Assessment of the Alignment of the Costs and Benefits of Clean Energy Assets

Prepared for:

Prepared by:
Navigant
Bay Adelaide Centre
333 Bay Street, Suite 1250
Toronto, Ontario M5H 2R2

navigant.com

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GLOSSARY

Clean Energy Benefits: the value of the benefits determined to be derived by or accruing to specified consumers as a result of the clean energy initiative, including as a result of clean energy costs

Clean Energy Costs: the value of the costs allocated to specified consumers as a result of the clean energy initiative, including as a result of past, present and expected costs incurred in respect of,
(a) the amounts to be paid or reflected by the IESO in adjustments made under section 25.33 of the *Electricity Act, 1998* or any provision that is the successor to that provision, which relate to contracts or amounts for,
(i) renewable energy generation or capacity,
(ii) conservation and demand management,
(iii) energy storage,
(iv) energy efficiency,
(v) natural gas generation and capacity, excluding contracts relating to amounts payable by the IESO under section 78.2 of the *Ontario Energy Board Act, 1998* and excluding such other contracts as may be prescribed,
(b) payments made or expected to be made under section 78.5 of the *Ontario Energy Board Act, 1998*, and
(c) such other costs or estimated costs as may be prescribed; ("coûts de l'énergie propre")
"clean energy initiative" means the policies of the Government of Ontario related to,
(a) eliminating coal generation and fostering the growth of and investment in clean, modern and reliable energy sources and technologies,
(b) removing barriers to and promoting opportunities for clean and renewable energy sources and technologies,
(c) promoting conservation, demand management and energy efficiency, and
(d) investing in energy infrastructure to ensure a clean, modern and reliable system; ("initiative pour l'énergie propre")
"electricity vendor" means,
(a) a licensed distributor,
(b) a licensed retailer,
(c) the IESO in circumstances where it directly invoices a specified consumer for electricity used in Ontario, or
(d) such other person as may be prescribed; ("vendeur d'électricité")

Fair Allocation Amount: An amount calculated such that Clean Energy Costs for various initiatives are paid for proportionally in time to the Clean Energy Benefits that RPP-Eligible Ratepayers receive from these initiatives.

Fair Hydro Act: A bill in the Legislative Assembly of Ontario designed to align Clean Energy Costs with Clean Energy Benefits.

Regulated Price Plan: A regulated price available to residential and small commercial ratepayers.

1. OVERVIEW

Blake, Cassels & Graydon LLP retained Navigant Consulting Ltd. (Navigant), on behalf of the Ontario Ministry of Energy, to evaluate the extent to which clean energy costs are incurred over the same period as clean energy benefits, and if not, to assess alternate cost recovery structures that provide better alignment.[1] This analysis mirrors the goals and structure of the Ontario Fair Hydro Plan. The analysis considered natural gas, wind, and solar electricity generation assets, as well as conservation programs and the early retirement of Ontario's coal-fired generation assets (the "Clean Energy Assets"). Navigant also calculated a Fair Allocation Amount, which is the payment stream for the Clean Energy Assets where Clean Energy Costs are proportional to Clean Energy Benefits over the useful life of the assets.

Ontario ratepayers currently pay for the entire capital cost of natural gas, wind, and solar electricity generation assets over the term of power purchase agreements, which generally run for 20 years. Provincial ratepayers pay for conservation programs in the year the costs are incurred. Similarly, over the period of 2009 to 2014, ratepayers made annual payments associated with the early shutdown of coal fired-generation assets.

The benefits associated with the natural gas, wind, and solar electricity generation assets are tied to (i) when they produce electricity, and/or (ii) when they are available to produce electricity. Similarly, the benefits associated with conservation and the early retirement of coal-fired electricity generation assets are tied to the avoided electricity generation and the avoided emissions, respectively. These benefits occur over the entire life of the conservation measures and the expected remaining life of retired coal-fired generation assets.

Three primary questions are addressed in this report:

1) What is the technical feasibility of operating clean energy assets beyond the twenty-year power purchase agreement term?
2) What are the costs of operating the clean energy assets over their useful life, considering prudent maintenance and repowering expenditures, which would be borne by ratepayers after the twenty-year power purchase agreement term?
3) What is the appropriate allocation of clean energy costs to Regulated Price Plan (RPP)-eligible in each period if clean energy costs are aligned with clean energy benefits?[2]

The first question determines the period over which the clean energy costs can be reasonably allocated. Ontario's natural gas-fired generating facilities are expected to operate for 40 years with prudent maintenance and capital expenditure, and that wind and solar facilities are expected to operate for 25 years, or 50 years with one full repowering in year 25. The remaining useful life of the coal-fired generation facilities, absent the early shutdown, is approximately 15 years.

The second question determines the costs in addition to the payments under the existing power purchase agreements that would be borne by Ontario ratepayers if the Clean Energy Assets operated over their entire useful life. These costs cover on-going operations and maintenance, as well as repowering and/or major maintenance as required.

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[1] Clean energy costs and clean energy benefits are a s defined in the Fair Hydro Act, 2017.

[2] Specified consumers is as defined in the Fair Hydro Act, 2017.

Figure 1-1 below illustrates four clean energy cost recovery scenarios.[4]

Figure 1-1 Allocated Clean Energy Costs for RPP Eligible Consumers (Nominal$ Million)

Source: Navigant analysis

In Figure 1-1, the blue line represents a status quo scenario. The green line represents the Fair Allocation Amount, a calculated value where all costs are amortized and allocated proportionally to the Clean Energy Benefits provided by the Clean Energy Assets over their useful life. The dotted green line represents the Fair Allocation Amount if the remaining costs of the assets are allocated proportionally to the remaining benefits of the assets. This dotted line is below the solid green line because payment over 2005-2016 was above the Fair Allocation Amount in these years.

