with them being situated in key areas and able to respond to dynamic grid changes.

As new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.
Scope of Study

Background
Comms - Place content here

Scenario Development

Base Case
This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The carbon price is based on the assumption of a benchmark of 370 tonnes CO$_2$/GWh allowance for existing natural gas generation and $50/tonne carbon price in 2022 and held constant thereafter.

Potential Pathways
This study examines potential pathways to lower emissions through an illustration of complete gas phase out (Scenario 1) and maintaining lowered emissions at current levels (Scenario 2 and 3), as illustrated in Figure 2. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^2\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO$_2$/year. The purpose of developing these Scenarios was not to create estimates of likely outcomes, but to allow the IESO to provide insights gleaned from the range of potential pathways.

Figure 2 | Pathway Description

---

2 2017 was a lower than expected demand year, and as a result, emissions were lower as the gas fleet operated less.

16 Considerations for Phasing Out Natural Gas in the Electricity System | Public
Modeling Approach

Scenario 1 and Scenario 3 uses a supply mix-based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliable system in Ontario. Increased shares from any one type of replacement resource comes with increased risks, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix-based approach will consider demand-side and supply-side options. Scenario 2 considers a tightening of carbon policy to drive changes, and did not apply a supply mix-based approach.

In considering the candidate options, the study considers possible replacement technologies that are sufficiently mature today. As the reliability and planning coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. It is difficult to predict technology innovations, policy developments, and grid evolutions that could manifest in the study time frame – factors that could result in alternate supply mixes. The IESO aimed to provide a set of reasonable forward looking lowest cost estimates given professional judgement and the current information available. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization capacity expansion model that selects resource build-out over the 20-year period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO₂ emissions at or below annual emissions target

It is important to note that certain physical or other practical constraints, such as availability of suitable land-use, non-CO₂ environmental impacts, societal acceptance of the replacement technology, among others, were not considered in this least-cost optimization capacity expansion model. And so, the outcome of such a model does not imply technical or physical feasibility.
A set of nominal costs was assumed to allow this portfolio analysis to be carried out. Cost and performance assumptions for each considered candidate options are provided in Table 1. Associated transmission cost assumptions with each resource are provided in Table 2. It is very difficult to determine the required transmission investments without knowing where new generation would be located. Such determination would require much more extensive consideration working with generation developers which cannot be completed within the scope for this report. For instance, it is recognized that much of the easier locations in the transmission system to incorporate wind generation, for example, have already been used to connect the existing wind generation through the past wind generation acquisition processes. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations. Sensitivity scenarios were performed without considering any transmission costs or costs associated with ensuring an operable power system such as tool upgrades and market structure changes, which concluded that the cost-optimized supply mix outcomes are not very sensitive to transmission costs—which is sensible as transmission costs are normally relatively minor compared with supply costs. However, the actual extent of the impact of transmission cost would not be known until full details for implementation are considered.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Levelized Unit Energy Cost ($2021/MWh)</th>
<th>Capacity Cost ($2021/kW-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td></td>
<td>39%</td>
<td>Cost projection based on average of industry capital cost projections³</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td></td>
<td>17%</td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>Cost Curve</td>
<td></td>
<td>50%</td>
<td>Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs</td>
</tr>
<tr>
<td>Small Modular Reactors</td>
<td>ca</td>
<td>NA</td>
<td>85%</td>
<td></td>
</tr>
<tr>
<td>Firm Imports</td>
<td>150</td>
<td>NA</td>
<td>Variable</td>
<td>Cost assumption based on requirement of new build hydroelectric capacity in Quebec to provide year-round firm capacity</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>Four achievable potential scenarios from the 2019 Achievable Potential Study</td>
<td>were made available to the model with seasonal energy and capacity reductions and annual program costs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Response</td>
<td>NA</td>
<td>67</td>
<td>NA</td>
<td>Cost based on recent capacity auctions</td>
</tr>
</tbody>
</table>

³ Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)
Table 2 | Transmission Assumptions for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2021M)</th>
<th>O&amp;M Cost ($2021M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1,500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>Firm Imports</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
<tr>
<td>(&lt;= 3,300 MW)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the capacity expansion model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

Consistent with the project scope details provided in the June 2021 stakeholder engagement session, candidate options include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

Two limits are placed on the total amount of new capacity for new resource types. A maximum of 3,300 MW of firm import capacity is assumed as this is the largest amount that has an available preliminary estimate of transmission enhancement costs\(^4\). There is also an upper limit of 2,000 MW of incremental demand response capacity, which is consistent with a similar modeling exercise performed for the 2016 Ontario Planning Outlook. Including currently contracted demand response, this is equivalent to roughly 10% of peak demand.

Supply portfolios are modeled seasonally (summer and winter) over 20 years. In each season, the supply portfolios are required to meet the capacity, energy, and emissions, and operability requirements referenced above. Hourly modeling in a multi-year capacity expansion optimization model is generally impractical given processing constraints. The purpose of the seasonal capacity expansion model is to develop supply portfolios with roughly the right amount of capacity and energy to meet system needs. The supply portfolios were followed by an assessment using an hourly energy dispatch model to determine whether the portfolio could meet energy needs in all hours. Other feasibility assessments were also performed, such as assessing the required storage duration and the frequency with which demand response was activated.

Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

\(^4\) Review of Ontario Interties, IESO, 2014
The resulting portfolios developed using the least-cost optimization capacity expansion model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path and do not directly imply technical or physical feasibility. Notably, the results are heavily influenced by the relative cost assumptions which are likely to change over time. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

**Scenario 2** is a market-based approach where an increase in carbon price and a decrease in the emissions threshold reduce the utilization of gas by 2030. The carbon price assumes a linear increase from $50/tonne in 2022 to $170/tonne by 2030 and the benchmark for all natural gas facilities linearly decline from 370 tonnes/GWh in 2021 to 0 tonnes/GWh by 2030. The demand, conservation, supply and transmission outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

These scenarios were also informed by the multitude of input from the public webinars, stakeholders and communities feedback – written feedback can be found on the IESO website.

An economic hourly dispatch model was used to determine the outcomes of the three scenarios. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability, emissions and imports and exports. While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Base Case to understand which factors are the largest drivers of ratepayer costs. Figure 3 illustrates the modelling approach for the three Scenarios.

**Figure 3 | Modelling Approach for Scenario 1, 2 and 3**
**Areas of Study**

The three scenarios were examined from various lenses, including areas of reliability, costs, wholesale market impacts, operability and timing to the electricity system, as shown in Table 3.

**Table 3 | Areas of Study**

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>• Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>• Considerations for locational requirements for siting resources, or transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>• Ancillary services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale</td>
<td>• Least cost replacement resource portfolio</td>
</tr>
<tr>
<td>Market</td>
<td>• Potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>• Use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>• Impact on wholesale market pricing and how market value of system needs may change</td>
</tr>
<tr>
<td>Operability</td>
<td>• Operability and impact to wholesale market design</td>
</tr>
<tr>
<td></td>
<td>• Whether the market can operate the supply mix</td>
</tr>
<tr>
<td>Timing</td>
<td>• Typical timelines associated with construction of generation or transmission</td>
</tr>
</tbody>
</table>

**Areas of Study Not Considered**

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.
The study will assess Ontario emissions based on the scenarios described in earlier. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.
Study Findings

Scenario 1 - Supply mix-based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030. The incremental supply above the Base Case required to completely replace natural gas generation by 2030 is about 17,000 MW, as shown in Figure 4. In addition to this resource mix, Energy Efficiency Scenario B of peak 1,600 MW savings from the APS is also included as part of the lowest-cost resource mix (not shown in the figure).

Figure 4 | 2030 Incremental Installed Capacity, Scenario 1

The incremental nuclear, wind and solar capacity produce less annual energy (19 TWh) than the natural gas energy (31 TWh) was forecast to produce in 2030 in the 2020 APO. The remaining energy gap is made up by energy efficiency (9 TWh) and imports. Storage and demand response are required to replace the capacity currently provided by natural gas as well as the incremental capacity gap identified in the 2020 APO. Storage and demand response also help balance periods of high baseload generation and periods of insufficient supply. From the candidate options, new hydroelectric capacity was not selected by the capacity expansion model due to the high assumed costs associated with new build hydroelectric generation.
The complete phase-out of gas by 2030 with replacement by the above mix would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later.

Besides those energy efficiency savings considered in the 2020 APO, there are potential opportunities to achieve greater electricity savings as identified in the APS. The most recent APS, which was the first integrated electricity and natural gas APS, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the Base Case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

Ontario regularly trades electricity with neighbouring jurisdictions. [NTD: where is the reference to 3300MW of firm import from Quebec?] There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.

[NTD: we need to discuss the difficulties in replacing gas with wind and storage as the main supply resources; the seasonal storage need]

The emissions forecast for Scenario 1 relative to the Base Case is x.

The cost implications of Scenario 1 relative to the Base Case is x.

**Scenario 2 - Market based approach where increased carbon cost and decreased benchmark reduce the utilization of gas to reduce emissions by 2030 to current levels**
The market based approach relies on economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs and lowered carbon benchmark. As indicated above this scenario assumes an increase to cost of carbon from $50/tonne in 2022 to $170/tonne by 2030 and a decline of the natural gas benchmark of 370 tonne/GWh in 2022 to 0 tonne/GWh by 2030. This also assumes that the cost of energy from other jurisdictions remains the same as APO 2020. The entire reason for having a GHG allowance benchmark of 370 tCO₂/GWh was to minimize the impact of the carbon price on trade. In the absence of a benchmark allowance (i.e. allowance of 0 tCO₂/GWh) it is very likely that the carbon pricing policy would have to include adjustments at the border to account for the GHG emissions associated with the energy in other jurisdictions. Border adjustments are not considered in this analysis, instead the GHG emissions associated with the increased imports were quantified. A border adjustment policy could significantly impact the amount of imports considered in this analysis.

With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for this scenario. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions is expected significantly impact Ontario’s markets. Since gas resources frequently set price as the marginal resource in Ontario, the higher cost of gas would result in broadly raised market clearing prices. Many resources would subsequently be able to recover an increased portion of their costs through energy markets. The higher market clearing prices in Ontario would also make Ontario electricity exports into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will offset some Ontario natural gas production. The change to natural gas production, imports and exports relative to the Base Case is provided in Figure 5 below.

Figure 5 | Natural Gas, Imports and Exports Relative to the Base Case

The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO Base Case. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.

The reduced natural gas production results in GHG emissions remain around 4 Mt CO₂/yr megatonnes in Scenario 2 which is consistent to the 2016 to 2020 historical level and declining to 3 Mt CO₂/yr megatonnes by 2030, as shown in Figure 6.

Emission Forecast for Scenario 2 and the 2020 APO Base Case

The cost implications of Scenario 2 relative to the Base Case is x.
The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

**Scenario 3 - Supply mix-based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels**

The incremental supply of about 9,000 MW above the Base Case, where natural gas are assumed to remain in service, is shown in Figure 7. In addition to this supply mix, Energy Efficiency Scenario B of peak 1,600 MW savings from the achievable potential study is also included as part of the lowest-cost resource mix (not shown in the figure).

**Figure 7 | 2030 Incremental Installed Capacity, Scenario 3**

The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, this need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected in the capacity expansion model, as this energy is required to displace natural gas generation from an energy perspective. Despite similar cost assumptions, wind was favoured over solar by the capacity expansion model. This is likely because total energy demand is higher in the winter than summer, despite higher capacity requirements in the winter. Since the capacity need is met by storage and demand response, the expansion model finds that wind is more effective at meeting the energy need.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity, assumed in the capacity expansion model, were sufficient to meet the supply needs of the system.
The partial use of gas as well as a diverse supply mix of renewables, energy storage, and demand response would lead to less severe impacts to Ontario’s markets. Gas resources would continue to frequently set price as the marginal resource in Ontario, but increased renewables would result in somewhat lower overall energy. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later.

The emissions forecast for Scenario 3 relative to the Base Case is x.

The cost implications of Scenario 3 relative to the Base Case is x.

### Developing a Transmission Plan

[NTD: up front should we provide the same background we gave in APO re: Reliability = Adequacy + Security]

As indicated in the section above on Modeling Approach, the least-cost optimization that led to the supply mixes contemplated in Scenarios 1, 2, and 3 did not consider locational or siting-related matters pertaining to those supply mixes. As such, a detailed Transmission Plan to correspond with those scenarios is not able to be developed. However, the IESO has experience from past transmission planning initiatives to comment on the potential scope of a Transmission Plan to reduce the reliance on natural gas generation. The development of a Transmission Plan would consider the need to relieve constraints to deliver the replacement supply mix as well as the needs that would emerge if strategically located gas plant are retired.

### Delivering the Replacement Supply Mix

Of the 11,000 MW of installed natural gas-fired generation, the majority of a large portion is located in or around the Greater Toronto Area, with the balance primarily in western Ontario. Further, given portfolios resulting from the least-cost optimization model, it is expected that much of that portfolio would not be practical to site in a large urban and suburban footprint, given the expected land-use requirements (e.g., wind) or the natural location (e.g., firm imports). This would imply that the retirement or reduced reliance on these gas plants would create a net requirement for transporting power into the GTA and surrounding area compared to the system that we have today.

[NTD: these notes are a content outline only.]

- **Phase 2 FETT reinforcement**
  - Trafalgar x Oakville
- Meadowvale x Hurontario
- Reterrnating the Milton bypass

- North-South reinforcement
  - Essa to Pinard via Sudbury (Hanmer) and Timmins (Porcupine)
  - Collector circuits?

- Eastern Ontario reinforcement
  - Doubling up Outaouis
  - 230 kV between Merrivale + St. Lawrence
  - Bowmanville x Cherrywood
  - Etc., refer to the old interconnection review report

Maintaining Reliability Currently Provided by Strategically Located Gas Plants

[NTD: these notes are a content outline only.]

- Investments needed to relieve equipment loading:
  - Portlands = Third Supply to Toronto
  - Sithe Goreway and Halton Hills = new 500/230 kV autotransformation converting Milton SS to TS, and potentially at Kleinburg
  - York Energy Centre = new transmission reinforcement from Buttonville x Armitage
  - Brighton Beach, East and West Windsor = new (500 kV?) major transmission reinforcement into the west of Chatham area [NTD: get Megan Lund to review]

- Investments needed for voltage control
  - Between PEC, Goreway, Halton Hills, they provide a total of +X to -Y Mvar of dynamic reactive power support. Although reactive power is extremely locationally dependent, we can assume that new reactive power devices will need to be installed on the same order of magnitude and provide a similar response.
      - Implications of the response type – cannot be static capacitor or reactor banks, but needs to be dynamic. May not even be able to be SVCs because they are not an active source, and when thyristors are fully ON they are just capacitors or reactors.

Investments needed for frequency control

Gas-fired generators are synchronous machines and help ensure acceptable frequency response and system stability. If capacity from gas-fired generators is replaced with inverter-based resources, investments or the introduction of new market mechanisms to procure a Fast Frequency Response product would likely be required. The IESO will need to investigate the nature of these potential investments.
While controller technology used in IBRs may be able to provide Fast Frequency Response, it is mostly currently in the piloting stage (e.g., AESO’s Oct 2020 FFR pilot announcement). Of particular concern may be the design of Ontario’s Under-frequency Load Shedding Program for the Central Island, as currently gas-fired generators are the only source of governor response (primary frequency response) in the Central Island, and IESO’s 2018 UFLS study identified little margin compared with NERC and NPCC requirements.

Operability Considerations

Operability can be defined as the ability of the IESO to fulfill its legislated objects to direct the operation and maintain the reliability of IESO-controlled grid.

The IESO-controlled grid is operated day to day (24/7) and minute to minute at the level of reliability such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of reliability is achieved by operating the IESO-controlled grid to meet adequacy criteria for anticipated demand, system security criteria for specified contingencies, and re-preparation criteria for restoring reliability following contingencies or major events such as blackouts.

Operability can be defined as the ability to operate the power system second to second and manage a variety of real-time conditions with due regard for potential loss of transmission elements. Power system reliability must be maintained under differing seasonal system conditions and variability of supply, as well as through fluctuations in intra-hour and intra-day load; all the while respecting appropriate thermal, voltage and transient stability limits that might be present due to the transmission system limitations.

Operability is assessed and forecasted to ensure the power system at the transmission and distribution level is adequately prepared for expected real-time conditions. It must also have the ability to absorb and adapt to future changes on the power system.

The following principles are required to enable an operable system:

**Diversity** – Having a balanced variation of characteristics available across the system

**Flexibility** – Ability to easily respond to changing circumstances or conditions across the system

**Manageability** – Ability to have visibility, monitor and dispatch resources across the system

**Location** – Ability to support power flow toward loads as well as ability to facilitate efficient system restoration

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5 For additional information, see Section 11.3 of IESO Market Manual 7.1.

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In order to implement the replacement supply mixes, a number of things will need to occur to ensure the power system remains operable. The following are operability considerations that will need to be addressed with the replacement supply mix.

**Diversity**

Diversity in the characteristics of the supply mix is important to ensure risks inherent in each technology and fuel type are mitigated. As such, the total portfolio must provide sufficient energy capability to be sustainable under a wide variety of conditions including short-term extreme weather, mid-term environmental extremes and other fuel delivery challenges.

Diversity in technology and fuel type is required to mitigate the risks of any operating restrictions arising from such criteria as air emission restrictions, hydroelectric restrictions, and cooling water temperature change restrictions as well as to provide ancillary services from a broad range of technology types to reduce the risk of availability of service due to fuel scarcity.

It is also important to mitigate against common mode problems (e.g., shutdown of entire stations creating contingencies too large to be effectively managed). The ability to have ancillary services from a diverse supply of technology types are required to mitigate the risk of availability of service due to fuel scarcity.

Finally, the replacement supply mix must also be located in diverse locations to mitigate a common mode of failure from eliminating access to a large regional supply. Although locational diversity is important, there are also specific locations where replacement supply is important.

**Flexibility**

Flexibility in what characteristics the supply mix can provide is important as it allows Ontario to maintain reliability through both anticipated and unanticipated changes on the system. The current gas fleet provides sustainable energy and is able to follow a 5-minute dispatch. This is of particular importance on days where demand is high. Reliance on energy limited resources does not provide the inter or intra hour flexibility required to maintain a balance between supply and demand.

**IESO’s Experience in Flexibility**

On June 28, 2021, demand was high all day and evening peak reached 22,300 MW. Wind contributed to the system’s energy need but was only able to provide 11% of its installed capacity in the peak hour for a total of 500 MW (wind was performing 400 MW under the forecast).

Low water conditions caused a concern with the hydro-electric resources on several river systems. In an attempt to conserve the energy limited hydroelectric resources for utilization at peak, these resources were constrained down in off-peak hour. To replace the energy limited resources, other non-energy limited units were dispatched up including flexible gas resources.
A total of 6,000 MW of gas fired generation was dispatched to meet the 22,300 MW peak. Much of this was constrained on early in the day to offset the energy limited resources and to provide Operating Reserve. No other fuel type offered the flexibility to constrain on for this purpose.

An Energy Emergency Alert was issued indicating that all available resources were committed. Considering there was no other resources available and approximately 30% of the demand was supplied by the gas fleet, this demonstrates the importance of having flexible energy that can be sustained throughout the day.

Another instance where the flexibility of the gas fleet has proven invaluable is during wind “cutouts”. Changes to weather conditions may cause wind generation in a particular area to all cease generating within a very short window or at the same time resulting in a “cutout”. In these instances, having resources that can be dispatched quickly to ensure the balance of supply and demand is maintained after such an event would become more important with the increased penetration of wind in the replacement supply mix. Locational diversity of where the wind is placed will help mitigate the size of this potential loss of generation, however, will not eliminate the need for flexibility to remain. In order to ensure that, the replacement supply mix must have the flexibility to both follow 5 minute dispatches in both directions but also do it quickly (i.e. have a fast ramp rate).

**Ramping Considerations**

The IESO has an obligation to maintain a constant balance of supply and demand. The gas fleet plays an important role in allowing us to balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. In a summer day morning, a ramp-up rate of up to 30 MW/minute is required. On the other hand, an equal amount of ramp-down rate is required when consumption drops in the evening up to , these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

Today, flexible resources make up about 40% of the current fleet. Of the flexible resources, 11,000 MW of gas generation accounts for more than 70%. Flexible resources respond to 5-minute dispatch to balance the supply with demand. Wind and solar resources are curtailed under surplus baseload generation conditions, however, they are not dispatched up or down for ramping purposes. At present, hourly demand response resources and imports/exports are scheduled at an hour interval. The replacement resource mix capacity is primarily coming from inflexible wind and solar and hourly scheduled demand response and firm imports. Storage resources are mostly used for regulation purposes now and development and integration of large scale storage resources are still years away.

Balancing the supply with demand with such replacement capacity is challenging. Hybrid resources (wind or solar paired with batteries) could provide fast ramping capabilities. Additional flexibility could come from changes to operating procedures and scheduling protocols and changes to operation of non-dispatchable resources.
Not only does the existing gas fleet provide flexibility in their generation output, it also has the ability to provide local reactive power when needed. This characteristic is essential and will need to be replaced in order to ensure the maintenance of voltages in specific areas.

Additional characteristics of flexibility our existing gas fleet provides is inertial and frequency response. To reliably operate the power system, supply and demand must be continually balanced to maintain system frequency at 60 Hz. In the event of a large loss of generation, declining frequency can result in interruptions to customer loads. Gas generators have a large rotating mass within that produces energy. These rotating masses Spinning resources provide inertial and frequency response that is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

Gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. Synchronous generators provide spinning inertia directly proportional to the unit’s physical size. The more synchronous units that are online, the more the inertia on the power system. This inertia acts as a force to resist a change in the frequency of the system. Following a large generation contingency on the power system, the energy lost is evidenced with a corresponding drop in the system frequency.

Gas fired generators store kinetic energy in proportion to their size when synchronized. Immediately following a contingency, this kinetic energy stored is released and acts as a suppressant to the frequency decline. This phenomenon is known as the inertial response. With the elimination of the large generating units such as coal and gas, the province may lack sufficient ability to suppress frequency decline following a contingency which may result in under frequency load shedding. This inertial response will need to be replaced if gas were eliminated to ensure the system is recoverable following a contingency.

Gas generators have governors which automatically react to changes in system frequency by changing their output in proportion to the frequency deviation. This reaction is known as frequency response and helps to stabilize the frequency decline and ultimately aid in its recovery. Without the frequency response characteristics our current gas fleet provides, the recovery from large generation and load contingencies can pose challenges on the reliable operation of the power system.

Manageability

The bulk of our gas-fired generation fleet is visible to the IESO and also dispatchable. Should the gas-fired generation fleet be replaced with resources on the distribution system, the IESO will require visibility and dispatchability of those resources to maintain reliability.
If the replacement supply mix incorporates an increasing number of small resources that are embedded, distributed and possibly aggregated, the impact on situational awareness must be considered. Situational awareness is important as it provides operators foresight into what changes could potentially happen. It is being aware of the environment and understanding the information that is available at hand and what that means now and in the future. This could be increasingly complex with a larger number of resources on the system which would increase the complexity of operation and consequently increase the risk of human error. A large increase in the number of resources and market participants providing capacity to Ontario could require significant tool upgrades to manage the increased volume of data the IESO would be receiving.

The IESO currently has full visibility and control of resources connected to the high voltage transmission system but the same cannot be said for those connected to the distribution system. In the event there is an increased penetration of resources on the distribution system, operators must have sufficient capability to monitor and dispatch the power system.

Ensuring manageability with an increased penetration on the distribution system and number of resources, significant changes to our existing market participation framework, tools and rules will require changes which could cost upwards of $25 million.

### Additional Reliability Concerns and Considerations

The IESO-controlled grid is operated day to day (24/7) and minute to minute at the level of reliability such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of reliability is achieved by operating the IESO-controlled grid to meet adequacy criteria for anticipated demand, system security criteria for specified contingencies, and re-preparation criteria for restoring reliability following contingencies or major events such as blackouts.

The IESO-controlled grid is operated and its reliability maintained with due regard for planned or unplanned transmission element outages.

### Additional Operability Considerations

#### Locational Importance of the Supply Mix

The transmission system limitations on the IESO-controlled grid result in flow gates that impede flow of power toward loads. These flow gates are reflected through the system operating limits such as thermal, voltage and angular stability limits that indirectly describe specific system deficiencies. To provide unrestricted flow of power toward loads, to minimize losses, and to enable outages for transmission elements maintenance, sometimes, it is necessary to position a generator of certain capability at the specific location.

During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in locations to minimize transmission investments needed to incorporate the resource into the system. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by virtue of where they are located, also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.

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Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.

There are specific areas in the province, should replacement supply mix be located, would provide higher value than other areas of the province. Replacement supply mix located on the east side of Flow East Towards Toronto (FETT) flow gate is important to accommodate the expected demand growth in the area as well as the retirement of the Pickering Nuclear Generating Station. Currently, Lennox, a gas generator, is the best source low minimum loading points and its ability achieve high generation output. Also, Portlands, Sithe Goreway and Halton Hills gas generators provide specific support to enable unrestricted flow of power through the FETT flow gate.

The location of generation close to load pockets is important to reduce congestion and to reduce losses on the transmission system and ensure loads are being served.

Generation located in areas that can reduce autotransformer loading is also important. Having Portlands GS connected on the 115 kV side of the Leaside/Manby autos helps to reduce the loading there. The location of Sithe Goreway GS helps to reduce loadings at Claireville. Halton Hills GS also currently assists in the reduction of load on the Trafalgar autotransformers.

These natural gas generators are important to keep loadings reduced during planned transformer outage or if a forced transformer outage were to occur. Should these gas generators be phased out, new generators must be strategically placed to serve these purposes and help maintain system operability. In addition, due to their reactive power capability, Portlands, Halton Hills and Goreway GS are the key elements in supporting the flow of power towards Toronto during high demand days.

In the Leamington area, we are currently anticipating an increased dependency on the gas-powered Brighton Beach GS facility to manage the area load exposure to prolonged load reductions during outage conditions. The availability of the Brighton Beach generation has implications on managing the workload in the control room as well, considering that other means of the managing load in the area might be complex and time consuming. A replacement for that generation, in that area will also be required to help mitigate load exposure.

In the Leaside/Manby area, the phenomena that we try prevent from happening is dependent on primary demand. During high primary demand conditions, recent IESO studies show significant penalties to Flow Away from the Bruce Complex (FABC) flow gate limit as a result of Pickering units being out of service. The situation is aggravated with unavailability of gas units at Goreway, Halton Hills and Portlands GS (and Darlington NGS if on outage). Considering the significant amount of penalties on the flow from the west, adequacy concerns would arise to supply load in the Toronto area without gas generation and after the Pickering retirement.

During low primary demand, and with the expectation of the Darlington Vacuum Building outage scheduled for 20xx, IESO studies indicate a great dependency on the Pickering nuclear units as well as the fleet of gas generating units in the area to manage high voltages. Managing the area without the gas generators will potentially expose the system to frequent switching of the lines and with that increased risk of equipment failures. It is therefore important to ensure that the equivalent capacity in placed in the area to replace the gas.
We must also ensure that adequate capacity is available to the area to accommodate a Darlington NGS outage after the Pickering NGS units have retired. If the gas is not replaced in that area, Ontario may experience shortfalls with the current transmission infrastructure.

Additional Operability Considerations

Single Largest Contingencies
The single largest contingency that impacts adequacy and operability is typically the loss of the largest generator. However, there are circumstances wherein the single largest contingency consists of multiple loss or bottling of generators. Examples are as follows:

- A loss of an element that removes a connected generator and station service, resulting in the loss of a second generator
- A loss of a transmission element that results in bottling a number of generation behind the interface
- A loss of an auxiliary element that results in the removal of multiple generators
- A loss of a generator and assumed amount of DERs that would also be lost a result of the primary contingency

In the event that there is significant penetration of supply on the distribution side, there could be impacts to the amount of operating reserve the IESO must carry.

System Restoration Plan
As part of the IESO’s emergency preparedness we maintain plans to restore the system following a complete blackout. Ontario currently has sufficient black start capability to restore the power system in the event of a blackout.

The IESO begins the restoration by starting “black start” units that must be capable of energizing long transmission lines (ability to absorb high voltage), and provide starting current to other generators. Once the first generators are on, load can be brought back to balance the power system. As we continue to restore the province, strategically placed generating units with significant load pickup capability and significant MX-reactive power absorbing capability are required to ensure the whole province can be restored. The current location of some gas plants are serving that purpose of picking up load and absorbing MX throughout the restoration process. In the absence of gas, a suitable replacement for this purpose will be required.

Ramping Considerations
During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. In a summer day morning, a ramp-up rate of up to 30 MW/minute is required. On the other hand, an equal amount of ramp-down rate is required when consumption drops in the evening; these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

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Balancing the supply with demand with such replacement capacity is challenging. Hybrid resources (wind or solar paired with batteries) could provide fast ramping capabilities. Additional flexibility could come from changes to operating procedures and scheduling protocols and changes to operation of non-dispatchable resources.

**Inverter Based Resource**

Rapid growth of inverter-based resources ("IBRs") add complexity to grid reliability. These include most solar and wind as well as battery storage, hybrid generation and many DER. Some inverter-based resource performance issues have been significant in recent grid disturbances, such as the tripping of a number of BPS-connected solar PV generation that occurred during the 2016 Blue Cut Fire, 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California. Gas-fired generators are synchronous machines and help ensure acceptable frequency response and system stability. If capacity from gas-fired generators is replaced with inverter-based resources, investments may be required. The IESO will need to investigate the nature of these potential investments. While controller technology used in IBRs may be able to provide Fast Frequency Response, it is mostly currently in the piloting stage (e.g., AESO’s Oct 2020 FFR pilot announcement). Of particular concern may be the design of Ontario’s Under-frequency Load Shedding Program for the Central Island, as currently gas-fired generators are the only source of governor response (primary frequency response) in the Central Island, and IESO’s 2018 UFLS study identified little margin compared with NERC and NPCC requirements.

**Practical Considerations**

**Gas Under Contract**
Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.

**Eliminates Competition**

The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30–40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

**Land Use and Siting**

Replacing natural gas with new large scale non-carbon emitting resources can pose a number of practical challenges in regards to land use, siting and location. Most economic and accessible hydroelectric sites have been developed; some potential is undeveloped, with a majority of it located along Ontario’s northern rivers (e.g. Abitibi and Moosonee rivers). Northern hydroelectric sites are generally remote, resulting in relatively higher construction costs, as well as requiring potentially significant transmission investments to connect them. While we have proven technology on on-shore wind, there is a moratorium on off shore siting. Depending on the location, large penetration of renewables will require transmission investments to connect them, there is also less suitable locations to develop overhead transmission routes.

**Variable Generation and Storage**

- story about making this look like 100% gas plant will be very expensive

**Timing**

Reductions in emissions through the addition of new non-carbon emitting resources and accompanying transmission would require new investments, significant amount of time and resources to develop the designs and the required specifications, to identify appropriate sites and routes, to manage the extensive stakeholdering and consultation, and to mange the acquisitioning and building of these assets. Lead time of supply resource vary depending on the generation, and the lead time of transmission can be seven years or even longer. New technology and resource risks should recognize the uncertainty associated with construction completion and longer lead times required to reach dependable operation. This transformation of the system would require detailed planning which is outside the scope of this study. Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of our generation capacity.

**Hydro Quebec Imports Considerations**
Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years that expire in 2023, and it is assumed that these particular agreements are not extended. Imports from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The interconnections in northern Ontario are these type of connections with limited capacities. The interconnection at Bauharnois near St. Lawrence is a same type of interconnection but with a capacity to connect up to 800 MW of generation into Ontario. With the intent to allow dynamic power transactions between Ontario and Quebec, the 1,250 MW tie in the Ottawa area was added. It includes an AC-to-DC-to-AC conversion facilities to address the system issue.

Also due to the nature of the system in Ontario near Ottawa, the 1,250 MW tie and the 800 MW tie cannot be operated at the combined total level of 2,050 MW in summer peak periods. The IESO has recommended Hydro One to upgrade Hawthorne TS x Merivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. A firm import capability of 1,650 MW can be obtained with this upgrade. For a firm import capacity beyond 1,650 MW would require significant transmission investments. The scope and cost of such investment is not known without discussions/negotiations with Quebec. A nominal cost based on past consideration was used in the development of the portfolios.

Quebec has very large water storage capability and is projected to have large surplusses of energy for many decades, however, their capacity availability is far more constrained. Quebec's winter peak electricity demand is projected to grow over the next decade, decreasing its surplus tightening their already tight winter capacity availability where, and exports are generally curtailed during winter peaks, as more than 80% of Quebec households use electric heating. Quebec is expected to continue to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. However, for this analysis it is assumed that Quebec can supply summer and winter capacity up to 3,300 MW, with the appropriate transmission upgrades. While Quebec is building more wind capacity, it is not assumed that this is significant enough to allow them to be able to provide winter capacity to Ontario. this capacity will be energy limited and their ability to export to Ontario will also be limited.

Wholesale Market Impacts

Context

The wholesale market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of wholesale market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy

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price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to a new pricing patterns influenced by the characteristics of the replacement resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with the “Base Case” in which the gas fleet continues to operate.

The High Base-Load Case assumed that a fleet of somewhat inflexible resources is added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide very flexible output intrahour output flexibility or stand by energy such as operating reserves. In contrast, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources that operate based on energy pricing arbitrage and operating reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power-markets market could be impacted if resources types with attributes on two opposite ends of a spectrum of attributes were chosen utilized to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

The High Base-Load Case

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources offer into the energy market at low to zero prices, and since they replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy,
meaning the availability of energy above that needed to meet the province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case, traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes to the High Base-Load Case. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, there is an increase in the fraction of the year where energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for these hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tend to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydroelectric availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure 8 below. Only single illustrative prices have been shown below for clarity. The reader should note that real market impacts will extend more broadly to multiple locational prices following Market Renewal.
As shown in the above graph, the High Capacity Case will see increasing price variability in both frequency and magnitude. This reflects the introduction of an increased fraction of variable renewables on the grid as a replacement for gas resources. In contrast, for the High Base-Load Case, prices will be broadly depressed and there will be less variability. While there is still some price variation that will be important for resources in the energy markets, the high degree of low marginal cost baseload generation on the system may make pursuing large revenue opportunities more challenging.

**Market Impacts**

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and directionally indicate how wholesale market outcomes could result. More importantly, this exercise has shown that the wholesale market is able to provide intuitive signals that reflect the system needs and the value of the resources able to meet the needs. Significant changes in Ontario’s wholesale markets are a reflection of changes in the supply and demand conditions in the underlying system. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

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Opportunities to Move Towards an Emission-Free System in the Longer Term

**Hydrogen**

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

**Carbon Capture Utilization and Storage**

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO$_2$ to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

**Increasing Hydroelectric Flexibility**

Place content here – to be provided by Paul Norris/OWA – revisiting the social, environment, cultural, ecological restrictions to now also consider climate change/electricity to see if we can increase operational flexibility in hydroelectric fleet.

**Distributed Energy Resources**

Place content here

**Broader Planning and Coordination**

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 Mt CO$_2$/year when considering increased gas
production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.
Conclusion

Comms - Place content here
Appendices

Place content here
Disclaimer [Meaghan McConnell to provide disclaimer once study is close to completion]

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Table of Contents [BC]
List of Figures [BC]
List of Tables [BC]

Executive Summary [Communications]

- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X billion, and initiate work immediately for the development X, Y, Z

Chapter 1: Introduction

Study motivation [Communications]

- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.

- Such an undertaking would require a comprehensive plan to develop and invest in suitable replacement supply and reorient the system around the new supply mix in order to maintain the reliability of the system.

Objectives of the study [Communications]

- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered

Report contents [Communications]
Describe how the report is organized

Chapter 2: Background and Context Setting

Role of natural gas [MTI]

- How we expect gas will support future reliable electricity system operation (e.g. capacity, energy, operability), including the technical characteristics of Ontario’s gas fleet

The focus of the analysis will be on the reliability, cost, wholesale market, operability, and timing impacts that need to be addressed should the phase out of natural gas be considered. To do that, it is important to recognize the role that natural gas currently plans in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity and about 7% of total energy in the province, as shown in Figure X.

Figure X: 2022 Installed Capacity and Energy of Natural Gas

[Insert 2022 pie chart – Installed Capacity and Energy Production].

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable supply, including X MW of wind and X MW of solar, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as there is they are not energy limited. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial as well as frequency response which aids in system recovery following a contingency. Many gas plants are also strategically located near major demand centers to provide local and regional reliability. Some gas plants were developed in lieu of major transmission upgrades in the area. Should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

[Operations: add in additional context of operability characteristics of gas]

Electricity emissions projection of base case [SK]

As outlined in the 2020 Annual Planning Outlook, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO₂ e by 2030, still well below 2005 levels. This expected
increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the outlook assumes that natural gas will fill in system capacity needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

**Summary of current government policy and emissions targets [SK]**

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing GHG emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 t/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/t of carbon dioxide emissions and increasing to $170/t by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

**Challenges to be considered if phasing out gas generation**

- Gas plants are under contract [SK]

Much of Ontario’s current natural gas-fired generation is under contract. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.
The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e., Resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

- Locational importance of the gas fleet [JL]
  - During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in strategic locations to reduce the reliance on the transmission system to bring power into the load centres. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by being located where they are, they also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.
  - Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.
  - These gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. This was not a concern when coal-fired generation with gas-fired generation. Without the gas-fired generation, transmission or reactive power source may be required. An example of this is the Toronto area. The peak load in the area may not be supplied reliably without the local gas-fired generation.

- Ramping capability
  - During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. Conversely, when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas-fired generation, there will need to be resources available to ramp quickly to balance the system.

- Inertial and frequency response
  - In the event of a large loss of generation, inertial and frequency response is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of
both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

- **Restoration path**
  - Today, we have black start units that are able to generate without any supply of electricity. This is necessary to prepare the system following a black out. A restoration path requires strategically placed generating units with significant load pickup capability and significant MX absorbing capability to be operable. Currently gas plants are serving that purpose. In the absence of gas, a suitable replacement for this purpose will be required.

- **Visibility and Control**
  - The bulk of our gas-fired generation fleet is not only visible to the IESO but also dispatchable. If our gas-fired generation fleet were replaced with resources on the distribution system, we would lose visibility and control of a significant amount of MW. This could not only increase complexity of operation but also increase the need for additional services.

- **Volume of Resources/Market Participants**
  - A large increase in the number of resources and market participants providing capacity to Ontario would create increased workload in the control room. This could potentially distract from other tasks which increased the risk of human error.

- **Contingencies**
  - In the event the gas fleet is replaced with distributed energy resources, consideration will have to be taken to the amount of sympathetic loss of those resources. Our single largest contingency assessment will need to take into account not only the loss of a generator, but also the assumed amount of sympathetic loss that would also result.

- **Lessons learned from off coal [JL]**

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fire generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation outputs in addition to dealing with constant demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all.
There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. One important aspect to keep in mind is the variability of wind generation output tends to be seasonal. This poses even greater challenge for storage facilities to complement variable generation in providing what gas generation can provide.

**Opportunities and benefits for phasing out gas generation**

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability:

- Where IESO has needed to procure more supply it has been procuring increasing quantities of these types of resources through IESO’s former DR auction, which has evolved to a capacity auction open to various types of resources including storage and DR.

- The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (also known as Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

- In the event we have an increase to the number of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load generation in key areas where it is needed to help control flows for system limits. This would also help keep things balanced if a unit was lost since it wouldn’t have as much of a large scale impact on the grid. Having multiple units could benefit voltage post contingency with them being situated in key areas and able to respond to dynamic grid changes.

As these new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.