The orange line represents a scenario where the Clean Energy Asset costs incurred by Ontario ratepayers from 2005 to 2016 in excess of the fair allocation amount are rebated in 2017-2021 in quantities designed to reduce the Global Adjustment by approximately 25 percent in these years. The difference between the costs actually incurred by Ontario ratepayers from 2005 to 2016 and the fair allocation amount is approximately $5.7 billion (Nominal $), which would be worth approximately $6.7 billion in 2017 with interest.

4 Not all expenditures under the Global Adjustment are clean energy costs. Most notably excluded are costs associated with nuclear generation. Clean energy costs are also only those costs allocated to RPP-eligible customers.

All amortized costs in the fair allocation amount and the status quo scenarios are structured to end in 2050. Thus the annual costs associated with all four scenarios in Figure 1-1 have an identical net present value[5] over the 2005 to 2050 period.

A table of key financial assumptions is provided in Table 1-1 and a table key technology assumptions is provided in Table 1-2.

Table 1-1 Key Modeling Assumptions

Parameter	Value
Discount Rate	4.5%
Borrowing Rate	4.5%
Inflation Rate	2%

Table 1-2 Key Technology Assumptions

Technology	Parameter	Value
Natural Gas	Repowering Cost (2017$/kW)	Plant-Specific
Natural Gas	Year 1 Fixed O&M (2017$/kW-yr)	Plant-Specific
Wind	2040 Repowering Cost (2017$/kW)	$2,291
Wind	Year 1 Fixed O&M (2017$/kW-yr)	$49.25
Wind	Fixed O&M Escalation	2%
Wind	Initial Capacity Factor	32%
Wind	Repowered Capacity Factor	37%
Wind	Capacity Factor Degradation	1.6%
Solar	2040 Repowering Cost (2017$/kW)	$933
Solar	Year 1 Fixed O&M (2017$/kW-yr)	$27
Solar	Fixed O&M Escalation	2%
Solar	Initial Capacity Factor	32%
Solar	Repowered Capacity Factor	37%
Solar	Capacity Factor Degradation	0.5%

5 A societal discount rate of 4.5% is used throughout the analysis to represent the time value of money.

2. TECHNICAL FEASIBILITY OF LIFETIME EXTENSION FOR CLEAN ENERGY ASSETS

This section outlines the assumptions and research underlying the feasibility of achieving the modeled lifetimes for the clean energy analysis. It is broken into three subsections, exploring (1) standard practice and experience when planning and designing clean energy assets, (2) the state of the Ontario fleet, and (3) leasing, regulatory, and contract issues associated with lifetime extension. Each of these subsections is further divided between gas, wind, and solar assets. The expected lifetimes were formulated using a combination of interviews, literature review, and consulting publicly available and Navigant proprietary databases.

Overall, no significant leasing, regulatory, or contract issues were identified which would limit lifetime extension. Navigant ultimately identified a useful life of forty years for the gas units (with partial repowering in some cases), and a useful life of twenty-five years for solar and wind units (with another twenty-five years possible after full repowering), after investigating the design and component failure rates and replacement costs for these asset classes.

2.1 Planning and Design Experience

2.1.1 Gas

Power stations utilizing natural gas are most frequently developed assuming a twenty-year life of the plant design, which is often dictated by the terms of commercial contracts. The actual plant life, however, can exceed forty years if the operator follows prudent operations and maintenance (O&M) practices and the recommend repair and replacement intervals for combustion turbine (CT) hot section components and balance of plant equipment.

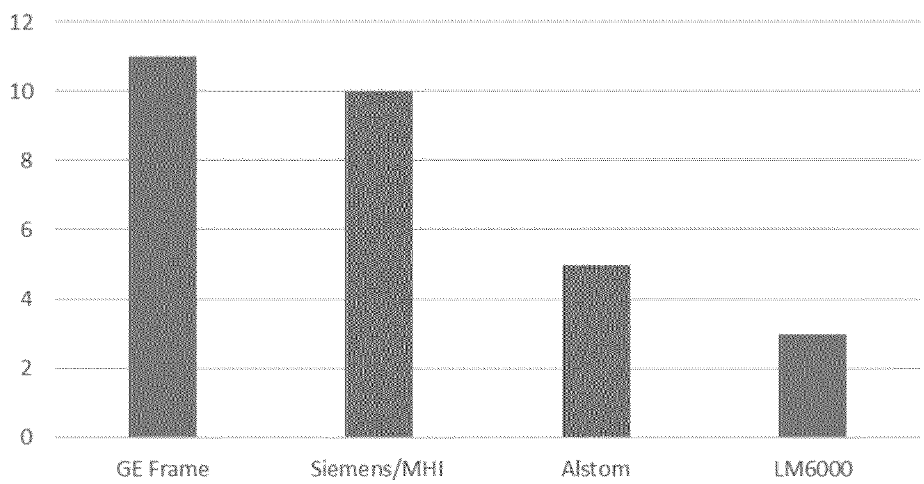
Over the longer term, while an existing plant can continue operations over this life span, advances in technology (such as improved heat rates) may make the plant's energy offers uncompetitive and limit operations to a few peaking hours a year.

Most recently constructed natural gas power stations in Ontario (and throughout North America) utilize CTs as the prime mover, either in simple cycle or combined cycle configuration. In simple cycle configuration, the combustion turbine directly drives a generator, requiring relatively fewer pieces of equipment, which lowers the cost per kilowatt (kW) of capacity. In combined cycle (CC) configuration, the exhaust heat from the CT is recovered in a heat recovery steam generator (HRSG) which produces steam to drive a steam turbine generator. This maximizes efficiency of the energy conversion of natural gas to electricity, but at a higher installed capacity cost than simple cycle configuration. In addition, some plants in Ontario were designed for co-generation (cogen), where a percentage of the steam produced in the CC application is delivered to another company, the steam host, to be utilized in the company's non-electric processes.