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**Chapter 3: Scope of Study**

- Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

**Scenario development** [RM, VV, DR, SK, JP, JL]
**Base Case**

This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^1\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO2e.

The underlying forecast used for the off-gas scenarios is the 2020 APO Scenario 1 (Base Case) load forecast whereby demand commences at 141 TWh to 174 TWh, increasing at an annual rate of x% per year with conservation energy savings embedded at 3 – 16 TWh. The demand forecast assumes the expected recovery from the COVID-19 pandemic downturn recovers to 2019 levels by the end of 2022. The carbon cost is based on the assumption of a benchmark of 370 t CO2/GWh and $50/t carbon price. This carbon cost assumption is used in Scenario 1 and 3. For the Scenario 2, the carbon benchmark is projected to decline to 0 t CO2/GWh and a carbon price of $170/t by 2030.

**Potential Pathways**

This study examines potential pathways to lower emissions through an illustration of complete gas phase out and maintaining stable emissions at current levels:

[Make the 3 Scenarios to something more visual]

1) **Scenario 1** - Supply mix based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030

2) **Scenario 2** - Market based approach that examines higher gas prices and lowered benchmark to reduce utilization of gas to reduce emissions by 2030 to current levels

3) **Scenario 3** - Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to compete with other resources to reduce emissions by 2030 to current levels

Scenario 1 and 3 uses a supply mix based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliability system in Ontario. Increased shares from any one type of replacement comes with increased risks pertaining to that single source, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix based approach will consider demand-side and supply-side options.

In considering the candidate options, the study considers possible replacement technologies that are established and feasible today. As the reliability coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale.

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\(^1\) 2017 was a low demand year, and as a result, emissions were lower as the gas fleet ran less.
scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization that selects resource build-out over the 20 year planning period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO2 emissions at or below annual emissions target
- Sufficient flexible resource to meet system operability requirements, mostly related to ramp rates and integration of variable resources

Cost and performance assumptions for each considered resource are given in Table X. Associated transmission cost assumptions with each resource are provided in Table Y. It should be noted that it is very difficult to determine the required transmission investments without knowing where new generation would be located. Such determination would require much more extensive consideration working with generation developers which cannot be completed within the time allowed for this report. For example, for wind generation, it is recognized that much of the easier locations in the transmission system to incorporate wind generation have already been used to connect the existing wind generation through the past wind generation acquisition processes. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations.

A set of nominal costs was assumed to allow this portfolio analysis to be carried out.

**Table X:** Candidate Options for Replacement Supply for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC ($2020/MWh)</th>
<th>Capacity Cost ($2020/kW-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td>39%</td>
<td></td>
<td>Cost projection based on average of industry capital cost projections²</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td>17%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td>Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>Cost Curve</td>
<td>50%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small Modular</td>
<td>NA</td>
<td>85%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

² Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)
Reactors
Firm Imports 150 NA Variable Cost assumption based on requirement of new build hydroelectric capacity in Quebec to provide year-round firm capacity.

Energy Efficiency
Four achievable potential scenarios from the 2019 Achievable Potential Study were made available to the model with seasonal energy and capacity reductions and annual program costs.

Demand Response
NA 67 NA Cost based on recent capacity auctions.

Table Y: Transmission Assumptions for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2020M)</th>
<th>O&amp;M Cost ($2020M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>(&lt;= 3,300 MW)</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the optimization model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

Portfolios are modeled seasonally (summer and winter) over 20 years. In each year, the resource portfolios are required to meet the capacity, energy, emissions, and operability requirements referenced above. Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

Consistent with the project scope details provided in the stakeholder engagement sessions in advance of this study, all supply scenarios include the proposed 300 MW small modular reactor at Ontario Power Generation’s Darlington nuclear facility.

The resulting portfolios developed using the least-cost optimization model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one
path. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

Two laminations of the replacement supply mix were considered, an unconstrained replacement resource mix assuming no barriers on supply resource, regulatory hurdles, land use and other barriers that may limit the amount of resources we can feasibly take up by 2030; and another where constraints were placed.

Scenario 2 is a market based approach that examines higher gas prices to reduce the utilization of gas and its corresponding emissions by 2030. The 2020 APO Scenario 1 is augmented to assume a linear increase to the cost of carbon from $xx/tonne in 20xx to $170/tonne by 2030 plus a linear decline to the benchmark for all natural gas facilities from 370 tonne/GWh in 2021 to zero by 2030. The demand, conservation, transmission and economic outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

An energy production assessment is conducted that includes the economic imports and exports between Ontario and its neighbouring jurisdictions. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability and emissions. The result of the energy assessment is a reduction in gas generation for exports and an increase in imports to meet domestic consumption needs, based on the economics of the higher cost of natural gas from increased cost of carbon and the elimination of the natural gas facility benchmark by 2030.

[Insert figure of modelling approach flow chart]

- [DR: Outline the assumptions and methodology used for Scenario 1 and 3].

**Areas of study**

The three scenarios described above will be examined from various lenses, including areas of reliability, costs and wholesale market impacts, operability and timing to the electricity system.

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>• Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>• Locational requirements for siting resources, or transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>• Ancillary Services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale Market</td>
<td>• Lowest net present value replacement supply mix cost</td>
</tr>
<tr>
<td></td>
<td>• A coarse range of potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>• The assessment will use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>• Impact on wholesale market pricing how market value of system needs may change</td>
</tr>
<tr>
<td>Operability</td>
<td>• Operability and impact to wholesale market design (e.g. day-ahead and real-time energy, Operating Reserve, and Ancillary Services) and confirmation that the market can operate the supply mix</td>
</tr>
<tr>
<td>Timing</td>
<td>• Typical timelines associated with construction of generation</td>
</tr>
</tbody>
</table>
or transmission (e.g. environmental assessments, regulatory
tproceedings, construction, commissioning, etc.)

Areas of study that is out of scope [BC]

It is expected that the electricity system will play a key role in achieving lowered emissions
target through demand growth driven by electrification of transportation, building and industrial
dend-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the
economy will be an integral part of the overall provincial target for lowering emissions. As the
economy decarbonizes, we will expect increased demand for electricity. While a high
electrification demand scenario or increases to the federal carbon price to understand the
extent of fuel switching were not considered as part of this study, impacts of electrification on
demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in Chapter 3. Ontario
imports from and exports to its five neighbours every day of the year. To forecast the impact of
imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and
develops regional commodity and carbon price forecasts for fuels used to produce electricity. It
is expected that as Ontario moves to a lower emissions projection, so will our neighbours.
Jurisdictions around us are evolving and policy changes are underway in the United States as
they take in their own pathways to lowering emissions. This study will assume the interaction
relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will
not consider how emissions in other jurisdictions may be affected by imports and exports of
energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s
electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting
Ontario.

This report is intended to provide analyses and to communicate information to policy-makers
and other decision makers to make informed decisions. The study is not intended to provide
recommendations for policy decisions or to identify one alternative over another as preference.

>>>>>

Chapter 4: Study Findings

Study Findings: Scenario 1 - Complete gas phase-out by 2030

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- While the cost of new generation technologies and the trajectory of total costs over time
  are uncertain, it is imperative to compare the total and average costs for each scenario
to the Reference scenario to understand which factors are the largest drivers of
ratepayer costs.
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

The incremental supply required to completely replace natural gas generation by 2030 is shown in Figure x. In addition to this resource mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix. Two supply portfolios are shown: one with no resource limitations other than demand response, and the other with resource limits of 6,000 MW on wind, solar and storage.

Figure x: 2030 Incremental Installed Capacity, Scenario 1

The complete phase-out of gas by 2030 with replacement by a diverse mix of primarily variable renewable energy and storage resources would lead to a variety of key developments in Ontario's markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario's markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” outlined in Chapter 4.

Energy Efficiency
Besides those energy efficiency savings considered in the most recent Annual Planning Outlook published in December 2020 and this study, there are potential opportunities to achieve greater electricity savings as identified in the Achievable Potential Study (APS). The most recent APS, which was the first integrated electricity and natural gas achievable potential study, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the reference case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

**Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030**

The market based approach relies on an energy production assessment that includes economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs. As indicated above this scenario assumes an increase to cost of carbon from $x /tonne in 2022 to $170/tonne by 2030 and an elimination of the natural gas benchmark of 370 t/GWh in 2022 to zero by 2030. With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for Scenario 2. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions will result in an increase to the market clearing prices for Ontario, making Ontario electricity production into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will also offsetting more Ontario natural gas production. The change to natural gas production, imports and exports relative to the base case is provided in the figure below.

Figure x: Natural Gas, Imports and Exports TWh comparison.

The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO case analysis. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.
The reduced natural gas production results in GHG emissions remain around 4 MegaTonnes with the market based approach which is consistent to the 2016 to 2020 historical level and declining to 3 Megatonnes by 2030.

Figure x: Emission forecast for Scenario 2 and the 2020 APO Base Case

The cost implications of Scenario 2 relative to the Base Case is x.

Other considerations: The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs**

- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.
The incremental supply required to stabilize 2030 greenhouse gas emissions at 2016-2020 levels is shown in Figure Z. In addition to this supply mix, Energy Efficiency Scenario B from the achievable potential study is also included as part of the lowest-cost resource mix.

**Figure Z: 2030 Incremental Installed Capacity, Scenario 3**

The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, the need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected, as this energy is required to displace natural gas generation from an energy perspective.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity were sufficient to meet the supply needs of the system.

Energy Efficiency

[Same discussions as Scenario 1]

**Wholesale Market Impacts** [Market Development & Resource Procurement]

**Background / Introduction:**

The Wholesale Market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of wholesale market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to new pricing patterns influenced by the characteristics of the replacement
resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with a “Base Case” in which the gas fleet continues to operate.

For the High Base-Load Case, it has been assumed that a fleet of somewhat inflexible resources has been added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide very flexible output or stand by energy such as operating reserves. In contrast, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources that operate based on energy pricing arbitrage and operating reserve revenues, as well as capacity payments.

The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power-markets market could be impacted if resources on two opposite ends of a spectrum of attributes were chosen to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

The High Base-Load Case

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources offer into the energy market at low to zero prices, and since they replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy, meaning the availability of energy above that needed to meet the province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the
ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes to the High Base-Load Case. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, there is an increase in the fraction of the year where energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for these hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydro availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, the the impacts to impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Figure below. (Note: graph annotation still needed, showing how prices become more flat and/or variable)
Market Impacts Discussion

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.

Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and directionally indicate how wholesale market outcomes could result. More importantly, this exercise has shown that the wholesale market is able to provide intuitive signals that reflect the system needs and the value of the resources able to meet the needs. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

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Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.

Available Alternatives and Considerations: Hydro Quebec Imports
Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years. Import from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The interconnections in northern Ontario are these type of connections with limited capacities. The interconnection at Bauharnois near St. Lawrence is a same type of interconnection but with a capacity to connect up to 800 MW of generation into Ontario. With the intent to allow dynamic power transactions between Ontario and Quebec, the 1250 MW tie in the Ottawa area was added. It includes an ac-to-dc-to-ac conversion facilities to address the system issue.

Also due to the nature of the system in Ontario near Ottawa, the 1250 MW tie and the 800 MW tie cannot be operated at the combined total level of 2050 MW in summer peak periods. The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. A firm import capability of 1650MW can be obtained with this upgrade. For a firm import capacity beyond 1650 MW would require significant transmission investments. The scope and cost of such investment is not known without discussions/negotiations with Quebec. A nominal cost based on past consideration was used in the development of the portfolios.

Quebec’s electricity demand is projected to grow over the next decade, decreasing its surplus, and exports are generally curtailed during winter peaks, as more than 80% of Québec households use electric heating. Quebec is expected to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. While Quebec is building more wind capacity, this capacity will be energy limited and their ability to export to Ontario will also be limited.

Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030) [RM, VV, DR, SK, JP, JL, DCP]

- In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030
- This section aims to help frame discussions around longer term government targets to reduce economy-wide emissions where electricity could play a significant role.
- Role of demand-side options (e.g. additional EE)
- Analysis will outline opportunities and barriers that will need to be addressed including how emerging technologies may participate in the future (e.g. CCUS, hydrogen, etc.)
Hydrogen

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may be come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

Carbon Capture Utilization and Storage

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO2 to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

Distributed Energy Resources

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Broader Planning and Coordination

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 MT/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.
Chapter 5: Conclusion

- Key takeaways [Communications]
1. Considerations for Phasing Out Natural Gas in the Electricity System
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Disclaimer

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Executive Summary

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Study Assumptions and Limitations

Scenario resource portfolios have been developed to understand the high-level electricity system impacts of replacing natural gas-fired generation. These portfolios require certain technical and practical assumptions, and have passed a high-level litmus tests for reliability and operability (to meet expected seasonal capacity, energy and ramping needs), but should not be viewed as detailed power system plans. If directed to pursue the replacement of natural gas-fired generation further, a more rigorous analysis would be required to develop tools that can more accurately incorporate real-time market dynamics in the portfolio building process. In particular, most commercially available tools have limitations on how these newer resources, such as storage, are modelled, as storage was not expected to become a significant part of the resource mix when these tools were developed.

Below is a list of optimistic technical and practical assumptions made to facilitate the study:

- Technical
  - Large scale energy storage can be completely operationalized, although the IESO has limited experience with candidate storage technologies, pumped hydro aside.
    - Storage has been modelled to provide capacity, load following and ancillary services; however, modelling limitations raise questions as to if storage can provide the full suite of these services, especially during periods of consistently high demand, weather-limited fuel supply or contingency scenarios.
  - A 300 MW small modular nuclear reactor will reach in-service by 2030 at the Darlington site, as announced by OPG.
  - Increased visibility and dispatchability of incremental resources on distribution systems.
    - Assumed to leverage the existing transmission system, to the extent possible, siting non-emitting resources in zones to replace gas while minimising cost.
    - IESO systems will be upgraded to allow for continuous monitoring, dispatch, and contingency analysis.
  - Resource siting does not result in operability challenges – local or global.
    - All requirements for load following, voltage support, frequency response, etc. can be met.
    - NOTE: without knowing exactly where all of the incremental resources are sited there is no way to accurately assess the potential operability challenges. This analysis assumes that there will not be significant operability challenges, which represents a very optimistic assumption.

- Practical:
  - Land use/siting is not an issue even with such a large scale of renewables.
    - To secure the volumes of renewables needed, off-shore wind may form part of scenario portfolios. This represents another particularly optimistic assumption.
Scenarios have been developed absent a detailed transmission plan.

- Physical locations of new resources would be required, but it’s reasonable to think upgrades are needed to enable resources in the North, increase imports from Québec, and add to supply for the GTA.
- Enabling policies would be in place to support increased energy efficiency and the fast-tracking of permitting and construction to enable siting of resources in key electrical areas.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.

**Key Findings**

Place holder for content

[NTD: To be included is a Board requested insight citing the volume of CO2 avoided with each scenario and the cost in $/Mt.]
Introduction

**Study Motivation**
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**Objectives of Study**
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**Report Contents**
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Background and Context

Current Government Emissions Policy and Emissions Targets

Ontario’s electricity system has been steadily reducing GHG emissions since the mid 2000’s, and now represents around 2-4% of total GHG emissions in the province.

Figure 1 – Historical GHG Emissions in Ontario by Sector

Electricity emissions went from a peak of approximately 21% of total emissions in the early 2000’s, to around 3% by 2018. Transport went from a low of 26% of emissions in 1990, increasing steadily to 38% of emissions by 2018. On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing greenhouse gas (GHG) emissions to 30 percent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

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In order to achieve provincial GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 tonnes CO$_2$e/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/tonne of CO$_2$ emissions and increasing linearly to $170/tonne by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries. Ontario’s natural gas fleet has an average emissions factor around 420 tonnes CO$_2$e/GWh. This means that on average, with a threshold allowance of 370 tonnes CO$_2$e/GWh, the Ontario gas fleet is only paying for 50 tonnes CO$_2$e/GWh, or only about 12% of their emissions. The threshold allowance was implemented to lesson impacts on inter-jurisdictional electricity trade.

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers. As described above, the current policy only exposes the natural gas fleet to approximately 12% of the carbon price, which does not have a significant impact on the cost of gas fired generation in Ontario. However, if the gas fleet was exposed to the full carbon price, some sort of border adjustment for imports would likely also have to be implemented to account for the GHGs associated with the generation in the originating jurisdiction.

### Planning and Operating the Bulk Electric System

When considering changes to Ontario’s resource mix, it is important to remember that the grid is an integrated system, part of the North American Eastern Interconnection, and guided by North American and Ontario-specific reliability standards. Ontario’s portfolio of resources is procured to work together with the transmission system in order to provide capacity and energy where it is needed, and the services required to maintain real-time reliability.

Capacity and energy adequacy are assessed as part of IESO’s [Annual Planning Outlook](https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Operating-Reserve-Markets) (APO), identifying provincial and local shortfalls that must be met to achieve reliability standards. These shortfalls feed into transmission planning and the [Resource Adequacy Framework](https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Ancillary-Services-Market), which will align acquisitions with evolving system needs.

As mentioned above, there are other services required to maintain reliability, and include\(^2\,^3\):

- **Operating Reserve (OR)** – stand-by power or demand reduction that can be called on with short notice to deal with an unexpected mismatch between generation and load.


\(^3\) [https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Ancillary-Services-Market](https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Ancillary-Services-Market)
• **Certified Black Start Facilities** – facilities that help system reliability by being able to restart with no outside source of power following a blackout event, and would be called on during restoration efforts by helping to re-energize other portions of the power system.

• **Regulation Service** – corrects for short-term changes in electricity use that might affect the stability of the power system, including variations in power system frequency.

• **Reactive Support and Voltage Control Service (RSVC)** – required in order to maintain acceptable reactive power and voltage levels on the grid.

• **Reliability Must-Run (RMR)** – contracts that allow the IESO to call on the counterparty to produce electricity if it is needed to maintain the reliability of the electricity system.

It is important to understand that no single resource can provide the full suite of services, and the level of services needed is a function of various aspects of uncertainty, including those inherent to the resource mix itself, requiring an iterative assessment process. Aspects of uncertainty include the loss of system elements (resource and transmission), changes in transmission-connected load and distribution-connected net load (considers effects of load, embedded generation, and loss of distribution elements), and generation fuel availability (wind, sun, and natural gas), some or all of which can be impacted by weather, which has hourly, daily, and seasonal variability.

In order to mitigate risks associated with uncertainty, and maintain an operable system that can respond second-to-second in real-time and be re-postured in anticipation of future events, the IESO also guides resource selection and the build out of the transmission system based on the following principles:

• **Diversity** – having a balanced variation of characteristics available across the system.

• **Flexibility** – ability to easily respond to changing circumstances or conditions across the system.

• **Manageability** – ability to have visibility, monitoring and dispatch of resources across the system.

Further discussion of these principals can be found in the sections below.

[DM asks if we should note if one scenario is more operable than another]

[SP should also comment on designing the resource mix for the future]

**Diversity**
Diversity in the characteristics of the resource mix, and where resources are located, is important to ensure risks inherent to each resource (technology, fuel type, or otherwise) are mitigated. As such, the total portfolio must provide sufficient system capability to meet adequacy and other service level requirements, and be sustainable under a wide variety of conditions (short-term extreme weather, mid-term environmental extremes, and fuel delivery challenges) and operating restrictions (air emissions, water flow, and cooling water temperature).

Flexibility

Flexibility in what characteristics the supply mix can provide allows Ontario to maintain reliability through both anticipated and unanticipated changes on the system. This includes This is of particular importance on days where demand is high, stretching available resources capable of responding to ramping

- Load Following – sufficient flexibility to continuously match supply and demand under normal and unexpected operating conditions.

Ramping – sharp changes in consumption up or down (in summer morning/evening)

IESO’s Experience in Flexibility

On June 28, 2021, demand was high all day and evening peak reached 22,300 MW. Wind contributed to the system’s energy need but was only able to provide 11% of its installed capacity in the peak hour for a total of 500 MW (wind was performing 400 MW under the forecast).

Low water conditions caused a concern with the hydro-electric resources on several river systems. In an attempt to conserve the energy limited hydroelectric resources for utilization at peak, these resources were constrained down in off-peak hour. To replace the energy limited resources, other non-energy limited units were dispatched up including flexible gas resources.

A total of 6,000 MW of gas fired generation was dispatched to meet the 22,300 MW peak. Much of this was constrained on earlier in the day to offset the energy limited resources and to provide Operating Reserve. No other fuel type offered the flexibility to constrain on for this purpose.

An Energy Emergency Alert was issued indicating that all available resources were committed. Considering there was no other resources available and approximately 30% of the demand was supplied by the gas fleet, this demonstrates the importance of having flexible energy that can be sustained throughout the day.

Manageability

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The bulk of Ontario’s generation fleet is visible to the IESO and also dispatchable. Should the gas-fired generation fleet be replaced with resources on the distribution system, the IESO will require visibility and dispatchability of those resources to maintain reliability (and how requirements for OR may change, increased risk of single element losses, resulting in multiple losses or Gx bottling). Detailed technical specifications of all resources will be required to ensure that engineering studies can effectively model system behaviour under a range of conditions.

If the replacement supply mix incorporates an increasing number of small resources that are embedded, distributed and possibly aggregated, the impact on situational awareness must be considered. Situational awareness is important as it provides operators foresight into what changes could potentially happen. It is being aware of the environment and understanding the information that is available at hand and what that means now and in the future. This will be increasingly complex with a larger number of resources on the system which would increase the complexity of operation and consequently increase the risk of human error. A large increase in the number of resources and market participants providing capacity to Ontario could require significant tool upgrades to manage the increased volume of data the IESO would be receiving.

The IESO currently has full visibility and control of resources connected to the high voltage transmission system but the same cannot be said for those connected to the distribution system. To date, this has been manageable due to the limited size of the fleet of distributed resources. In the event there is an increased penetration of resources on the distribution system, operators must have sufficient capability to monitor and dispatch the power system.

Ensuring manageability with an increased penetration on the distribution system and number of resources, significant changes to our existing market participation framework, tools and rules will require changes which could cost upwards of $25 million.

[Closer to MRP costs. Also mention IESO staffing impacts to a variety of functions (registration, validation and modelling, metering, settlements.)]

Additional Operability Concerns and Considerations

Operational Scope

The IESO-controlled grid is operated day to day (24/7) and minute to minute at the level of reliability such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of reliability is achieved by operating the IESO-controlled grid to meet adequacy criteria for anticipated demand, system security criteria for specified contingencies, and re-preparation criteria for restoring reliability following contingencies or major events such as blackouts.
The IESO-controlled grid is operated and its reliability maintained with due regard for planned or unplanned transmission element outages. This is the key aspect that distinguishes the system planning from the system operation. While the transmission system is planned and designed based on the strict cost-benefit criteria within the well-defined scope, in reality, more often than not, the transmission system is operated in out-of-scope conditions as a result of maintenance outages and forced outages. In other words, the operators must keep the “lights on” even if they are faced with unplanned operating scenarios resulting from different system events ranging from transmission elements malfunction to events like forest fires, tornadoes and ice storms. In addition, the operators must act quickly to restore the load lost during the above mentioned events.

When considering future generation mix, even though it is hard to quantify operability requirements to cover for the above mentioned events, it is clear that certain generating technologies available today are more preferred than the others.

**Locational Implications of the Supply Mix on Operation**

Considering that the locational importance of the generation mix is already discussed in the section “Developing a Transmission Plan”, the following discussion focuses on the impact of the generation mix on complexity of operation of the transmission system. The examples used in the discussion are based on the current operation and they do not factor in the impact of the Transmission Plan.

The transmission system limitations on the IESO-controlled grid result in flow-gates or interfaces that impede flow of power toward loads. These flow-gates are reflected through the system operating limits such as thermal, voltage and angular stability limits that indirectly describe specific system deficiencies. These system operating limits are derived by the IESO and together with the specific operating instructions are used by the Control Room operators to operate the transmission system reliably.

In the discussion of the supply mix change, it is important to factor in the effort of developing the system operating limits as well as their complexity in order to minimize the instances of human error during the operation. Complexity of system operating limits and operating instructions is often dependent on generation technology used in the generation mix.

To provide unrestricted flow of power toward loads, to minimize losses, and to enable outages for transmission elements maintenance, sometimes, it is necessary to position a generator of certain capability at the specific location.

During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in locations to minimize transmission investments needed to incorporate the resource into the system. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by virtue of where they are located, also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.

Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.

There are specific areas in the province, should replacement supply mix be located, would provide higher value than other areas of the province. The location of generation close to load pockets is important to reduce congestion and to reduce losses on the transmission system and ensure loads are being served.
Replacement supply mix located on the east side of Flow East Towards Toronto (FETT) interface is important to accommodate the expected demand growth in the area as well as the retirement of the Pickering Nuclear Generating Station. Currently, Lennox, a gas generator near Napanee, is the best source low minimum loading points and its ability achieve high generation output. Also, GTA-located plants such as Portlands, Goreway and Halton Hills gas generators provide specific support to enable unrestricted flow of power through the FETT flow gate.

Similarly, Kirkland Lake gas generators enable flow of power from hydroelectric generation stations in the northeastern part of Ontario towards the load centres.

Generation located in areas that can reduce autotransformer loading is also important. Having Portlands GS connected on the 115 kV side of the Leaside/Manby autos helps to reduce the loading there. The locations of the Goreway and Halton Hills generating stations help reduce loading on transformers supplying the GTA.

These natural gas generators are important to keep loadings reduced during planned transformer outage or if a forced transformer outage were to occur. Should these gas generators be phased out, new supply must be strategically placed to serve these purposes and help maintain system operability. In addition, due to their reactive power capability, Portlands, Halton Hills and Goreway GS are the key elements in supporting the voltage and flow of power towards Toronto during high demand days.

In the Leamington area, an increased dependency on the gas-powered Brighton Beach GS facility is expected to manage the area load exposure to prolonged load reductions during outage conditions. A replacement for that generation, in that area will also be required to help mitigate load exposure.

In the Leaside/Manby area, reliability challenges are highly dependent on primary demand. During high primary demand conditions, recent IESO studies show significant penalties to Flow Away from the Bruce Complex (FABC) flow gate limit as a result of Pickering units being out of service. The situation is aggravated with unavailability of gas units at Goreway, Halton Hills and Portlands GS (and Darlington NGS if on outage). Considering the significant amount of penalties on the flow from the west, adequacy concerns would arise to supply load in the Toronto area without gas generation and after the Pickering retirement.

During low primary demand, and with the expectation of the Darlington Vacuum Building outage scheduled for 20xx, IESO studies indicate a great dependency on the Pickering nuclear units as well as the fleet of gas generating units in the area to manage high voltages. Managing the area without the gas generators will potentially expose the system to frequent switching of the lines and with that increased risk of equipment failures. It is therefore important to ensure that the equivalent capacity in placed in the area to replace the gas.

We must also ensure that adequate capacity is available to the area to accommodate a Darlington NGS outage after the Pickering NGS units have retired. If the gas is not replaced in that area, Ontario may experience shortfalls with the current transmission infrastructure.

Inverter Based Resources

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Rapid growth of inverter-based resources (“IBRs”) add complexity to grid reliability. These include most solar and wind as well as battery storage, hybrid generation and many DER. Some inverter-based resource performance issues have been significant in recent grid disturbances, such as the tripping of a number of BPS-connected solar PV generation that occurred during the 2016 Blue Cut Fire, 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California. External jurisdictions, such as California, are gaining experience with large penetrations of distributed inverter-based resources. Recent events have highlighted the need to understand the volume of these resources that will trip coincidentally due to faults on the power system.

**Broader Planning and Coordination**

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 Mt/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions. Maintaining gas on the system beyond 2030 can be an enabler of cost effective economy-wide decarbonisation.

**Role of Natural Gas-Fired Generation and Other Resources**

The focus of this study is to investigate the requirements and system impacts that need to be addressed should the phase out of natural gas be considered. To achieve this, it is important to recognize the role that natural gas currently plays in the electricity system by way of illustrating the services it provides, and its technical characteristics, to understand what will need to be replaced by other resources.

As outlined above, natural gas-fired generation contributes a range of reliability services to Ontario’s supply mix. The flexibility of gas is particularly valuable, providing load-following, ramping capability, operating reserve, and capacity under all weather conditions. With Ontario’s significant level of variable and intermittent supply, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid. Gas is also able to provide sustained energy when needed as it is generally available at all times of the day.

Today, gas generation provides the required ability to follow demand changes with the fuel availability to run when required. Gas generation also provides value in managing the high amount of variable wind and solar generation outputs in addition to dealing with constant demand changes in the system. Hydroelectric generation does provide load following capability when it can, but its output depends on water availability, including environmental restrictions and cascading river system impacts. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all. When considering which resource(s) to use in place of the natural gas fleet, there are no readily available resource types that can offer the same level of on-demand energy availability and flexibility by themselves.
Aside from balancing supply/demand of energy through flexibility, current gas resources provide a number of technical benefits to the grid. Gas generators support provincial transmission security and provide voltage stability particularly in specific locations where the transmission system may not be easily be reinforced or local supply makes sense. Additionally, they provide fast dynamic response which aids in system recovery following a significant contingency, maintaining system frequency and voltage. Many gas plants are also strategically located near major demand centers to provide local and regional reliability, and minimize losses on the transmission system. Some gas plants were developed in lieu of major transmission upgrades in areas where they were deemed cost prohibitive or not possible due to specific environmental or social concerns. Should gas generation be phased out, additional transmission and voltage support may be required to deliver provincial capacity. In some areas, transmission upgrades may be required to support local load centres if new supply can’t be located in the same area (e.g. insufficient land is available for new supply).

The current gas fleet provides continuous energy and is able to follow a 5-minute dispatch. Another instance where the flexibility of the gas fleet has proven invaluable is during wind “cutouts”. Changes to weather conditions may cause wind generation in a particular area to all cease generating within a very short window or at the same time resulting in a “cutout”. In these instances, having resources that can be dispatched quickly to ensure the balance of supply and demand is maintained after such an event would become more important with the increased penetration of wind in the replacement supply mix. Locational diversity of where the wind is placed will help mitigate the size of this potential loss of generation, however will not eliminate the need for flexibility to remain. In order to ensure that, the replacement supply mix must have the flexibility to both follow 5 minute dispatches in both directions but also do it quickly (i.e. have a fast ramp rate).

Reliance on energy limited resources does not provide the inter or intra hour flexibility required to maintain a balance between supply and demand.

The gas fleet plays an important role in allowing us to balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp changes in consumption or sharp changes in renewable generation.

Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

Today, flexible resources make up about 40% of the current fleet. Of the flexible resources, 11,000 MW of gas generation accounts for more than 70%. Flexible resources respond to 5-minute dispatch to balance the supply with demand.

Gas generators have a large rotating mass within that produces energy. These rotating masses provide inertial and frequency response that is required to help in the recovery of system frequency.

Gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations.

Gas fired generators store kinetic energy in proportion to their size when synchronized. Immediately following a contingency, this kinetic energy stored is released and acts as a suppressant to the frequency decline.
Lastly, natural gas-fired generators are synchronous machines, and help ensure acceptable frequency response and system stability. If capacity from natural gas-fired generators is replaced with inverter-based resources ("IBR") like solar, wind, and battery storage, measures will need to be taken to replace this service. While controller technology used in IBRs may be able to provide frequency response, they are currently in the piloting stage. There would also be a requirement for IBRs providing this service to hold back energy output that may otherwise be available so that it can respond to an under-frequency event by injecting that available energy it was otherwise holding back. This would require additional investment in the capacity contemplated in the supply mix of this report. This would also require the design of a new mechanisms to procure FFR, as normally FFR is naturally provided by the inertial response of synchronous machines, and is inherent in the synchronous resource.

**Lessons Learned from Off Coal**

Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario’s generation capacity. When coal generation phase out was being considered, gas fired generation was a mature technology available with similar, yet less flexible operating characteristics due longer start-up times and higher minimum loading points. Bringing on large numbers of generators with a different fuel-type than coal also posed new administrative and operational challenges, with the IESO developing new approaches to monitor and operate different forms of generation. New approaches were developed to manage variable generation, including ramped-up EE programs, increased visibility of current variable generation output, enhanced methods to forecast variable generation output, and processes to dispatch variable generation resources. Further, certain coal-fired power plants were located in strategic areas that supported load centres and ultimately reduced the reliance of power being delivered from the transmission system. For instance, the former coal-fired Hearn generating station supported Toronto and central GTA transmission systems, while the coal-fired Lakeview generating station supported the southwestern and western GTA transmission systems. The replacement of such strategically located facilities was achieved by adding facilities like Portlands Energy Centre, Goreway and Halton Hills in a way to avoid the need to reinforce significant amounts of the transmission system that Hearn and Lakeview otherwise supported.

To replace the gas fleet, we will face similar challenges and need to employ similar strategies, utilizing a combination of many resources to be discussed.
Opportunities to Move Towards an Emissions-Free System in the Longer-Term

There are multiple pathways to removing CO₂ emissions from the electricity system for the future. However, these options must be commercially feasible, scalable and cost effective in the near term. In developing the replacement supply-mix for this study, the following resource options are considered to create a diversified low-carbon energy portfolio: energy efficiency, demand response, wind, solar, energy storage, hydroelectric, nuclear small modular reactors, and Hydro-Québec firm imports.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW⁴, accounting for about 25% of total installed capacity, as shown in , and represents about 7% of total energy in the province, as shown in Figure 3.

**Figure 2 | 2020 Installed Capacity by Fuel Type**

[Diagram showing installed capacity by fuel type]

**Figure 3 | 2020 Energy Output by Fuel Type**

Ontario benefits from a diverse supply mix, contributing to reliability under a wide range of weather and operating conditions. No single resource type provides all of the essential reliability services.

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⁴ Ontario’s natural gas fleet is largely connected on the transmission system.

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Different resources provide different services, and the portfolio works together to provide a resilient and flexible system, as shown in Error: Reference source not found.

Table 1 | Resource Characteristics

<table>
<thead>
<tr>
<th>Reliability Service</th>
<th>Nuclear</th>
<th>Gas</th>
<th>Hydro-electric</th>
<th>Wind</th>
<th>Solar</th>
<th>Bioenergy</th>
<th>Demand Response</th>
<th>Storage</th>
<th>Imports</th>
<th>Energy Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Energy</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Load</td>
<td>X</td>
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<td></td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Operating Reserve</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X*</td>
<td></td>
</tr>
<tr>
<td>Voltage Regulation</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Frequency Regulation</td>
<td></td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Local Supply</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Security</td>
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<td></td>
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<td></td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Imports are able to provide 30-minute reserve only.
There are multiple pathways to removing CO₂ emissions from the electricity system for the future. However, these options must be commercially feasible, scalable and cost effective in the near term. The IESO has been engaged in enabling new types of resources for a number of years and is working to explore the potential of emerging technologies. While these resources are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability. In considering phasing out gas, the province will require resources that have similar characteristics and services, individually or in aggregate. As new emerging technologies commercialize and performance becomes better understood, these will be incorporated into future outlooks. This section will outline candidate options for the replacement supply-mix.

**Energy Efficiency**

Through the delivery of programs, training and other mechanisms, the province is able to cost-effectively meet its electricity system needs that enables Ontario’s electricity consumers to improve the energy efficiency of their homes, businesses, institutions and industrial facilities. The IESO recognizes that energy efficiency programs provide continued opportunities for electricity consumers to save on energy costs.

In 2019, the IESO completed the first integrated electricity and natural gas conservation Achievable Potential Study (APS). The APS identifies and quantifies energy and demand savings, greenhouse gas (GHG) emissions reduction, and associated costs from energy efficiency measures for the period of 2019-2038. Four achievable potential scenarios from the APS were made available to the model with seasonal energy and capacity reductions and annual program costs.\(^5\)

**Demand Response**

Demand Response (DR) – that is when consumers reduce their electricity consumption in response to prices and system needs - is playing an increasing role in Ontario's electricity system. DR resources can reduce their electricity consumption when wholesale prices are high or the reliability of the grid is threatened, receiving payments for the reductions they make. DR has already had a significant impact on energy demand and helped reduce peaks, providing a valuable and cost-effective resource to the system.

This study assumes an upper limit of 2,000 MW of incremental DR capacity, which is consistent with a similar modeling exercise performed for the 2016 Ontario Planning Outlook. Including currently contracted DR, this is equivalent to roughly 10% of peak demand.

**Wind, Solar and Energy Storage**

There are various forms of renewable energy, including energy generated from the wind or sun. The fuel availability for wind and solar generation is reliant on the weather, time of the year and time of the day. Solar generation is particularly important in the summer months when peak demands occur midday as solar panels reach their height of production. Wind production is usually greatest during cold winter months and at night, but can vary depending on geography and the time of year, making it a suitable complement to solar generation.

\[^5\] The APS identified cost effective potential for energy efficiency based on previous avoided energy and capacity costs. Under scenarios considering gas phase out, the avoided capacity and energy costs would likely be higher.

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Emerging energy storage technologies allow electricity to be captured and stored and then re-injected back into the grid when it is required. Energy storage technologies vary considerably in terms of their size and scale, how the energy is stored, how long it can be stored and the technology’s response time. The IESO is exploring how to leverage energy storage in conjunction with renewables in order to maximize the contribution variable generation makes to the system. However, due to the variable and uncertain nature of variable resources (e.g. wind resources are inherently variable minute-to-minute and hour-to-hour and can lead to forecast errors), this poses greater challenges for energy storage to smooth variable generation in order to mimic the consistency of gas.

**Hydro-electric**

Hydropower is another renewable source of energy produced by the falling or moving of water. It is a major contributor to Ontario’s supply mix, both as a form of baseload generation and during times of peak demand.

**Nuclear - Small Modular Reactors**

Small Modular Reactors (SMRs), like current nuclear reactors, are designed to provide reliable, carbon-free electricity, but with a much smaller land footprint than current reactors. Smaller plants mean they are more flexible and can be deployed not only in large established grids but also in smaller grids, remote off grid communities and for resource projects. Their designs and features mean they cannot only provide baseload generation but their ability to load follow means they can support intermittent renewable sources like wind and solar.

Consistent with the project scope details provided in the June 2021 stakeholder engagement session, candidate options include the proposed 300 MW SMR at Ontario Power Generation’s Darlington nuclear facility.

**Hydro-Québec Firm Imports**

Ontario trades with Québec on the open market on a non-firm basis. In 2016, the IESO and Hydro-Québec (HQ), executed a series of agreements to facilitate electricity trade between the two provinces. The electricity trade agreement includes electricity purchases whereby each year the IESO is entitled to purchase 2 TWh of electricity from HQ at a set contract price, electricity cycling whereby the IESO will export up to a contracted amount of electricity to HQ, and capacity sales. The electricity trade agreements with HQ are set to expire December 31, 2023, and it is assumed that these particular agreements are not extended in the study.

Imports from Québec are an option to replace gas generation. However, the extent HQ imports can contribute to reducing GHG emissions will depend on many factors including generation capacity and energy availability in the Québec system, the negotiated price and the transmission path availability between Québec and Ontario. Québec has large water storage capability and is projected to have surpluses of energy for many decades; however, their capacity availability is far more constrained. Québec is a winter peaking system and exports are generally curtailed during winter peaks. With the appropriate transmission upgrades, this analysis assumes that Québec can supply summer and winter capacity up to 3,300 MW.

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6 Québec experiences capacity shortfalls in the winter due to use of electricity for heating

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**Distributed Energy Resources**

The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (e.g. Distributed Energy Resources) to help address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

**Hydrogen**

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. It is light, storable, energy-dense, and when hydrogen is consumed, it produces no direct emissions of pollutants or GHGs. There are no known hydrogen reserves from which the fuel could be mined, instead, hydrogen is typically produced from a fossil fuel, or by using electricity to split water into its component molecules of hydrogen and oxygen (known as green hydrogen). Depending on how the hydrogen is produced, there could be significant GHG impacts (e.g. producing hydrogen from fossil fuels).

Hydrogen is one of the leading options for storing renewable energy, and could also enable long-term (e.g., interseasonal) energy storage. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines.

While hydrogen may provide a potential solution to remove emissions in the longer term, the IESO did not consider it while developing the resource supply mix. In the near-term, large-scale green hydrogen production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may come down significantly in the future and could make hydrogen more competitive in the longer-term, but this will likely occur past the 2030 timeframe considered in this study.

**Carbon Capture Utilization and Storage**

Carbon Capture Utilization and Storage (CCUS) solutions will also be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long-distance high-pressure pipelines to transport CO\(_2\) to storage sites will require further investigation to avoid siting and regulatory challenges.

Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario. It is also currently costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the resource supply mix.
Table 2 outlines the cost and performance assumptions for considered candidate options.

**Table 2 | Candidate Options for Replacement Supply for Scenarios 1 and 3**

<table>
<thead>
<tr>
<th>Resource</th>
<th>Levelized Unit Energy Cost ($2021/MWh)</th>
<th>Capacity Cost ($2021/kW-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td>39%</td>
<td></td>
<td>Cost projection based on average of industry capital cost projections.</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td>17%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
<tr>
<td>Hydro-electric</td>
<td>Cost Curve</td>
<td>50%</td>
<td></td>
<td>Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs.</td>
</tr>
<tr>
<td>SMRs</td>
<td>NA</td>
<td>85%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>HQ Firm Imports</td>
<td>Average import price from energy runs</td>
<td>135</td>
<td>Variable</td>
<td></td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>Four achievable potential scenarios from the 2019 APS</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DR</td>
<td>NA</td>
<td>67</td>
<td>NA</td>
<td>Cost based on recent capacity auctions.</td>
</tr>
</tbody>
</table>

7 Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)

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Scope of Study

The scenarios in this study consider the reliability, cost and wholesale market impacts, timing and basic operability implications to the electricity system. The scenarios in this study did not consider higher demand due to an increase in electrification or how emissions in other jurisdictions may be affected in the future.

Areas of Study Considered

The three scenarios were examined from various lenses, including areas of reliability, costs, wholesale market impacts, operability and timing to the electricity system, as shown in Error: Reference source not found.

Table 3 | Areas of Study

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>Considerations for locational requirements for siting resources, or transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>Ancillary services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale Market</td>
<td>Least cost replacement resource portfolio</td>
</tr>
<tr>
<td></td>
<td>Potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>Use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>Impact on wholesale market pricing and how market value of system needs may change</td>
</tr>
<tr>
<td>Operability(^8)</td>
<td>Basic Operability: capacity, energy, operating reserve, ramping requirements, load following capability</td>
</tr>
<tr>
<td></td>
<td>Impact to wholesale market design</td>
</tr>
<tr>
<td>Timing</td>
<td>Typical timelines associated with construction of generation or transmission</td>
</tr>
</tbody>
</table>

Areas of Study Not Considered

It is expected that the electricity system will play a key role in achieving lowered emissions targets through demand growth driven by electrification of transportation, building and industrial end-uses.

\(^8\) Model portfolios were developed at an aggregate level, to determine the rough cost implications. Detailed locational information would need to be developed before a detailed operability assessment could be completed.

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that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price were not considered as part of this study, impacts of electrification on demand will be considered in the 2021 APO and future APOs.

Ontario imports energy from and exports to its five neighbouring jurisdictions every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions target, so will our neighbours. Neighboring jurisdictions are evolving and policy changes are underway in the United States as they develop their own pathways to lowering emissions. However, these policies have not been finalized and to avoid speculative policy decisions (e.g. carbon pricing in other regions, future resource supply mixes in other regions, etc.) this study will not consider how emissions in other jurisdictions may be affected in the future. This study will assume the Eastern Interconnection as is from the 2020 APO Scenario 1 for the duration of the study period. The emissions forecast for this study will also consider Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

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Scenario Development

Base Case
This study leverages the 2020 APO Scenario 1 as the underlying base case. The 2020 APO Scenario 1 projects net energy demand to be 141 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period. By 2030, net energy demand is expected to reach 159 TWh. Summer peak demand is projected to be 25.5 GW and winter peak demand to be 24.6 GW by 2030.

In the 2020 APO, the total installed capacity of the supply mix, reflecting continued availability of existing resources following the end of their contract term or commitment, is expected to be 38 GW by 2030 as shown in Figure 4. Total energy efficiency program savings is also expected to be about 12 TWh by 2030.

Figure 4: 2020 Annual Planning Outlook, 2030 Installed Capacity (GW)

The carbon pricing assumptions used are $50/tonne\(^9\) starting 2022 (held constant thereafter) and a benchmark emissions rate of 370 tonnes CO\(_2\)/GWh allowance for existing natural gas generation.

As outlined in the 2020 APO, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO\(_2\) by 2030, still well below 2005 levels, shown in Figure 5.

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\(^9\) This assumption was based on IESO’s understanding of carbon pricing at the time and aligns with the forecast as discussed under Current Government Emissions Policy and Emissions Targets.
This expected increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the 2020 APO assumes that existing natural gas will fill in system energy needs. As electricity consumption increases, the rise in electricity sector emissions could be partially reduced, factoring in requirements to maintain system reliability, by increased energy efficiency and non-emitting resources in the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy change.

**Potential Pathways**

This study examines potential pathways to lower emissions through a complete gas phase out (**Scenario 1**) and maintaining emissions at current levels (**Scenarios 2 and 3**), as illustrated in Error: Reference source not found Error: Reference source not found. The current emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^{10}\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 Mt CO\(_2\) per year. The purpose of developing these Scenarios was not to create estimates of likely outcomes, but to allow the IESO to provide insights gleaned from the range of potential pathways. These scenarios were also informed by the multitude of input from the public webinar, stakeholders and communities’ feedback – written feedback can be found on the IESO website.

**Figure 6 | Pathway Description**

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10 2017 was a lower than expected demand year, and as a result, emissions were lower as the gas fleet operated less.
Modeling Approach

Scenario 1 and Scenario 3 use a supply mix-based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliable system in Ontario. Increased shares from any one type of replacement resource comes with risks since no single option can meet all system needs at all times. A diverse supply mix will help manage both the operational and cost risk of the changing supply mix. The supply mix-based approach considered demand-side and supply-side options. Scenario 2 maintains all of the supply mix assumptions from the APO 2020, but considers updated carbon policy to drive GHG reductions through a market-based approach.

The supply mixed-based approach for Scenarios 1 and 3 determined a replacement supply mix incremental to the existing resource fleet. In Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. In Scenario 3, all existing resources including natural gas are assumed to remain in service.

In considering the candidate options, the study considers possible replacement technologies that are sufficiently mature today. As the reliability and planning coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This consideration also provides more certainty on the cost estimates of the replacement supply mix. It is difficult to predict technological innovations, policy developments, and grid evolutions that could manifest in the study time frame – factors that could result in alternate supply mixes. The IESO aimed to provide a set of reasonable and forward-looking cost estimates, given professional judgement and the current information available. The study will also consider, to the extent possible, the transmission investments required for increased intra-jurisdictional trading. However, the costs associated to make the replacement supply mix operable within the power system and the necessary transmission upgrades were not included.

Supply portfolios are constructed using a least-cost optimization capacity expansion model that selects resource build-out over a 20-year period subject to a number of parameters. All resource portfolios are required to at least meet the total capacity contribution equal to summer and winter peak demand plus reserve margin; total annual energy demand, accounting for imports and exports; and annual CO₂ emissions target. It is important to note that certain physical or other practical constraints (e.g. availability of suitable land-use, non-CO₂ environmental impacts, societal acceptance of the replacement technology, among others) were not considered in this least-cost optimization.
capacity expansion model. And so, the outcome of such a model does not imply technical or physical feasibility.

Cost and performance assumptions for each option considered are provided in. Transmission cost assumptions associated with some of the resources from Table 2 are provided in Table 4. It is difficult to determine the required transmission investments without knowing where new generation would be located. For instance, it is recognized that much of the accessible locations in the transmission system to incorporate wind generation have already been developed to connect the existing wind generation fleet. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations. A portfolio analysis was performed without considering any transmission costs or costs associated with ensuring an operable power system (e.g. tool upgrades, market structure changes, among others). This sensitivity demonstrated that the cost-optimized replacement supply mix is not very sensitive to transmission costs. The actual extent of the impact of transmission costs cannot be known until full details for implementation are considered. Such determination would require much more extensive consideration and collaboration with generation developers, which cannot be completed within the timelines for this report.

**Table 4 | Transmission Assumptions for Scenarios 1 and 3**

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2021M)</th>
<th>O&amp;M Cost ($2021M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1,500 MW of additional wind and solar capacity.</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports</td>
<td>300</td>
<td>3</td>
<td>Based on preliminary consideration of increasing firm interconnection capacity with Québec.</td>
</tr>
<tr>
<td>(&lt;= 2,050 MW)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Firm Imports</td>
<td>1,500</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>(&lt;= 3,300 MW)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Supply mix portfolios are modeled seasonally (summer and winter) over 20 years. In each season, the supply mix portfolios are compared to the necessary capacity, energy and emissions requirements referenced above. Hourly modeling in a multi-year capacity expansion optimization model was considered impractical given processing constraints. The purpose of the seasonal capacity expansion model is to develop supply mix portfolios with the approximate amount of capacity and energy to meet system needs. The supply portfolios were followed by an assessment using an hourly energy dispatch model to determine whether the portfolio could meet energy requirements in all hours. Other feasibility assessments were also performed, such as assessing the required storage duration and the frequency with which DR was activated.

Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future. The resulting portfolios developed using the least-cost optimization
capacity expansion model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path and do not directly imply technical or physical feasibility. Notably, the results are heavily influenced by the relative cost assumptions which are likely to change over time. The results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while meeting capacity and energy requirements.

Scenario 2 is a market-based approach where an increase in carbon price and a decrease in the benchmark emissions rate reduce the utilization of gas by 2030. The carbon price assumes a linear increase from $50/tonne in 2022 to $170/tonne by 2030, while the benchmark emissions rate for all natural gas facilities linearly declines from 370 tonnes/GWh in 2021 to 0 tonnes/GWh by 2030. The demand, conservation, supply and transmission outlook assumptions are consistent to the Base Case.

An economic hourly dispatch model was used to determine the outcomes of the three scenarios. This assessment simulates the Ontario electricity market through a production-cost simulator to inform energy production, imports and exports, system costs, and emissions. While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Base Case to understand which factors are the largest drivers of ratepayer costs. Error: Reference source not found illustrates the modelling approach for the three scenarios.

Figure 7 | Modelling Approach for Scenarios 1, 2 and 3
Study Findings

Scenario 1

Scenario 1 examines a portfolio of replacement resources assuming all existing gas is phased out by 2030. The incremental supply above the Base Case required to completely replace natural gas generation by 2030 is about 17,000 MW, as shown in Figure 8. In addition to this resource mix, Energy Efficiency Scenario B of peak 1,600 MW savings from the APS is also included as part of the lowest-cost resource mix (not shown in the figure).

Figure 8 | 2030 Incremental Installed Capacity, Scenario 1

The incremental nuclear, wind and solar capacity produce less annual energy (19 TWh) than the natural gas energy (31 TWh) was forecast to produce in 2030 in the 2020 APO. The remaining energy gap is made up by energy efficiency (9 TWh) and imports. Storage and DR are required to replace the capacity currently provided by natural gas as well as the incremental capacity gap identified in the 2020 APO. Storage and DR also help balance periods of high baseload generation and periods of insufficient supply. From the candidate options, new hydroelectric capacity was not selected by the capacity expansion model due to the high assumed costs associated with new build hydroelectric generation.
This portfolio of resources, along with the assumptions presented, satisfied the high-level reliability requirements of the capacity expansion model. This portfolio was then simulated in IESO’s hourly energy dispatch model to determine if this mix would be able to reliably supply all energy needs when considering hourly market dynamics. This portfolio resulted in approximately 500 GWh of unserved energy; which amounts to about a day and half worth of all electricity consumed in the province. From a high level, the assumed portfolio does provide enough capacity and energy to meet system needs, however, it lacks the ability to deliver the energy precisely when it is needed: flexibility. To increase flexibility, the reservoir size of the storage fleet was increased until all energy needs were met. The initial portfolio assumed the storage fleet had 4 hours of storage, however this post-processing exercise indicated that far more storage would be needed to be able to satisfy the energy needs, as shown in Figure 9. For clarity, hours of storage refer to the number of hours the facility could be outputting at maximum injection when fully charged.

**Figure 9 | Hours of Storage Required compared to Percent of Unserved Energy Now Served**

The post-processing exercise was able to optimize the 4-hr storage fleet further to help reduce an additional 36% of the unserved energy, but as can be seen from the figure, to fill 100% of the energy gap, the storage fleet would need about 47 hours of storage. The above storage fleet with 4 hours of storage translates to an installed storage reservoir size of about 25 GWh. To serve the entire need in the hourly dynamic energy model, a reservoir size of closer to 300 GWh is needed. For context, the largest pumped-hydro storage projects being proposed in Ontario today are all under 10 GWh, however there are not enough potential sites in Ontario to provide 300 GWh of storage with pumped hydro alone. Batteries might be able to contribute as well, however, even the largest manufacturing plant in North America, Tesla’s Gigafactory, is only able to produce 20 GWh of storage per year.
This scenario also relies heavily on using DR as a peaking resource. From a high level, the amount of energy requested of the incremental DR fleet of 2000 MW, and assuming a 4 hour activation limit, is the equivalent of about 193 activations per year, or a capacity factor of approximately 9%. In addition, to help reduce the energy not served in the hourly dispatch model, the 4 hour activation limit on DR was not modelled, meaning that there were some activations where the model assumed DR was activated for tens of hours continuously. This type of operation greatly diverges from how today’s DR product operates and it may not be practical to assume that this level of service could be provided by this resource type.

The complete phase-out of gas by 2030 with replacement by the above mix would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy market prices, along with increased volatility. Overall system cost, however, would increase as a result of building new renewables; these resources would likely have the effect of lowering energy market prices while increasing capacity costs and potentially the cost of ancillary services. At the same time, storage resources tend to offer in the ancillary services markets, and the large build-out of storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later in the Appendix B under the Wholesale Market Impacts.

Besides those energy efficiency savings considered in the 2020 APO, there are potential opportunities to achieve greater electricity savings as identified in the APS. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentive levels. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the Base Case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Québec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.

The capital investment required for the replacement supply mix is about $27 Billion. Additional costs associated with the termination of the existing natural gas contracts also needs to be considered. The outstanding net revenue requirement would be at a minimum cost of $2.4 billion (absent all other potential compensation costs the asset owners may seek). System costs, recovered from ratepayers on an annualized basis, increase 17% (about $4 Billion) compared to the 2020 APO Base Case.

Figure 10 | Annual Cost of Electricity Service for 2030 for 2020 APO Base Case and Scenario 1
The emissions forecast for Scenario 1 is 0 Mega tonne for 2030 from a 12 Mega tonne forecast in the Base Case. The incremental unit cost for the emission reduction associated with the 12 Mega tonne reduction is $164/CO2 Mega tonne.

**Figure 11 | 2030 Emission Comparison and Unit Cost of CO2**

**Scenario 2**
Scenario 2 examines increased carbon cost and decreased benchmark to reduce the utilization of gas. This scenario relies on economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs and lowered carbon benchmark. As indicated above this scenario assumes an increase to cost of carbon from $50/tonne in 2022 to $170/tonne by 2030 and a decline of the natural gas benchmark of 370 tonne/GWh in 2022 to 0 tonne/GWh by 2030. This also assumes that the cost of energy from other jurisdictions remains the same as APO 2020. The entire reason for having a GHG allowance benchmark of 370 tCO$_2$/GWh was to minimize the impact of the carbon price on trade.

In the absence of a benchmark allowance (i.e. allowance of 0 tCO$_2$/GWh) it is very likely that the carbon pricing policy would have to include adjustments at the border to account for the GHG emissions associated with the energy in other jurisdictions. Border adjustments are not considered in this analysis, instead the GHG emissions associated with the increased imports were quantified. A border adjustment policy could significantly impact the amount of imports considered in this analysis.

With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for this scenario. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions is expected to significantly impact Ontario’s markets. Since gas resources frequently set price as the marginal resource in Ontario, the higher cost of gas would result in broadly raised energy market clearing prices. Many resources would subsequently be able to recover an increased portion of their costs through energy markets. The higher market clearing prices in Ontario would also make Ontario electricity exports into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will offset some Ontario natural gas production. The change to natural gas production, imports and exports relative to the Base Case is provided in Figure 12 below.

**Figure 12 | Natural Gas, Imports and Exports Relative to the Base Case**

The resource adequacy considerations are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO Base Case. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO Base Case; thus, no additional lead time is required for this portfolio mix other than what is already assumed in the 2020 APO Base Case.

The reduced natural gas production results in GHG emissions remaining around 4 Mt CO$_2$/yr in Scenario 2 which is consistent to the 2016 to 2020 historical level and declining to 3 Mt CO$_2$/yr by 2030, as shown in Figure 13.

**Figure 13 | Emission Forecast for Scenario 2 and the 2020 APO Base Case**

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System costs, recovered from ratepayers on an annualized basis, increase 3% (about $1 Billion) compared to the 2020 APO Base Case.

**Figure 14 | Annual Cost of Electricity Service for 2030 for 2020 APO Base Case and Scenario 2**

The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

**Scenario 3**

Scenario 3 examines a portfolio of replacement resources assuming existing gas is available to compete with other resources. The incremental supply of about 9,000 MW above the Base Case, where the natural gas fleet are assumed to remain in service, is shown in Figure 15. In addition to this supply mix, Energy Efficiency Scenario B of peak 1,600 MW savings from the APS is also included as part of the lowest-cost resource mix (not shown in the figure).

**Figure 15 | 2030 Incremental Installed Capacity, Scenario 3**
The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, this need for new capacity is largely met through energy efficiency, energy storage, and additional DR. Roughly 5,500 MW of wind are also selected in the capacity expansion model, as this energy is required to displace natural gas generation from an energy perspective. Despite similar cost assumptions, wind was favoured over solar by the capacity expansion model. This is because total energy demand is higher in the winter than summer, despite higher capacity requirements in the summer. Since the capacity need is met by storage and DR, the expansion model finds that wind is more effective at meeting the energy need.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. The hourly market dispatch model was used to confirm that 4-hours of storage duration per MW of storage capacity, assumed in the capacity expansion model, were sufficient to meet the supply needs of the system.

The partial use of gas as well as a diverse supply mix of renewables, energy storage, and DR would lead to less severe impacts to Ontario’s markets. Gas resources would continue to set price as the marginal resource in Ontario but less frequently. Increased renewable energy would displace some of the overall energy being supplied by the gas fleet. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later.

The emissions forecast for Scenario 3 relative to the Base Case is x.

[NTD: add emissions graph]
The capital investment required for the replacement supply mix is about $15 Billion. System costs, recovered from ratepayers on an annualized basis, decrease 8% (about $2 Billion) compared to the 2020 APO Base Case.

**Figure 16 | Annual Cost of Electricity Service for 2030 for 2020 APO Base Case and Scenario 3**
Steps and Challenges to Implementation

Generators termination for existing gas contract will result in financial and reputational impacts to the electricity industry. Ratepayers will also be further negatively impacted by stranding the natural gas assets and reducing competition by eliminating this supply option.

Large scale non-carbon emitting resources can pose several practical challenges, such as, land use, siting and location. Also with renewables located away from urban load centers major transmission infrastructure costs will be required in x billion range and will require 7 to 10 years to plan and implement.

Wholesale Market Impacts of installing non-carbon emitting resources with low to zero marginal cost resources will influenced price signals seen across the electricity system in Ontario that will also change import and export flows.

Developing a Transmission Plan

The ability of supply resources to meet demand across the province, and potentially other jurisdictions, relies on the transmission system to transport electricity to where it is needed. Within Ontario, bulk transmission interfaces form the boundaries of the 10 IESO electrical zones. The primary purpose of these interfaces is to describe power flows across the system and associated phenomenon which may limit these transfers. The bulk transmission system is also used to import power from, or export power to, neighbouring jurisdictions through a series of interties at specific points on the Ontario border. The maximum amount of power that these interfaces and interties can deliver is known as their transfer capability, which reflects constraints to ensure system stability, voltage performance, and acceptable thermal loading. Interface transfer capabilities are used in resource adequacy and transmission security assessments. Resource adequacy assessments are probabilistic studies that consider interface transfer capabilities with transmission facilities in-service, on planned outage, or following a limiting contingency event (a sudden or unplanned outage). Transmission security assessments are deterministic studies conducted at the zonal level that consider various transmission system disturbances, as defined according to applicable regulatory obligations. Zonal adequacy or security assessments may be more restrictive than resource adequacy assessments depending on the characteristics of the zone(s) being investigated. Intertie transfer capabilities are treated as interfaces in reliability assessments, and provide a number of system benefits, including: stability, frequency support and voltage support following a contingency, and the opportunity to consider imports and exports to manage resource needs where cost-effective.
As stated under Modeling Approach, the least-cost resource optimization for Scenarios 1 and 3 did not consider locational or siting-related matters, and as such, corresponding detailed Transmission Plans could not be developed. However, the IESO can draw upon experience from past transmission planning initiatives, and is able to comment on the potential scope of a Transmission Plan to reduce reliance on natural gas generation. The development of a Transmission Plan would consider the need to relieve constraints in order to deliver replacement resources, as well as the needs that would emerge if strategically located natural gas plants are retired. The following describes the potential scope in order to communicate the magnitude of potential reinforcement, the magnitude of potential cost impacts, and comment on the expected time necessary to plan, develop and implement reinforcements of such scope.

Note that this section is not intended to communicate a Transmission Plan. A Transmission Plan would require a proper planning exercise, executed with sufficiently detailed information regarding replacement resource siting, and including a thorough reliability assessment and a robust engagement with Indigenous communities, municipalities, and other stakeholders.

**Delivering the Replacement Resource Mix**

Of the 11,000 MW of installed natural gas-fired generation, a large portion is located in or around the Greater Toronto Area (GTA), with the balance primarily in western Ontario. When considering Scenario 1 and 3 resource mixes, it may not be practical to site some resources in large urban/suburban areas given expected land-use requirements (e.g., wind) or the origin of the resource (i.e., firm imports). This would imply that the retirement or reduced reliance on these natural gas plants would create a net requirement to transport power into the GTA and other load centres, as compared to Ontario’s current electricity system.

**Figure 17 | IESO Electrical Zones and Transmission Reinforcements**

![IESO Electrical Zones and Transmission Reinforcements](image_url)

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Northern Ontario Reinforcement (1, 2, 3)

The ability to deliver supply resources from northern Ontario towards the GTA and surrounding areas can be limiting for the existing system (as referenced in the 2020 APO), and siting a portion of replacement resources in northern Ontario would significantly worsen the impact of this constraint. In general, and following the reinforcement of the East-West Tie, there are three limiting paths to deliver supply resources from northern Ontario:

1. West of Sudbury
2. North of Sudbury
3. The North-South Tie

The West of Sudbury portion of the system, specifically the Missisagi East interface, is expected to be the next limiting east-west path for bulk power transfers following the reinforcement of the East-West Tie, and is centred in the greater Sault Ste. Marie area. This part of the system is a focus area for the IESO’s Northeast Bulk Plan. Depending on the magnitude of resources sited west of Sudbury, a reinforcement of this part of the transmission system could be addressed by a multi-circuit 230 kV line, or a new 500 kV line, extending from as far as Wawa TS to Hanmer TS (Sudbury area), a range of ~400 km. A reinforcement of this magnitude is expected to cost on the order of between $500 million and $1 billion, and take 7-10 years to fully plan, develop and implement.

The North of Sudbury portion of the system, specifically the 500 kV interface (D501P and the P502X-South), is expected to be a limiting north-south path for bulk power transfers from the northern parts of northeast Ontario. This 500 kV path, and its underlying 230 kV and 115 kV paths, generally extends from Pinard and the greater Kapuskasing area south to Timmins at Porcupine TS and the surrounding areas of Ansonville and Kirkland Lake. Depending on the magnitude of resources sited north of Sudbury, a reinforcement of this part of the transmission system could be addressed by a new 500 kV line paralleling the existing 500 kV system from Sudbury to Pinard via Porcupine, as well as potentially introducing a 230 kV underlaying system. A reinforcement of this magnitude is expected to cost on the order of $1 billion, and take 7-10 years to fully plan, develop and implement.

The North-South Tie is the 500 kV and 230 kV interface that supply resources from the north would have to flow through to get to the south at Essa TS in Barrie. Depending on the magnitude of resources sited in northern Ontario, a reinforcement of this part of the transmission system could be addressed by a new 500 kV single or multi-circuit line paralleling the existing 500 kV line, as well as a reinforcement to the 230 kV system emanating from Essa TS, as studies show that the 230 kV system can become thermally limiting with significant 500 kV injections at Essa. Reinforcements of this magnitude are expected to cost on the order of $1 billion, and take 7-10 years to fully plan, develop and implement.

A significant amount of voltage control devices would also be likely, particularly to control over-voltages at times when the system is lightly loaded, given the extent of new transmission lines that may be required.

The reinforcement scope indicated for North of Sudbury and the North-South Tie could also warrant consideration of introducing a new HVdc network to Ontario.

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Flow East Towards Toronto Stage 2 (4)

The IESO has recommended an initial reinforcement to the Flow East Towards Toronto ("FETT") interface, which is the primary flow gate that transfers power from western Ontario to Toronto and eastern Ontario. Depending on the magnitude of resources sited west of the FETT interface, further stages of reinforcement to the FETT interface could consist of new 230 kV transmission circuits in the western GTA, namely Brampton, Mississauga and Oakville; a new 500/230 kV autotransformer station at the existing Milton SS; and/or a new 500/230 kV autotransformer station near Kleinburg. Reinforcements of this magnitude could cost on the order of between $300 million and $500 million, and take 3-7 years to fully plan, develop and implement, depending on the scope of the reinforcement required.

Eastern Ontario Reinforcement (5)

In order to accommodate 3,300 MW of non-emitting firm imports under Scenario 1, and assuming that such amounts are available and economic, a reinforcement to the Ontario-Quebec intertie facilities may be within scope of potential transmission enhancements. To that end, much of the information in the 2014 “Review of Ontario Interties” report and the 2017 “Ontario-Quebec Interconnection Capability” report remain indicative of the scope of reinforcement. This may include doubling the Outaouais HVdc interconnection, reinforcement of the 230 kV network between the Quebec boarder to Merivale (Ottawa area), Hawthorne (Ottawa area) and St. Lawrence, and may require reinforcement to the 500 kV system between Bowmanville and Cherrywood (in Pickering), depending on the development of resources in eastern GTA and eastern Ontario. Reinforcements of this magnitude could cost on the order of between $1 billion and $1.5 billion, and take between 7-10 years to fully plan, develop and implement, depending on the scope of the reinforcement required.

Maintaining Reliability Currently Provided by Strategically Located Gas Plants

Natural gas plants that were strategically located are critical to the supply reliability of several areas.

Central Toronto is primarily supplied by the Cherrywood – Leaside 230 kV corridor and Leaside TS, which is a 230/115 kV autotransformer station. Without support from Portlands GS, or equivalent local replacement capacity, a new corridor to Central Toronto may be required to prevent collapse and an unacceptable out-rush across our interties. Past plans, including the 2007 IPSP, envisioned the “Third Supply Plan” as lengthy transmission, potentially under Lake Ontario from Pickering, Darlington or Niagara Falls.

The western part of the GTA is primarily supplied by Trafalgar TS and Claireville 500/230 kV autotransformer stations. Retirement of Pickering NGS will increase autotransformer loading, but would still remain within the available capacity; however, without support from Goreway GS and Halton Hills GS, the 500/230 kV transformation capacity will likely be exceeded. The solution would be to convert Milton switching station to a 500/230 kV autotransformer station at a cost of about $200 million.
York Region is supplied by the 230 kV circuits between Claireville TS to the south, and Minden to the north, and York Energy Centre GS ("YEC") plays a critical role in local reliability. A new transmission line between Buttonville and Newmarket was an alternative to the facility, but significant local opposition led to the local generation solution. Also, as demand in the area continues to grow, YEC’s role will remain critical. When the current supply capacity is no longer adequate (forecast 2030), additional generation and/or transmission will likely be required, even with YEC in service; however, without YEC or equivalent local generation, significantly more transmission infrastructure would likely be required. Reinforcements of this magnitude could cost on the order of several hundreds of millions of dollars above a resource mix that includes YEC, and would potentially require an additional new transmission corridor.

The West of Chatham area is experiencing significant load growth, primarily driven by the agricultural sector, with Brighton Beach GS, East Windsor GS and West Windsor GS playing a critical role in local reliability. Interim operating measures using local natural gas-fired generation are currently required while the first stage of transmission reinforcement is being implemented. Additional reinforcement is envisioned within the decade, and the existing local natural gas generation could still play a role in the solution along with transmission reinforcement and new local generation.

The Kirkland Lake area supports a large amount of demand in the mining sector, and this demand is expected to increase given the volume of new connection requests received by the IESO. Plans are underway to reinforce the 115 kV transmission grid between Ansonville and Kirkland Lake; however, this reinforcement envisioned some continued reliance on Kirkland Lake GS. Without support from Kirkland Lake GS or equivalent local replacement capacity, additional and significant reinforcement may be required.

As mentioned under The Role of Natural Gas, natural gas-fired generators provide dynamic reactive power that is critical in maintaining acceptable voltages during high demand periods. Reactive power cannot be transferred over long distances; thus replacement reactive power sources must be installed locally. Portland GS, Goreway GS, Halton Hills GS and YEC, provide a significant amount of reactive power capability, on the order of 1500 MVAr. Shunt capacitor banks cannot be used for this purpose as they do not provide the required dynamic reactive power. The cost of dynamic reactive power devices is high.

Lastly, and as also mentioned under The Role of Natural Gas, natural gas-fired generators provide frequency response. Of particular locational specific concern may be the design of Ontario’s Under-Frequency Load Shedding Program (UFLS) for the Central Island11 in Toronto, as natural gas-fired generators are currently the only source of governor response (primary frequency response) in the area, and IESO’s 2018 UFLS study identified little margin compared with NERC and NPCC requirements.

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11 For additional information, see Section 11.3 of IESO Market Manual 7.1.
Summary
In summary, the development and implementation of a Transmission Plan is expected to have tremendous scope, and may contemplate significant reinforcement to all levels of the transmission system, including the possible introduction of additional HVdc facilities. This reinforcement is expected to cost in the billions of dollars and may take over 10 years to complete the full scope, which suggests retirement of all natural gas generators by 2030 is infeasible. A detailed transmission planning exercise would be necessary to determine the full extent of reinforcements required, true cost estimates of these reinforcements, and when they could come into service, recognizing the immense logistical challenge of deploying so many large projects simultaneously while also executing normal maintenance programs.

Practical Considerations

Gas Generators Under Contract
Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners' needs to be included with the replacement costs to retire these generators prior to the end of their contract as identified in Scenario 112. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. However, the remaining contracted net revenue requirement of $x is considered as an estimated cost minimum cost expectation. Should natural gas be on the system, once the contract term ends, gas-fired generation can participate in competitive mechanisms to meet system needs in Scenario 2 and Scenario 3.

Stranded Assets Eliminates Competition
The natural gas fleet has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, the average age of large natural-gas resources (e.g. resources greater than 150 MW) is 13 years. Stranded costs resulting from coal retirements were typically modest because many of the plants were built decades ago and nearing the end of their useful lives. Much of the gas fleet is relatively young, increasing the potential for stranded costs if widespread closures occur within the next decade. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

Land Use and Siting

12 Scenario 1 assumes $2.4 in Net Revenue Requirement payments for cancelled contracts; however, additional possible compensation associated with implications of being locked out of the market to participate or other types of potential negative implications are not quantified.

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Replacing gas resources with new large scale non-carbon emitting resources can pose a number of practical challenges in regards to land use, siting and location. Most economic and accessible hydroelectric sites have been developed; some potential is undeveloped, with a majority of it located along Ontario’s northern rivers (e.g. Abitibi and Moosonee rivers). Northern hydroelectric sites are generally remote, resulting in relatively higher construction costs, as well as requiring potentially significant transmission investments to connect them. While we have proven technology on on-shore wind, there is a moratorium on off shore siting. Depending on the location, large penetration of renewables will require transmission investments to connect them and to delivery the generation to the demand locations at a cost ranging in x billions of capital costs, which will take well over 7 to 10 years to complete and implement. Detailed discussion on transmission development requirements for large renewable implementation is discussed in the Appendix A.

**Variable Generation and Storage**
- story about making this look like 100% gas plant will be very expensive

**Timing**

Reductions in emissions through the addition of new non-carbon emitting resources and the accompanying transmission would not only require new investments, but also the associated time to develop the designs and the required specifications. This would require significant effort to identify appropriate sites and routes, to manage the extensive stakeholdering and consultation, and to manage the acquisitioning and building of these assets. The lead time of supply resources vary depending on the type of generation; the lead time of transmission assets can be at least seven to ten years. New technology and resource risks should recognize the uncertainty associated with construction completion and the longer lead times required to reach dependable operation. This transformation of the system would require detailed planning which is outside the scope of this study. Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of our generation capacity.

**Market Impacts**

The implementation of low to zero marginal cost renewable generation will drive down the market clearing price and result in changes to the flow of imports and exports. As discussed in Scenario 1 and 3 with the increase of renewable generation into the supply mix will result in lower marginal costs in Ontario relative to surrounding jurisdictions. The market dynamics of lower domestic prices will result increased export demand from Ontario generators thus driving up the dispatch of natural gas generators and Ontario’s carbon emission in Scenario 3 when natural gas is still available. In effect, impacting Ontario’s ability to stabilize emissions in Scenario 3 would require the implementation of a cap or moratorium on the natural gas production; thus, the current market mechanism could need to be reevaluated. A detailed wholesale market simulations analysis is provided in Appendix B – Wholesale Market Impacts, which discusses the change in the market flow and implications to energy prices, net exports, operating reserve prices, and curtailed energy.
Potential System Evolution

Lessons Learned from GEA

Current Direction of System (i.e. in time, we will eventually achieve off gas)
Conclusion and Next Steps

Comms - Place content here
Appendices

Appendix B: Wholesale Market Impacts

Context

The wholesale market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of wholesale market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to new pricing patterns influenced by the characteristics of the replacement resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with the “Base Case” in which the gas fleet continues to operate.

The High Base-Load Case assumed that a fleet of somewhat inflexible resources is added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide intrahour output flexibility or stand-by energy such as operating reserves. In contrast, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would be comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources that operate based on energy pricing arbitrage and operating reserve revenues, as well as capacity payments.

High Base-Load Case
- Limited flexibility
- Not energy-limited
- Operate near full capacity
- Low to zero short-run marginal costs

High Capacity Case
- Highly Flexible Mix
- Energy-limited / standby / intermittent resources
- Low to zero short-run marginal costs or arbitrage focused

Bookend Approaches
The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power market could be impacted if resource types with attributes on two opposite ends of a spectrum were utilized to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

**The High Base-Load Case**

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources have low marginal fuel costs and therefore would offer into the energy market at low to zero prices. Since these new base-load technologies replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy, meaning the availability of energy above that needed to meet the province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices as well as the potential for a greater frequency of surplus energy conditions in the High Base-Load Case, traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes to the High Base-Load Case. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, there is an increase in the number of times each year where energy prices are substantially elevated compared to the Base Case as standby resources set the price. As a result, high energy market prices for
these hours, along with a general increase in variability, tend to occur to a greater degree in Ontario's energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydroelectric availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Error: Reference source not found below. Only single illustrative prices have been shown below for clarity. The reader should note that real market impacts will extend more broadly to multiple locational prices following Market Renewal.

**Figure 18 | Illustrative Energy Prices versus Percentage of Time**

As shown in Figure 18, the High Capacity Case will see increasing price variability in both frequency and magnitude. This reflects the introduction of an increased fraction of variable renewables on the grid as a replacement for gas resources. In contrast, for the High Base-Load Case, prices will be broadly depressed and there will be less variability. While there is still some price variation that will be important for resources in the energy markets, the high degree of low marginal cost baseload generation on the system may make pursuing large revenue opportunities more challenging.
**Market Impacts**

In both of the illustrative scenarios described above, Ontario’s markets provide important signals about the underlying conditions and needs of the electricity system. For the High Base-Load Case, the resource mix drives an overall reduction of energy prices but there are still some periods of relative surplus and scarcity (the tails in Figure 19), and therefore opportunities for price arbitrage for particular resources. There is also a corresponding premium in the operating reserve markets reflecting an increased need for flexibility given the high proportion of baseload resources. In the High Capacity Case, energy market prices can be highly volatile (especially the large tail in Figure 19), and these prices are an important signal for energy limited resources to store or supply energy. There is also an abundance of operating reserve available, broadly driving down operating reserve prices.

This high level picture masks a more complicated set of locational needs and impacts. In the future the IESO will introduce locational pricing across Ontario through the Market Renewal Program to ensure better alignment between system needs and dispatch. This will mean that energy market prices will be variable with a locational aspect. At a more granular level resources will then consider not only broad trends in electricity market pricing created by changes to the resource mix, but also highly locational system needs and variability in energy market prices in their land use and siting decisions. Where transmission constraints exist resources will be incentivized to locate and operate to respond to these highly locational signals, needs, and patterns of variability.

In any future resource scenario, the markets will continue to reflect the changing operational conditions on the electricity grid and will create incentives to respond to them. For example, when too much supply is available electricity prices will drop and resources who do not want to produce at low prices will be dispatched off. Similarly, for highly volatile conditions resources will be incentivized, and likely designed, to be able to ramp quickly to respond to these conditions. Other jurisdictions have introduced additional market products (e.g. ramping products) to reflect the evolving needs of an ever changing grid. The IESO will continue to monitor work in other jurisdictions where market evolutions are ongoing and will evolve the markets to meet Ontario’s needs in the future, including the impacts of potential policy measures such as of increased carbon pricing or directives to go off-gas.

The IESO is responsible for the reliability and security of Ontario’s electricity grid and for providing consumers with reliable power where and when they need it. For almost two decades and through several significant transitions in the sector the IESO has been achieving these goals through an open and transparent wholesale electricity market. With continuous improvements, the IESO expects this market to endure, providing a reliable and efficient dispatch of resources even as the resource mix and the broader sector evolves.

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complex problems such as the siting of replacement resources and the need to build new-transmission infrastructure could not be practically included in the analysis. Many other important-real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing,structural changes to the economy, and developments at the grid edge also could not be-incorporated into the analysis. It is not possible for the IESO to predict all these developments and-fundamentally, this was not the intent of this report. Instead, these results highlight that different sets of resources can be used to replace today’s fleet of gas-fired resources, and directionally indicate how wholesale market outcomes could result. More importantly, this exercise has shown that the wholesale market is able to provide intuitive signals-that reflect the system needs and the value of the resources able to meet the needs. Significant-changes in Ontario’s wholesale markets are a reflection of changes in the supply and demand-conditions in the underlying system. The decision to go off-gas implies a shift to resources with-different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending-on the Depending on the suite of replacement technologies, a move off-gas could lead to a-significant set of changes to flows and price signals seen across the electricity system in Ontario.
1. Considerations for Phasing Out Natural Gas in the Electricity System
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Background and Context

Ontario’s mix of electricity system resources – conservation, generation and transmission – are procured to work together to provide capacity and energy when and where it is needed, and to provide the services required to ensure real-time reliability. Reliability and the standards we adhere to are important, dictated by societal expectation, in order to maintain essential services and our quality of life with minimal interruption. Natural gas-fired generation plays an important role in this, contributing to a wide range of electricity system reliability services, and under all weather conditions.