The three types of units discussed above, simple cycle, combined cycle and co-generation, have different design parameters. The simple cycle units are fast-starting units that are designed for peaking applications to either stabilize the electrical grid with ancillary services, or to provide energy to the grid during times of high demand. Simple cycle units are typically designed for a low number of starts, less than fifty per year and are generally operated by a small operations staff.

There are 29 combustion turbines at the 16 gas-fired power stations in Ontario, of which the units at twelve were included in the model analysis (the remainder were in service prior to 2005, the analysis start year). Twenty-six of Ontario's combustion turbines are heavy frame type units and three are aero derivative units. The frame turbines include the Frame 7 series manufactured by General Electric (GE), the 501F/G series manufactured by Siemens/Mitsubishi Heavy Industries (MHI), and the GT11 series manufactured by Alstom. The three aero derivative turbines are all versions of the LM6000 turbine manufactured by GE. The distribution of Ontario's gas-fired combustion turbine manufacturers is shown in Figure 2-1 below.

Figure 2-1 Ontario Combustion Turbines by Manufacturer



Source: SNL, ABB Energy Velocity, and Navigant Analysis

The major maintenance and CT parts purchases are covered under long-term service agreements or contractual service agreements with the original equipment manufacturer. These agreements are very specific and require that the CTs be stopped and maintenance be conducted at the required intervals specified by the manufactures.

Combined cycle units were initially envisioned in the early 1990's as baseload power stations, however over time they changed to mid-merit units that assume load when renewable generation drops off and during periods of high demand. Though slower to start than simple cycle units, combined cycle units can still be brought online quickly to provide larger amounts of energy to the grid than simple cycle units. Given the mid-merit dispatch of these units, combined cycle units are typically designed to start between 150-250 times per year.

Co-generation units are highly efficient and either deliver part of the steam from the HRSG to a steam host, or in the case of combined heat and power (CHP) units, use the steam to generate hot water or cold water for various heating and/or cooling applications. Co-generation units are typically designed for baseload operations (less than 10 starts per year) to serve the steam host, and can meet the steam demand while fluctuating the amount of power generated.

Over the last 15 years the rate of gas-fired power station development has increased due to lower natural gas prices, environmental regulations (including CO_2 reduction mandates), and the increasing value of flexibility for renewable generation firming. With the growing penetration of renewable energy sources in the Ontario market we have also observed that natural gas stations have shifted from principally being dispatched during the day time to cover peak loads to being principally dispatched to firm renewable energy and maintain reliability during periods when wind and solar power plants drop off.

As units reach the end of their power sales contracts (usually 20 years), they have many lifetime extension options available. As mentioned, CTs can operate for 40 years if proper O&M practices have been followed. Most CTs have a major inspection that is required on the turbine rotors at either 200,000 factored fired hours/equivalent base hours or 5000 factored starts. The rotor is pulled, disassembled and inspected to determine if there has been damage to the turbine wheels; when this is complete the rotors are reassembled and can be certified for another 100,000 hours of operations. Given the dispatch regime of units analyzed, most the units did not reach this milestone during the initial 20-year term, and some units did not require it over the forty-year operating life. The HRSGs can also be operated for more than 20 years with proper repairs and replacement of components in the heat affected zones, the super-heater sections, and high flow rate areas such as the economizer. Steam turbines and generators also have expected lives of at least 40 years if the proper maintenance and inspections are conducted at the recommended intervals. Due principally to the concurrent expected life of the CTs, steam turbines, and generators, Navigant assumed that all gas plants would have a 40-year life, with repowering as necessary.

2.1.2 Wind

Until the past few years, wind plants were generally planned to be in operation for 20 years. Recently, many wind project developers have increased the planning life to 25 or even 30 years. This increase in planned life of wind plants is reflective of reliability improvements in key components such as gearboxes, and that repairs and replacements to components can extend longevity of a wind plant.

However, lifetimes of individual components within a wind plant vary widely. The towers are mostly steel and last 50 to 100 years. The foundations and cables have similar long lifetimes. The gearboxes generally last 5 to 7 years and therefore are replaced twice on average over a 20-year plant lifetime. Lastly, blades generally last 10 to 12 years and therefore are replaced once on average over a 20-year plant lifetime.

Further, the accuracy of wind plant generation forecasts has improved over time. In the early years of the industry, plants consistently underperformed compared to forecasts of availability, reliability, and cost. More recently, cost and reliability forecasts have become more accurate due to technology advancements in manufacturing and operation of wind turbine components as well as the wealth of industry experience that is now available for forecasting purposes.

Most wind plants have decommissioning plans in place, as required either by lenders or leaseholder agreements. These plans generally call for complete removal of the equipment and reclamation of the land for a suitable use. However, most owners expect that the wind turbines will be either be refurbished (replaced with similar components) or fully repowered (replaced with larger components) at least once prior to the ultimate removal of equipment.

2.1.3 Solar

Solar plants are most commonly planned to be in operation for 20 years. Contracts usually take the form of a solar land lease or power purchase agreement (PPA), where the fixed monthly fee or power price is determined based on the amount of electricity the plant is expected to produce for 20 years after installation. Solar facilities in Ontario that are 10 MW or above in size have 20-year contracts through either the renewable energy standard offer program (RESOP), feed-in-tariff (FIT) or large renewable procurement (LRP) programs. Twenty-year contract terms are typical in the US and other markets although some can be for less than 20 years.

Several public and private tools have become available to forecast generation through the lifetime of solar contracts over the past ten years. Performance of solar facilities relies on key inputs such as system capacity, configuration (fixed tilt vs. single-axis or dual-axis tracker technology) and location. These forecasting models also account for losses due to shading and snow, as well as DC/AC losses. Over time, these models have become more sophisticated and accurate resulting in generation experience being consistent with planning assumptions.

As photovoltaic (PV) module technology progresses, the technical lifetime of panels has increased from 20 to 25 years, and even 30 years for more advanced models. The lifetime of other components has improved at a slower rate. Ground-mount racking is typically constructed of galvanized steel and aluminum with a 20-year warranty from the manufacturer. Standard warranties for inverters are typically 10 years (an increase from the historical 5 years) with extended options available at extra cost. The technical lifetime for system wiring is typically 12 years. Therefore, inverters and wiring are replaced at least once on average over a 20-year lifetime.

For most existing solar contracts in Ontario, the current plan is to dismantle and liquidate after the 20-year contract term. However, with longer technical lifetimes due to technology improvements, some investors may choose to continue to operate the system as a merchant, and sell power into the market for years 21 through 30 at the local price of power.

Decommissioning usually doesn't include equipment reuse, as the second set of inverters and wiring would be near end of life and panel technology is advancing quickly enough that it would likely not be reused either.

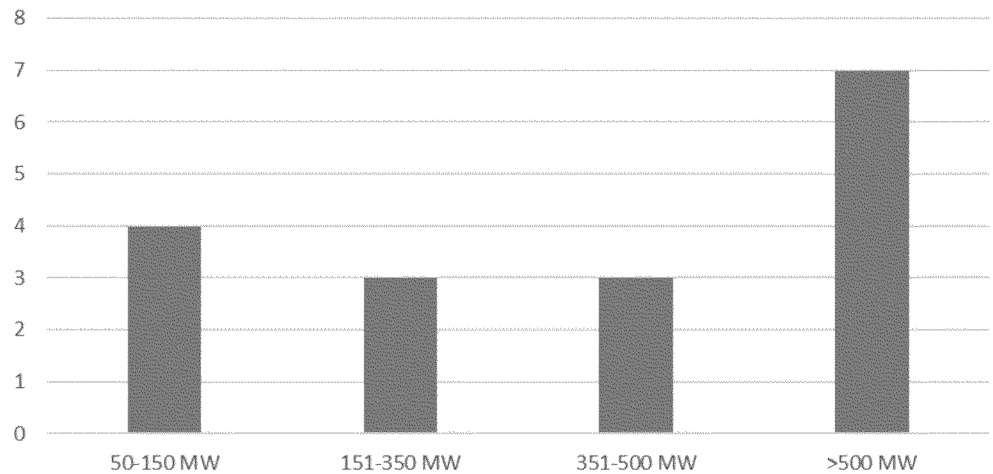
2.2 State of the Contracted Generator Fleet

2.2.1 Current State of Operating Fleet

2.2.1.1 *Gas*

A total of 17 natural gas-fired power plants located in Ontario were evaluated with a total installed capacity of 7,291 MW. Of these, 13 plants were considered in this lifetime extension analysis. Most plants were combined cycle but some were also co-generation or simple cycle. The plants had installed capacities ranging from 73 MW to 1005 MW, with the average installed capacity being 456 MW. The distribution of the natural gas-fired power plants can be seen in Figure 2-2 below.

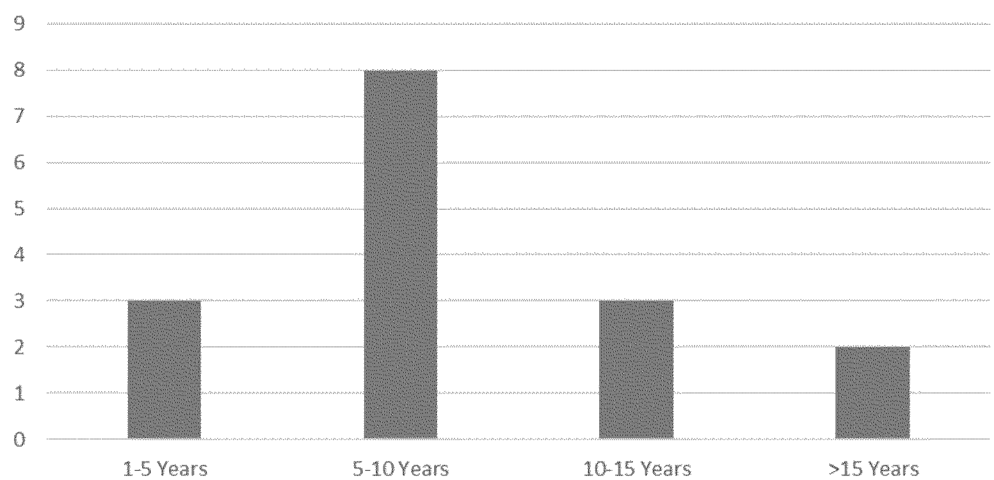
Figure 2-2 Size Distribution of Gas-Fired Generating Stations in Ontario



Source: Navigant Analysis

The average age of the gas-fired plants was 9 years, with the oldest being the Cardinal Power Plant which is 23 years old and the newest being the Napanee Generating Station which is under construction with a milestone commercial operation date of December 2018. Most plants have been in service for under 10 years, as shown in Figure 2-3 below.