When considering how natural gas-fired generation operates and the value it provides, it is also helpful to understand the grander state of emissions in Ontario, including emissions policy, to seek out the best opportunities to reduce emissions in the province overall.

Planning and Operating the Bulk Electric System

While evolving Ontario’s resource mix, it is important to remember that the grid is an integrated system, part of the North American Eastern Interconnection, and guided by North American and Ontario-specific reliability standards. Ontario’s mix of electricity system resources – conservation, generation and transmission – are procured to work together to provide capacity and energy when and where it is needed, and to provide the services required to ensure real-time reliability. Reliability and the standards we adhere to are important, dictated by societal expectation, in order to maintain essential services and our quality of life with minimal interruption.

Capacity and energy adequacy are assessed as part of IESO’s Annual Planning Outlook (APO), identifying provincial and local shortfalls that must be met to achieve reliability standards. These shortfalls feed into the Conservation and Demand Management Framework, the Resource Adequacy Framework and transmission planning, which align initiatives and procurements with evolving system needs.

As mentioned above, there are other services required to maintain reliability, and include:

- **Operating Reserve (OR)** – stand-by power or demand reduction that can be called on with short notice to deal with an unexpected mismatch between generation and load.

- **Certified Black Start Facilities** – facilities that help system reliability by being able to restart with no outside source of power following a blackout event, and would be called on during restoration efforts by helping to re-energize other portions of the power system.

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1 IESO’s Operating Reserve Market webpage
2 IESO’s Ancillary Services webpage
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• **Regulation Service** – corrects for short-term changes in electricity use that might affect the stability of the power system, including variations in power system frequency.

• **Reactive Support and Voltage Control Service (RSVC)** – required in order to maintain acceptable reactive power and voltage levels on the grid.

It is important to understand that no single resource can provide the full suite of services, and the level of services needed is a function of various aspects of uncertainty, including those inherent to the resource mix itself, requiring an iterative assessment process. Aspects of uncertainty include the loss of system elements (supply and transmission), changes in transmission-connected load and distribution-connected net load (considers effects of load, conservation, embedded generation and loss of distribution elements, as applicable) and generation fuel availability (water, wind, sun and natural gas), some or all of which can be impacted by weather, which has hourly, daily and seasonal variability.

In order to mitigate risks associated with uncertainty, and maintain an operable system that can respond second-to-second in real-time and be re-postured in anticipation of future events, the IESO also guides resource selection and placement based on the following principles:

• **Diversity** – having a balanced variation of characteristics available across the system.

• **Flexibility** – ability to easily respond to changing circumstances and conditions across the system.

• **Manageability** – ability to see, monitor and dispatch resources across the system.

These principles are further discussed in the sections below along with additional notes on operational scope and complexity.

**Diversity**

Diversity in the characteristics of the resource mix, and where resources are located, is important to ensure risks inherent to each resource (technology, fuel type or otherwise) are mitigated. As such, the total mix must provide sufficient system capability to meet adequacy and other service level requirements, and be sustainable under a wide variety of conditions (short-term extreme weather, mid-term environmental extremes and fuel delivery challenges) and operating restrictions (air emissions, water flow and cooling system temperatures).

**Flexibility**

To ensure that the system can reliably match supply and demand, Ontario’s resource mix must provide sufficient flexibility in the form of “load following” – responding to anticipated and unanticipated changes on the system; and “ramping” – responding to sharp changes in consumption due to increases or decreases in system demand (e.g. winter mornings). System performance
related to load following and ramping is governed by legally binding North American Reliability Standards.

IESO’s Experience in Flexibility

On June 28, 2021, demand was high during the day and peaked in the evening, reaching 22,300 MW. The need for flexibility on this day would prove critical, as an Energy Emergency Alert was eventually issued, indicating that all available resources had been committed.

Wind contributed to the system’s energy need, but only provided 11% of its installed capacity in the peak hour, a total of 500 MW, and 400 MW under what had been forecast.

Low water conditions on several river systems caused concern over hydro-electric fuel availability, so to conserve these energy-limited resources for utilization at peak, they were constrained down in off-peak hours. To replace this energy, non-energy-limited resources were dispatched up, including natural gas-fired generation.

A total of 6,000 MW of natural gas-fired generation was dispatched to meet the 22,300 MW peak, with much of this generation constrained on earlier in the day to conserve energy-limited resources and to provide OR. No other fuel-type in Ontario’s resource mix offered the needed flexibility to constrain on for this purpose.

By the end of the day approximately 30% of the demand was supplied by the natural gas fleet, with its utilization demonstrating the importance of resource flexibility.

Manageability

The IESO currently has full visibility and control of resources connected to the high voltage transmission system, the bulk of Ontario’s generation fleet, but the same cannot be said for those resources connected to the distribution system. To date, this has been manageable because of the limited volume of distributed resources, but should this volume increase due to the phase-out of natural gas-fired generation or otherwise, the IESO will require visibility and dispatchability of those resources to maintain reliability. Detailed technical specifications of all resources will be required to ensure that engineering studies can effectively model system behaviour under a range of conditions.

With an increasing number of small resources that are embedded, distributed and possibly aggregated, the impact on situational awareness must also be considered. To maintain reliability and meet applicable standards, system operators require sufficient data for real-time monitoring in order to perform operational planning analyses and real-time assessments. A large increase in the number of resources and market participants providing this data could require significant changes to IESO’s existing market participation framework, tools and rules, and would cost in the tens of millions based on previous experience.
Additional Notes on Operational Scope and Complexity

In real-time, the IESO-controlled grid (ICG) is operated to ensure that reasonably foreseeable contingencies will not result in the loss of a major portion of the power system (or unintentional separation of a major portion of the power system). This level of reliability is achieved by operating the ICG to meet adequacy criteria for anticipated demand, system security criteria for specified contingencies and re-preparation criteria for restoring reliability following contingencies or major events such as blackouts.

The ICG is operated, and its reliability maintained, with due regard for planned and potential unplanned transmission element outages. To cover expected operating conditions, the transmission system is planned and designed within a well-defined scope; however, the system may experience out-of-scope conditions as a result of maintenance outages and forced outages. Reliability standards require system operators to consider unplanned operating scenarios resulting from different system events, ranging from transmission element malfunctions to events like forest fires, tornadoes and ice storms.

These transmission system limitations result in flow-gates or interfaces that impede the flow of power toward loads, and are reflected through system operating limits such as thermal, voltage and angular stability limits that indirectly describe specific system deficiencies. These system operating limits are derived by the IESO, formulated based on specific combinations of resources in service, and together with specific operating instructions, are used by control room operators to operate the ICG reliably. To provide unrestricted flow of power toward loads, and also minimize losses and enable outages for transmission element maintenance, siting certain amounts of local generation may be necessary.

When planning the future resource mix, specific operability requirements can be difficult to quantify, and experience has shown that a diverse resource mix provides the most adaptable, flexible approach to achieving reliability and cost-effectiveness.

The Role of Natural Gas-Fired Generation

The focus of this study is to investigate the requirements and system impacts that need to be addressed should the phase-out of natural gas-fired generation be considered. To achieve this, it is important to recognize the role that the natural gas fleet currently plays in the electricity system, by way of identifying the services it provides through its technical characteristics, and to understand what will need to be replaced by other resources.

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
As illustrated in Table 1 and Figure 1 below, natural gas fuels a number of technologies and technological configurations, providing a wide range of reliability services to the electricity system, and under all weather conditions. With Ontario’s significant level of variable and intermittent supply, natural gas-fired generation is counted on frequently to provide flexibility, filling in gaps to address short-term supply and demand variability. Once online, natural gas-fired generation is capable of quickly ramping up and down in response to system conditions to maintain reliability, but it can also provide sustained energy when needed as the underlying commodity is generally available all times the year. Today, flexible resources make up about 40% of Ontario’s resource fleet. Of the flexible resources, 11,000 MW of natural gas-fired generation accounts for more than 70%.

Table 1 | Reliability Services Provided by Natural Gas-Fired Generation

| Placeholder |

Figure 1 | Ontario Natural Gas Technology and Configuration Capacity Breakdown

| Placeholder |

Aside from balancing supply and demand through flexibility, the natural gas fleet also provides a number of technical benefits to the ICG. Natural gas generators support provincial transmission security and provide voltage stability, particularly in specific locations where the transmission system may not be easily reinforced. They also provide fast dynamic response, which aids in system recovery following a significant contingency, maintaining system frequency and voltage. The ability to provide this response is due to the large rotating masses inherent to some natural gas technologies, storing kinetic energy, which acts as a suppressant to frequency decline following a contingency event.

Many natural gas facilities are also strategically located near major demand centers to provide local and regional reliability, and minimize losses on the transmission system. Some natural gas facilities were developed in lieu of major transmission upgrades in areas where they were deemed cost prohibitive or not possible due to specific environmental or social concerns. Should gas generation be phased out, additional transmission and voltage support may be required to deliver provincial capacity. In some areas, transmission upgrades may be required to support local load centres if new resources can’t be located in the same area (e.g. insufficient land is available for new supply).

When considering which resources to use in place of the natural gas fleet, there are no readily available resource types that can offer the same level of on-demand energy availability and flexibility by themselves.

Although this study seeks to remove all natural gas-fired generation, it is important to note that some Combined Heat and Power (CHP) facilities support industry (e.g. process steam, district heating and hot water, CO₂ feedstock), and that a mandate to shutdown natural gas facilities would impact a number of businesses that rely on these facilities.

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3 As of the study date.

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Lessons Learned from Off Coal

Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario’s generation capacity. When coal generation phase out was being considered, gas fired generation was a mature technology available with similar, yet less flexible operating characteristics due longer start-up times and higher minimum loading points. Bringing on large numbers of generators with a different fuel-type than coal also posed new administrative and operational challenges, with the IESO developing new approaches to monitor and operate different forms of generation. New approaches were developed to manage variable generation, including ramped-up Energy Efficiency programs, increased visibility of current variable generation output, enhanced methods to forecast variable generation output, and processes to dispatch variable generation resources. Further, certain coal-fired power plants were located in strategic areas that supported load centres and ultimately reduced the reliance of power being delivered from the transmission system. For instance, the former coal-fired Hearn generating station supported Toronto and central GTA transmission systems, while the coal-fired Lakeview generating station supported the southwestern and western GTA transmission systems. The replacement of such strategically located facilities was achieved by adding facilities like Portlands Energy Centre, Goreway and Halton Hills in a way to avoid the need to reinforce significant amounts of the transmission system that Hearn and Lakeview otherwise supported.

To replace the gas fleet, the province will face similar challenges and need to employ similar strategies, utilizing a combination of many resources to be discussed.

State of Emissions in Ontario

Ontario’s electricity system has been steadily reducing greenhouse gas (GHG) emissions since the mid 2000’s, driven by the closure of coal facilities and the procurement of renewable resources, and now represents approximately 3% of total GHG emissions in the province – this from an all-time high of approximately 21% in 2000. On the other hand, Transport has risen from approximately 26% of total provincial emissions in 1990, to approximately 39% today, potentially illustrating higher impact opportunities to reduce emissions outside of the electricity system.

Figure 2 | Historical GHG Emissions in Ontario by Sector

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4 IPCC Official Canada Emissions Data: Ontario historical emissions data was retrieved from Canada’s official Greenhouse Gas Inventory, published by Environment Canada here.

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Government Emissions Policy and Targets

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reduce GHG emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. In order to achieve this commitment, industry performance standards have been proposed to regulate large emitters.

Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program, which will regulate GHG emissions from large industrial facilities by setting thresholds that those facilities are required to meet. The EPS program sets a threshold allowance of 370 tonnes CO$_2$e/GWh for existing generators, and 0 tonnes CO$_2$e/GWh for any new-build generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently $40/tonne CO$_2$e, and set to increase linearly to $170/tonne CO$_2$e by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset emissions, or can be sold to other large emitters. Ontario’s natural gas fleet currently has an average emissions factor of approximately 420 tonnes CO$_2$e/GWh, which means on average, and with a threshold allowance of 370 tonnes CO$_2$e/GWh, the Ontario fleet only pays for a fraction of what it is emitting (50 tonnes CO$_2$e/GWh, or about 12%). This threshold allowance was implemented to lessen carbon policy impacts on inter-jurisdictional electricity trade, but also with the consequence of lowering price driven consumption behaviour among ratepayers when these fractional costs are passed along. If Ontario’s natural gas fleet was fully exposed to the federal carbon price, border adjustments to inter-jurisdictional electricity trade may be required; otherwise, Ontario could see increases in emissions based imports.

The Federal Government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS), meeting the federal benchmark stringency requirements for the sources of GHG emissions that it covers, and intends to remove the application of the OBPS from Ontario facilities on January 1, 2022, the same day the EPS program takes effect.

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Opportunities to Move Towards an Emissions-Free System in the Longer-Term

There are multiple pathways to removing CO$_2$ emissions from the electricity system for the future. However, these options must be commercially feasible, scalable and cost effective in the near term. In developing the replacement resource-mix for this study, the following resource options are considered to create a diversified low-carbon energy portfolio: energy efficiency, demand response, wind, solar, energy storage, hydroelectric, nuclear small modular reactors, and Hydro-Québec firm imports.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW$^5$, accounting for about 25% of total installed capacity, as shown in Figure 2, and represents about 7% of total energy in the province, as shown in Figure 4.

**Figure 3 | 2020 Installed Capacity by Fuel Type**

**Figure 4 | 2020 Energy Output by Fuel Type**

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$^5$ Ontario’s natural gas fleet is largely connected on the transmission system.

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Ontario benefits from a diverse resource mix, contributing to reliability under a wide range of weather and operating conditions. No single resource type provides all of the essential reliability services. Different resources provide different services, and the portfolio works together to provide a resilient and flexible system, as shown in Tables X and Y.

### Table X | Reliability Services Provided by Non-Intermittent Emissions-Free Resources

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<th>Reliability Services</th>
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</table>
There are multiple pathways to removing CO₂ emissions from the electricity system for the future. However, these options must be commercially feasible, scalable and cost effective in the near term. The IESO has been engaged in enabling new types of resources for a number of years and is working to explore the potential of emerging technologies. While these resources are generally unproven as to their ability to provide services similar to natural gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability. In considering phasing out natural gas, the province will require a mix of resources that have similar characteristics and provide similar services as the resource mix we have today that includes natural gas. As new emerging technologies commercialize and performance becomes better understood, these will be incorporated into future outlooks. The sections below outline candidate options for a replacement resource mix.

**Energy Efficiency**

Through the delivery of programs, training and other mechanisms, the province is able to cost-effectively meet its electricity system needs, enabling electricity consumers to improve the energy efficiency of their homes, businesses, institutions and industrial facilities. The IESO recognizes that energy efficiency programs provide continued opportunities for electricity consumers to save on energy costs while providing overall electricity system benefits.

In 2019, the IESO completed the first integrated electricity and natural gas conservation Achievable Potential Study (APS). The APS identifies and quantifies energy and demand savings, greenhouse gas (GHG) emissions reduction, and associated costs from energy efficiency measures for the period

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Table Y | Reliability Services Provided by Wind, Solar, Storage and Hybrid

<table>
<thead>
<tr>
<th>Reliability Services</th>
<th>Intermittent Emissions-Free Resources, Storage and Hybrid</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Wind</td>
</tr>
<tr>
<td>Capacity</td>
<td></td>
</tr>
<tr>
<td>Energy</td>
<td></td>
</tr>
<tr>
<td>Flexibility</td>
<td></td>
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<tr>
<td>Operating Reserve</td>
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<tr>
<td>Black Start</td>
<td>🎈</td>
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<tr>
<td>Regulation</td>
<td></td>
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<tr>
<td>Reactive Support</td>
<td></td>
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<tr>
<td>Voltage Control</td>
<td></td>
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<tr>
<td>Local Security</td>
<td></td>
</tr>
</tbody>
</table>

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
of 2019-2038. Four achievable potential scenarios from the APS were made available to the model with seasonal energy and capacity reductions and annual program costs.\(^6\)

**Demand Response**

Demand Response (DR) is when consumers reduce their electricity consumption in response to prices and system needs and it is playing an increasing role in Ontario’s electricity system. DR resources can reduce their electricity consumption when wholesale prices are high or the reliability of the grid is threatened, receiving payments for the reductions they make. DR has already had a significant impact on energy demand and helped reduce peaks, providing a valuable and cost-effective resource to the system.

This study assumes an upper limit of 2,000 MW of incremental DR capacity. Including currently contracted DR, this is equivalent to roughly 10% of peak demand.

**Wind, Solar and Energy Storage**

There are various forms of renewable energy, including energy generated from the wind and sun. The fuel availability for wind and solar generation is reliant on the weather, time of the year and time of the day. Solar generation is particularly important in the summer months when peak demands occur midday as solar panels reach their height of production. Wind production is usually greatest during cold winter months and at night, but can vary depending on geography and the time of year, making it a suitable complement to solar generation.

Emerging energy storage technologies allow electricity to be captured and stored and then re-injected back into the grid when it is required. Energy storage technologies vary considerably in terms of their size and scale, how the energy is stored, how long it can be stored and the technology’s response time. The IESO is exploring how to leverage energy storage in conjunction with renewables in order to maximize the contribution variable generation makes to the system. However, due to the variable and uncertain nature of variable resources (e.g. wind resources are inherently variable minute-to-minute and hour-to-hour and can lead to forecast errors), this poses greater challenges for energy storage to smooth variable generation in order to mimic the consistency of gas.

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\(^6\) The APS identified cost effective potential for energy efficiency based on previous avoided energy and capacity costs. Under scenarios considering gas phase out, the avoided capacity and energy costs would likely be higher.

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In addition to these challenges, solar, wind, battery storage and applicable hybrids are inverter-based resources (IBRs), which add complexity to grid reliability. Some IBR performance issues have been significant in recent grid disturbances, such as the tripping of a number of BPS-connected solar PV generators that occurred during the 2016 Blue Cut Fire, 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California ([Report (nerc.com)](https://www.nerc.com)). External jurisdictions, such as California, are gaining experience with large penetrations of distributed IBRs. Recent events have highlighted the need to understand the volume of these resources that will trip coincidentally due to faults on the power system. While controller technology used in IBRs may be able to provide frequency response, they are currently in the piloting stage. There would also be a requirement for IBRs providing this service to hold back energy output that may otherwise be available so that it can respond to an under-frequency event by injecting that available energy it was otherwise holding back.

**Hydro-electric**

Hydropower is another renewable source of energy produced by the falling or moving of water. It is a major contributor to Ontario’s supply mix, both as a form of baseload generation and during times of peak demand. Hydroelectric generation does provide load following capability when it can, but its output depends on water availability, including environmental restrictions and cascading river system impacts. Waterpower could be a significant source of non-carbon emitting energy, however, most of its potential is in northern Ontario which generally lacks transmission connection access to the grid.

**Nuclear - Small Modular Reactors**

Small Modular Reactors (SMRs), like current nuclear reactors, are designed to provide reliable, carbon-free electricity, but with a much smaller land footprint than current reactors. Smaller plants mean they are more flexible and can be deployed not only in large established grids but also in smaller grids, remote off grid communities and for resource projects. Their designs and features are expected to deliver baseload generation along with load following capability. These features could help support intermittent renewable sources like wind and solar, but actual performance still needs to be proven.

Consistent with the project scope details provided in the IESO’s June 2021 stakeholder engagement session, candidate options include the proposed 300 MW SMR at Ontario Power Generation’s Darlington nuclear facility.

**Hydro-Québec Firm Imports**

Ontario trades with Québec on the open market on a non-firm basis. In 2016, the IESO and Hydro-Québec (HQ), executed a series of agreements to facilitate electricity trade between the two provinces. The electricity trade agreement includes electricity purchases whereby each year the IESO is entitled to purchase 2 TWh of electricity from HQ at a set contract price, electricity cycling whereby the IESO will export up to a contracted amount of electricity to HQ, and capacity sales. The electricity trade agreements with HQ are set to expire December 31, 2023, and it is assumed that these particular agreements are not extended in the study.

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7 2020 NERC’s Long Term Reliability Assessment

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Imports from Québec are an option to replace gas generation. However, the extent HQ imports can contribute to reducing GHG emissions will depend on many factors including generation capacity and energy availability in the Québec system, the negotiated price and the transmission path availability between Québec and Ontario. Québec has large water storage capability and is projected to have surpluses of energy for many decades; however, their capacity availability is far more constrained. Québec is a winter peaking system and exports are often curtailed during winter peaks. With the appropriate transmission upgrades, this analysis assumes that Québec can supply summer and winter capacity up to 3,300 MW.

**Distributed Energy Resources**

The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (e.g. Distributed Energy Resources) to help address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

**Hydrogen**

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. It is light, storable, energy-dense, and when hydrogen is consumed, it produces no direct emissions of pollutants or GHGs. There are no known hydrogen reserves from which the fuel could be mined, instead, hydrogen is typically produced from a fossil fuel, or by using electricity to split water into its component molecules of hydrogen and oxygen (known as green hydrogen). Depending on how the hydrogen is produced, there could be significant GHG impacts (e.g. producing hydrogen from fossil fuels), or a significant increase in electricity demand (when producing green hydrogen).

Hydrogen is one of the leading options for storing renewable energy, and could also enable long-term (e.g., inter-seasonal) energy storage. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. In addition, there is potential for hydrogen produced using electricity and water to more closely link the electricity markets with new sectors in industry, transportation and residential/commercial heating. Considering the potential for the broader economy-wide impact of large-scale hydrogen infrastructure, the Ontario government is in the process of developing an Ontario hydrogen strategy. A hydrogen strategy discussion paper was released in November of 2020 to solicit feedback from relevant stakeholders. The feedback is currently being reviewed and will inform the next steps for developing the provincial strategy.

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8 Québec experiences capacity shortfalls in the winter due to use of electricity for heating
9 Details of the Ontario Hydrogen strategy process can be found here: https://www.ontario.ca/page/low-carbon-hydrogen

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While hydrogen may provide a potential solution to remove emissions in the longer term, the IESO did not consider it while developing the resource supply mix. In the near-term, large-scale green hydrogen production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may come down significantly in the future and could make hydrogen more competitive in the longer-term, but this will likely occur past the 2030 timeframe considered in this study.

**Carbon Capture Utilization and Storage**

Carbon Capture Utilization and Storage (CCUS) solutions will also be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long-distance high-pressure pipelines to transport CO$_2$ to storage sites will require further investigation to avoid siting and regulatory challenges.

Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario. It is also currently costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the resource supply mix.

**Green/Renewable Natural Gas**

Renewable Natural Gas (RNG) is methane captured from organic waste at landfills, livestock operations, farms, and sewage treatment facilities. RNG offers decarbonization benefits through the removal of carbon-heavy streams from the environment (i.e. methane leaking into the atmosphere from sources such as livestock and landfills), where the end product is a carbon-free RNG that can displace conventional natural gas. RNG is interchangeable with conventional natural gas and can be injected into the natural gas distribution system. Like conventional natural gas, RNG can be used as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). It can thus be used to fuel natural gas vehicles/transit fleets, power industry and residential heating.

RNG can play an important role in Ontario’s clean energy future, however questions have been raised about how much RNG can be produced from biomass and at what cost. Since the debate continues on the scalability and economics of RNG production, the IESO did not consider it while developing the resource supply mix.

**Candidate Options**

Based on the need for replacement resources to be commercially feasible, scalable and cost effective in the near term, a number of candidate options have identified. Cost and performance assumptions have been summarized in Table 2 below.

**Table 2 | Candidate Options for Replacement Resources**

<table>
<thead>
<tr>
<th>Candidate Options for Replacement Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td>19 Considerations for Phasing Out Natural Gas in the Electricity System</td>
</tr>
<tr>
<td>Resource</td>
</tr>
<tr>
<td>-------------------</td>
</tr>
<tr>
<td>Wind</td>
</tr>
<tr>
<td>Solar</td>
</tr>
<tr>
<td>Energy Storage</td>
</tr>
<tr>
<td>Hydro-electric</td>
</tr>
<tr>
<td>SMRs</td>
</tr>
<tr>
<td>HQ Firm Imports</td>
</tr>
<tr>
<td>Energy Efficiency</td>
</tr>
<tr>
<td>DR</td>
</tr>
</tbody>
</table>

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10 Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Scope of Study

The scenarios in this study consider the reliability, cost and wholesale market impacts, timing and basic operability implications to the electricity system. The scenarios in this study did not consider higher demand due to an increase in electrification or how emissions in other jurisdictions may be affected in the future.

Areas of Study Considered

The three scenarios were examined from various lenses, including areas of reliability, costs, wholesale market impacts, operability and timing to the electricity system, as shown in Table 3.

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>Considerations for locational requirements for siting resources, or transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>Ancillary services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale Market</td>
<td>Least cost replacement resource portfolio</td>
</tr>
<tr>
<td></td>
<td>Potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>Use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>Impact on wholesale market pricing and how market value of system needs may change</td>
</tr>
<tr>
<td>Operability</td>
<td>Basic Operability: capacity, energy, operating reserve, ramping requirements, load following capability</td>
</tr>
<tr>
<td></td>
<td>Impact to wholesale market design</td>
</tr>
<tr>
<td>Timing</td>
<td>Typical timelines associated with construction of generation or transmission</td>
</tr>
</tbody>
</table>

11 Model portfolios were developed at an aggregate level, to determine the rough cost implications. Detailed locational information would need to be developed before a detailed operability assessment could be completed.

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Areas of Study Not Considered

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price were not considered as part of this study, impacts of electrification on demand will be considered in the 2021 APO and future APOs.

Ontario imports energy from and exports to its five neighbouring jurisdictions every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions target, so will our neighbours. Neighboring jurisdictions are evolving and policy changes are underway in the United States as they develop their own pathways to lowering emissions. However, these policies have not been finalized and to avoid speculative policy decisions (e.g. carbon pricing in other regions, future resource supply mixes in other regions, etc.) this study did not consider how emissions in other jurisdictions may be affected in the future. This study will assume the Eastern Interconnection as is from the 2020 APO Scenario 1 for the duration of the study period. The emissions forecast for this study will also consider Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

Study Assumptions and Limitations

A resource portfolio was developed to understand the high-level electricity system impacts of replacing natural gas-fired generation. This portfolio was designed to meet basic capacity and energy adequacy requirements (seasonal capacity and hourly energy) in a cost-effective manner, ignoring more complex technical analytics and implementation practicality that would otherwise be required of a detailed power system plan. If directed to pursue natural gas-fired generation replacement further, a more rigorous analysis would be required, including the development of tools that better incorporate real-time market dynamics in the portfolio building process. In particular, most commercially available tools have modelling limitations in respect of newer resources, such as storage, as these resources were not contemplated at the time they were developed.

Table 4 below lists a number of optimistic technical and practical assumptions made to facilitate the study.

Table 4 | Technical and Practical Assumptions

<table>
<thead>
<tr>
<th>Category</th>
<th>Assumption</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage</td>
<td>Large-scale energy storage can be completely operationalized.</td>
<td>IESO has limited experience with candidate storage technologies, pumped hydro aside.</td>
</tr>
<tr>
<td></td>
<td>Storage is simplistically modelled to provide capacity, load following and ancillary services.</td>
<td>Modelling limitations raise questions as to whether storage can provide the full suite of these</td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th><strong>Market Interface</strong></th>
<th>IESO will have increased visibility and dispatchability of incremental resources on distribution systems.</th>
<th>IESO systems to be upgraded to allow for continuous monitoring, dispatch, and contingency analysis.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operability</strong></td>
<td>Resource siting does not result in operability challenges – local or global – and all requirements for load following, voltage support, frequency response, etc. can be met.</td>
<td>To fully assess potential operability challenges, detailed information on size, location, and operating characteristics of the replacement fleet would be required.</td>
</tr>
<tr>
<td><strong>Land-Use</strong></td>
<td>The study assumes that resources are sited where needed, even with the large volume of resources contemplated in the supply mix.</td>
<td>A near doubling of the transmission-connected wind and solar fleet may require off-shore wind, currently delayed by an Ontario moratorium.</td>
</tr>
<tr>
<td><strong>Transmission Planning</strong></td>
<td>The resource portfolio is assumed to leverage the existing transmission system, to the extent possible, but upgrades are needed to enable resources in the North, increase imports from Québec, and add to GTA supply.</td>
<td>A complete Transmission Planning exercise is required, and would take 12 to 18 months.</td>
</tr>
<tr>
<td><strong>Policy</strong></td>
<td>Enabling policies are in place to support increased energy efficiency and the fast-tracking of permitting and construction to enable siting of resources in key electrical areas.</td>
<td>Any change in policy, for or against the replacement of natural gas-fired generation, will take time, and may sway with changes in government.</td>
</tr>
</tbody>
</table>
Scenario Development

Leveraging the 2020 Annual Planning Outlook as the basis, potential pathways were explored to reduce emissions from current projections. Three scenarios were examined using a supply-mix and a market-based approach to lower emissions.

Base Case

This study leverages the 2020 APO Scenario 1 as the underlying base case. This forecast assumed a shallow recession due to the global pandemic, followed by a rapid return to pre-pandemic demand levels. The 2020 APO Scenario 1 projects net energy demand to be 141 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period. By 2030, net energy demand is expected to reach 159 TWh. Summer peak demand is projected to be 25.5 GW and winter peak demand to be 24.6 GW by 2030.

In the 2020 APO, the total installed capacity of the supply mix, reflecting continued availability of existing resources following the end of their contract term or commitment, is expected to be 38 GW by 2030 as shown in Figure 5. Total energy efficiency program savings is also expected to be about 12 TWh by 2030.

Figure 5| 2020 Annual Planning Outlook, 2030 Installed Capacity (GW)
The carbon pricing assumptions used are $50/tonne\textsuperscript{12} starting 2022 (held constant thereafter) and a benchmark emissions rate of 370 tonnes CO\textsubscript{2}/GWh allowance for existing natural gas generation.

As outlined in the 2020 APO, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO\textsubscript{2} by 2030, still well below 2005 levels, shown in Error: Reference source not found.

Figure 6 | 2020 Annual Planning Outlook, Electricity Sector GHG Emissions, Historical and Forecast

This expected increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective. In the 2020 APO, should a need exist after the continued availability of existing resources, new “proxy” generation is modelled and is assumed to be clean (ie. no emissions) and priced as a single cycle gas turbine. As electricity consumption increases, the rise in electricity sector emissions could be partially reduced, factoring in requirements to maintain system reliability, by increased energy efficiency and non-emitting resources in the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy change.

**Potential Pathways**

This study examines potential pathways to lower emissions through a complete gas phase out (Scenario 1) and maintaining emissions at current levels (Scenarios 2 and 3), as illustrated in Figure 7. The current emissions baseline is an average of electricity sector emissions from 2016 to 2020\textsuperscript{13} to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4

\textsuperscript{12} This assumption was based on IESO’s understanding of carbon pricing at the time and aligns with the forecast as discussed under Current Government Emissions Policy and Emissions Targets.

\textsuperscript{13} 2017 was a lower than expected demand year, and as a result, emissions were lower as the gas fleet operated less.

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Mt CO₂ per year. The purpose of developing these Scenarios was not to create estimates of likely outcomes, but to allow the IESO to provide insights gleaned from the range of potential pathways. These scenarios were also informed by the multitude of input from the public webinar, stakeholders and communities' feedback – written feedback can be found on the IESO website.

### Figure 7 | Pathway Description

<table>
<thead>
<tr>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply mix-based approach that examines a portfolio of replacement resources assuming all existing gas is phased out by 2030</td>
<td>Market-based approach with increased carbon cost and decreased benchmark</td>
<td>Supply mix-based approach that examines a portfolio of replacement resources assuming existing gas is available to compete with other resources</td>
</tr>
</tbody>
</table>

### Modeling Approach

**Scenario 1** and **Scenario 3** use a supply mix-based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliable system in Ontario. Increased shares from any one type of replacement resource comes with risks since no single option can meet all system needs at all times. A diverse supply mix will help manage both the operational and cost risk of the changing supply mix. The supply mix-based approach considered demand-side and supply-side options. **Scenario 2** maintains all of the supply mix assumptions from the APO 2020, but considers updated carbon policy to drive GHG reductions through a market-based approach. Scenario 2 is a market-based approach where an increase in carbon price and a decrease in the benchmark emissions rate reduce the utilization of gas by 2030. The carbon price assumes a linear increase from $50/tonne in 2022 to $170/tonne by 2030, while the benchmark emissions rate for all natural gas facilities linearly declines from 370 tonnes/GWh in 2021 to 0 tonnes/GWh by 2030.

The supply mixed-based approach for Scenarios 1 and 3 determined a replacement supply mix incremental to the existing resource fleet. In Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. In Scenario 3, all existing resources including natural gas are assumed to remain in service.

In considering the candidate options, the study considered possible replacement technologies that are sufficiently mature today. As the reliability and planning coordinator, a principle applied to the study was to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This consideration also provided more certainty on the cost estimates of the replacement supply mix. It is difficult to predict technological innovations, policy developments, and grid evolutions that could manifest in the study time frame – factors that could result in alternate
supply mixes. The IESO aimed to provide a set of reasonable and forward-looking cost estimates, given professional judgement and the current information available. The study also considered, to the extent possible, the transmission investments required for increased intra-jurisdictional trading. However, the costs associated to make the replacement supply mix operable within the power system and the necessary transmission upgrades were not included.

Supply mixes were constructed using a least-cost optimization capacity expansion model that selected resource build-out over a 20-year period subject to a number of parameters. All resource portfolios were required to at least meet the total capacity contribution equal to summer and winter peak demand plus reserve margin; total annual energy demand, accounting for imports and exports; and annual CO₂ emissions target. It is important to note that certain physical or other practical constraints (e.g. availability of suitable land-use, non-CO₂ environmental impacts, societal acceptance of the replacement technology, among others) were not considered in this least-cost optimization capacity expansion model. And so, the outcome of such a model does not imply technical or physical feasibility.

Cost and performance assumptions for each option considered are provided in Table 2. Transmission cost assumptions associated with some of the resources from Table 2 are provided in Table 5. It is difficult to determine the required transmission investments without knowing where new generation would be located. For instance, it is recognized that much of the accessible locations in the transmission system to incorporate wind generation have already been developed to connect the existing wind generation fleet. Investments in the interconnection facilities with neighbouring jurisdictions will need to be jointly developed. A portfolio analysis was performed without considering any transmission costs or costs associated with ensuring an operable power system (e.g. tool upgrades, market structure changes, among others). This sensitivity demonstrated that the cost-optimized replacement supply mix is not very sensitive to transmission costs. The actual extent of the impact of transmission costs cannot be known until full details for implementation are considered. Such determination would require much more extensive consideration and collaboration with generation developers, which cannot be completed within the timelines for this report.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2021M)</th>
<th>O&amp;M Cost ($2021M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1,500 MW of additional wind and solar capacity.</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(&lt;= 2,050 MW)</td>
<td>300</td>
<td>3</td>
<td>Based on preliminary consideration of increasing firm interconnection capacity with Québec.</td>
</tr>
<tr>
<td>Firm Imports</td>
<td>1,500</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>(&lt;= 3,300 MW)</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Supply mix portfolios are modeled seasonally (summer and winter) over 20 years. In each season, the supply mix portfolios are compared to the necessary capacity, energy and emissions requirements referenced above. Hourly modeling in a multi-year capacity expansion optimization model was considered impractical given processing constraints. The purpose of the seasonal capacity expansion model is to develop supply mix portfolios with the approximate amount of capacity and energy to meet system needs. The supply portfolios were followed by an assessment using an hourly energy dispatch model to determine whether the portfolio could meet energy requirements in all hours. Other feasibility assessments were also performed, such as assessing the required storage duration and the frequency with which DR was activated.

Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future. The resulting portfolios developed using the least-cost optimization capacity expansion model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path and do not directly imply technical or physical feasibility. Notably, the results are heavily influenced by the relative cost assumptions which are likely to change over time. The results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while meeting capacity and energy requirements.

An economic hourly dispatch model was used to determine the outcomes of the three scenarios. This assessment simulates the Ontario electricity market through a production-cost simulator to inform energy production, imports and exports, system costs, and emissions. While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Base Case to understand which factors are the largest drivers of ratepayer costs. Figure 8 illustrates the modelling approach for the three scenarios.

Figure 8 | Modelling Approach for Scenarios 1, 2 and 3
Study Findings

A potential pathway to phase out all existing natural gas from the electricity system would require over 17,000 MW of incremental non-carbon emitting capacity, and potentially incremental 1,600 MW of energy efficiency; resulting in an increase monthly residential bills in the order of 60%, or an additional $100/month.

The study examined 3 scenarios as described. The balance of this report focuses on Scenario 1 (impacts upon cost and reliability of complete phase-out of gas generation in Ontario by 2030), as it has the most conclusive results and directly responds to the resolutions passed by municipalities.

Scenario 2 examined the impact of raising the cost of carbon, while Scenario 3 examined a resource-mix approach to holding emissions at 2016-2020 levels. In both cases, significant cost increases were observed without material emissions reductions. The preliminary results for these scenarios do not fully capture likely import/export results due to evolving US carbon policy. The two scenarios were not developed further, as they do not add sufficient value to this study.

Scenario 1 examines a portfolio of replacement resources assuming all existing gas is phased out by 2030. The incremental supply above the Base Case required to completely replace natural gas generation by 2030 is about 17,000 MW, as shown in Figure 9. In addition to this supply, Energy Efficiency Scenario B of peak 1,600 MW savings from the Available Potential Study (APS) is also included as part of the lowest-cost resource mix (not shown in the figure).

Figure 9 | 2030 Incremental Installed Capacity, Scenario 1
The incremental nuclear, wind and solar capacity produce less annual energy (19 TWh) than the natural gas energy (31 TWh) was forecast to produce in 2030 in the 2020 APO. The remaining energy gap is made up by energy efficiency (9 TWh) and imports, firm and economic. Storage and DR are required to replace the capacity currently provided by natural gas as well as the incremental capacity gap identified in the 2020 APO. Storage and DR also help balance periods of high baseload generation and periods of insufficient supply. From the candidate options, new hydroelectric capacity was not selected by the capacity expansion model due to likelihood of completing construction by 2030, and the high assumed costs associated with new build hydroelectric generation.

This portfolio of resources, along with the assumptions presented, satisfied the high-level reliability requirements of the capacity expansion model. This portfolio was then simulated in IESO’s hourly energy dispatch model to determine if this mix would be able to reliably supply all energy needs when considering hourly market dynamics. This portfolio resulted in approximately 500 GWh of unserved energy; which amounts to about a day and half worth of all electricity consumed in the province. From a high level, the assumed portfolio does provide enough capacity and energy to meet system needs, however, it lacks the ability to deliver the energy precisely when it is needed – the flexibility requirement. To increase flexibility, the reservoir size of the storage fleet was increased until all energy needs were met. The initial portfolio assumed the storage fleet had 4 hours of maximum output when fully charged, however; this post-processing exercise indicated that far more storage would be needed to be able to satisfy the energy needs, as shown in Figure 10. The ability to re-charge storage devices during multi-day high demand or low wind events (e.g. summer heat waves) was not considered.