Figure 2-3 Age Distribution of Gas-Fired Generating Stations in Ontario



Source: Navigant Analysis

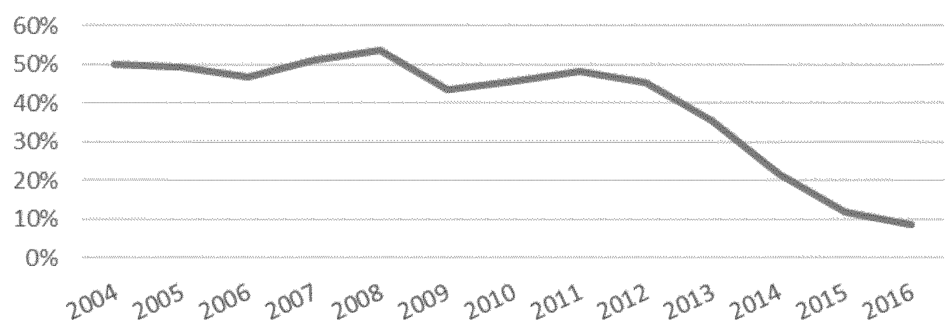
The net capacity factors for the different type of gas-fired power plants have shown a downward trend in general. Combined cycle units showed a peak capacity factor in 2007, when there were only two units in commercial operation, of 52%. As more units came online after 2008 the net capacity factor dropped to the mid 20% range and rose through 2012 to 34%. Since 2012 however, the net capacity factor has shown a downward trend as demonstrated in Figure 2-4. Below. Capacity factors have been pressured in recent years by renewable build, the return of some nuclear generating stations to service, low provincial load growth, and reduced power prices in some of Ontario's neighbors. These factors have been partially offset by the retirement of Ontario's coal fleet, but reduced capacity factors in the later years of those stations limited the upside for the CCGT fleet.

Figure 2-4 CCGT Annual Net Capacity Factor (Ontario)

Source: ABB Energy Velocity

Cogeneration units have also shown a similar trend in capacity factors. From 2004 through 2012, the capacity factor was almost flat at around 50%; however, since 2012, the net capacity factor has shown a steep decline to 9% in 2016 as shown in Figure 2-5 below.

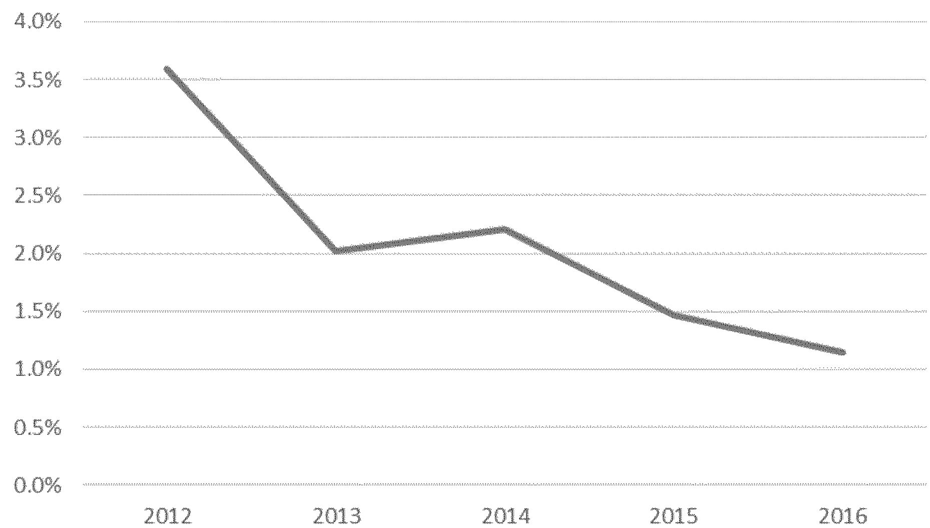
Figure 2-5 Co-Generation Annual Net Capacity Factor (Ontario)



Source: ABB Energy Velocity

The single simple cycle power station, York Energy Centre, which came on line in 2012 has shown a steady downward trend from 4% in 2012 to 1% in 2016 as demonstrated in Figure 2-6.

Figure 2-6 Simple Cycle Net Capacity Factor (Ontario)



Source: ABB Energy Velocity

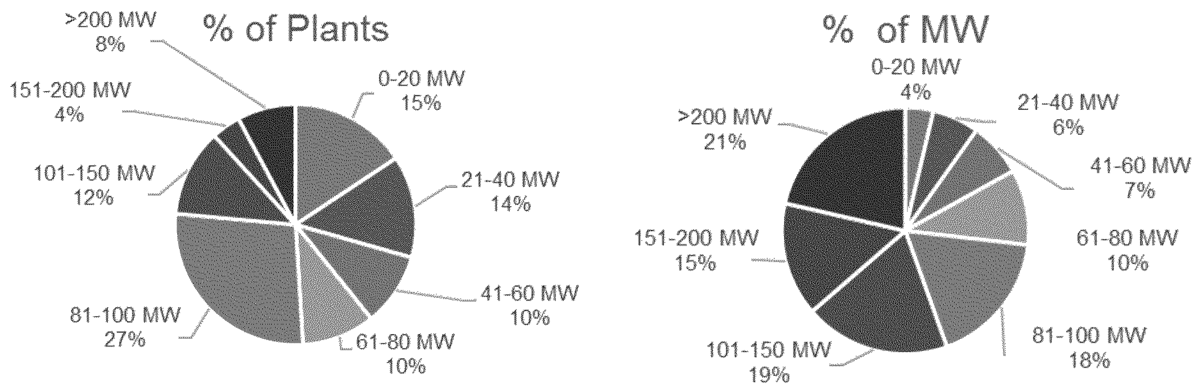
Given the relatively low utilization of the Ontario gas fleet as measured by capacity factor, starts, and hours of operation, Navigant estimates that the plants have a dependable life of forty years, with some plants requiring a major rotor replacement and others not requiring such replacement over the forty-year life. Given the lifetime of the plants, this results in some plants retiring in the 2040s and others in the 2050s after the end of the analysis scope.