**Figure 10 | Hours of Storage Required compared to Percent of Unserved Energy Now Served**
The post-processing exercise was able to optimize the 4-hour storage fleet further to help reduce an additional 36% of the unserved energy, but as can be seen from the figure, to fill 100% of the energy gap, volumes of the storage fleet would need up to 47 hours of storage. The above storage fleet with 4 hours of storage translates to an installed storage reservoir size of about 25 GWh. To serve the entire need in the hourly dynamic energy model, a reservoir size of closer to 300 GWh is needed. For context, the largest pumped-hydro storage projects being proposed in Ontario today are each under 10 GWh, however there are not enough potential sites in Ontario to provide 300 GWh of storage with pumped hydro alone. Batteries might be able to contribute as well, however, even the largest manufacturing plant in North America, Tesla’s Gigafactory, is only able to produce 20 GWh of storage per year.

This scenario also relies heavily on using DR as a peaking resource. From a high level, the amount of energy of the incremental 2,000 MW of DR, assuming a 4 hour activation limit, is the equivalent of about 193 activations per year, or a capacity factor of approximately 9%. In addition, to help reduce the energy not served in the hourly dispatch model, the 4 hour activation limit on DR was overridden, meaning that there were some activations where the model assumed DR was activated for tens of hours continuously. This type of operation greatly diverges from how today's DR product operates and it may not be practical to assume that this level of service could be provided by this resource type. Certain demand response resources, using behind-the-meter generation or storage, may be able to respond this frequently, but it is unlikely that industry would reduce load as often.

The complete phase-out of gas by 2030 with replacement by the above mix would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy market prices, along with increased volatility. Overall system cost, however, would increase as a result of building new renewables; these resources would likely have the effect of lowering energy market prices while increasing capacity costs and potentially the cost of ancillary services. At the same time, storage resources tend to offer in the ancillary services markets, and the large build-out of storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later in the Appendix B under the Wholesale Market Impacts.

Besides those energy efficiency savings considered in the 2020 APO, there are potential opportunities to achieve greater electricity savings as identified in the APS. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentive levels. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the Base Case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.
Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Québec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres would be required. This would have significant cost implications. Determining the right balance between self-sufficiency and reliance on imports would require consideration by policy makers.

The capital investment required for the replacement resource mix is about $27 Billion. When considered in the form of commercial revenue requirements over the lives of the resources, and adding operating costs, this translates to an annual cost of electricity service increase of $5.7 Billion. This 20% increase is the cost of removing 12.2 Mega tonnes of CO$_2$e per year, or in terms of an emissions reduction rate, $464/tonne CO$_2$e.

The impact on residential customers is both important and significant. Since fixed costs have increased, Global Adjustment (GA) will increase, but there will also be an overall shift in cost recovery from market revenues to GA. This is driven by the addition of low marginal cost resources, which will decrease market clearing prices and market compensation. Since Class B customers (residential) pick-up the majority of GA due to the ICI program, the overall result is a 60% increase in monthly residential bills, or an additional $100/month.

Table X: Summary of Electricity System Cost and Residential Customer Impacts

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Overnight Capital Cost ($B)</th>
<th>2030 Cost of Electricity Service ($ B)</th>
<th>2030 Greenhouse Gas Emissions (MT CO$_2$e)</th>
<th>2030 Cost of Carbon Reduced ($/tonne CO$_2$e)</th>
<th>2030 Residential Bill for 750 kWh ($/Month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020 APO Base Case</td>
<td>--</td>
<td>26</td>
<td>12.2</td>
<td>--</td>
<td>163.40</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>27</td>
<td>32</td>
<td>0</td>
<td>464</td>
<td>260.94</td>
</tr>
</tbody>
</table>
Steps and Challenges to Implementation

Generators termination for existing gas contract will result in financial and reputational impacts to the electricity industry. Ratepayers will also be further negatively impacted by stranding the natural gas assets and reducing competition by eliminating this supply option.

Large scale non-carbon emitting resources can pose several practical challenges, such as, land use, siting and location. Also with renewables located away from urban load centers major transmission infrastructure costs will be required in $\times$ billion range and will require 10+ years to plan and implement.

Wholesale market impacts of installing non-carbon emitting resources with low to zero marginal cost resources will influenced price signals seen across the electricity system in Ontario that will also change import and export flows.

Developing a Transmission Plan

The ability of supply resources to meet demand across the province, and potentially other jurisdictions, relies on the transmission system to transport electricity to where it is needed. Within Ontario, bulk transmission interfaces form the boundaries of the 10 IESO electrical zones. The primary purpose of these interfaces is to describe power flows across the system and associated phenomenon which may limit these transfers. The bulk transmission system is also used to import power from, or export power to, neighbouring jurisdictions through a series of interties at specific points on the Ontario border. The maximum amount of power that these interfaces and interties can deliver is known as their transfer capability, which reflects constraints to ensure system stability, voltage performance, and acceptable thermal loading. Interface transfer capabilities are used in resource adequacy and transmission security assessments. Resource adequacy assessments are probabilistic studies that consider interface transfer capabilities with transmission facilities in-service, on planned outage, or following a limiting contingency event (a sudden or unplanned outage). Transmission security assessments are deterministic studies conducted at the zonal level that consider various transmission system disturbances, as defined according to applicable regulatory obligations. Zonal adequacy or security assessments may be more restrictive than resource adequacy assessments depending on the characteristics of the zone(s) being investigated. Intertie transfer capabilities are treated as interfaces in reliability assessments, and provide a number of system benefits, including: stability, frequency support and voltage support following a contingency, and the opportunity to consider imports and exports to manage resource needs where cost-effective.
As stated under Modeling Approach, the least-cost resource optimization for Scenario 1 did not consider locational or siting-related matters, and as such, corresponding detailed Transmission Plans could not be developed. However, the IESO can draw upon experience from past transmission planning initiatives, and is able to comment on the potential scope of a Transmission Plan to reduce reliance on natural gas generation. The development of a Transmission Plan would consider the need to relieve constraints in order to deliver replacement resources, as well as the needs that would emerge if strategically located natural gas plants are retired. The following describes the potential scope in order to communicate the magnitude of potential reinforcement, the magnitude of potential cost impacts, and comment on the expected time necessary to plan, develop and implement reinforcements of such scope.

Note that this section is not intended to communicate a Transmission Plan. A Transmission Plan would require a more complete planning exercise, executed with sufficiently detailed information regarding replacement resource siting, and including a thorough reliability assessment and a robust engagement with Indigenous communities, municipalities, and other stakeholders.

**Delivering the Replacement Resource Mix**

Of the 11,000 MW of installed natural gas-fired generation, a large portion is located in or around the Greater Toronto Area (GTA), with the balance primarily in western Ontario. When considering resource mixes, it may not be practical to site some resources in large urban/suburban areas given expected land-use requirements (e.g., wind) or the origin of the resource (i.e., firm imports). This would imply that the retirement or reduced reliance on these natural gas plants would create a net requirement to transport power into the GTA and other load centres, as compared to Ontario’s current electricity system.

**Figure 11 | IESO Electrical Zones and Transmission Reinforcements**

![IESO Electrical Zones and Transmission Reinforcements](image)
Northern Ontario Reinforcement (1, 2, 3)

The ability to deliver supply resources from northern Ontario towards the GTA and surrounding areas can be limiting for the existing system (as referenced in the 2020 APO), and siting a portion of replacement resources in northern Ontario would significantly worsen the impact of this constraint. In general, and following the reinforcement of the East-West Tie, there are three limiting paths to deliver supply resources from northern Ontario:

1. West of Sudbury
2. North of Sudbury
3. The North-South Tie

The West of Sudbury portion of the system, specifically the Mississagi East interface, is expected to be the next limiting east-west path for bulk power transfers following the reinforcement of the East-West Tie, and is centred in the greater Sault Ste. Marie area. This part of the system is a focus area for the IESO’s Northeast Bulk Plan. Depending on the magnitude of resources sited west of Sudbury, a reinforcement of this part of the transmission system could be addressed by a multi-circuit 230 kV line, or a new 500 kV line, extending from as far as Wawa TS to Hanmer TS (Sudbury area), a range of ~400 km. A reinforcement of this magnitude is expected to cost on the order of between $500 million and $1 billion, and take 7-10 years to fully plan, develop and implement.

The North of Sudbury portion of the system, specifically the 500 kV interface (D501P and the P502X-South), is expected to be a limiting north-south path for bulk power transfers from the northern parts of northeast Ontario. This 500 kV path, and its underlying 230 kV and 115 kV paths, generally extends from Pinard and the greater Kapuskasing area south to Timmins at Porcupine TS and the surrounding areas of Ansonville and Kirkland Lake. Depending on the magnitude of resources sited north of Sudbury, a reinforcement of this part of the transmission system could be addressed by a new 500 kV line paralleling the existing 500 kV system from Sudbury to Pinard via Porcupine, as well as potentially introducing a 230 kV underlaying system. A reinforcement of this magnitude is expected to cost on the order of $1 billion, and take 7-10 years to fully plan, develop and implement.

The North-South Tie is the 500 kV and 230 kV interface that supply resources from the north would have to flow through to get to the south at Essa TS in Barrie. Depending on the magnitude of resources sited in northern Ontario, a reinforcement of this part of the transmission system could be addressed by a new 500 kV single or multi-circuit line paralleling the existing 500 kV line, as well as a reinforcement to the 230 kV system emanating from Essa TS, as studies show that the 230 kV system can become thermally limiting with significant 500 kV injections at Essa. Reinforcements of this magnitude are expected to cost on the order of $1 billion, and take 7-10 years to fully plan, develop and implement.

A significant amount of voltage control devices would also be likely, particularly to control over-voltages at times when the system is lightly loaded, given the extent of new transmission lines that may be required.
The reinforcement scope indicated for North of Sudbury and the North-South Tie could also warrant consideration of introducing a new HVdc network to Ontario.

Flow East Towards Toronto Stage 2 (4)

The IESO has recommended an initial reinforcement to the Flow East Towards Toronto ("FETT") interface, which is the primary flow gate that transfers power from western Ontario to Toronto and eastern Ontario. Depending on the magnitude of resources sited west of the FETT interface, further stages of reinforcement to the FETT interface could consist of new 230 kV transmission circuits in the western GTA, namely Brampton, Mississauga and Oakville; a new 500/230 kV autotransformer station at the existing Milton SS; and/or a new 500/230 kV autotransformer station near Kleinburg. Reinforcements of this magnitude could cost on the order of between $300 million and $500 million, and take 3-7 years to fully plan, develop and implement, depending on the scope of the reinforcement required.

Eastern Ontario Reinforcement (5)

In order to accommodate 3,300 MW of non-emitting firm imports under Scenario 1, and assuming that such amounts are available and economic, a reinforcement to the Ontario-Quebec intertie facilities may be within scope of potential transmission enhancements. To that end, much of the information in the 2014 “Review of Ontario Interties” report and the 2017 “Ontario-Quebec Interconnection Capability” report remain indicative of the scope of reinforcement. This may include doubling the Outaouais HVdc interconnection, reinforcement of the 230 kV network between the Quebec boarder to Merivale (Ottawa area), Hawthorne (Ottawa area) and St. Lawrence, and may require reinforcement to the 500 kV system between Bowmanville and Cherrywood (in Pickering), depending on the development of resources in eastern GTA and eastern Ontario. Reinforcements of this magnitude could cost on the order of between $1 billion and $1.5 billion, and take between 7-10 years to fully plan, develop and implement, depending on the scope of the reinforcement required.

Maintaining Reliability Currently Provided by Strategically Located Gas Plants

Natural gas plants that were strategically located are critical to the supply reliability of several areas. Central Toronto is primarily supplied by the Cherrywood – Leaside 230 kV corridor and Leaside TS, which is a 230/115 kV autotransformer station. Without support from Portlands Energy Centre GS, or equivalent local replacement capacity, a new corridor to Central Toronto may be required to prevent collapse and an unacceptable out-rush across our interties. Past plans, including the 2007 IPSP, envisioned the “Third Supply Plan” as lengthy transmission, potentially under Lake Ontario from Pickering, Darlington or Niagara Falls.

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The western part of the GTA is primarily supplied by Trafalgar TS and Claireville 500/230 kV autotransformer stations. Retirement of Pickering NGS will increase autotransformer loading, but would still remain within the available capacity; however, without support from Goreway GS and Halton Hills GS, the 500/230 kV transformation capacity will likely be exceeded. The solution would be to convert Milton switching station to a 500/230 kV autotransformer station at a cost of about $200 million.

York Region is supplied by the 230 kV circuits between Claireville TS to the south, and Minden to the north, and York Energy Centre GS (“YEC”) plays a critical role in local reliability. A new transmission line between Buttonville and Newmarket was an alternative to the facility, but significant local opposition led to the local generation solution. Also, as demand in the area continues to grow, YEC’s role will remain critical. When the current supply capacity is no longer adequate (forecast 2030), additional generation and/or transmission will likely be required, even with YEC in service; however, without YEC or equivalent local generation, significantly more transmission infrastructure would likely be required. Reinforcements of this magnitude could cost on the order of several hundreds of millions of dollars above a resource mix that includes YEC, and would potentially require an additional new transmission corridor.

The West of Chatham area is experiencing significant load growth, primarily driven by the agricultural sector, with Brighton Beach GS, East Windsor GS and West Windsor GS playing a critical role in local reliability. Interim operating measures using local natural gas-fired generation are currently required while the first stage of transmission reinforcement is being implemented. Additional reinforcement is envisioned within the decade, and the existing local natural gas generation could still play a role in the solution along with transmission reinforcement and new local generation.

The Kirkland Lake area supports a large amount of demand in the mining sector, and this demand is expected to increase given the volume of new connection requests received by the IESO. Plans are underway to reinforce the 115 kV transmission grid between Ansonville and Kirkland Lake; however, this reinforcement envisioned some continued reliance on Kirkland Lake GS. Without support from Kirkland Lake GS or equivalent local replacement capacity, additional and significant reinforcement may be required.

As mentioned under The Role of Natural Gas, natural gas-fired generators provide dynamic reactive power that is critical in maintaining acceptable voltages during high demand periods. Reactive power cannot be transferred over long distances; thus replacement reactive power sources must be installed locally. Portland GS, Goreway GS, Halton Hills GS and YEC, provide a significant amount of reactive power capability, on the order of 1500 MVAR. Shunt capacitor banks cannot be used for this purpose as they do not provide the required dynamic reactive power. The cost of dynamic reactive power devices is high, in the order of $500M to $1B to address the reactive requirements currently provided by the GTA gas plants.
Lastly, and as also mentioned under The Role of Natural Gas, natural gas-fired generators provide frequency response. Of particular locational specific concern may be the design of Ontario’s Under-Frequency Load Shedding Program (UFLS) for the Central Island in Toronto, as natural gas-fired generators are currently the only source of governor response (primary frequency response) in the area, and IESO’s 2018 UFLS study identified little margin compared with NERC and NPCC requirements.

Summary

In summary, the development and implementation of a Transmission Plan is expected to have tremendous scope, and may contemplate significant reinforcement to all levels of the transmission system, including the possible introduction of additional HVdc facilities. This reinforcement is expected to cost several billions of dollars and may take over 10 years to complete the full scope, which suggests retirement of all natural gas generators by 2030 is infeasible. A detailed transmission planning exercise would be necessary to determine the full extent of reinforcements required, true cost estimates of these reinforcements, and when they could come into service, recognizing the immense logistical challenge of deploying so many large projects simultaneously while also executing normal maintenance programs.

Practical Considerations

Gas Generators Under Contract

Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners needs to be included with the replacement costs to retire these generators prior to the end of their contract as identified in Scenario 1. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. However, the remaining contracted net revenue requirement is considered as an estimated cost minimum cost expectation.

Stranded Assets

14 For additional information, see Section 11.3 of IESO Market Manual 7.1.
15 Scenario 1 assumes $2.4 in Net Revenue Requirement payments for cancelled contracts; however, additional possible compensation associated with implications of being locked out of the market to participate or other types of potential negative implications are not quantified.

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The natural gas fleet has considerable economic life remaining. The majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, the average age of large natural-gas resources (e.g. resources greater than 150 MW) is 13 years. Stranded costs resulting from coal retirements were typically modest because many of the plants were built decades earlier and were nearing the end of their useful lives. Much of the gas fleet is relatively young, increasing the potential for stranded costs if widespread closures occur within the next decade. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

**Land Use and Siting**

Replacing gas resources with new large scale non-carbon emitting resources can pose a number of practical challenges in regards to land use, siting and location. Most economic and accessible hydroelectric sites have been developed; some potential is undeveloped, with a majority of it located along Ontario’s northern rivers (e.g. Abitibi and Moose rivers). Northern hydroelectric sites are generally remote, resulting in relatively higher construction costs, as well as requiring potentially significant transmission investments to connect them.

**Timing**

Reducions in emissions through the addtion of new non-carbon emitting resources and the accompanying transmission would not only require new investments, but also the associated time to develop the designs and the required specifications. This would require significant effort to identify appropriate sites and routes, to manage the extensive stakeholdering and consultation, and to manage the acquisitioning and building of these assets. The lead time of supply resources vary depending on the type of generation; the lead time of transmission assets can be at least seven to ten years. New technology and resource risks should recognize the uncertainty associated with construction completion and the longer lead times required to reach dependable operation. This transformation of the system would require detailed planning which is outside the scope of this study. Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of our generation capacity.

**Market Impacts**

The implementation of low to zero marginal cost renewable generation will drive down the market clearing price and result in changes to the flow of imports and exports. As discussed in Scenario 1 and 3 with the increase of renewable generation into the supply mix will result in lower marginal costs in Ontario relative to surrounding jurisdictions. The market dynamics of lower domestic prices will result increased export demand from Ontario generators thus driving up the dispatch of natural gas generators and Ontario’s carbon emission in Scenario 3 when natural gas is still available. In effect, impacting Ontario’s ability to stabilize emissions in Scenario 3 would require the implementation of a cap or moratorium on the natural gas production; thus, the current market mechanism could need to be reevaluated. A detailed wholesale market simulations analysis is provided in Appendix B – Wholesale Market Impacts, which discusses the change in the market flow and implications to energy prices, net exports, operating reserve prices, and curtailed energy.

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Conclusion and Next Steps

For Scenario 1, the IESO has modelled a 100 per cent emissions free supply mix to meet the 2030 timeline that in theory meets basic standards for reliability (capacity, energy, ramping). This supply mix posed challenges and required highly optimistic assumptions:

• Building and upgrading transmission and generation infrastructure, including environmental and local approvals, would take far longer than 8 years. Practical and regulatory challenges of building multiple reinforcements at the same time would likely be extremely challenging.
• The supply mix assumed year-round supply from Quebec. Quebec currently imports from other jurisdictions during winter and long-term reports indicate they will be below their reserve margins for capacity by 2030.
• New storage technologies are not currently proven at the scale required - without prudent testing and piloting, system reliably cannot be guaranteed in extreme conditions including protracted heat waves or cold snaps. The Scenario 1 supply mix did not consider multi-day high demand conditions.
• The necessary number of demand response providers is unlikely. Modelling indicates that demand response would be activated almost 200 times per year.
• Expertise and equipment required for the proposed infrastructure expansion is limited and insufficient for this timeframe.

Although the model supply mix met basic reliability metrics, the optimistic assumptions would need to be addressed to ensure a reliable supply for the province. This could not be accomplished by 2030.
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1. Considerations for Phasing Out Natural Gas in the Electricity System
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Executive Summary

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This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.

Key Findings

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Background and Context

Ontario’s portfolio of resources is procured to work together with the transmission system in order to provide capacity and energy when and where it is needed, and the services required to maintain real-time reliability. Natural gas-fired generation plays an important role, providing the full range of reliability services needed to operate the electricity system, and under all weather conditions.

When considering how natural gas-fired generation operates and the value it provides, it is also helpful to understand the grander state of emissions in Ontario, including emissions policy, to seek out the best opportunities to reduce emissions in the province overall.

Planning and Operating the Bulk Electric System

While evolving Ontario’s resource mix, it is important to remember that the grid is an integrated system, part of the North American Eastern Interconnection, and guided by North American and Ontario-specific reliability standards. Ontario’s portfolio of resources is procured to work together with the transmission system in order to provide capacity and energy when and where it is needed, and to provide the services required to maintain real-time reliability. These resources also include conservation measures, which can defer or eliminate the need for other resources, depending on the achievable potential where they are required.

Capacity and energy adequacy are assessed as part of IESO’s Annual Planning Outlook (APO), identifying provincial and local shortfalls that must be met to achieve reliability standards. These shortfalls feed into transmission planning and the Resource Adequacy Framework, which will align acquisitions with evolving system needs.

As mentioned above, there are other services required to maintain reliability, and include\(^1,2\):

- **Operating Reserve (OR)** – stand-by power or demand reduction that can be called on with short notice to deal with an unexpected mismatch between generation and load.

- **Certified Black Start Facilities** – facilities that help system reliability by being able to restart with no outside source of power following a blackout event, and would be called on during restoration efforts by helping to re-energize other portions of the power system.

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- **Regulation Service** – corrects for short-term changes in electricity use that might affect the stability of the power system, including variations in power system frequency.

- **Reactive Support and Voltage Control Service (RSVC)** – required in order to maintain acceptable reactive power and voltage levels on the grid.

**Reliability Must-Run (RMR)** — contracts that allow the IESO to call on the counterparty to produce electricity if it is needed to maintain the reliability of the electricity system.

It is important to understand that no single resource can provide the full suite of services, and the level of services needed is a function of various aspects of uncertainty, including those inherent to the resource mix itself, requiring an iterative assessment process. Aspects of uncertainty include the loss of system elements (resource and transmission), changes in transmission-connected load and distribution-connected net load (considers effects of load, embedded generation, and loss of distribution elements), and generation fuel availability (water, wind, sun, and natural gas), some or all of which can be impacted by weather, which has hourly, daily, and seasonal variability.

In order to mitigate risks associated with uncertainty, and maintain an operable system that can respond second-to-second in real-time and be re-postured in anticipation of future events, the IESO also guides resource selection and the build out of the transmission system based on the following principles:

- **Diversity** – having a balanced variation of characteristics available across the system.

- **Flexibility** – ability to easily respond to changing circumstances or conditions across the system.

- **Manageability** – ability to have visibility, monitoring and dispatch of resources across the system.

Further discussion of these principles is found in the sections below, as well as Operational Scope and Locational Importance.

**Diversity**

Diversity in the characteristics of the resource mix, and where resources are located, is important to ensure risks inherent to each resource (technology, fuel type or otherwise) are mitigated. As such, the total portfolio must provide sufficient system capability to meet adequacy and other service level requirements, and be sustainable under a wide variety of conditions (short-term extreme weather, mid-term environmental extremes and fuel delivery challenges) and operating restrictions (air emissions, water flow and cooling water temperature).

**Flexibility**

To ensure that the system can reliably match supply and demand, Ontario’s resource mix must provide sufficient flexibility to provide “load following” – responding to anticipated and unanticipated changes on the system; and “ramping” – to meet sharp changes in consumption, due to increases or
decreases in system demand (e.g. winter mornings). System performance related to load following and ramping is governed by legally binding North American Reliability Standards.

IESO’s Experience in Flexibility

On June 28, 2021, demand was high during the day and peaked in the evening, reaching 22,300 MW. Wind contributed to the system’s energy need but only provided 11% of its installed capacity in the peak hour, a total of 500 MW, and 400 MW under what had been forecast.

Low water conditions on several river systems caused concern over hydroelectric fuel availability, and in an attempt to conserve the energy limited hydroelectric resources for utilization at peak, they were constrained down in off-peak hours. To replace the energy limited resources, other non-energy limited resources were dispatched up, including flexible natural gas resources.

A total of 6,000 MW of natural gas-fired generation was dispatched to meet the 22,300 MW peak. Much of this was constrained on earlier in the day to offset the energy limited resources and to provide Operating Reserve. No other fuel-type offered the needed flexibility to constrain on for this purpose.

An Energy Emergency Alert was issued indicating that all available resources were committed.

Approximately 30% of the demand was supplied by the natural gas fleet on this day, demonstrating the importance of having flexible resources on the system.

Manageability

The IESO currently has full visibility and control of resources connected to the high voltage transmission system, the bulk of Ontario’s generation fleet, but the same cannot be said for those resources connected to the distribution system. To date, this has been manageable due to the limited size of the distributed resource fleet, but should natural gas-fired generation be replaced with resources on the distribution system, the IESO will require visibility and dispatchability of those resources to maintain reliability. Detailed technical specifications of all resources will be required to ensure that engineering studies can effectively model system behaviour under a range of conditions.
If the replacement resource mix incorporates an increasing number of small resources that are embedded, distributed and possibly aggregated, the impact on situational awareness must be considered. To maintain reliability and meet related standards, system operators require sufficient data to provide Real-Time Monitoring and perform Operational Planning Analyses and Real-time Assessments. A large increase in the number of resources and market participants providing capacity to Ontario could require significant tool upgrades to manage the increased volume of data received by the IESO.

Ensuring manageability under the above conditions would require significant changes to our existing market participation framework, tools and rules, and would cost in the tens of millions based on previous experience.

**Operational Scope**

In real-time, the IESO-controlled grid (ICG) is operated to ensure that reasonably foreseeable contingencies will not result in the loss of a major portion of the power system (or unintentional separation of a major portion of the power system). This level of reliability is achieved by operating the ICG to meet adequacy criteria for anticipated demand, system security criteria for specified contingencies, and re-preparation criteria for restoring reliability following contingencies or major events such as blackouts.

The ICG is operated, and its reliability maintained, with due regard for planned and potential unplanned transmission element outages. To cover expected operating conditions, the transmission system is planned and designed within a well-defined scope. However, the system may experience out-of-scope conditions as a result of maintenance outages and forced outages. Reliability standards require system operators to consider unplanned operating scenarios resulting from different system events, ranging from transmission element malfunctions to events like forest fires, tornadoes and ice storms.

When planning the future resource mix, specific operability requirements can be difficult to quantify. No single resource type can deliver all necessary reliability services, and experience has shown that a diverse resource mix provides the most adaptable, flexible approach to achieving reliability and cost-effectiveness.

**Locational Importance**

The locational importance of the resource mix is discussed in the section “Developing a Transmission Plan”. The following discussion focuses on the impact of the resource mix on complexity of operation of the transmission system, with examples based on current operation. These examples are intended to illustrate the integrated nature of Ontario’s power system. System limits are formulated based on specific combinations of resources in service. Local area requirements are often met by an integrated approach that includes transmission, local supply and local conservation initiatives.

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
The transmission system limitations on the ICG result in flow-gates or interfaces that impede flow of power toward loads. These flow-gates are reflected through the system operating limits such as thermal, voltage and angular stability limits that indirectly describe specific system deficiencies. These system operating limits are derived by the IESO and together with the specific operating instructions are used by the Control Room operators to operate the transmission system reliably.

To provide unrestricted flow of power toward loads, minimize losses, and enable outages for transmission element maintenance, siting certain amounts of local generation may be necessary.

During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in locations to minimize transmission investments needed to incorporate the resource into the system. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by virtue of where they are located, also play important roles. Without this gas-fired generation, transmission investments may be required.

There are specific areas in the province, should replacement resource mix be located, would provide higher value than other areas of the province. The location of generation close to load pockets is important to reduce congestion and to reduce losses on the transmission system and ensure loads are being served.

The replacement resource mix located on the east side of the Flow East Towards Toronto (FETT) interface is important to accommodate the expected demand growth in the area as well as the retirement of the Pickering Nuclear Generating Station. Currently, Lennox, a gas generator near Napanee, provides locational value as well as flexibility due to its low minimum loading points and ability to achieve high generation output. Also, GTA-located plants such as Portlands, Goreway and Halton Hills provide specific support to enable unrestricted flow of power through the FETT flow gate. Collectively, these resources help address transmission limitations feeding the Toronto area. Additionally, limits on generator outputs in Western Ontario (e.g. Bruce Nuclear) are formulated on the basis of key resources in the GTA, including gas plants.

Similarly, Kirkland Lake gas generators enable flow of power from hydroelectric generation stations in the northeastern part of Ontario towards the load centres.

Generation located in areas that can reduce autotransformer loading is also important. Having Portlands GS connected on the 115 kV system in Toronto reduces loading on transformers serving the east end of the city. The locations of the Goreway and Halton Hills generating stations also help reduce loading on transformers supplying the GTA.

These natural gas generators are important to keep loading reduced during planned transformer outages or if a forced transformer outage were to occur. Should these gas generators be phased out, new supply must be strategically placed to serve these purposes and help maintain system operability. In addition, due to their reactive power capability, Portlands, Halton Hills and Goreway GS are the key elements in supporting the voltage and flow of power towards Toronto during high demand days.

In the Leamington area, increased dependency on Brighton Beach GS is required to manage the potential for prolonged load reductions during outage conditions. If Brighton Beach is to be shutdown, local replacement generation would be required to continue to mitigate this risk.
We must also ensure that adequate capacity is available to the area to accommodate a Darlington NGS outage after the Pickering NGS units have retired. If the gas is not replaced in that area, Ontario may experience shortfalls with the current transmission infrastructure.

Rapid growth of inverter-based resources (“IBRs”) add complexity to grid reliability. IBRs include most solar, wind, battery storage, hybrid generation and many DERs. Some IBR performance issues have been significant in recent grid disturbances, such as the tripping of a number of BPS-connected solar PV generators that occurred during the 2016 Blue Cut Fire, 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California.

**The Role of Natural Gas-Fired Generation**

The focus of this study is to investigate the requirements and system impacts that need to be addressed should the phase out of natural gas-fired generation be considered. To achieve this, it is important to recognize the role that natural gas-fired generation currently plays in the electricity system by way of identifying the services it provides through its technical characteristics, and to understand what will need to be replaced by other resources.

As illustrated in the table below, natural gas fuels a number of technologies and technological configurations, providing the full range of reliability services to the electricity system, and under all weather conditions. With Ontario’s significant level of variable and intermittent supply, natural gas is counted on frequently to provide flexibility, filling in gaps to address short-term supply and demand variability. Once online, natural gas is capable of quickly ramping up and down in response to system conditions to maintain reliability, but it can also provide sustained energy when needed as it is generally available at all times of the day. Today, flexible resources make up about 40% of the current fleet. Of the flexible resources, 11,000 MW of gas generation accounts for more than 70%.

<table>
<thead>
<tr>
<th>Reliability Services</th>
<th>Natural Gas Technologies and Configurations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SCGT</td>
</tr>
<tr>
<td>Capacity</td>
<td></td>
</tr>
<tr>
<td>Energy</td>
<td></td>
</tr>
<tr>
<td>Flexibility</td>
<td></td>
</tr>
<tr>
<td>Operating Reserve</td>
<td></td>
</tr>
<tr>
<td>Black Start</td>
<td>![Circle]</td>
</tr>
<tr>
<td>Regulation</td>
<td></td>
</tr>
<tr>
<td>Reactive Support</td>
<td></td>
</tr>
<tr>
<td>Voltage Control</td>
<td></td>
</tr>
<tr>
<td>Local Security</td>
<td></td>
</tr>
</tbody>
</table>

Table X: Reliability Services Provided by Natural Gas-Fired Generation
Aside from balancing supply and demand through flexibility, gas also provides a number of technical benefits to the ICG. Gas generators support provincial transmission security and provide voltage stability, particularly in specific locations where the transmission system may not be easily reinforced. They also provide fast dynamic response, which aids in system recovery following a significant contingency, maintaining system frequency and voltage. The ability to provide this response is due to the large rotating masses inherent to some gas technologies, storing kinetic energy, which acts as a suppressant to frequency decline following a contingency event.

Many gas plants are also strategically located near major demand centers to provide local and regional reliability, and minimize losses on the transmission system. Some gas plants were developed in lieu of major transmission upgrades in areas where they were deemed cost prohibitive or not possible due to specific environmental or social concerns. Should gas generation be phased out, additional transmission and voltage support may be required to deliver provincial capacity. In some areas, transmission upgrades may be required to support local load centres if new resources can’t be located in the same area (e.g. insufficient land is available for new supply).

When considering which resources to use in place of the natural gas fleet, there are no readily available resource types that can offer the same level of on-demand energy availability and flexibility by themselves.

Although this study seeks to remove all natural gas-fired generation, it is important to note that some CHP facilities support industry (e.g. process steam, district heating and hot water, CO₂ feedstock), and that a mandate to shutdown natural gas facilities would impact a number of businesses.

**Lessons Learned from Off Coal**

Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario’s generation capacity. When coal generation phase out was being considered, gas fired generation was a mature technology available with similar, yet less flexible operating characteristics due longer start-up times and higher minimum loading points. Bringing on large numbers of generators with a different fuel-type than coal also posed new administrative and operational challenges, with the IESO developing new approaches to monitor and operate different forms of generation. New approaches were developed to manage variable generation, including ramped-up Energy Efficiency programs, increased visibility of current variable generation output, enhanced methods to forecast variable generation output, and processes to dispatch variable generation resources. Further, certain coal-fired power plants were located in strategic areas that supported load centres and ultimately reduced the reliance of power being delivered from the transmission system. For instance, the former coal-fired Hearn generating station supported Toronto and central GTA transmission systems, while the coal-fired Lakeview generating station supported the southwestern and western GTA transmission systems. The replacement of such strategically located facilities was achieved by adding facilities like Portlands Energy Centre, Goreway and Halton Hills in a way to avoid the need to reinforce significant amounts of the transmission system that Hearn and Lakeview otherwise supported.

To replace the gas fleet, the province will face similar challenges and need to employ similar strategies, utilizing a combination of many resources to be discussed.

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State of Emissions in Ontario

Ontario’s electricity system has been steadily reducing greenhouse gas (GHG) emissions since the mid 2000’s, driven by the closure of coal facilities and the procurement of renewable resources, and now represents approximately 3% of total GHG emissions in the province – this from an all-time high of approximately 21% in 2000. On the other hand, Transport has risen from approximately 26% of total provincial emissions in 1990, to approximately 39% today, potentially illustrating higher impact opportunities to reduce emissions outside of the electricity system.

Figure 1 – Historical GHG Emissions in Ontario by Sector

Government Emissions Policy and Targets

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reduce GHG emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. In order to achieve this commitment, industry performance standards have been proposed to regulate large emitters.

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15 Considerations for Phasing Out Natural Gas in the Electricity System | Public
Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program, which will regulate GHG emissions from large industrial facilities by setting thresholds that those facilities are required to meet. The EPS program sets a threshold allowance of 370 tonnes CO$_2$e/GWh for existing generators, and 0 tonnes CO$_2$e/GWh for any new-build generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently $40/tonne CO$_2$e, and set to increase linearly to $170/tonne CO$_2$e by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset emissions, or can be sold to other large emitters. Ontario’s natural gas fleet currently has an average emissions factor of approximately 420 tonnes CO$_2$e/GWh, which means on average, and with a threshold allowance of 370 tonnes CO$_2$e/GWh, the Ontario fleet only pays for a fraction of what it is emitting (50 tonnes CO$_2$e/GWh, or about 12%). This threshold allowance was implemented to lessen carbon policy impacts on inter-jurisdictional electricity trade, but also with the consequence of lowering price driven consumption behaviour among ratepayers when these fractional costs are passed along. If Ontario’s natural gas fleet was fully exposed to the federal carbon price, border adjustments to inter-jurisdictional electricity trade may be required; otherwise, Ontario could see increases in emissions based imports.

The Federal Government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS), meeting the federal benchmark stringency requirements for the sources of GHG emissions that it covers, and intends to remove the application of the OBPS from Ontario facilities on January 1, 2022, the same day the EPS program takes effect.
Opportunities to Move Towards an Emissions-Free System in the Longer-Term

There are multiple pathways to removing CO₂ emissions from the electricity system for the future. However, these options must be commercially feasible, scalable and cost-effective in the near term. In developing the replacement resource-mix for this study, the following resource options are considered to create a diversified low-carbon energy portfolio: energy efficiency, demand response, wind, solar, energy storage, hydroelectric, nuclear small modular reactors, and Hydro-Québec firm imports.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity, as shown in Figure 2, and represents about 7% of total energy in the province, as shown in Figure 3.

Figure 2 | 2020 Installed Capacity by Fuel Type

![Figure 2: 2020 Installed Capacity by Fuel Type]

Figure 3 | 2020 Energy Output by Fuel Type

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4 Ontario’s natural gas fleet is largely connected on the transmission system.

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Ontario benefits from a diverse resource mix, contributing to reliability under a wide range of weather and operating conditions. No single resource type provides all of the essential reliability services. Different resources provide different services, and the portfolio works together to provide a resilient and flexible system, as shown in Tables X and Y.

Table X | Reliability Services Provided by Non-Intermittent Emissions-Free Resources

<table>
<thead>
<tr>
<th>Reliability Services</th>
<th>Non-Intermittent Emissions-Free Resources</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Nuclear</td>
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<tr>
<td>Capacity</td>
<td></td>
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<tr>
<td>Energy</td>
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<tr>
<td>Flexibility</td>
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<td>Operating Reserve</td>
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<td>Voltage Control</td>
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<td>Local Security</td>
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</tbody>
</table>
There are multiple pathways to removing CO₂ emissions from the electricity system for the future. However, these options must be commercially feasible, scalable and cost effective in the near term. The IESO has been engaged in enabling new types of resources for a number of years and is working to explore the potential of emerging technologies. While these resources are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability. In considering phasing out gas, the province will require resources that have similar characteristics and services, individually or in aggregate. As new emerging technologies commercialize and performance becomes better understood, these will be incorporated into future outlooks. This section will outline candidate options for the replacement resource mix.

### Energy Efficiency

Through the delivery of programs, training and other mechanisms, the province is able to cost-effectively meet its electricity system needs that enables Ontario’s electricity consumers to improve the energy efficiency of their homes, businesses, institutions and industrial facilities. The IESO recognizes that energy efficiency programs provide continued opportunities for electricity consumers to save on energy costs.

In 2019, the IESO completed the first integrated electricity and natural gas conservation Achievable Potential Study (APS). The APS identifies and quantifies energy and demand savings, greenhouse gas (GHG) emissions reduction, and associated costs from energy efficiency measures for the period of 2019-2038. Four achievable potential scenarios from the APS were made available to the model with seasonal energy and capacity reductions and annual program costs.\(^5\)

### Demand Response

\(^5\) The APS identified cost effective potential for energy efficiency based on previous avoided energy and capacity costs. Under scenarios considering gas phase out, the avoided capacity and energy costs would likely be higher.
Demand Response (DR) – that is when consumers reduce their electricity consumption in response to prices and system needs - is playing an increasing role in Ontario's electricity system. DR resources can reduce their electricity consumption when wholesale prices are high or the reliability of the grid is threatened, receiving payments for the reductions they make. DR has already had a significant impact on energy demand and helped reduce peaks, providing a valuable and cost-effective resource to the system.

This study assumes an upper limit of 2,000 MW of incremental DR capacity, which is consistent with a similar modeling exercise performed for the 2016 Ontario Planning Outlook. Including currently contracted DR, this is equivalent to roughly 10% of peak demand.

Wind, Solar and Energy Storage

There are various forms of renewable energy, including energy generated from the wind and sun. The fuel availability for wind and solar generation is reliant on the weather, time of the year and time of the day. Solar generation is particularly important in the summer months when peak demands occur midday as solar panels reach their height of production. Wind production is usually greatest during cold winter months and at night, but can vary depending on geography and the time of year, making it a suitable complement to solar generation.

Emerging energy storage technologies allow electricity to be captured and stored and then re-injected back into the grid when it is required. Energy storage technologies vary considerably in terms of their size and scale, how the energy is stored, how long it can be stored and the technology’s response time. The IESO is exploring how to leverage energy storage in conjunction with renewables in order to maximize the contribution variable generation makes to the system. However, due to the variable and uncertain nature of variable resources (e.g. wind resources are inherently variable minute-to-minute and hour-to-hour and can lead to forecast errors), this poses greater challenges for energy storage to smooth variable generation in order to mimic the consistency of gas.