2.2.1.2 *Wind*

The following is a profile of the wind fleet in Ontario as of year-end 2016:

- Number of Plants and MW. There were 656 wind plants in operation in Ontario with a total capacity of 4,751 MW.
- Size Distribution. As shown on the left side of Figure 2-7 below, the most common wind plant size in Ontario is 81-100 MW, with 27% of wind plants, followed by the 21-40 MW segment with 14% of wind plants. On a MW capacity basis, the right side of Figure 2-7 below shows that the >200 MW is the largest segment with 21% of total MW, followed by the 101-150 MW segment with 19% of total MW.

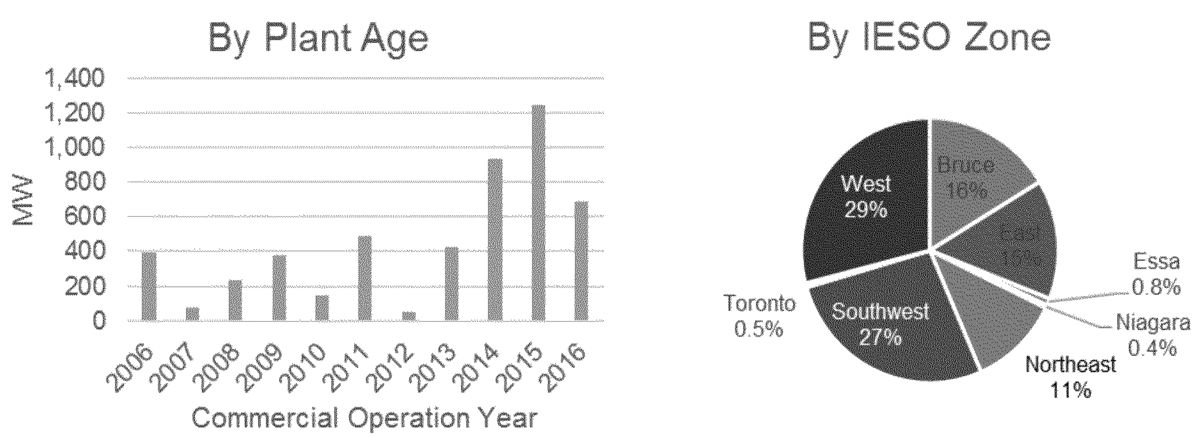
Figure 2-7 Distribution of Wind Plants



Source: Navigant Analysis

- Age Distribution. As shown on the left side of Figure 2-8 below, the most common commercial operation year is 2015, when 1,250 MW of capacity was installed. 15 plants with 557 WTGs were started up in Ontario in 2015.
- Location. As shown on the right side of Figure 2-8 below, the West and Southwest zones (as defined by Ontario's Independent Electricity System Operator) had the most wind power capacity, with 29% and 27% of installations, respectively.

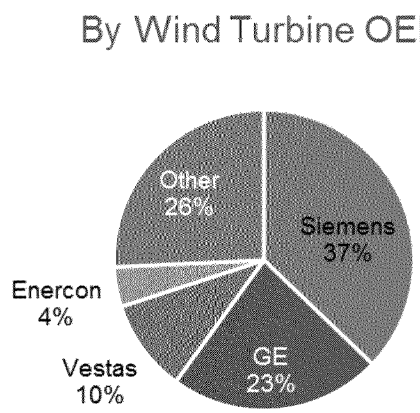
Figure 2-8 Age and Location of Wind Plants (Ontario)

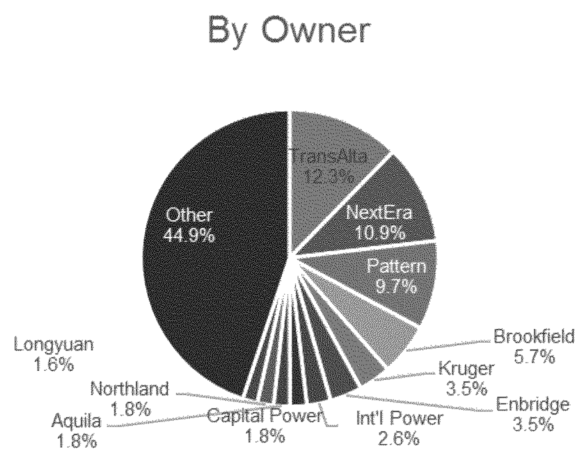


Source: Navigant Analysis

- Wind Turbine OEM Market Share. As shown on the left side of Figure 2-9 below, the WTG market in Ontario is relatively concentrated, with 74% of the market controlled by the top 4 suppliers: Siemens (37%), GE (23%), Vestas (10%), and Enercon (4%).
- Wind Plant Owner Market Share. As shown on the right side of Figure 2-9 below, the wind plant ownership market in Ontario is relatively dispersed, with only 53% of the market controlled by the top 10 owners. The leading owners are TransAlta Utilities (12%), NextEra Energy (11%), and Pattern Energy (10%).