In addition to these challenges, solar, wind, battery storage and applicable hybrids are inverter-based resources (“IBRs”), which add complexity to grid reliability. Some IBR performance issues have been significant in recent grid disturbances, such as the tripping of a number of BPS-connected solar PV generators that occurred during the 2016 Blue Cut Fire, 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California. External jurisdictions, such as California, are gaining experience with large penetrations of distributed IBRs. Recent events have highlighted the need to understand the volume of these resources that will trip coincidentally due to faults on the power system. While controller technology used in IBRs may be able to provide frequency response, they are currently in the piloting stage. There would also be a requirement for IBRs providing this service to hold back energy output that may otherwise be available so that it can respond to an under-frequency event by injecting that available energy it was otherwise holding back.

Hydro-electric

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Hydropower is another renewable source of energy produced by the falling or moving of water. It is a major contributor to Ontario’s supply mix, both as a form of baseload generation and during times of peak demand. Hydroelectric generation does provide load following capability when it can, but its output depends on water availability, including environmental restrictions and cascading river system impacts.

**Nuclear - Small Modular Reactors**

Small Modular Reactors (SMRs), like current nuclear reactors, are designed to provide reliable, carbon-free electricity, but with a much smaller land footprint than current reactors. Smaller plants mean they are more flexible and can be deployed not only in large established grids but also in smaller grids, remote off grid communities and for resource projects. Their designs and features mean they cannot only provide baseload generation but their ability to load follow means they can support intermittent renewable sources like wind and solar.

Consistent with the project scope details provided in the June 2021 stakeholder engagement session, candidate options include the proposed 300 MW SMR at Ontario Power Generation’s Darlington nuclear facility.

**Hydro-Québec Firm Imports**

Ontario trades with Québec on the open market on a non-firm basis. In 2016, the IESO and Hydro-Québec (HQ), executed a series of agreements to facilitate electricity trade between the two provinces. The electricity trade agreement includes electricity purchases whereby each year the IESO is entitled to purchase 2 TWh of electricity from HQ at a set contract price, electricity cycling whereby the IESO will export up to a contracted amount of electricity to HQ, and capacity sales. The electricity trade agreements with HQ are set to expire December 31, 2023, and it is assumed that these particular agreements are not extended in the study.

Imports from Québec are an option to replace gas generation. However, the extent HQ imports can contribute to reducing GHG emissions will depend on many factors including generation capacity and energy availability in the Québec system, the negotiated price and the transmission path availability between Québec and Ontario. Québec has large water storage capability and is projected to have surpluses of energy for many decades; however, their capacity availability is far more constrained. Québec is a winter peaking system and exports are often curtailed during winter peaks. With the appropriate transmission upgrades, this analysis assumes that Québec can supply summer and winter capacity up to 3,300 MW.

**Distributed Energy Resources**

The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (e.g. Distributed Energy Resources) to help address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

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6 Québec experiences capacity shortfalls in the winter due to use of electricity for heating
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Hydrogen

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. It is light, storable, energy-dense, and when hydrogen is consumed, it produces no direct emissions of pollutants or GHGs. There are no known hydrogen reserves from which the fuel could be mined, instead, hydrogen is typically produced from a fossil fuel, or by using electricity to split water into its component molecules of hydrogen and oxygen (known as green hydrogen). Depending on how the hydrogen is produced, there could be significant GHG impacts (e.g. producing hydrogen from fossil fuels).

Hydrogen is one of the leading options for storing renewable energy, and could also enable long-term (e.g., inter-seasonal) energy storage. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines.

While hydrogen may provide a potential solution to remove emissions in the longer term, the IESO did not consider it while developing the resource supply mix. In the near-term, large-scale green hydrogen production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may come down significantly in the future and could make hydrogen more competitive in the longer-term, but this will likely occur past the 2030 timeframe considered in this study.

Carbon Capture Utilization and Storage

Carbon Capture Utilization and Storage (CCUS) solutions will also be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long-distance high-pressure pipelines to transport CO\textsubscript{2} to storage sites will require further investigation to avoid siting and regulatory challenges.

Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario. It is also currently costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the resource supply mix.

Green/Renewable Natural Gas

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Renewable Natural Gas (RNG) is methane captured from organic waste at landfills, livestock operations, farms, and sewage treatment facilities. RNG offers decarbonization benefits through the removal of carbon-heavy streams from the environment (i.e. methane leaking into the atmosphere from sources such as livestock and landfills), where the end product is a carbon-free RNG that can displace conventional natural gas. RNG is interchangeable with conventional natural gas and can be injected into the natural gas distribution system. Like conventional natural gas, RNG can be used as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). It can thus be used to fuel natural gas vehicles/transit fleets, power industry and residential heating.

RNG can play an important role in Ontario’s clean energy future, however questions have been raised about how much RNG can be produced from biomass and at what cost. Since the debate continues on the scalability and economics of RNG production, the IESO did not consider it while developing the resource supply mix.

Candidate Options

Based on the need for replacement resources to be commercially feasible, scalable and cost effective in the near term, a number of candidate options have identified. Cost and performance assumptions have been summarized in Table X below:

<table>
<thead>
<tr>
<th>Resource</th>
<th>Levelized Unit Energy Cost ($2021/MWh)</th>
<th>Capacity Cost ($2021/kW-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td>39%</td>
<td></td>
<td>Cost projection based on average of industry capital cost projections’</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td>17%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
<tr>
<td>Hydro-electric</td>
<td>Cost Curve</td>
<td>50%</td>
<td></td>
<td>Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs.</td>
</tr>
<tr>
<td>SMRs</td>
<td>NA</td>
<td>85%</td>
<td></td>
<td>A 300 MW SMR was included as a base assumption. As such, it was not included in the calculation of incremental cost.</td>
</tr>
<tr>
<td>HQ Firm Imports</td>
<td>Average import price from energy runs</td>
<td>135</td>
<td>Variable</td>
<td></td>
</tr>
<tr>
<td>Energy</td>
<td>Four achievable potential scenarios from the 2019 APS</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

7 Projection Sources: Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), International Energy Agency (IEA), Lazard, & Center for Advancement through Technological Integration (CEATI)

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| Efficiency | DR | NA | 67 | NA | Cost based on recent capacity auctions. |

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Scope of Study

The scenarios in this study considers the reliability, cost and wholesale market impacts, timing and basic operability implications to the electricity system. The scenarios in this study did not consider higher demand due to an increase in electrification or how emissions in other jurisdictions may be affected in the future.

Areas of Study Considered

The three scenarios were examined from various lenses, including areas of reliability, costs, wholesale market impacts, operability and timing to the electricity system, as shown in Table 2.

Table 2 | Areas of Study

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>Considerations for locational requirements for siting resources, or</td>
</tr>
<tr>
<td></td>
<td>transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>Ancillary services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale</td>
<td>Least cost replacement resource portfolio</td>
</tr>
<tr>
<td>Market</td>
<td>Potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>Use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>Impact on wholesale market pricing and how market value of system needs</td>
</tr>
<tr>
<td></td>
<td>may change</td>
</tr>
<tr>
<td>Operability&lt;sup&gt;8&lt;/sup&gt;</td>
<td>Basic Operability: capacity, energy, operating reserve, ramping</td>
</tr>
<tr>
<td></td>
<td>requirements, load following capability</td>
</tr>
<tr>
<td>Timing</td>
<td>Typical timelines associated with construction of generation or</td>
</tr>
<tr>
<td></td>
<td>transmission</td>
</tr>
</tbody>
</table>

Areas of Study Not Considered

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses.

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<sup>8</sup> Model portfolios were developed at an aggregate level, to determine the rough cost implications. Detailed locational information would need to be developed before a detailed operability assessment could be completed.

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that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price were not considered as part of this study, impacts of electrification on demand will be considered in the 2021 APO and future APOs.

Ontario imports energy from and exports to its five neighbouring jurisdictions every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions target, so will our neighbours. Neighboring jurisdictions are evolving and policy changes are underway in the United States as they develop their own pathways to lowering emissions. However, these policies have not been finalized and to avoid speculative policy decisions (e.g. carbon pricing in other regions, future resource supply mixes in other regions, etc.) this study did not consider how emissions in other jurisdictions may be affected in the future. This study will assume the Eastern Interconnection as is from the 2020 APO Scenario 1 for the duration of the study period. The emissions forecast for this study will also consider Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

**Study Assumptions and Limitations**

A resource portfolio was developed to understand the high-level electricity system impacts of replacing natural gas-fired generation. This portfolio was designed to meet basic capacity and energy adequacy requirements (seasonal capacity and hourly energy) in a cost-effective manner, ignoring more complex technical analytics and implementation practicality that would otherwise be required of a detailed power system plan. If directed to pursue natural gas-fired generation replacement further, a more rigorous analysis would be required, including the development of tools that better incorporate real-time market dynamics in the portfolio building process. In particular, most commercially available tools have modelling limitations in respect of newer resources, such as storage, as these resources were not contemplated at the time they were developed.

Table XX below lists a number of optimistic technical and practical assumptions made to facilitate the study:

<table>
<thead>
<tr>
<th>Category</th>
<th>Assumption</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage</td>
<td>Large-scale energy storage can be completely operationalized.</td>
<td>IESO has limited experience with candidate storage technologies, pumped hydro aside.</td>
</tr>
<tr>
<td>Storage</td>
<td>Storage is simplistically modelled to provide capacity, load following and ancillary services.</td>
<td>Modelling limitations raise questions as to whether storage can provide the full suite of these services, especially during periods of consistently high demand, weather-limited fuel supply or</td>
</tr>
</tbody>
</table>

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| **Nuclear** | 300MW of small modular nuclear reactors will reach in-service by 2030 at Darlington NGS. | A 300 MW SMR has been included as a base assumption. |
| **Market Interface** | IESO will have increased visibility and dispatchability of incremental resources on distribution systems. | IESO systems to be upgraded to allow for continuous monitoring, dispatch, and contingency analysis. |
| **Operability** | Resource siting does not result in operability challenges – local or global – and all requirements for load following, voltage support, frequency response, etc. can be met. | To fully assess potential operability challenges, detailed information on size, location, and operating characteristics of the replacement fleet would be required. |
| **Land-Use** | The study assumes that resources are sited where needed, even with the large volume of renewables contemplated in the resource portfolio. | A near doubling of the transmission-connected wind and solar fleet may require off-shore wind, currently delayed by an Ontario moratorium. |
| **Transmission Planning** | The resource portfolio is assumed to leverage the existing transmission system, to the extent possible, but upgrades are needed to enable resources in the North, increase imports from Québec, and add to GTA supply. | A proper Transmission Planning exercise is required, and would take 12 to 18 months. |
| **Policy** | Enabling policies are in place to support increased energy efficiency and the fast-tracking of permitting and construction to enable siting of resources in key electrical areas. | Any change in policy, for or against the replacement of natural gas-fired generation, will take time, and may sway with changes in government. |
Scenario Development

To be filled.

Base Case

This study leverages the 2020 APO Scenario 1 as the underlying base case. This forecast assumed a shallow recession due to the global pandemic, followed by a rapid return to pre-pandemic demand levels. The 2020 APO Scenario 1 projects net energy demand to be 141 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period. By 2030, net energy demand is expected to reach 159 TWh. Summer peak demand is projected to be 25.5 GW and winter peak demand to be 24.6 GW by 2030.

In the 2020 APO, the total installed capacity of the supply mix, reflecting continued availability of existing resources following the end of their contract term or commitment, is expected to be 38 GW by 2030 as shown in Figure 4. Total energy efficiency program savings is also expected to be about 12 TWh by 2030.

Figure 4 | 2020 Annual Planning Outlook, 2030 Installed Capacity (GW)

The carbon pricing assumptions used are $50/tonne\(^9\) starting 2022 (held constant thereafter) and a benchmark emissions rate of 370 tonnes CO\(_2\)/GWh allowance for existing natural gas generation.

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\(^9\) This assumption was based on IESO's understanding of carbon pricing at the time and aligns with the forecast as discussed under Current Government Emissions Policy and Emissions Targets.
As outlined in the 2020 APO, the electricity sector emissions are forecast to increase to 12.2 megatonnes CO$_2$ by 2030, still well below 2005 levels, shown in Figure 5.

This expected increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the 2020 APO assumes that existing natural gas will fill in system energy needs. As electricity consumption increases, the rise in electricity sector emissions could be partially reduced, factoring in requirements to maintain system reliability, by increased energy efficiency and non-emitting resources in the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy change.

**Potential Pathways**

This study examines potential pathways to lower emissions through a complete gas phase out (**Scenario 1**) and maintaining emissions at current levels (**Scenarios 2 and 3**), as illustrated in Error: Reference source not foundError: Reference source not found. The current emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^{10}\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 Mt CO$_2$ per year. The purpose of developing these Scenarios was not to create estimates of likely outcomes, but to allow the IESO to provide insights gleaned from the range of potential pathways. These scenarios were also informed by the multitude of input from the public webinar, stakeholders and communities' feedback – written feedback can be found on the IESO [website](#).

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10 2017 was a lower than expected demand year, and as a result, emissions were lower as the gas fleet operated less.

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Figure 6 | Pathway Description

<table>
<thead>
<tr>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply mix-based approach that examines a portfolio of replacement resources assuming all existing gas is phased out by 2030</td>
<td>Market-based approach with increased carbon cost and decreased benchmark</td>
<td>Supply mix-based approach that examines a portfolio of replacement resources assuming existing gas is available to compete with other resources</td>
</tr>
</tbody>
</table>

Modeling Approach

**Scenario 1** and **Scenario 3** use a supply mix-based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliable system in Ontario. Increased shares from any one type of replacement resource comes with risks since no single option can meet all system needs at all times. A diverse supply mix will help manage both the operational and cost risk of the changing supply mix. The supply mix-based approach considered demand-side and supply-side options. Scenario 2 maintains all of the supply mix assumptions from the APO 2020, but considers updated carbon policy to drive GHG reductions through a market-based approach.

The supply mixed-based approach for Scenarios 1 and 3 determined a replacement supply mix incremental to the existing resource fleet. In Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. In Scenario 3, all existing resources including natural gas are assumed to remain in service.

In considering the candidate options, the study considered possible replacement technologies that are sufficiently mature today. As the reliability and planning coordinator, a principle applied to the study was to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This consideration also provided more certainty on the cost estimates of the replacement supply mix. It is difficult to predict technological innovations, policy developments, and grid evolutions that could manifest in the study time frame – factors that could result in alternate supply mixes. The IESO aimed to provide a set of reasonable and forward-looking cost estimates, given professional judgement and the current information available. The study also considered, to the extent possible, the transmission investments required for increased intra-jurisdictional trading. However, the costs associated to make the replacement supply mix operable within the power system and the necessary transmission upgrades were not included.

Supply mixes were constructed using a least-cost optimization capacity expansion model that selected resource build-out over a 20-year period subject to a number of parameters. All resource portfolios were required to at least meet the total capacity contribution equal to summer and winter peak demand plus reserve margin; total annual energy demand, accounting for imports and exports;
and annual CO₂ emissions target. It is important to note that certain physical or other practical constraints (e.g. availability of suitable land-use, non-CO₂ environmental impacts, societal acceptance of the replacement technology, among others) were not considered in this least-cost optimization capacity expansion model. And so, the outcome of such a model does not imply technical or physical feasibility.

Cost and performance assumptions for each option considered are provided in Table 2. Transmission cost assumptions associated with some of the resources from Table 1 are provided in Table 3. It is difficult to determine the required transmission investments without knowing where new generation would be located. For instance, it is recognized that much of the accessible locations in the transmission system to incorporate wind generation have already been developed to connect the existing wind generation fleet. Investments in the interconnection facilities with neighbouring jurisdictions will need jointly developed. A portfolio analysis was performed without considering any transmission costs or costs associated with ensuring an operable power system (e.g. tool upgrades, market structure changes, among others). This sensitivity demonstrated that the cost-optimized replacement supply mix is not very sensitive to transmission costs. The actual extent of the impact of transmission costs cannot be known until full details for implementation are considered. Such determination would require much more extensive consideration and collaboration with generation developers, which cannot be completed within the timelines for this report.

### Table 3 | Transmission Assumptions for Scenarios 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2021M)</th>
<th>O&amp;M Cost ($2021M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1,500 MW of additional wind and solar capacity.</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 2,050 MW)</td>
<td>300</td>
<td>3</td>
<td>Based on preliminary consideration of increasing firm interconnection capacity with Québec.</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 3,300 MW)</td>
<td>1,500</td>
<td>15</td>
<td></td>
</tr>
</tbody>
</table>

Supply mix portfolios are modeled seasonally (summer and winter) over 20 years. In each season, the supply mix portfolios are compared to the necessary capacity, energy and emissions requirements referenced above. Hourly modeling in a multi-year capacity expansion optimization model was considered impractical given processing constraints. The purpose of the seasonal capacity expansion model is to develop supply mix portfolios with the approximate amount of capacity and energy to meet system needs. The supply portfolios were followed by an assessment using an hourly energy dispatch model to determine whether the portfolio could meet energy requirements in all hours. Other feasibility assessments were also performed, such as assessing the required storage duration and the frequency with which DR was activated.

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Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future. The resulting portfolios developed using the least-cost optimization capacity expansion model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path and do not directly imply technical or physical feasibility. Notably, the results are heavily influenced by the relative cost assumptions which are likely to change over time. The results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while meeting capacity and energy requirements.

An economic hourly dispatch model was used to determine the outcomes of the three scenarios. This assessment simulates the Ontario electricity market through a production-cost simulator to inform energy production, imports and exports, system costs, and emissions. While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Base Case to understand which factors are the largest drivers of ratepayer costs. Error: Reference source not found illustrates the modelling approach for the three scenarios.

**Figure 7 | Modelling Approach for Scenarios 1, 2 and 3**

- **Supply Mix-Based Approach**
  - Scenario 1 and 3
    - Resource portfolio least-cost optimizer that meets reliability and emissions requirements
    - Test portfolio on storage, ramping, transmission and market impacts

- **Market-Based Approach**
  - Scenario 2
    - Increase carbon cost and decrease carbon benchmark for all gas generators
    - Simulate in economic hourly dispatch model

- **Informed By**
  - Input from stakeholders and communities
  - IESO’s 2020 Annual Planning Outlook Scenario 1 (Base Case)

**Considerations for Phasing Out Natural Gas in the Electricity System | Public**
Study Findings

To be filled.

The study examined 3 scenarios as described. The balance of this report focuses on Scenario 1 (impacts upon cost and reliability of complete phase-out of gas generation in Ontario by 2030), as it has the most conclusive results and directly responds to the resolutions passed by municipalities.

Scenario 2 examined the impact of raising the cost of carbon, while Scenario 3 examined a resource-mix approach to holding emissions at 2016-2020 levels. In both cases, significant cost increases were observed without material emissions reductions. The preliminary results for these scenarios do not fully capture likely import/export results due to evolving US carbon policy. The two scenarios were not developed further, as they do not add sufficient value to this study.

Scenario 1 examines a portfolio of replacement resources assuming all existing gas is phased out by 2030. The incremental supply above the Base Case required to completely replace natural gas generation by 2030 is about 17,000 MW, as shown in Figure 8. In addition to this supply, Energy Efficiency Scenario B of peak 1,600 MW savings from the Available Potential Study (APS) is also included as part of the lowest-cost resource mix (not shown in the figure).

Figure 8 | 2030 Incremental Installed Capacity, Scenario 1
The incremental nuclear, wind and solar capacity produce less annual energy (19 TWh) than the natural gas energy (31 TWh) was forecast to produce in 2030 in the 2020 APO. The remaining energy gap is made up by energy efficiency (9 TWh) and imports, firm and economic. Storage and DR are required to replace the capacity currently provided by natural gas as well as the incremental capacity gap identified in the 2020 APO. Storage and DR also help balance periods of high baseload generation and periods of insufficient supply. From the candidate options, new hydroelectric capacity was not selected by the capacity expansion model due to likelihood of completing construction by 2030, and the high assumed costs associated with new build hydroelectric generation.

This portfolio of resources, along with the assumptions presented, satisfied the high-level reliability requirements of the capacity expansion model. This portfolio was then simulated in IESO’s hourly energy dispatch model to determine if this mix would be able to reliably supply all energy needs when considering hourly market dynamics. This portfolio resulted in approximately 500 GWh of unserved energy; which amounts to about a day and half worth of all electricity consumed in the province. From a high level, the assumed portfolio does provide enough capacity and energy to meet system needs, however, it lacks the ability to deliver the energy precisely when it is needed – the flexibility requirement. To increase flexibility, the reservoir size of the storage fleet was increased until all energy needs were met. The initial portfolio assumed the storage fleet had 4 hours of maximum output when fully charged, however; this post-processing exercise indicated that far more storage would be needed to be able to satisfy the energy needs, as shown in Figure 9. The ability to re-charge storage devices during multi-day high demand events (e.g. summer heat waves) was not considered.

Figure 9 | Hours of Storage Required compared to Percent of Unserved Energy Now Served
The post-processing exercise was able to optimize the 4-hour storage fleet further to help reduce an additional 36% of the unserved energy, but as can be seen from the figure, to fill 100% of the energy gap, volumes of the storage fleet would need up to 47 hours of storage. The above storage fleet with 4 hours of storage translates to an installed storage reservoir size of about 25 GWh. To serve the entire need in the hourly dynamic energy model, a reservoir size of closer to 300 GWh is needed. For context, the largest pumped-hydro storage projects being proposed in Ontario today are all under 10 GWh, however there are not enough potential sites in Ontario to provide 300 GWh of storage with pumped hydro alone. Batteries might be able to contribute as well, however, even the largest manufacturing plant in North America, Tesla’s Gigafactory, is only able to produce 20 GWh of storage per year.

This scenario also relies heavily on using DR as a peaking resource. From a high level, the amount of energy requested of the incremental DR fleet of 2000 MW, and assuming a 4 hour activation limit, is the equivalent of about 193 activations per year, or a capacity factor of approximately 9%. In addition, to help reduce the energy not served in the hourly dispatch model, the 4 hour activation limit on DR was not modelled, meaning that there were some activations where the model assumed DR was activated for tens of hours continuously. This type of operation greatly diverges from how today’s DR product operates and it may not be practical to assume that this level of service could be provided by this resource type.

The complete phase-out of gas by 2030 with replacement by the above mix would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy market prices, along with increased volatility. Overall system cost, however, would increase as a result of building new renewables; these resources would likely have the effect of lowering energy market prices while increasing capacity costs and potentially the cost of ancillary services. At the same time, storage resources tend to offer in the ancillary services markets, and the large build-out of storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later in the Appendix B under the Wholesale Market Impacts.

Besides those energy efficiency savings considered in the 2020 APO, there are potential opportunities to achieve greater electricity savings as identified in the APS. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentive levels. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the Base Case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

Ontario regularly trades electricity with neighbouring jurisdictions. There is hydroelectric capacity potential from Manitoba and Québec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres would be required. This would have significant cost implications. Determining the right balance between self-sufficiency and reliance on imports would require consideration by policy makers.
The capital investment required for the replacement resource mix is about $27 Billion. When considered in the form of commercial revenue requirements over the lives of the resources, and adding operating costs, this translates to an annual cost of electricity service increase of $5.7 Billion. This 20% increase is the cost of removing 12.2 Mega tonnes of CO$_2$e per year, or in terms of an emissions reduction rate, $464$/tonne CO$_2$e.

The impact on residential customers is both important and significant. Since fixed costs have increased, Global Adjustment (GA) will increase, but there will also be an overall shift in cost recovery from market revenues to GA. This is driven by the addition of low marginal cost resources, which will decrease market clearing prices and market compensation. Since Class B customers (residential) pick-up the majority of GA due to the ICI program, the overall result is a 60% increase in monthly residential bills, or an additional $100/month.

**Table X: Summary of Electricity System Cost and Residential Customer Impacts**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Overnight Capital Cost ($B)</th>
<th>2030 Cost of Electricity Service ($ B)</th>
<th>2030 Greenhouse Gas Emissions (MT CO$_2$e)</th>
<th>2030 Cost of Carbon Reduced ($/tonne CO$_2$e)</th>
<th>2030 Residential Bill for 750 kWh ($/Month)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020 APO Base Case</td>
<td>--</td>
<td>26</td>
<td>12.2</td>
<td>--</td>
<td>163.40</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>27</td>
<td>32</td>
<td>0</td>
<td>464</td>
<td>260.94</td>
</tr>
</tbody>
</table>
Steps and Challenges to Implementation

Generators termination for existing gas contract will result in financial and reputational impacts to the electricity industry. Ratepayers will also be further negatively impacted by stranding the natural gas assets and reducing competition by eliminating this supply option.

Large scale non-carbon emitting resources can pose several practical challenges, such as, land use, siting and location. Also with renewables located away from urban load centers major transmission infrastructure costs will be required in x billion range and will require 7 to 10 years to plan and implement.

Wholesale Market Impacts of installing non-carbon emitting resources with low to zero marginal cost resources will influence price signals seen across the electricity system in Ontario that will also change import and export flows.

Developing a Transmission Plan

The ability of supply resources to meet demand across the province, and potentially other jurisdictions, relies on the transmission system to transport electricity to where it is needed. Within Ontario, bulk transmission interfaces form the boundaries of the 10 IESO electrical zones. The primary purpose of these interfaces is to describe power flows across the system and associated phenomenon which may limit these transfers. The bulk transmission system is also used to import power from, or export power to, neighbouring jurisdictions through a series of interties at specific points on the Ontario border. The maximum amount of power that these interfaces and interties can deliver is known as their transfer capability, which reflects constraints to ensure system stability, voltage performance, and acceptable thermal loading. Interface transfer capabilities are used in resource adequacy and transmission security assessments. Resource adequacy assessments are probabilistic studies that consider interface transfer capabilities with transmission facilities in-service, on planned outage, or following a limiting contingency event (a sudden or unplanned outage). Transmission security assessments are deterministic studies conducted at the zonal level that consider various transmission system disturbances, as defined according to applicable regulatory obligations. Zonal adequacy or security assessments may be more restrictive than resource adequacy assessments depending on the characteristics of the zone(s) being investigated. Intertie transfer capabilities are treated as interfaces in reliability assessments, and provide a number of system benefits, including: stability, frequency support and voltage support following a contingency, and the opportunity to consider imports and exports to manage resource needs where cost-effective.
As stated under Modeling Approach, the least-cost resource optimization for Scenario 1 did not consider locational or siting-related matters, and as such, corresponding detailed Transmission Plans could not be developed. However, the IESO can draw upon experience from past transmission planning initiatives, and is able to comment on the potential scope of a Transmission Plan to reduce reliance on natural gas generation. The development of a Transmission Plan would consider the need to relieve constraints in order to deliver replacement resources, as well as the needs that would emerge if strategically located natural gas plants are retired. The following describes the potential scope in order to communicate the magnitude of potential reinforcement, the magnitude of potential cost impacts, and comment on the expected time necessary to plan, develop and implement reinforcements of such scope.

Note that this section is not intended to communicate a Transmission Plan. A Transmission Plan would require a proper planning exercise, executed with sufficiently detailed information regarding replacement resource siting, and including a thorough reliability assessment and a robust engagement with Indigenous communities, municipalities, and other stakeholders.

**Delivering the Replacement Resource Mix**

Of the 11,000 MW of installed natural gas-fired generation, a large portion is located in or around the Greater Toronto Area (GTA), with the balance primarily in western Ontario. When considering resource mixes, it may not be practical to site some resources in large urban/suburban areas given expected land-use requirements (e.g., wind) or the origin of the resource (i.e., firm imports). This would imply that the retirement or reduced reliance on these natural gas plants would create a net requirement to transport power into the GTA and other load centres, as compared to Ontario’s current electricity system.

**Figure 10 | IESO Electrical Zones and Transmission Reinforcements**
Northern Ontario Reinforcement (1, 2, 3)

The ability to deliver supply resources from northern Ontario towards the GTA and surrounding areas can be limiting for the existing system (as referenced in the 2020 APO), and siting a portion of replacement resources in northern Ontario would significantly worsen the impact of this constraint. In general, and following the reinforcement of the East-West Tie, there are three limiting paths to deliver supply resources from northern Ontario:

1. West of Sudbury
2. North of Sudbury
3. The North-South Tie

The West of Sudbury portion of the system, specifically the Mississagi East interface, is expected to be the next limiting east-west path for bulk power transfers following the reinforcement of the East-West Tie, and is centred in the greater Sault Ste. Marie area. This part of the system is a focus area for the IESO’s Northeast Bulk Plan. Depending on the magnitude of resources sited west of Sudbury, a reinforcement of this part of the transmission system could be addressed by a multi-circuit 230 kV line, or a new 500 kV line, extending from as far as Wawa TS to Hanmer TS (Sudbury area), a range of ~400 km. A reinforcement of this magnitude is expected to cost on the order of between $500 million and $1 billion, and take 7-10 years to fully plan, develop and implement.

The North of Sudbury portion of the system, specifically the 500 kV interface (D501P and the P502X-South), is expected to be a limiting north-south path for bulk power transfers from the northern parts of northeast Ontario. This 500 kV path, and its underlying 230 kV and 115 kV paths, generally extends from Pinard and the greater Kapuskasing area south to Timmins at Porcupine TS and the surrounding areas of Ansonville and Kirkland Lake. Depending on the magnitude of resources sited north of Sudbury, a reinforcement of this part of the transmission system could be addressed by a new 500 kV line paralleling the existing 500 kV system from Sudbury to Pinard via Porcupine, as well as potentially introducing a 230 kV underlaying system. A reinforcement of this magnitude is expected to cost on the order of $1 billion, and take 7-10 years to fully plan, develop and implement.

The North-South Tie is the 500 kV and 230 kV interface that supply resources from the north would have to flow through to get to the south at Essa TS in Barrie. Depending on the magnitude of resources sited in northern Ontario, a reinforcement of this part of the transmission system could be addressed by a new 500 kV single or multi-circuit line paralleling the existing 500 kV line, as well as a reinforcement to the 230 kV system emanating from Essa TS, as studies show that the 230 kV system can become thermally limiting with significant 500 kV injections at Essa. Reinforcements of this magnitude are expected to cost on the order of $1 billion, and take 7-10 years to fully plan, develop and implement.

A significant amount of voltage control devices would also be likely, particularly to control overvoltages at times when the system is lightly loaded, given the extent of new transmission lines that may be required.

The reinforcement scope indicated for North of Sudbury and the North-South Tie could also warrant consideration of introducing a new HVdc network to Ontario.
Flow East Towards Toronto Stage 2 (4)

The IESO has recommended an initial reinforcement to the Flow East Towards Toronto ("FETT") interface, which is the primary flow gate that transfers power from western Ontario to Toronto and eastern Ontario. Depending on the magnitude of resources sited west of the FETT interface, further stages of reinforcement to the FETT interface could consist of new 230 kV transmission circuits in the western GTA, namely Brampton, Mississauga and Oakville; a new 500/230 kV autotransformer station at the existing Milton SS; and/or a new 500/230 kV autotransformer station near Kleinburg. Reinforcements of this magnitude could cost on the order of between $300 million and $500 million, and take 3-7 years to fully plan, develop and implement, depending on the scope of the reinforcement required.

Eastern Ontario Reinforcement (5)

In order to accommodate 3,300 MW of non-emitting firm imports under Scenario 1, and assuming that such amounts are available and economic, a reinforcement to the Ontario-Quebec intertie facilities may be within scope of potential transmission enhancements. To that end, much of the information in the 2014 “Review of Ontario Interties” report and the 2017 “Ontario-Quebec Interconnection Capability” report remain indicative of the scope of reinforcement. This may include doubling the Outaouais HVdc interconnection, reinforcement of the 230 kV network between the Quebec boarder to Merivale (Ottawa area), Hawthorne (Ottawa area) and St. Lawrence, and may require reinforcement to the 500 kV system between Bowmanville and Cherrywood (in Pickering), depending on the development of resources in eastern GTA and eastern Ontario. Reinforcements of this magnitude could cost on the order of between $1 billion and $1.5 billion, and take between 7-10 years to fully plan, develop and implement, depending on the scope of the reinforcement required.

Maintaining Reliability Currently Provided by Strategically Located Gas Plants

Natural gas plants that were strategically located are critical to the supply reliability of several areas.

Central Toronto is primarily supplied by the Cherrywood – Leaside 230 kV corridor and Leaside TS, which is a 230/115 kV autotransformer station. Without support from Portlands GS, or equivalent local replacement capacity, a new corridor to Central Toronto may be required to prevent collapse and an unacceptable out-rush across our interties. Past plans, including the 2007 IPSP, envisioned the “Third Supply Plan” as lengthy transmission, potentially under Lake Ontario from Pickering, Darlington or Niagara Falls.

The western part of the GTA is primarily supplied by Trafalgar TS and Claireville 500/230 kV autotransformer stations. Retirement of Pickering NGS will increase autotransformer loading, but would still remain within the available capacity; however, without support from Goreway GS and Halton Hills GS, the 500/230 kV transformation capacity will likely be exceeded. The solution would be to convert Milton switching station to a 500/230 kV autotransformer station at a cost of about $200 million.
York Region is supplied by the 230 kV circuits between Claireville TS to the south, and Minden to the north, and York Energy Centre GS (“YEC”) plays a critical role in local reliability. A new transmission line between Buttonville and Newmarket was an alternative to the facility, but significant local opposition led to the local generation solution. Also, as demand in the area continues to grow, YEC’s role will remain critical. When the current supply capacity is no longer adequate (forecast 2030), additional generation and/or transmission will likely be required, even with YEC in service; however, without YEC or equivalent local generation, significantly more transmission infrastructure would likely be required. Reinforcements of this magnitude could cost on the order of several hundreds of millions of dollars above a resource mix that includes YEC, and would potentially require an additional new transmission corridor.

The West of Chatham area is experiencing significant load growth, primarily driven by the agricultural sector, with Brighton Beach GS, East Windsor GS and West Windsor GS playing a critical role in local reliability. Interim operating measures using local natural gas-fired generation are currently required while the first stage of transmission reinforcement is being implemented. Additional reinforcement is envisioned within the decade, and the existing local natural gas generation could still play a role in the solution along with transmission reinforcement and new local generation.

The Kirkland Lake area supports a large amount of demand in the mining sector, and this demand is expected to increase given the volume of new connection requests received by the IESO. Plans are underway to reinforce the 115 kV transmission grid between Ansonville and Kirkland Lake; however, this reinforcement envisioned some continued reliance on Kirkland Lake GS. Without support from Kirkland Lake GS or equivalent local replacement capacity, additional and significant reinforcement may be required.

As mentioned under The Role of Natural Gas, natural gas-fired generators provide dynamic reactive power that is critical in maintaining acceptable voltages during high demand periods. Reactive power cannot be transferred over long distances; thus replacement reactive power sources must be installed locally. Portland GS, Goreway GS, Halton Hills GS and YEC, provide a significant amount of reactive power capability, on the order of 1500 MVAR. Shunt capacitor banks cannot be used for this purpose as they do not provide the required dynamic reactive power. The cost of dynamic reactive power devices is high, in the order of $500M to $1B to address the reactive requirements currently provided by the GTA gas plants.

Lastly, and as also mentioned under The Role of Natural Gas, natural gas-fired generators provide frequency response. Of particular locational specific concern may be the design of Ontario’s Under-Frequency Load Shedding Program (UFLS) for the Central Island 11 in Toronto, as natural gas-fired generators are currently the only source of governor response (primary frequency response) in the area, and IESO’s 2018 UFLS study identified little margin compared with NERC and NPCC requirements.

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11 For additional information, see Section 11.3 of IESO Market Manual 7.1.

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Summary

In summary, the development and implementation of a Transmission Plan is expected to have tremendous scope, and may contemplate significant reinforcement to all levels of the transmission system, including the possible introduction of additional HVdc facilities. This reinforcement is expected to cost in the billions of dollars and may take over 10 years to complete the full scope, which suggests retirement of all natural gas generators by 2030 is infeasible. A detailed transmission planning exercise would be necessary to determine the full extent of reinforcements required, true cost estimates of these reinforcements, and when they could come into service, recognizing the immense logistical challenge of deploying so many large projects simultaneously while also executing normal maintenance programs.

Practical Considerations

Gas Generators Under Contract

Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners' needs to be included with the replacement costs to retire these generators prior to the end of their contract as identified in Scenario 1\(^\text{12}\). The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. However, the remaining contracted net revenue requirement is considered as an estimated cost minimum cost expectation.

Stranded Assets

The natural gas fleet has considerable economic life remaining. The majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, the average age of large natural-gas resources (e.g. resources greater than 150 MW) is 13 years. Stranded costs resulting from coal retirements were typically modest because many of the plants were built decades earlier and were nearing the end of their useful lives. Much of the gas fleet is relatively young, increasing the potential for stranded costs if widespread closures occur within the next decade. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

Land Use and Siting

Replacing gas resources with new large scale non-carbon emitting resources can pose a number of practical challenges in regards to land use, siting and location. Most economic and accessible hydroelectric sites have been developed; some potential is undeveloped, with a majority of it located along Ontario’s northern rivers (e.g. Abitibi and Moose rivers). Northern hydroelectric sites are generally remote, resulting in relatively higher construction costs, as well as requiring potentially significant transmission investments to connect them.

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\(^{12}\) Scenario 1 assumes $2.4 in Net Revenue Requirement payments for cancelled contracts; however, additional possible compensation associated with implications of being locked out of the market to participate or other types of potential negative implications are not quantified.

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Timing

Reductions in emissions through the addition of new non-carbon emitting resources and the accompanying transmission would not only require new investments, but also the associated time to develop the designs and the required specifications. This would require significant effort to identify appropriate sites and routes, to manage the extensive stakeholdering and consultation, and to manage the acquisitioning and building of these assets. The lead time of supply resources vary depending on the type of generation; the lead time of transmission assets can be at least seven to ten years. New technology and resource risks should recognize the uncertainty associated with construction completion and the longer lead times required to reach dependable operation. This transformation of the system would require detailed planning which is outside the scope of this study. Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of our generation capacity.

Market Impacts

The implementation of low to zero marginal cost renewable generation will drive down the market clearing price and result in changes to the flow of imports and exports. As discussed in Scenario 1 and 3 with the increase of renewable generation into the supply mix will result in lower marginal costs in Ontario relative to surrounding jurisdictions. The market dynamics of lower domestic prices will result increased export demand from Ontario generators thus driving up the dispatch of natural gas generators and Ontario’s carbon emission in Scenario 3 when natural gas is still available. In effect, impacting Ontario’s ability to stabilize emissions in Scenario 3 would require the implementation of a cap or moratorium on the natural gas production; thus, the current market mechanism could need to be reevaluated. A detailed wholesale market simulations analysis is provided in Appendix B – Wholesale Market Impacts, which discusses the change in the market flow and implications to energy prices, net exports, operating reserve prices, and curtailed energy.
Conclusion and Next Steps

For scenario #1, the IESO has modelled a 100 per cent emissions free supply mix to meet the 2030 timeline that in theory meets basic standards for reliability (capacity, energy, ramping). This supply mix posed challenges and required highly optimistic assumptions:

- Building and upgrading transmission and generation infrastructure, including environmental and local approvals, would take far longer than 8 years. Practical and regulatory challenges of building multiple reinforcements at the same time would likely be extremely challenging.
- The supply mix assumed year-round supply from Quebec. Quebec currently imports from other jurisdictions during winter and long-term reports indicate they will be below their reserve margins for capacity by 2030.
- New storage technologies are not currently proven at the scale required - without prudent testing and piloting, system reliably cannot be guaranteed in extreme conditions including protracted heat waves or cold snaps. The scenario #1 supply mix did not consider multi-day high demand conditions.
- The necessary number of demand response providers is unlikely. Modelling indicates that demand response would be activated almost 200 times per year.
- Expertise and equipment required for the proposed infrastructure expansion is limited and insufficient for this timeframe.