Figure 2-9 Turbine OEMs and Owners of Wind Plants (Ontario)



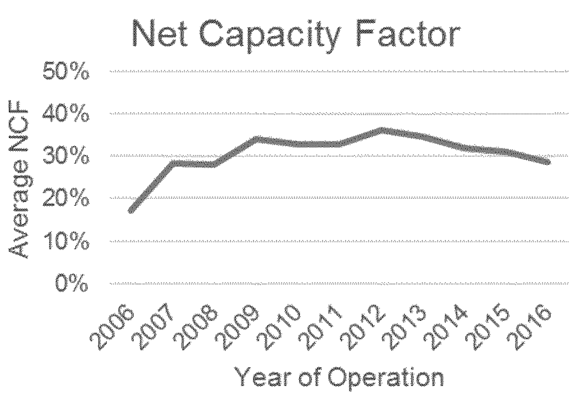


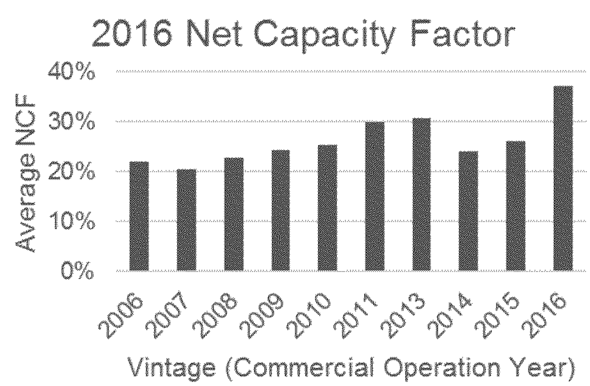
Source: SNL, ABB Energy Velocity, Navigant Analysis

- Net Capacity Factor. As shown on the left side of Figure 2-10 below, the average net capacity factor (NCF) for wind plants in Ontario was 29% in 2016. This value is slightly lower than the 2012 peak of 36% but considerably higher than the 2006 average of 17%. The slight reduciton since 2012 may be due to lower winds, increased curtailment due to transmission constraints, or the impact of a few smaller plants with lower NCFs starting up in 2014.

  The right side of Figure 2-10 below shows average 2016 NCFs for wind plants in Ontario by vintage (commercial operation year). The trend is generally upwards, meaning that newer wind plants generally have higher NCFs compared to their older counterparts. The average 2016 NCF for plants that started up in 2016 was 37%, considerably higher than any other vintage. Wind plant capacity factors are assumed to degrade at 1.6% per year.

Figure 2-10 Net Capacity Factor of Wind Plants (Ontario)





Source: ABB Energy Velocity

- Plant Condition and O&M Practices. Wind plants in North America typically have WTG warranties in place for the first 2 to 5 years of operation. During the warranty period O&M is typically performed by the WTG vendor. When O&M is performed by an operator other than the OEM, the operator will follow the OEM's maintenance practices as required to maintain the warranty. Most wind plants are therefore usually in excellent condition for the first 2 to 5 years of operation regardless of the operator. Two-thirds of the Ontario fleet have been in operation 5 years or less, so the average Ontario wind plant is generally in very good condition.

Given the age and expected life of Ontario's wind fleet, the wind plants are expected to begin exiting their current twenty-year contracts in the mid to late 2020s and repowering in the early to mid-2030s (more information on repowering assumptions is available in section 3.1.2.2).

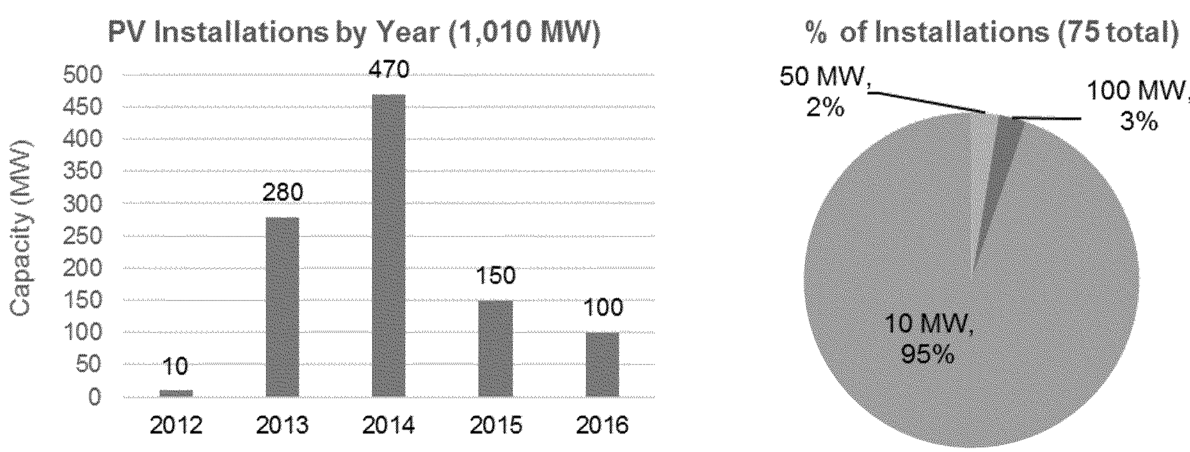
2.2.1.3 *Solar*

Ontario has a large amount of solar capacity below 10 MW, which was modeled in the financial analysis, but Navigant's lifetime extension analysis for solar plants was based on systems 10 MW or greater. These systems were deemed representative of the larger solar fleet.

The following is a profile of the solar fleet in Ontario as of year-end 2016 (of systems 10 MW or greater):

- Number of Plants and MW. There was a total of 75 solar ground-mounted systems (10 MW or greater) in operation in Ontario with a total capacity of 1,010 MW at the end of 2016.
- Age Distribution. The left side of Figure 2-11 below shows the introduction of solar capacity over time starting in 2012. The year 2014 saw the highest capacity and number of installations. The average age of the fleet is 3.3 years.
- Size Distribution. As shown in the right side of Figure 2-11 below, the most common PV system size in Ontario is 10 MW which is the cap for projects except for the Samsung projects which are 100 MWs in size, and some of the LRP projects. 2012 and 2013 saw only 10 MW installations. In 2014-2016, two 50 MW and one 100 MW system were introduced by Samsung.