Although the model supply mix met basic reliability metrics, the optimistic assumptions would need to be addressed to ensure a reliable supply for the province. It is highly unlikely that this could be accomplished by 2030.
Appendices

Appendix B: Wholesale Market Impacts

Context

The wholesale market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of wholesale market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to new pricing patterns influenced by the characteristics of the replacement resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with the “Base Case” in which the gas fleet continues to operate.

The High Base-Load Case assumed that a fleet of somewhat inflexible resources is added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide intra-hour output flexibility or stand-by energy such as operating reserves. In contrast, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would be comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources that operate based on energy pricing arbitrage and operating reserve revenues, as well as capacity payments.

**High Base-Load Case**
- Limited flexibility
- Not energy-limited
- Operate near full capacity
- Low to zero short-run marginal costs

**High Capacity Case**
- Highly Flexible Mix
- Energy-limited / standby / intermittent resources
- Low to zero short-run marginal costs or arbitrage focused

Bookend Approaches
The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power market could be impacted if resource types with attributes on two opposite ends of a spectrum were utilized to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

**The High Base-Load Case**

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources have low marginal fuel costs and therefore would offer into the energy market at low to zero prices. Since these new base-load technologies replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy, meaning the availability of energy above that needed to meet the province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices as well as the potential for a greater frequency of surplus energy conditions in the High Base-Load Case, traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

**The High Capacity Case**

The High Capacity Case represents a contrasting set of outcomes to the High Base-Load Case. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, there is an increase in the number of times each year where energy prices are substantially elevated compared to the Base Case as standby resources set the price. As a result, high energy market prices for
these hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydroelectric availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Error: Reference source not found below. Only single illustrative prices have been shown below for clarity. The reader should note that real market impacts will extend more broadly to multiple locational prices following Market Renewal.

**Figure 11 | Illustrative Energy Prices versus Percentage of Time**

As shown in Figure 11, the High Capacity Case will see increasing price variability in both frequency and magnitude. This reflects the introduction of an increased fraction of variable renewables on the grid as a replacement for gas resources. In contrast, for the High Base-Load Case, prices will be broadly depressed and there will be less variability. While there is still some price variation that will be important for resources in the energy markets, the high degree of low marginal cost baseload generation on the system may make pursuing large revenue opportunities more challenging.

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Market Impacts

In both of the illustrative scenarios described above, Ontario’s markets provide important signals about the underlying conditions and needs of the electricity system. For the High Base-Load Case, the resource mix drives an overall reduction of energy prices but there are still some periods of relative surplus and scarcity (the tails in Figure 19), and therefore opportunities for price arbitrage for particular resources. There is also a corresponding premium in the operating reserve markets reflecting an increased need for flexibility given the high proportion of baseload resources. In the High Capacity Case, energy market prices can be highly volatile (especially the large tail in Figure 19), and these prices are an important signal for energy limited resources to store or supply energy. There is also an abundance of operating reserve available, broadly driving down operating reserve prices.

This high level picture masks a more complicated set of locational needs and impacts. In the future the IESO will introduce locational pricing across Ontario through the Market Renewal Program to ensure better alignment between system needs and dispatch. This will mean that energy market prices will be variable with a locational aspect. At a more granular level resources will then consider not only broad trends in electricity market pricing created by changes to the resource mix, but also highly locational system needs and variability in energy market prices in their land use and siting decisions. Where transmission constraints exist resources will be incentivized to locate and operate to respond to these highly locational signals, needs, and patterns of variability.

In any future resource scenario, the markets will continue to reflect the changing operational conditions on the electricity grid and will create incentives to respond to them. For example, when too much supply is available electricity prices will drop and resources who do not want to produce at low prices will be dispatched off. Similarly, for highly volatile conditions resources will be incentivized, and likely designed, to be able to ramp quickly to respond to these conditions. Other jurisdictions have introduced additional market products (e.g. ramping products) to reflect the evolving needs of an ever changing grid. The IESO will continue to monitor work in other jurisdictions where market evolutions are ongoing and will evolve the markets to meet Ontario’s needs in the future, including the impacts of potential policy measures such as of increased carbon pricing or directives to go off-gas.

The IESO is responsible for the reliability and security of Ontario’s electricity grid and for providing consumers with reliable power where and when they need it. For almost two decades and through several significant transitions in the sector the IESO has been achieving these goals through an open and transparent wholesale electricity market. With continuous improvements, the IESO expects this market to endure, providing a reliable and efficient dispatch of resources even as the resource mix and the broader sector evolves.
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Disclaimer

This document and the information contained herein is provided for informational purposes only. Although the IESO has sought to make this document useful and informative, on the basis of the best information available to the IESO at the time, the information remains subject to change, including as a result of the uncertainties identified herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.
Executive Summary

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Key Findings

The following key findings provide insights into the opportunities and challenges the sector has to consider under future pathways for lowered emissions.

E.g. To lower emissions by 2030 to 2016-2020 levels, it is expected to cost $X-Y billion, and these are the things that have to happen for that to work. These are the challenges expected for the three scenarios.

NTD: Some initial thoughts on my key takeaways so far (Dave D). Feel free to comment/edit/add.

We can refine as the costs come in:

- Our model portfolios were intended to help us understand the likely range of costs for the proposed shift from gas.
- We have done our best to produce portfolios that are technically feasible. The mixes that we have put forward have passed our coarse tests for reliability and operability, but should not be viewed as detailed power system plans. If we were directed to implement these supply mixes, we would need to devote significant effort to refining the mix, develop tools, and operationalize the plan.
- We believe that a 2030 date for gas phase out is extremely ambitious. To develop a feasible mix for this scenario, we have relied on a number of optimistic assumptions – both technical and practical:
  - Technical
    - Our mix assumes that large scale energy storage can be completely operationalized. At present, we have limited experience with the likely storage technologies, with the exception of pumped hydro. We believe that the storage we have modelled can provide capacity, load following and ancillary services. The limitations of our modelling raise questions about how we might address multi-day high demand events (e.g. heat wave or polar vortex).
    - We assume that a small modular nuclear reactor will be in service.
    - We assume that IESO would have full visibility of all resources on the distribution systems, and the ability to dispatch these resources. We assume that IESO systems would be upgraded to allow for continuous monitoring, dispatch, and contingency analysis.
    - We have assumed that we can leverage the existing transmission system as much as possible, siting non-emitting resources in zones to replace where gas exists today.
  - Practical:
    - Our portfolio includes a significant build-out of renewable resources. We have assumed that land use/siting is not an issue. To secure the volumes of renewables needed, off-shore wind may need to be considered.
    - We have not provided a detailed transmission plan, as the physical locations of new resources would need to be known first. We believe that it is reasonable to think that at a minimum significant upgrades are need to enable resources in the North, increase imports from Quebec, and add to supply for the GTA.
We would require a number of enabling policies to support increased energy efficiency, fast-track construction, enable siting of resources in key electrical areas.

- **Operability:**
  - Our portfolio does not have any locational details which would be required to assess its operability. Without generation in key locations, and full visibility and control of resources placed on the distribution system, the portfolio may be difficult to operate reliably.
  - Certain characteristics provided by the existing gas fleet such as inertial and frequency response, ancillary services and voltage support will need to be replaced for reliable operation.
  - The portfolio will also need to be dispatchable and provide the flexibility of operation our gas fleet provides to ensure operability during times, particularly when ramping capability is required.
Introduction

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Considerations for Phasing Out Natural Gas in the Electricity System | Public
Background and Context

Role of Natural Gas

The focus of this study will investigate the impacts that need to be addressed should the phase out of natural gas be considered. To achieve that, it is important to recognize the role that natural gas currently plays in the electricity system by way of illustrating the services it provides and the technical characteristics to understand what will need to be replaced by other options.

Ontario’s current gas-fired generation fleet is comprised of about 50 stations across the province. Today, gas installed capacity is about 11,000 MW, accounting for about 25% of total installed capacity, as shown in Figure 1, and represents about 7% of total energy in the province.

**Figure 1 | 2022 Installed Capacity by Fuel Type**

Natural gas-fired generation provides a number of services to the electricity system, including intermediate and peaking capacity and energy production capability. While gas has provided a much lower amount of energy in recent years, gas does provide value through the capacity it provides on high demand days. With Ontario’s significant level of variable and intermittent supply, gas can provide flexibility by filling in gaps to address short-term supply and demand variability. Along with their high ramp rates, once online, gas is capable of quickly ramping up and down in response to system conditions to maintain reliability of the grid and can provide sustained energy when needed as there are generally available at all times of the day. Gas provides load following capability to support operability and is a reliable provider of operating reserves, especially during spring freshet when fewer resources are capable of providing operating reserve. Gas generators support provincial transmission security and provides voltage stability. Additionally, they provide inertial-as-well-asfast frequency-dynamic response which aids in system recovery following a significant contingency in maintaining system frequency. Many gas plants are also strategically located near major demand centers to meet identified local reliability needs and continue to be relied on for provide local and regional reliability supply. As some gas plants were developed in lieu of major transmission upgrades in the area, should gas generation be phased out, additional transmission and reactive support may be required to deliver provincial capacity and may be required to support local load centres.

Electricity Emissions Projection in 2020 Annual Planning Outlook

As outlined in the 2020 Annual Planning Outlook (APO), the electricity sector emissions are forecast to increase to 12.2 megatonnes (Mt) CO₂ by 2030, still well below 2005 levels. This expected increase is due to reduced nuclear production as a result of nuclear refurbishment and retirements, and growing demand, resulting in increased production from gas-fired generation. Currently, gas fired generation is likely the most competitive resource from a cost perspective, and as such, the
2020 APO assumes that existing natural gas will fill in system energy needs. As electricity consumption increases, the rise in electricity sector emissions could be reduced by increased energy efficiency and non-emitting resources to the Ontario market. The emissions forecast will change as the supply mix, demand forecast, carbon pricing, transmission outlook and government policy changes.

**Current Government Emissions Policy and Emissions Targets**

On November 29, 2018, Ontario released the "Made-in-Ontario Environment Plan", committing to reducing greenhouse gas (GHG) emissions to 30 per cent below 2005 levels by 2030, in line with the Federal Government’s Paris Agreement commitments. There has been a steep decline in emissions from 2005, driven in large part by improvements in the electricity sector, including closing coal-fired electricity generation.

In order to achieve GHG emissions reductions, industry performance standards have been proposed to regulate large emitters. Starting January 1, 2022, Ontario will adopt a new pricing scheme under the Emissions Performance Standards (EPS) program. Ontario’s EPS program will regulate GHG emissions from large industrial facilities by setting the standards for lowering emissions (i.e. emissions limits) that those facilities are required to meet. The EPS program sets a threshold of 370 tonnes CO\(_2\)/GWh allowance for existing generators. Generators emitting above their allowance pay the federal carbon price on those emissions, currently priced at $40/tonne of CO\(_2\) emissions and increasing to $170/tonne by 2030. Generators emitting below their allowance receive credits that can be used in future years to offset future carbon costs or sold to other emitting industries. **With a threshold allowance of 370 tonnes CO\(_2\)/GWh, there are currently no natural gas generating units in Ontario that would receive a credit.**

The federal government has accepted Ontario’s EPS program as an alternative to the federal output-based pricing system (OBPS) and intends to remove the application of the OBPS from Ontario facilities effective January 1, 2022. The federal government agrees that Ontario’s EPS program meets the federal benchmark stringency requirements for the sources of GHG emissions that it covers.

**Lessons Learned from Off Coal**

Looking at the past through the coal phase out period, replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of Ontario generation capacity. When coal generation phase out was being considered, gas fired generation was a mature technology available with similar operating characteristics for the task. Gas generation provides the required ability to follow demand changes with the fuel availability to run when required. In the system today, gas generation provides even greater value in managing the high amount of variable wind and solar generation outputs in addition to dealing with constant demand changes in the system. Hydroelectric generation can provide the load following capability, but its output depends on water availability. Fuel availability is not a concern for nuclear generation but it is not able to follow demand changes quickly, if at all. **When considering which resource(s) to use in place of the natural gas fleet, there are no readily available resource types that can offer the same level of on-demand energy availability and flexibility by themselves. To replace the gas fleet, a combination of many resources would be required, including (but not limited to) variable generation, storage, imports and DRdemand response.**
Bringing on large numbers of generators with a different fuel-type than coal posed new administrative and operational challenges. The IESO developed new approaches to monitor and operate different forms of generation. New approaches were developed to manage variable generation, including increased visibility of current variable generation output, enhanced methods to forecast variable generation output, and processes to dispatch variable generation resources.

- Leveraged the transmission system as much as possible to minimize additional transmission investment.

Further, certain coal-fired power plants were located in strategic areas that supported loads centres and ultimately reduced the reliance of power being delivered from the transmission system. For instance, the former coal-fired Hearn generating station supported Toronto and central GTA transmission systems, Lakeview supported the southwestern and western GTA. The replacement of such strategically located facilities was achieved by what has been colloquially referred to as the "smart gas strategy", which saw adding facilities like Portlands Energy Centre, as well as Sithe Goreway and Halton Hills sited in a way to avoid the need to reinforce significant amounts of the transmission system that Hearn and Lakeview otherwise supported.

Opportunities and Benefits for Phasing Out Gas Generation

There are promising new generation technologies for the future, but they are not yet commercially feasible on a large scale in the near term. The IESO has been engaged in enabling new types of resources for a number of years. The IESO is exploring how to leverage storage in conjunction with renewables, for example, in order to maximize the contribution variable generation makes to the system. With wind resources, variability of generation output tends to be seasonal. This seasonality poses greater challenges for storage facilities to complement variable generation in providing what gas generation can provide.

In considering phasing out gas, the province will require resources that have similar characteristics and services that gas provides. The IESO is working to explore the potential of emerging technologies. While they are generally unproven as to their ability to provide services similar to gas on a large scale, a number of initiatives are underway to move the ability of newer resources forward in supporting system reliability. Where IESO has needed to procure more supply, it has been procuring increasing quantities of these types of resources through IESO's former Demand Response auction, which has evolved to a capacity auction open to various types of resources including storage and Demand Response.

The IESO is developing a roadmap to develop ways to leverage small scale generation located within distribution networks (e.g. Distributed Energy Resources) to address provincial energy needs. On this end, the IESO is also currently testing Ontario’s first ever local electricity market in York Region by allowing resources like solar panels, energy storage, district energy and aggregated consumers such as supermarkets, manufacturers and home owners to help reduce peaks.

In the event the amount of resources replacing the gas-fired generation is greater than the current number of gas fired resources, depending on their location, there may be an increased ability to load dispatch generation supply resources in key areas where it is needed to help control flows for system limits. Large number of resources can minimize loss of generation risk considering a loss of unit would not have as much of a large scale impact on the grid. Having multiple units could benefit

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voltage post-contingency with them being situated in key areas and able to respond to dynamic grid changes.

As new emerging technologies commercialize and performance becomes well known, these will be incorporated into future outlooks.
Scope of Study

Background
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Scenario Development

Base Case
This off-gas study relies upon the 2020 Annual Planning Outlook Scenario 1 as the underlining base forecast (Base Case) for studying alternative lower emission scenarios. The carbon price is based on the assumption of a benchmark of 370 tonnes CO$_2$/GWh allowance for existing natural gas generation and $50/tonne carbon price in 2022 and held constant thereafter.

Potential Pathways
This study examines potential pathways to lower emissions through an illustration of complete gas phase out (Scenario 1) and maintaining lowered emissions at current levels (Scenario 2 and 3), as illustrated in Error: Reference source not found. The lowered emissions baseline will be an average of electricity sector emissions from 2016 to 2020\(^2\) to better reflect the level of expected emissions, and to avoid single year fluctuations from external factors like weather. The average electricity sector emissions from 2016 to 2020 is about 4.4 megatonnes CO$_2$/Mt CO$_2$/year. The purpose of developing these Scenarios was not to create estimates of likely outcomes, but to allow the IESO to provide insights gleaned from the range of potential pathways.

<table>
<thead>
<tr>
<th>Figure 2</th>
<th>Pathway Description</th>
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<td><strong>Scenario 1</strong></td>
<td>Supply mix based approach that examines a portfolio of replacement resources assuming all existing gas is phased out by 2030</td>
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<td><strong>Scenario 2</strong></td>
<td>Market based approach where increased carbon cost and decreased benchmark reduce utilisation of gas based resources.</td>
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<td><strong>Scenario 3</strong></td>
<td>Supply mix based approach that examines a portfolio of replacement resources that assumes existing gas is available to compete with other resources to reduce emissions by 2030</td>
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2 2017 was a lower than expected demand year, and as a result, emissions were lower as the gas fleet operated less.

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**Modeling Approach**

**Scenario 1 and Scenario 3** uses a supply mix-based approach that examines a diversified, low-carbon energy portfolio of replacement resources. A diverse supply has historically been the foundation for a reliable system in Ontario. Increased shares from any one type of replacement resource comes with increased risks, and so a diverse supply will manage those risks, as well as to manage cost risks that would exist with a limited pool of resources. The supply mix-based approach will consider demand-side and supply-side options. Scenario 2 considers a tightening of carbon policy to drive changes, and did not apply a supply mix-based approach.

In considering the candidate options, the study considers possible replacement technologies that are **feasible** today. As the reliability and planning coordinator, a principle applied to the study is to ensure the replacement technologies are feasible and can be executed on a large scale given the time frame. This lens of assuming established technologies also lends more certainty on the costs estimates of the replacement supply mix. It is difficult to predict technology innovations, policy developments, and grid evolutions that could manifest in the study time frame – factors that could result in alternate supply mixes. The IESO aimed to provide a set of reasonable forward looking lowest cost estimates given professional judgement and the current information available. The study will also consider to the extent possible the transmission investments required to deliver provincial capacity or that may be required to support local load centres.

Supply portfolios are constructed using a least-cost optimization capacity expansion model that selects resource build-out over the 20-year period subject to a number of parameters. All resource portfolios are required to meet or exceed the following parameters:

- Total capacity contribution during summer and winter peaks equal to demand plus reserve margin
- Sufficient energy to meet total energy demand, accounting for imports and exports
- CO₂ emissions at or below annual emissions target

It is important to note that certain physical or other practical constraints, such as availability of suitable land-use, non-CO₂ environmental impacts, societal acceptance of the replacement technology, among others, were not considered in this least-cost optimization capacity expansion model. And so, the outcome of such a model does not imply technical or physical feasibility.
A set of nominal costs was assumed to allow this portfolio analysis to be carried out. Cost and performance assumptions for each considered candidate options are provided in Table 1. Associated transmission cost assumptions with each resource are provided in Table 2. It is very difficult to determine the required transmission investments without knowing where new generation would be located. Such determination would require much more extensive consideration working with generation developers which cannot be completed within the scope for this report. For instance, it is recognized that much of the easier locations in the transmission system to incorporate wind generation, for example, have already been used to connect the existing wind generation through the past wind generation acquisition processes. Investments in the interconnection facilities with neighbouring jurisdictions will need joint investigations and negotiations.

Sensitivity scenarios: A portfolio analysis was performed without considering any transmission costs or costs associated with ensuring an operable power system such as tool upgrades and market structure changes, which concluded that the cost-optimized supply mix outcomes are not very sensitive to transmission costs—which is sensible as transmission costs are normally relatively minor compared with supply costs. However, the actual extent of the impact of transmission cost would not be known until full details for implementation are considered.

Table 1 | Candidate Options for Replacement Supply for Scenario 1 and 3

<table>
<thead>
<tr>
<th>Resource</th>
<th>LUEC Levelized Unit Energy Cost ($2021/MWh)</th>
<th>Capacity Cost ($2021/kW-year)</th>
<th>Capacity Factor</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>54</td>
<td>39%</td>
<td></td>
<td>Cost projection based on average of industry capital</td>
</tr>
<tr>
<td>Solar</td>
<td>52</td>
<td>17%</td>
<td></td>
<td>cost projections³</td>
</tr>
<tr>
<td>Energy Storage</td>
<td>NA</td>
<td>135</td>
<td>11.4%</td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>Cost Curve</td>
<td>50%</td>
<td></td>
<td>Cost curve from Hatch Acres hydro potential study adjusted to reflect recent hydroelectric project costs</td>
</tr>
<tr>
<td>Small Modular Reactors</td>
<td>ca</td>
<td>NA</td>
<td>85%</td>
<td></td>
</tr>
<tr>
<td>Firm Imports</td>
<td>150</td>
<td>NA</td>
<td>Variable</td>
<td>Cost assumption based on requirement of new build hydroelectric capacity in Quebec to provide year-round firm capacity</td>
</tr>
<tr>
<td>Energy Efficiency</td>
<td>Four achievable potential scenarios from the 2019 Achievable Potential Study were made available to the model with seasonal energy and capacity reductions and annual program costs</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand</td>
<td>NA</td>
<td>67</td>
<td>NA</td>
<td>Cost based on recent</td>
</tr>
</tbody>
</table>
**Table 2 | Transmission Assumptions for Scenario 1 and 3**

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capital Cost ($2021M)</th>
<th>O&amp;M Cost ($2021M/year)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>500</td>
<td>2.5</td>
<td>Costs are per 1,500 MW of additional wind and solar capacity</td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>2,500</td>
<td>12.5</td>
<td>Transmission costs are for incremental hydroelectric capacity above 500 MW, based on Hatch Acres hydro potential study. Assumes the construction of new transmission to Northeastern Ontario.</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 1,800 MW)</td>
<td>825</td>
<td>4.13</td>
<td>Based on IESO/OPA review of firm interconnection capacity</td>
</tr>
<tr>
<td>Firm Imports (&lt;= 3,300 MW)</td>
<td>2,200</td>
<td>22</td>
<td></td>
</tr>
</tbody>
</table>

The supply portfolios determined by the capacity expansion model are incremental to the existing resource fleet. For Scenario 1, all existing resources except natural gas generation are assumed to remain in service in 2030. For Scenario 3, all existing resource including natural gas are assumed to remain in service.

Consistent with the project scope details provided in the June 2021 stakeholder engagement session, candidate options include the proposed 300 MW small modular reactor at Ontario Power Generation's Darlington nuclear facility.

Two limits are placed on the total amount of new capacity for new resource types. A maximum of 3,300 MW of firm import capacity is assumed as this is the largest amount that has an available preliminary estimate of transmission enhancement costs. There is also an upper limit of 2,000 MW of incremental demand response capacity, which is consistent with a similar modeling exercise performed for the 2016 Ontario Planning Outlook. Including currently contracted demand response, this is equivalent to roughly 10% of peak demand.

Supply portfolios are modeled seasonally (summer and winter) over 20 years. In each season, the supply portfolios are required to meet the capacity, energy, and emissions, and operability requirements referenced above. Hourly modeling in a multi-year capacity expansion optimization model is generally impractical given processing constraints. The purpose of the seasonal capacity expansion model is to develop supply portfolios with roughly the right amount of capacity and energy to meet system needs. The supply portfolios were followed by an assessment using an hourly energy dispatch model to determine whether the portfolio could meet energy needs in all hours. Other feasibility assessments were also performed, such as assessing the required storage duration and the frequency with which demand response was activated.

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4 Review of Ontario Interties, IESO, 2014

16 Considerations for Phasing Out Natural Gas in the Electricity System | Public
Costs for each portfolio are a combination of energy costs, capacity costs, and incremental transmission costs. An optimization algorithm is used to determine the least-cost resource portfolio for a given demand future.

The resulting portfolios developed using the least-cost optimization capacity expansion model are representative choices on a spectrum of possible supply decisions; they are not meant to prescribe any one path and do not directly imply technical or physical feasibility. Notably, the results are heavily influenced by the relative cost assumptions which are likely to change over time. Instead, the results indicate the scale of required resources that would be required to achieve the emissions reductions targets of the scenarios while maintaining system reliability.

**Scenario 2** is a market-based approach where an increase in carbon price and a decrease in the emissions threshold reduce the utilization of gas by 2030. The carbon price assumes a linear increase from $50/tonne in 2022 to $170/tonne by 2030 and the benchmark for all natural gas facilities linearly decline from 370 tonnes/GWh in 2021 to 0 tonnes/GWh by 2030. The demand, conservation, supply and transmission outlook assumptions are consistent to the Base Case (2020 APO Scenario 1).

These scenarios were also informed by the multitude of input from the public webinars, stakeholders and communities feedback – written feedback can be found on the IESO website.

An economic hourly dispatch model was used to determine the outcomes of the three scenarios. This assessment simulates the Ontario electricity market based on the system economics to inform system costs and system performance such as operability, emissions and imports and exports. While the cost of new generation technologies and the trajectory of total costs over time are uncertain, it is imperative to compare the total and average costs for each scenario to the Base Case to understand which factors are the largest drivers of ratepayer costs. Figure 3 illustrates the modelling approach for the three Scenarios.

**Figure 3 | Modelling Approach for Scenario 1, 2 and 3**
Areas of Study

The three scenarios were examined from various lenses, including areas of reliability, costs, wholesale market impacts, operability and timing to the electricity system, as shown in Table 3.

Table 3 | Areas of Study

<table>
<thead>
<tr>
<th>Area of Assessment</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability</td>
<td>Diversity of supply for energy and capacity</td>
</tr>
<tr>
<td></td>
<td>Considerations for locational requirements for siting resources, or transmission required to offer alternatives</td>
</tr>
<tr>
<td></td>
<td>Ancillary services requirements</td>
</tr>
<tr>
<td>Cost and Wholesale Market</td>
<td>Least cost replacement resource portfolio</td>
</tr>
<tr>
<td></td>
<td>Potential net present value of system costs</td>
</tr>
<tr>
<td></td>
<td>Use costs for known supply technologies and transmission</td>
</tr>
<tr>
<td></td>
<td>Impact on wholesale market pricing and how market value of system needs may change</td>
</tr>
<tr>
<td>Operability</td>
<td>Operability and impact to wholesale market design</td>
</tr>
<tr>
<td></td>
<td>Whether the market can operate the supply mix</td>
</tr>
<tr>
<td>Timing</td>
<td>Typical timelines associated with construction of generation or</td>
</tr>
</tbody>
</table>
Areas of Study Not Considered

It is expected that the electricity system will play a key role in achieving lowered emissions target through demand growth driven by electrification of transportation, building and industrial end-uses that currently rely on direct combustion of fossil fuels. Deep decarbonization of the economy will be an integral part of the overall provincial target for lowering emissions. As the economy decarbonizes, we will expect increased demand for electricity. While a high electrification demand scenario or increases to the federal carbon price to understand the extent of fuel switching were not considered as part of this study, impacts of electrification on demand will be considered in the IESO 2021 APO and future APOs.

The study will assess Ontario emissions based on the scenarios described in earlier. Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity. It is expected that as Ontario moves to a lower emissions projection, so will our neighbours. Jurisdictions around us are evolving and policy changes are underway in the United States as they take in their own pathways to lowering emissions. This study will assume the interaction relationship of imports and exports with our neighbours as assumed in the 2020 APO, and will not consider how emissions in other jurisdictions may be affected by imports and exports of energy to and from Ontario in the future. Emissions forecast for the study will look at Ontario’s electricity sector only, excluding possible impacts of carbon from other jurisdictions affecting Ontario.

This report is intended to provide analyses and to communicate information to policy-makers and other decision makers to make informed decisions. The study is not intended to provide recommendations for policy decisions or to identify one alternative over another as preference.
Study Findings

Scenario 1 - Supply mix-based approach that examines a portfolio of replacement resources that assumes all existing gas is phased out by 2030. The incremental supply above the Base Case required to completely replace natural gas generation by 2030 is about 17,000 MW, as shown in Figure 4. In addition to this resource mix, Energy Efficiency Scenario B of peak 1,600 MW savings from the APS is also included as part of the lowest-cost resource mix (not shown in the figure).

Figure 4 | 2030 Incremental Installed Capacity, Scenario 1

The incremental nuclear, wind and solar capacity produce less annual energy (19 TWh) than the natural gas energy (31 TWh) was forecast to produce in 2030 in the 2020 APO. The remaining energy gap is made up by energy efficiency (9 TWh) and imports. Storage and demand response are required to replace the capacity currently provided by natural gas as well as the incremental capacity gap identified in the 2020 APO. Storage and demand response also help balance periods of high baseload generation and periods of insufficient supply. From the candidate options, new hydroelectric capacity was not selected by the capacity expansion model due to the high assumed costs associated with new build hydroelectric generation.
The complete phase-out of gas by 2030 with replacement by the above mix would lead to a variety of key developments in Ontario’s markets. Gas resources frequently set price as the marginal resource in Ontario. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later.

Besides those energy efficiency savings considered in the 2020 APO, there are potential opportunities to achieve greater electricity savings as identified in the APS. The most recent APS, which was the first integrated electricity and natural gas APS, was completed by the IESO and the Ontario Energy Board in 2019. The study identifies how much energy can be saved through the implementation of energy efficiency measures. Four scenarios of achievable potential were analyzed by taking into account realistic adoption rates of cost effective measures over the study period considering a number of factors including market barriers, customer payback acceptance, perception of non energy impacts and awareness of energy efficiency measures. The highest potential results of the four scenarios come from Scenario B, which assumes idealized program design and the highest incentives level. The scenario identifies an additional 9 TWh electricity savings by 2030 can be procured beyond those already included in the Base Case demand forecast. The resulted savings would further lower net electricity demands to be served by generation resources.

Ontario regularly trades electricity with neighbouring jurisdictions. [NTD: where is the reference to 3300MW of firm import from Quebec?] There is hydroelectric capacity potential from Manitoba and Quebec and limited clean imports availability from Minnesota, New York and Michigan. Depending on the level of firm imports, significant expansion of transmission lines to bring supply from provincial borders to consumers in the load centres may be required. This would have significant cost implications and we will need to determine the right balance between being self-sufficient and relying on our neighbours.

[NTD: we need to discuss the difficulties in replacing gas with wind and storage as the main supply resources; the seasonal storage need]

The emissions forecast for Scenario 1 relative to the Base Case is x.

The cost implications of Scenario 1 relative to the Base Case is x.

Scenario 2 - Market based approach where increased carbon cost and decreased benchmark reduce the utilization of gas to reduce emissions by 2030 to current levels
The market based approach relies on economic imports and exports as a means to determining the operation of the Ontario natural gas facilities when impacted by higher carbon costs and lowered carbon benchmark. As indicated above this scenario assumes an increase to cost of carbon from $50/tonne in 2022 to $170/tonne by 2030 and a decline of the natural gas benchmark of 370 tonne/GWh in 2022 to 0 tonne/GWh by 2030. This also assumes that the cost of energy from other jurisdictions remains the same as APO 2020. The entire reason for having a GHG allowance benchmark of 370 tCO$_2$/GWh was to minimize the impact of the carbon price on trade. In the absence of a benchmark allowance (i.e. allowance of 0 tCO$_2$/GWh) it is very likely that the carbon pricing policy would have to include adjustments at the border to account for the GHG emissions associated with the energy in other jurisdictions. Border adjustments are not considered in this analysis, instead the GHG emissions associated with the increased imports were quantified. A border adjustment policy could significantly impact the amount of imports considered in this analysis.

With no changes to the demand and supply mix from the 2020 APO Base Case, energy production from nuclear, hydroelectric, wind and solar resources is unchanged for this scenario. Change in energy production is from natural gas, imports and exports; and is the driver for difference to the cost and emission outcomes.

The higher carbon cost assumptions is expected significantly impact Ontario’s markets. Since gas resources frequently set price as the marginal resource in Ontario, the higher cost of gas would result in broadly raised market clearing prices. Many resources would subsequently be able to recover an increased portion of their costs through energy markets. The higher market clearing prices in Ontario would also make Ontario electricity exports into neighbouring jurisdiction less attractive thus driving down exports from gas generation. Furthermore, higher market clearing prices will attract more economic imports to Ontario that will offset some Ontario natural gas production. The change to natural gas production, imports and exports relative to the Base Case is provided in Figure 5 below.

The reliability impacts are not impacted in this scenario as no changes are made to the supply mix from the 2020 APO Base Case. No incremental infrastructure changes are required for the generation or transmission systems in this scenario that differs from the 2020 APO base case; thus, no additional lead time is required to this portfolio mix than other than what is already assumed in the 2020 APO base case.

The reduced natural gas production results in GHG emissions remain around 4 Mt CO$_2$/yr megatonnes in Scenario 2 which is consistent to the 2016 to 2020 historical level and declining to 3 Mt CO$_2$/yr megatonnes by 2030, as shown in Figure 6.

The cost implications of Scenario 2 relative to the Base Case is x.

Figure 5 | Natural Gas, Imports and Exports Relative to the Base Case

Figure 6 | Emission Forecast for Scenario 2 and the 2020 APO Base Case

...
The implementation for the markets based approach is a function of government regulatory decisions on the cost of carbon and the elimination of the benchmark to natural gas facilities, which is beyond the control of the IESO.

Scenario 3 - Supply mix-based approach that examines a portfolio of replacement resources that assumes existing gas is available to complete with other resources to reduce emissions by 2030 to current levels.

The incremental supply of about 9,000 MW above the Base Case, where natural gas are assumed to remain in service, is shown in Figure 7. In addition to this supply mix, Energy Efficiency Scenario B of peak 1,600 MW savings from the achievable potential study is also included as part of the lowest-cost resource mix (not shown in the figure).

Figure 7 | 2030 Incremental Installed Capacity, Scenario 3

![Figure 7](image_url)

The 2020 APO found that 3,600 MW of new capacity was needed to meet resource adequacy needs by 2030 if all existing resources remained in service. In Scenario 3, this need for new capacity is largely met through energy efficiency, energy storage, and additional demand response. Roughly 5,500 MW of wind are also selected in the capacity expansion model, as this energy is required to displace natural gas generation from an energy perspective. Despite similar cost assumptions, wind was favoured over solar by the capacity expansion model. This is likely because total energy demand is higher in the winter than summer, despite higher capacity requirements in the winter. Since the capacity need is met by storage and demand response, the expansion model finds that wind is more effective at meeting the energy need.

Energy storage plays an important balancing role in Scenario 3, reducing energy surpluses and providing electricity to the system at times of need. Additional time-series analysis was conducted to confirm that 4-hours of storage duration per MW of storage capacity, assumed in the capacity expansion model, were sufficient to meet the supply needs of the system.

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The partial use of gas as well as a diverse supply mix of renewables, energy storage, and demand response would lead to less severe impacts to Ontario’s markets. Gas resources would continue to frequently set price as the marginal resource in Ontario, but increased renewables would result in somewhat lower overall energy. Since renewables tend to offer into the energy market at low to zero prices, these replacement resources would more frequently set energy price, and the result would be a general lowering of overall energy prices, along with increased volatility. At the same time, battery storage resources tend to offer in the ancillary services markets, and the large build-out of battery storage technologies in this scenario would tend to broadly decrease operating reserve prices in Ontario’s markets. Many resources would subsequently depend on increased capacity prices or capacity payments to recover costs. These outcomes are similar to the illustrative “High Capacity Case” discussed later.

The emissions forecast for Scenario 3 relative to the Base Case is x.

The cost implications of Scenario 3 relative to the Base Case is x.

Developing a Transmission Plan

[NTD: up front should we provide the same background we gave in APO re: Reliability = Adequacy + Security]

As indicated in the section above on Modeling Approach, the least-cost optimization that led to the supply mixes contemplated in Scenarios 1, 2, and 3 did not consider locational or siting-related matters pertaining to those supply mixes. As such, a detailed Transmission Plan to correspond with those scenarios is not able to be developed. However, the IESO has experience from past transmission planning initiatives to comment on the potential scope of a Transmission Plan to reduce the reliance on natural gas generation. The development of a Transmission Plan would consider the need to relieve constraints to deliver the replacement supply mix as well as the needs that would emerge if strategically located gas plant are retired.

Delivering the Replacement Supply Mix

Of the 11,000 MW of installed natural gas-fired generation, the majority a large portion is located in or around the Greater Toronto Area, with the balance primarily in western Ontario. Further, given portfolios resulting from the least-cost optimization model, it is expected that much of that portfolio would not be practical to site in a large urban and suburban footprint, given the expected land-use requirements (e.g., wind) or the natural location (e.g., firm imports). This would imply that the retirement or reduced reliance on these gas plants would create a net requirement for transporting power into the GTA and surrounding area compared to the system that we have today.

[NTD: these notes are a content outline only.]

- Phase 2 FETT reinforcement
  - Trafalgar x Oakville

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- Meadowvale x Hurontario
- Retetermining the Milton bypass
- **North-South reinforcement**
  - Essa to Pinard via Sudbury (Hanmer) and Timmins (Porcupine)
  - Collector circuits?
- **Eastern Ontario reinforcement**
  - Doubling up Outaouis
  - 230 kV between Merrivale + St. Lawrence
  - Bowmanville x Cherrywood
  - Etc., refer to the old interconnection review report

**Maintaining Reliability Currently Provided by Strategically Located Gas Plants**

[NTD: these notes are a content outline only.]

- **Investments needed to relieve equipment loading:**
  - Portlands = Third Supply to Toronto
  - Sithe Goreway and Halton Hills = new 500/230 kV autotransformation converting Milton SS to TS, and potentially at Kleinburg
  - York Energy Centre = new transmission reinforcement from Buttonville x Armitage
  - Brighton Beach, East and West Windsor = new (500 kV?) major transmission reinforcement into the west of Chatham area [NTD: get Megan Lund to review]

- **Investments needed for voltage control**
  - Between PEC, Goreway, Halton Hills, they provide a total of +X to -Y Mvar of dynamic reactive power support. Although reactive power is extremely locationally dependent, we can assume that new reactive power devices will need to be installed on the same order of magnitude and provide a similar response.
    - Implications of the response type – cannot be static capacitor or reactor banks, but needs to be dynamic. May not even be able to be SVCs because they are not an active source, and when thyristors are fully ON they are just capacitors or reactors.

**Investments needed for frequency control**

Gas-fired generators are synchronous machines and help ensure acceptable frequency response and system stability. If capacity from gas-fired generators is replaced with inverter-based resources, investments or the introduction of new market mechanisms to procure a Fast Frequency Response product would likely be required. The IESO will need to investigate the nature of these potential investments.
While controller technology used in IBRs may be able to provide Fast Frequency Response, it is mostly currently in the piloting stage (e.g., AESO’s Oct 2020 FFR pilot announcement). Of particular concern may be the design of Ontario’s Under-frequency Load Shedding Program for the Central Island, as currently gas-fired generators are the only source of governor response (primary frequency response) in the Central Island, and IESO’s 2018 UFLS study identified little margin compared with NERC and NPCC requirements.

Operability Considerations

Operability can be defined as the ability of the IESO to fulfill its legislated objects to direct the operation and maintain the reliability of IESO-controlled grid.

The IESO-controlled grid is operated day to day (24/7) and minute to minute at the level of reliability such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of reliability is achieved by operating the IESO-controlled grid to meet adequacy criteria for anticipated demand, system security criteria for specified contingencies, and re-preparation criteria for restoring reliability following contingencies or major events such as blackouts.

The IESO-controlled grid is operated and its reliability maintained with due regard for planned or unplanned transmission element outages.

Operability can be defined as the ability to operate the power system second to second and manage a variety of real-time conditions with due regard for potential loss of transmission elements. Power system reliability must be maintained under differing seasonal system conditions and variability of supply, as well as through fluctuations in intra-hour and intra-day load; all the while respecting appropriate thermal, voltage and transient stability limits that might be present due to the transmission system limitations.

Operability is assessed and forecasted to ensure the power system at the transmission and distribution level is adequately prepared for expected real-time conditions. It must also have the ability to absorb and adapt to future changes on the power system.

The following principles are required to enable an operable system:

**Diversity** – Having a balanced variation of characteristics available across the system

**Flexibility** – Ability to easily respond to changing circumstances or conditions across the system

**Manageability** – Ability to have visibility, monitor and dispatch resources across the system

**Location** – Ability to support power flow toward loads as well as ability to facilitate efficient system restoration

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5 For additional information, see Section 11.3 of IESO Market Manual 7.1.
In order to implement the replacement supply mixes, a number of things will need to occur to ensure the power system remains operable. The following are operability considerations that will need to be addressed with the replacement supply mix.

**Diversity**

Diversity in the characteristics of the supply mix is important to ensure risks inherent in each technology and fuel type are mitigated. As such, the total portfolio must provide sufficient energy capability to be sustainable under a wide variety of conditions including short-term extreme weather, mid-term environmental extremes and other fuel delivery challenges.

Diversity in technology and fuel type is required to mitigate the risks of any operating restrictions arising from such criteria as air emission restrictions, hydroelectric restrictions, and cooling water temperature change restrictions as well as to provide ancillary services from a broad range of technology types to reduce the risk of availability of service due to fuel scarcity.

It is also important to mitigate against common mode problems (e.g., shutdown of entire stations creating contingencies too large to be effectively managed). The ability to have ancillary services from a diverse supply of technology types are required to mitigate the risk of availability of service due to fuel scarcity.

Finally, the replacement supply mix must also be located in diverse locations to mitigate a common mode of failure from eliminating access to a large regional supply. Although locational diversity is important, there are also specific locations where replacement supply is important.

**Flexibility**

Flexibility in what characteristics the supply mix can provide is important as it allows Ontario to maintain reliability through both anticipated and unanticipated changes on the system. The current gas fleet provides sustainable energy and is able to follow a 5-minute dispatch. This is of particular importance on days where demand is high. Reliance on energy limited resources does not provide the inter or intra hour flexibility required to maintain a balance between supply and demand.

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**IESO’s Experience in Flexibility**

On June 28, 2021, demand was high all day and evening peak reached 22,300 MW. Wind contributed to the system’s energy need but was only able to provide 11% of its installed capacity in the peak hour for a total of 500 MW (wind was performing 400 MW under the forecast).

Low water conditions caused a concern with the hydro-electric resources on several river systems. In an attempt to conserve the energy limited hydroelectric resources for utilization at peak, these resources were constrained down in off-peak hour. To replace the energy limited resources, other non-energy limited units were dispatched up including flexible gas resources.
A total of 6,000 MW of gas fired generation was dispatched to meet the 22,300 MW peak. Much of this was constrained earlier in the day to offset the energy limited resources and to provide Operating Reserve. No other fuel type offered the flexibility to constrain on for this purpose.

An Energy Emergency Alert was issued indicating that all available resources were committed. Considering there was no other resources available and approximately 30% of the demand was supplied by the gas fleet, this demonstrates the importance of having flexible energy that can be sustained throughout the day.

Another instance where the flexibility of the gas fleet has proven invaluable is during wind “cutouts”. Changes to weather conditions may cause wind generation in a particular area to all cease generating within a very short window or at the same time resulting in a “cutout”. In these instances, having resources that can be dispatched quickly to ensure the balance of supply and demand is maintained after such an event would become more important with the increased penetration of wind in the replacement supply mix. Locational diversity of where the wind is placed will help mitigate the size of this potential loss of generation, however, will not eliminate the need for flexibility to remain. In order to ensure that, the replacement supply mix must have the flexibility to both follow 5 minute dispatches in both directions but also do it quickly (i.e. have a fast ramp rate).

**Ramping Considerations**

The IESO has an obligation to maintain a constant balance of supply and demand. The gas fleet plays an important role in allowing us to balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. In a summer day morning, a ramp-up rate of up to 30 MW/minute is required. On the other hand, an equal amount of ramp-down rate is required when consumption drops in the evening up to, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

Today, flexible resources make up about 40% of the current fleet. Of the flexible resources, 11,000 MW of gas generation accounts for more than 70%. Flexible resources respond to 5-minute dispatch to balance the supply with demand. Wind and solar resources are curtailed under surplus baseload generation conditions, however, they are not dispatched up or down for ramping purposes. At present, hourly demand response resources and imports/exports are scheduled at an hour interval. The replacement resource mix capacity is primarily coming from inflexible wind and solar and hourly scheduled demand response and firm imports. Storage resources are mostly used for regulation purposes now and development and integration of large scale storage resources are still years away.

Balancing the supply with demand with such replacement capacity is challenging. Hybrid resources (wind or solar paired with batteries) could provide fast ramping capabilities. Additional flexibility could come from changes to operating procedures and scheduling protocols and changes to operation of non-dispatchable resources.
Not only does the existing gas fleet provide flexibility in their generation output, it also has the ability to provide local reactive power when needed. This characteristic is essential and will need to be replaced in order to ensure the maintenance of voltages in specific areas.

**Additional characteristics** of flexibility our existing gas fleet provides is inertial and frequency response. To reliably operate the power system, supply and demand must be continually balanced to maintain system frequency at 60 Hz. In the event of a large loss of generation, declining frequency can result in interruptions to customer loads. Gas generators have a large rotating mass within that produces energy. These rotating masses **Spinning resources** provide inertial and frequency response that is required to help in the recovery of system frequency. Inertial response dampens the frequency decline post contingency while frequency response helps to bring the frequency back up. Without the gas fired generation, alternative forms of both inertial and frequency response will need to be put in its place to reduce the risk of under frequency load shedding.

Gas-fired generation being synchronous type generators provide important function in voltage control and dynamic support in maintaining system security for normal operation and during system contingency situations. Synchronous generators provide spinning inertia directly proportional to the unit’s physical size. The more synchronous units that are online, the more the inertia on the power system. This inertia acts as a force to resist a change in the frequency of the system. Following a large generation contingency on the power system, the energy lost is evidenced with a corresponding drop in the system frequency.

Gas fired generators store kinetic energy in proportion to their size when synchronized. Immediately following a contingency, this kinetic energy stored is released and acts as a suppressant to the frequency decline. This phenomenon is known as the inertial response. With the elimination of the large generating units such as coal and gas, the province may lack sufficient ability to suppress frequency decline following a contingency which may result in under frequency load shedding. This inertial response will need to be replaced if gas were eliminated to ensure the system is recoverable following a contingency.

Gas generators have governors which automatically react to changes in system frequency by changing their output in proportion to the frequency deviation. This reaction is known as frequency response and helps to stabilize the frequency decline and ultimately aid in its recovery. Without the frequency response characteristics our current gas fleet provides, the recovery from large generation and load contingencies can pose challenges on the reliable operation of the power system.

**Manageability**

The bulk of our gas-fired generation fleet is visible to the IESO and also dispatchable. Should the gas-fired generation fleet be replaced with resources on the distribution system, the IESO will require visibility and dispatchability of those resources to maintain reliability.
If the replacement supply mix incorporates an increasing number of small resources that are embedded, distributed and possibly aggregated, the impact on situational awareness must be considered. Situational awareness is important as it provides operators foresight into what changes could potentially happen. It is being aware of the environment and understanding the information that is available at hand and what that means now and in the future. This could be increasingly complex with a larger number of resources on the system which would increase the complexity of operation and consequently increase the risk of human error. A large increase in the number of resources and market participants providing capacity to Ontario could require significant tool upgrades to manage the increased volume of data the IESO would be receiving.

The IESO currently has full visibility and control of resources connected to the high voltage transmission system but the same cannot be said for those connected to the distribution system. In the event there is an increased penetration of resources on the distribution system, operators must have sufficient capability to monitor and dispatch the power system.

Ensuring manageability with an increased penetration on the distribution system and number of resources, significant changes to our existing market participation framework, tools and rules will require changes which could cost upwards of $25 million.

Additional Reliability Concerns and Considerations

The IESO-controlled grid is operated day to day (24/7) and minute to minute at the level of reliability such that the loss of a major portion of the power system (or unintentional separation of a major portion of the power system) will not result from reasonably foreseeable contingencies. This level of reliability is achieved by operating the IESO-controlled grid to meet adequacy criteria for anticipated demand, system security criteria for specified contingencies, and re-preparation criteria for restoring reliability following contingencies or major events such as blackouts.

The IESO-controlled grid is operated and its reliability maintained with due regard for planned or unplanned transmission element outages.

Additional Operability Considerations

Locational Importance of the Supply Mix

The transmission system limitations on the IESO-controlled grid result in flow gates that impede flow of power toward loads. These flow gates are reflected through the system operating limits such as thermal, voltage and angular stability limits that indirectly describe specific system deficiencies. To provide unrestricted flow of power toward loads, to minimize losses, and to enable outages for transmission elements maintenance, sometimes, it is necessary to position a generator of certain capability at the specific location.

During the process of replacing coal-fired generation with gas-fired generation, some of the gas fleet was procured in locations to minimize transmission investments needed to incorporate the resource into the system. In some cases, the intent was to specifically avoid transmission investments. Some of the other gas-fired generation, by virtue of where they are located, also play important roles in the local load supply. Without these gas-fired generation, transmission investments may be required.
Some of the gas-fired non-utility generators, or “NUGs”, also have locational importance, as outlined in the IESO’s 2015 NUG Framework Assessment Report.

There are specific areas in the province, should replacement supply mix be located, would provide higher value than other areas of the province. Replacement supply mix located on the east side of Flow East Towards Toronto (FETT) flow gate interface is important to accommodate the expected demand growth in the area as well as the retirement of the Pickering Nuclear Generating Station. Currently, Lennox, a gas generator, is the best source low minimum loading points and its ability achieve high generation output. Also, Portlands, Sithe Goreway and Halton Hills gas generators provide specific support to enable unrestricted flow of power through the FETT flow gate.

The location of generation close to load pockets is important to reduce congestion and to reduce losses on the transmission system and ensure loads are being served.

Generation located in areas that can reduce autotransformer loading is also important. Having Portlands GS connected on the 115 kV side of the Leaside/Manby autos helps to reduce the loading there. The location of Sithe Goreway GS helps to reduce loadings at Claireville. Halton Hills GS also currently assists in the reduction of load on the Trafalgar autotransformers.

These natural gas generators are important to keep loadings reduced during planned transformer outage or if a forced transformer outage were to occur. Should these gas generators be phased out, new generators must be strategically placed to serve these purposes and help maintain system operability. In addition, due to their reactive power capability, Portlands, Halton Hills and Goreway GS are the key elements in supporting the flow of power towards Toronto during high demand days.

In the Leamington area, we are currently anticipating an increased dependency on the gas-powered Brighton Beach GS facility to manage the area load exposure to prolonged load reductions during outage conditions. The availability of the Brighton Beach generation has implications on managing the workload in the control room as well, considering that other means of the managing load in the area might be complex and time consuming. A replacement for that generation, in that area will also be required to help mitigate load exposure.

In the Leaside/Manby area, the phenomena that we try prevent from happening is dependent on primary demand. During high primary demand conditions, recent IESO studies show significant penalties to Flow Away from the Bruce Complex (FABC) flow gate limit as a result of Pickering units being out of service. The situation is aggravated with unavailability of gas units at Goreway, Halton Hills and Portlands GS (and Darlington NGS if on outage). Considering the significant amount of penalties on the flow from the west, adequacy concerns would arise to supply load in the Toronto area without gas generation and after the Pickering retirement.

During low primary demand, and with the expectation of the Darlington Vacuum Building outage scheduled for 20xx, IESO studies indicate a great dependency on the Pickering nuclear units as well as the fleet of gas generating units in the area to manage high voltages. Managing the area without the gas generators will potentially expose the system to frequent switching of the lines and with that increased risk of equipment failures. It is therefore important to ensure that the equivalent capacity in placed in the area to replace the gas.
We must also ensure that adequate capacity is available to the area to accommodate a Darlington NGS outage after the Pickering NGS units have retired. If the gas is not replaced in that area, Ontario may experience shortfalls with the current transmission infrastructure.

Additional Operability Considerations

Single Largest Contingencies

The single largest contingency that impacts adequacy and operability is typically the loss of the largest generator. However, there are circumstances wherein the single largest contingency consists of multiple loss or bottling of generators. Examples are as follows:

- A loss of an element that removes a connected generator and station service, resulting in the loss of a second generator
- A loss of a transmission element that results in bottling a number of generation behind the interface
- A loss of an auxiliary element that results in the removal of multiple generators
- A loss of a generator and assumed amount of DERs that would also be lost as a result of the primary contingency

In the event that there is significant penetration of supply on the distribution side, there could be impacts to the amount of operating reserve the IESO must carry.

System Restoration Plan

As part of the IESO’s emergency preparedness we maintain plans to restore the system following a complete blackout. Ontario currently has sufficient black start capability to restore the power system in the event of a blackout.

The IESO begins the restoration by starting “black start” units that must be capable of energizing long transmission lines (ability to absorb high voltage), and provide starting current to other generators. Once the first generators are on, load can be brought back to balance the power system. As we continue to restore the province, strategically placed generating units with significant load pickup capability and significant MX-reactive power absorbing capability are required to ensure the whole province can be restored. The current location of some gas plants are serving that purpose of picking up load and absorbing MX throughout the restoration process. In the absence of gas, a suitable replacement for this purpose will be required.

Ramping Considerations
During morning pickup and evening drop off, the gas fleet plays an important role in balancing supply and demand. With its fast ramp capability, they are often used to supply the sharp increase in consumption seen in the mornings. In a summer day morning, a ramp-up rate of up to 30 MW/minute is required. On the other hand, an equal amount of ramp-down rate is required when consumption drops in the evening, these fast moving resources are able to reduce their output at the necessary rates to maintain a reliable balance between supply and demand. They are also able to follow and balance any sudden and unexpected changes to our renewable energy fleet whose fuel can vary significantly during the day. Without the gas fired-generation, there will need to be resources available to ramp quickly to balance the system.

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Balancing the supply with demand with such replacement capacity is challenging. Hybrid resources (wind or solar paired with batteries) could provide fast ramping capabilities. Additional flexibility could come from changes to operating procedures and scheduling protocols and changes to operation of non-dispatchable resources.

Inverter Based Resource

Rapid growth of inverter-based resources ("IBRs") add complexity to grid reliability. These include most solar and wind as well as battery storage, hybrid generation and many DER. Some inverter-based resource performance issues have been significant in recent grid disturbances, such as the tripping of a number of BPS-connected solar PV generation that occurred during the 2016 Blue Cut Fire, 2017 Canyon 2 Fire, and 2020 San Fernando Disturbance in California. Gas-fired generators are synchronous machines and help ensure acceptable frequency response and system stability. If capacity from gas-fired generators is replaced with inverter-based resources, investments may be required. The IESO will need to investigate the nature of these potential investments. While controller technology used in IBRs may be able to provide Fast Frequency Response, it is mostly currently in the piloting stage (e.g., AESO’s Oct 2020 FFR pilot announcement). Of particular concern may be the design of Ontario’s Under-frequency Load Shedding Program for the Central Island, as currently gas-fired generators are the only source of governor response (primary frequency response) in the Central Island, and IESO’s 2018 UFLS study identified little margin compared with NERC and NPCC requirements.

Practical Considerations

Gas Under Contract

Considerations for Phasing Out Natural Gas in the Electricity System | Public
Much of Ontario’s current natural gas-fired generation is under contract with the IESO. The IESO’s generation contracts do not provide the IESO with termination for convenience rights once the facility has achieved commercial operation. Financial compensation to the asset owners of natural gas-fired generators needs to therefore be added to the replacement costs to retire these generators prior to the end of their contract. The IESO will need to engage with asset owners to determine the associated terms and costs. Absent precedence, it is difficult to quantify the costs of early contract termination. Once the contract term ends, natural gas-fired generation is expected to participate in competitive mechanisms to meet system needs.

**Eliminates Competition**

The natural gas fleet also has considerable economic life remaining. Majority of the fleet came into commercial operation in the last 15 years. Taking Lennox GS out of consideration, large natural-gas resources (i.e. resources greater than 150 MW) average life is currently 13 years. Given the average resource is expected to operate 30-40 years, shutting down these resources early removes a cost-effective source of capacity from competitive acquisitions.

**Land Use and Siting**

Replacing natural gas with new large scale non-carbon emitting resources can pose a number of practical challenges in regards to land use, siting and location. Most economic and accessible hydroelectric sites have been developed; some potential is undeveloped, with a majority of it located along Ontario’s northern rivers (e.g. Abitibi and Moosonee rivers). Northern hydroelectric sites are generally remote, resulting in relatively higher construction costs, as well as requiring potentially significant transmission investments to connect them. While we have proven technology on on-shore wind, there is a moratorium on off shore siting. Depending on the location, large penetration of renewables will require transmission investments to connect them, there is also less suitable locations to develop overhead transmission routes.

**Variable Generation and Storage**

- story about making this look like 100% gas plant will be very expensive

**Timing**

Reductions in emissions through the addition of new non-carbon emitting resources and accompanying transmission would require new investments, significant amount of time and resources to develop the designs and the required specifications, to identify appropriate sites and routes, to manage the extensive stakeholdering and consultation, and to manage the acquisitioning and building of these assets. Lead time of supply resource vary depending on the generation, and the lead time of transmission can be seven years or even longer. New technology and resource risks should recognize the uncertainty associated with construction completion and longer lead times required to reach dependable operation. This transformation of the system would require detailed planning which is outside the scope of this study. Replacing coal generation took more than a decade, requiring careful preparation and execution to replace a quarter of our generation capacity.

**Hydro Quebec Imports Considerations**
Ontario trades with Quebec on the open market on a non-firm basis. Ontario has entered into electricity trade agreements with Quebec in recent years that expire in 2023, and it is assumed that these particular agreements are not extended. Imports from Quebec is an option to replace gas generation. To what extent it can contribute in reducing the GHG will depend on many factors such as generation capacity and energy availability in the Quebec system, the negotiated price and the transmission path availability between Quebec and Ontario.

Due to the nature of Ontario and Quebec system, Ontario and Quebec cannot be connected for synchronous operation. Generation or load needs to be connected radially to either system to have import and export. The interconnections in northern Ontario are these type of connections with limited capacities. The interconnection at Bauharnois near St. Lawrence is a same type of interconnection but with a capacity to connect up to 800 MW of generation into Ontario. With the intent to allow dynamic power transactions between Ontario and Quebec, the 1,250 MW tie in the Ottawa area was added. It includes an AC-to-DC-to-AC conversion facilities to address the system issue.

Also due to the nature of the system in Ontario near Ottawa, the 1,250 MW tie and the 800 MW tie cannot be operated at the combined total level of 2,050 MW in summer peak periods. The IESO has recommended Hydro One to upgrade Hawthorne TS x Merrivale TS transmission line to improve local area supply that would also improve firm import capability from Quebec. A firm import capability of 1,650 MW can be obtained with this upgrade. For a firm import capacity beyond 1,650 MW would require significant transmission investments. The scope and cost of such investment is not known without discussions/negotiations with Quebec. A nominal cost based on past consideration was used in the development of the portfolios.

Quebec has very large water storage capability and is projected to have large surplusses of energy for many decades, however, their capacity availability is far more constrained. Quebec’s winter peak electricity demand is projected to grow over the next decade, decreasing its surplus tightening their already tight winter capacity availability where, and exports are generally curtailed during winter peaks, as more than 80% of Quebec households use electric heating. Quebec is expected to continue to procure short-term capacity contracts to meet its capacity requirements for winter months. Quebec is a winter peaking system (experiences capacity shortfalls due to use of electricity for heating) and cannot confirm firm capacity to Ontario in the winter and so that capacity would have to be sought elsewhere. However, for this analysis it is assumed that Quebec can supply summer and winter capacity up to 3,300 MW, with the appropriate transmission upgrades. While Quebec is building more wind capacity, it is not assumed that this is significant enough to allow them to be able to provide winter capacity to Ontario. This capacity will be energy limited and their ability to export to Ontario will also be limited.

Wholesale Market Impacts

Context

The wholesale market outcomes are the result or a reflection of electricity system needs and the types of resources that meet those needs. As a result, the use of gas has an impact on the suite of wholesale market prices in Ontario. These include direct influences on energy, capacity, and ancillary services prices, as well as indirect influences on intertie flows through trader responses to energy.
price signals. Gas is one of the few resource types in Ontario with non-zero short-run marginal production costs, and therefore it has a relatively outsized impact on energy market prices. The removal of the gas fleet would therefore shift pricing across Ontario’s markets, leading to a new pricing patterns influenced by the characteristics of the replacement resources and their ability to supply key services. This section explores in more detail some of these potential impacts.

In order to better understand the potential wholesale power-market impacts of phasing-out gas generation resources, the IESO developed several “bounding” or “bookend” cases that describe, in an illustrative way, what could happen to market prices if technologies with specific sets of uniform attributes were used to replace Ontario’s existing gas fleet. Along these lines, a “High Base-Load Case” and a “High Capacity Case” were developed in which a fleet of resources with specific attributes were used to replace Ontario’s gas-fired generators. These were compared with the “Base Case” in which the gas fleet continues to operate.

The High Base-Load Case assumed that a fleet of somewhat inflexible resources is added to the grid to replace the existing gas fleet. The key distinguishing characteristics of these resources are that they are not energy-limited, typically operate near full capacity, have low to zero short-run marginal costs, and that they are not nimble enough to provide very flexible output intrahour output flexibility or stand by energy such as operating reserves. In contrast, for the High Capacity Case, it was assumed that a fleet of highly flexible but energy limited or standby resources, in combination with intermittent resources, were added to the grid to replace Ontario’s gas fleet. It was also assumed that the intermittent resources would comprise of renewables that typically offer into the energy market at low to zero prices while the energy-limited or standby resources that operate based on energy pricing arbitrage and operating reserve revenues, as well as capacity payments.

(Jason) NTD: Suggest adding a graphic here to contrast the two cases at opposite ends with maybe an bi-directional arrow in between?

The purpose of developing these cases was not to create estimates of likely market outcomes, but to develop insights, in the face of considerable uncertainty, in how Ontario’s wholesale power-markets market could be impacted if resources types with attributes on two opposite ends of a spectrum of attributes were chosen utilized to replace Ontario’s gas fleet. More diverse replacement resource supply mixes would be expected to considerably soften these extreme impacts, and the 3 scenarios outlined earlier in the report fall within these bookends. Simulations were used to investigate the potential impact on energy prices, net exports, operating reserve prices, and curtailed energy. The observations are described below.

**The High Base-Load Case**

The High Base-Load Case represents a significant build-out of new non-emitting base-load capacity resources to replace the gas fleet from Ontario’s electricity system. These new base-load resources offer into the energy market at low to zero prices, and since they replace gas resources that offer into the energy market at higher prices there is a corresponding decrease and flattening of energy market prices compared to the Base Case where the gas fleet continues to operate. As the replacement resources increase the baseload of the supply mix the occurrence of surplus energy,
meaning the availability of energy above that needed to meet the province’s energy requirements for most hours of the year, also increases.

Intertie flows are driven by prices arbitrage opportunities between jurisdictions. With the persistent decrease in energy market prices in the High Base-Load Case traders are incentivized to export inexpensive Ontario power to neighboring jurisdictions over the interties. As a result, Ontario could potentially see net exports approximately doubling compared to the Base Case. At the same time, since the new base-load capacity does not offer operating reserves in the ancillary services markets, operating reserve prices rise several times higher as the availability of supply of operating reserves in Ontario without a gas fleet is markedly reduced. Finally, the availability of inexpensive energy for certain times of the year is much greater than demand and so curtailed renewable and baseload energy may increase up to ten-fold compared to the Base Case.

These changes are an extreme outcome that is representative of the loss of a highly flexible gas fleet being replaced with non-emitting, largely inflexible, base-load resources. In this scenario, resources would earn lower revenues through the energy market. Therefore, they would have to rely on higher capacity and operating reserve payments to be revenue sufficient or investment decisions would be more focused on these other revenue streams.

The High Capacity Case

The High Capacity Case represents a contrasting set of outcomes to the High Base-Load Case. In this case, a large build-out of new renewables and standby resources such as storage are used to replace the gas-fleet. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. Similar to the resources in the High Base-Load Case, the renewables offer into the energy market at low to zero prices, and this tends to decrease and flatten energy prices for much the year. However, there is an increase in the fraction of the year where energy prices are substantially elevated compared to the Base Case as standby resources set the price. These standby resources offer into the energy market based on their opportunity costs which tend to be higher than the offers from the gas fleet that they helped replace. As a result, high energy market prices for these hours, along with a general increase in variability, tend to occur to a greater degree in Ontario’s energy markets.

The standby resources include energy storage technologies which tends to dampen the availability of surplus energy availability on the system. There may also be increased risks of unserved energy during certain high demand periods (i.e. the summer), when there is a lack of hydroelectric availability, and this may require the IESO to include more manual/out of market actions taken to ensure reliability. Otherwise, impacts to other flows and markets are more moderate than in the High Base-Load Case. Therefore, export and import levels do not change materially. As there would be much more capacity available to provide ancillary services, operating reserve prices decrease for most hours, and curtailed renewable and baseload energy is lower compared to the Base Case. In this scenario, resources would tend to earn a higher proportion of revenues through the energy market, and resources would need lower capacity and operating reserve prices. Investment decisions would need to factor in such changes to revenue opportunities.

An illustrative comparison of energy prices for the cases is shown in the Error: Reference source not found below. Only single illustrative prices have been shown below for clarity. The reader should
note that real market impacts will extend more broadly to multiple locational prices following Market Renewal.

**Figure 8 | Illustrative Energy Prices versus Percentage of Time**

As shown in the above graph, the High Capacity Case will see increasing price variability in both frequency and magnitude. This reflects the introduction of an increased fraction of variable renewables on the grid as a replacement for gas resources. In contrast, for the High Base-Load Case, prices will be broadly depressed and there will be less variability. While there is still some price variation that will be important for resources in the energy markets, the high degree of low marginal cost baseload generation on the system may make pursuing large revenue opportunities more challenging.

**Market Impacts**

In both illustrative scenarios, complex problems such as the siting of replacement resources and the need to build new transmission infrastructure could not be practically included in the analysis. Many other important real-world factors such as detailed technology assumptions, year-to-year variations, build-out timing, structural changes to the economy, and developments at the grid edge also could not be incorporated into the analysis. It is not possible for the IESO to predict all these developments and fundamentally, this was not the intent of this report.
Instead, these results highlight that different sets of resources can be used to replace today's fleet of gas-fired resources, and directionally indicate how wholesale market outcomes could result. More importantly, this exercise has shown that the wholesale market is able to provide intuitive signals that reflect the system needs and the value of the resources able to meet the needs. Significant changes in Ontario's wholesale markets are a reflection of changes in the supply and demand conditions in the underlying system. The decision to go off-gas implies a shift to resources with different characteristics, and there will be corresponding shifts across Ontario’s markets. Depending on the suite of replacement technologies, a move off-gas could lead to a significant set of changes to flows and price signals seen across the electricity system in Ontario.

Opportunities to Move Towards an Emission-Free System in the Longer Term

**Hydrogen**

There are several areas in industry that will be hard to decarbonize. Technologies such as large-scale hydrogen production present a possible pathway towards the deep decarbonization of these industries. Some amount of hydrogen could also potentially be integrated into the existing natural gas infrastructure, with the potential to transport natural gas and hydrogen blends in existing pipelines and to combust it in conventional natural gas turbines. Hydrogen can be produced in a variety of ways, ranging from the steam reforming of methane to water electrolysis. Hydrogen could also enable long-term (e.g. interseasonal) energy storage. In this study however, the IESO chose not to consider hydrogen as a significant part of the supply mix, as large-scale production costs are currently thought to be prohibitive as a realistic natural gas replacement. Production costs may come down significantly in the future and could make hydrogen more competitive in the longer term, but this will likely occur further out past the 2030 timeframe considered in this study.

**Carbon Capture Utilization and Storage**

Carbon Capture Utilization and Storage (CCUS) solutions will be a significant part of a longer-term economy-wide deep decarbonization strategy and could be important for reaching lower emissions in many sectors. CCUS can be particularly helpful for hard-to-abate emissions that come from industrial processes where they may not be able to be addressed directly by electrification. In order for CCUS to be developed on a scale needed to lower emissions, it will require a collaborative approach. Areas of additional research and focus for CCUS will include specific geology for sequestration of carbon and the extent to which suitable sites exist in Ontario. Further, the use of existing or citing new long distance high pressure pipelines to transport CO₂ to storage sites will require further investigation to avoid siting and regulatory challenges. Although there is significant potential for large-scale CCUS in the long-term, this technology is currently unproven in Ontario, and has been seen as costly, with relatively high capital and operating costs. As a result, natural gas with carbon capture as a method for reducing emissions from the gas fleet was not assessed as part of the Scenarios given the forward looking timelines for this study.

**Increasing Hydroelectric Flexibility**

Place content here – to be provided by Paul Norris/OWA – revisiting the social, environment, cultural, ecological restrictions to now also consider climate change/electricity to see if we can increase operational flexibility in hydroelectric fleet.

Considerations for Phasing Out Natural Gas in the Electricity System | Public
Distributed Energy Resources

Broader Planning and Coordination

The electricity system is only a part of the lowering emissions strategy, and we must examine how Ontario uses energy as a whole. Electrification of the economy is where reducing economy-wide emissions can play a big role. For example, transportation electrification in the 2019 APO forecast resulted in a net economy-wide emissions reduction of 6 Mt/year when considering increased gas production to meet electricity needs of transportation electrification. Early retirement of gas-fired assets will increase the cost of electricity, making it a less economic fuel source, and thereby potentially slowing electrification and increasing economy-wide emissions.
Conclusion

Comms - Place content here
Appendices

Place content here
Off-Gas Material for Hydro One Discussion

Off-Gas Scenarios

- Scenario 1 - Complete gas phase-out by 2030 (in response to municipal city council resolutions)
- Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030
- Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs

Scenario 2 – Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030

Assumptions:

- Carbon benchmark of 370 tonne per GWh assumed to reach 0 tonne per GWh by 2030 for all gas fired generators (i.e. gas-fired generators pay the carbon tax on all emissions, including those in excess of the emissions allowances allowed by the Ontario EPS).
- Carbon tax is assumed to rise linearly from $50 per tonne in 2022 to $170 per tonne in 2030, and held constant at $170 per tonne thereafter.

Model Run:

- 2020 APO multi-area case run in UPLAN developed and produced to include the above carbon benchmark and carbon tax assumptions.

Results:

- Carbon emissions remained relatively stable at current levels, with the 0 BM case

- The implication is existing gas-fired generators will be uncompetitive with neighbouring jurisdiction generation due to higher variable operating costs; thus, exports will decline and gas generation will remain low.

- Higher marginal costs in Ontario due to the $170 per tonne carbon tax will result in a significant increase in imports.

- UPLAN model indicated the following imports in the various import ties:
Question: Is there additional transmission infrastructure required to enable this level of imports from the various import ties?
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Table of Contents [BC]
List of Figures [BC]
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Executive Summary [Communications]
- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X billion, and initiate work immediately for the development X, Y, Z

Chapter 1: Introduction
Study motivation [Communications]
- The future of gas generation in Ontario has become a focus of discussion for a number of municipalities as they consider efforts to tackle climate change, raising questions and concerns from stakeholders about the challenges and opportunities these discussions have raised.
- Such an undertaking would require a comprehensive plan to develop and invest in suitable replacement supply and reorient the system around the new supply mix in order to maintain the reliability of the system.

Objectives of the study [Communications]
- The objective of the study is to examine the reliability, cost, operability, timing, and wholesale market issues that would need to be addressed should the phase out of natural gas in the electricity system be considered

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- Emerging technologies, lowered emissions, others

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**Chapter 2: Scope of Study**

- Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions [Communications]

**Scenario development** [RM, VV, DR, SK, JP, JL]
- 2020 APO
  - Identify the base case assumptions
    - Base case for demand, supply, transmission, economics, GHG outlook, import/export, etc. is 2020 APO
    - Describe assumptions on benchmark of 370 t CO2/GWh and $50/t carbon price assumed in 2020 APO
  - Scenario 1 - Complete gas phase-out by 2030
    - Identify the assumptions, approach, methodology
  - Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030
    - Identify the assumptions, approach, methodology
  - Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs
    - Identify the assumptions, approach, methodology

**Areas of study** [RM, VV, DR, SK, JP, JL]
- Discuss the areas of study will include reliability, cost and wholesale market, operability, timing, emissions, others?

**Areas of study that is out of scope** [BC]
- Recommendations for policy decisions
- Demand impacts from decarbonization of the economy
- Consider emission impacts resulting from other jurisdictions

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**Chapter 3: Study Findings**

**Study Findings: Scenario 1 - Complete gas phase-out by 2030**
- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
- Cost [SK, JP]
- Import/Export [RM, VV, SK]
- Operability impacts [MTI]
- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

**Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030**
- Discussion of reliability impacts [RM, VV, DR]
- Lead times [RM, VV, DR, JL]
Study Findings: Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs

- Discussion of reliability impacts [RM, VV, DR]
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Market Impacts [Market Development & Resource Procurement]

- Qualitative description of market impacts of two bookend scenarios (replacement resource is baseload type resource vs. highly flexible resource); while the three specific scenarios outline above will likely fall within this bookend

Discussion on the opportunities to move towards an emission-free system in the longer term (post 2030) [RM, VV, DR, SK, JP, JL]

- In addition to the three scenarios, considering more broadly, this section will be a qualitative future looking analysis of potential strategies to move towards an emission-free electricity system beyond 2030
- This section aims to help frame discussions around longer term government targets to reduce economy-wide emissions where electricity could play a significant role.
- Analysis will outline opportunities and barriers that will need to be addressed including how emerging technologies may participate in the future (e.g. CCUS, hydrogen, etc.)

Chapter 4: Conclusion

- Key takeaways [Communications]
Off-Gas Scenarios

- Scenario 1 - Complete gas phase-out by 2030 (in response to municipal city council resolutions)
- Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030
- Scenario 3 - Supply mix based approach that examines a model portfolio of replacement resources that reduce emissions by 2030 with SMRs

Scenario 2 – Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030

Assumptions:

- Carbon benchmark of 370 tonne per GWh assumed to reach 0 tonne per GWh by 2030 for all gas fired generators (i.e. gas-fired generators pay the carbon tax on all emissions by 2030 as benchmark declines linearly from 370 tonne per GWh to 0 tonne per GWh).
- Carbon tax is assumed to rise linearly from $50 per tonne in 2022 to $170 per tonne in 2030, and held constant at $170 per tonne thereafter.

Model Run:

- 2020 APO multi-area case run in UPLAN developed and produced to include the above carbon benchmark and carbon tax assumptions.

Results:

- Carbon emissions remained relatively stable at current levels, with the 0BM (zero benchmark) case
- The implication is existing gas-fired generators will be uncompetitive with neighbouring jurisdictional generation due to higher variable operating costs; thus, exports will decline and gas generation will remain low. Natural gas production will remain consistent to 2021 levels in the 0BM case.
- Higher marginal costs in Ontario due to the $170 per tonne carbon tax will result in a significant increase in imports.
UPLAN model indicated the following imports in the various import ties:

Question: Is there additional transmission infrastructure required to enable this level of imports from the various import ties as modelled?
Off-Gas Material for Hydro One Discussion

Off-Gas Scenarios

- Scenario 1 - Complete gas phase-out by 2030 (in response to municipal city council resolutions)
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Scenario 2 – Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030

Assumptions:

- Carbon benchmark of 370 tonne per million kWh assumed to reach 0 tonne per million by 2030 for all gas fired generators
- Carbon tax is assumed to rise from $50 per tonne in 2022 to $170 per tonne in 2030, and held constant at $170 per tonne thereafter.

Model Run:

- 2020 APO multi-area case run in UPLAN developed and produced to include the above carbon benchmark and carbon tax assumptions.

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- Carbon emissions remained relatively stable at current levels, with the 0 BM case
- Implications is existing gas generators will be uncompetitive with neighbouring jurisdiction with a higher variable operating cost; thus, exports will decline and gas generation will remain low.
- Higher marginal costs in Ontario due to the $170 per tonne carbon tax will result in a significant increase in imports.
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Executive Summary [Communications]
- Highlight 3 to 5 key findings for this section [RM, VV, DR, SK, JP, JL]
  - E.g. To lower emissions by 2030 by X megatonnes, it is expected to cost $X
    billion, and initiate work immediately for the development X, Y, Z

Chapter 1: Introduction
Study motivation [Communications]
- The future of gas generation in Ontario has become a focus of discussion for a number
  of municipalities as they consider efforts to tackle climate change, raising questions and
  concerns from stakeholders about the challenges and opportunities these discussions have
  raised.
- Such an undertaking would require a comprehensive plan to develop and invest in
  suitable replacement supply and reorient the system around the new supply mix in order to
  maintain the reliability of the system.

Objectives of the study [Communications]
- The objective of the study is to examine the reliability, cost, operability, timing, and
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Chapter 2: Scope of Study
• Framing the discussion as a study focused on strategies to reduce emissions, including one scenario to look at gas phase out, in response to city council resolutions
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Scenario development [RM, VV, DR, SK, JP, JL]
This off-gas analysis is a based on the 2020 APO Scenario 1 projection provided in detail at the following cite.
Demand forecast with assumed conservation for the

• 2020 APO
  o Identify the base case assumptions
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  o Scenario 1 - Complete gas phase-out by 2030
    • Identify the assumptions, approach, methodology
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Scenario 2 is a market based approach that examines higher gas prices to reduce the utilization of gas to reduce emissions by 2030. Specifically, Scenario 2 assumes a linear increase to cost of carbon to $170/tonne by 2030 and a linear decline to the benchmark for all natural gas facilities from 370 Tonne/GWh in 2021 to zero by 2030. The demand, conservation, supply, and transmission assumptions are expected to remain unchanged from 2020 APO Sc1. An energy production assessment that includes the economic imports and exports between Ontario and its neighbours is conducted. This assessment used to simulate the Ontario electricity market based on system economic will inform system costs and system performance such as operability and emissions. The results of this energy assessment is a reduction in gas production for the export market and increase in imports to meet domestic consumption needs based on the economics of a higher cost of natural gas due to the cost of carbon.

Identify the assumptions, approach, methodology
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Chapter 3: Study Findings

Study Findings: Scenario 1 - Complete gas phase-out by 2030
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- Import/Export [RM, VV, SK]
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- Emission projections [SK]
- Other considerations [RM, VV, DR, SK, JP, JL; Market Development & Resource Procurement; MTI]
  - Wholesale market impacts, NYIBYism, stranded assets, engagement and consultations, siting, etc.

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  o Identify the assumptions, approach, methodology

• Scenario 2 – Market based approach that examines higher gas prices to reduce
  utilization of gas to reduce emissions by 2030

Scenario 2 is a market based approach that examines higher gas prices to reduce the
utilization of gas to reduce emissions by 2030. The 2020 APO scenario 1 is augmented to
assume a linear increase to the cost of carbon from $20/tonne in 20xx to $170/tonne by
2030 plus a linear decline to the benchmark for all natural gas facilities from 370
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is a reduction in gas generation for exports and an increase in imports to meet domestic consumption needs, based on the economics of the higher cost of natural gas due to the increase for the cost of carbon and the elimination of the natural gas facility benchmark.

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Areas of study [RM, VV, DR, SK, JP, JL]
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  The role of this report is to focus on the reliability, operability of the scenario and to generate the net present value of system cost for the 2022 to 2030 period, and emissions

Areas of study that is out of scope [BC]
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Chapter 3: Study Findings

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Study Findings: Scenario 2 - Market based approach that examines higher gas prices to reduce utilization of gas to reduce emissions by 2030

The market based approach relies on government regulatory changes to the cost of carbon and the elimination of the benchmark to natural gas facilities which are action beyond the control of the IESO.

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