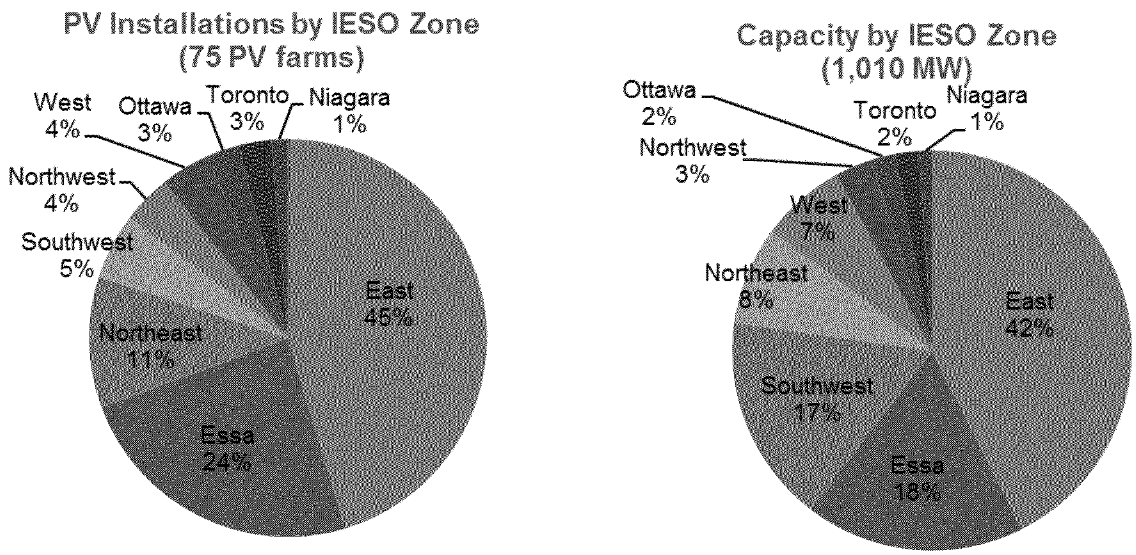
Figure 2-11 Age and Size Distribution of Ontario PV Systems 10 MW or greater



Source: Navigant Analysis

- Location. The number of installations are presented on the left side of Figure 2-12 below, and the total capacity on the right distributed across the IESO zones. As shown in the Figure 2-12 below, 45% of the operating PV systems in Ontario are in the East zone, which hosts 42% of the installed capacity. This large share is driven by available land, available transmission capacity and proximity to the load centers. Only 5% of operating PV systems are in the Southwest zone, but that represents 17% of the installed capacity due to larger system sizes in that region.

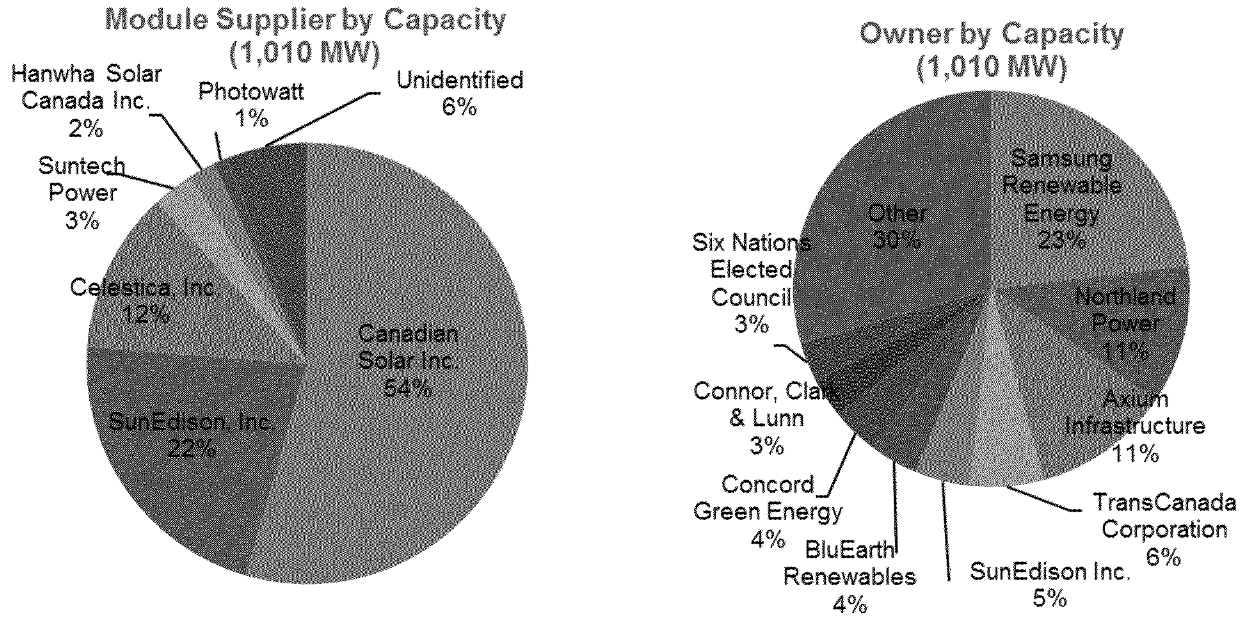
Figure 2-12 Location of Ontario PV Systems 10 MW or greater



Source: Navigant Analysis

- PV Module Supplier Market Share. As shown on the left side of Figure 2-13 below, the module market in Ontario is relatively concentrated, with 54% of the market controlled by the top supplier, Canadian Solar. 22% percent of the market has SunEdison panels (SunEdison filed for bankruptcy protection in the US in April 2016 and the company's Canadian unit filed for bankruptcy in October 2016). Other suppliers include Celestica (which is shutting down their solar manufacturing division in 2017), Suntech Power, Hanwha and Photowatt.
- PV System Owner Market Share. The right side of Figure 2-13 below shows the 10 owners with the highest PV operating capacity in Ontario. Samsung owns the largest portion of the operating fleet at 23%. Northland Power and Axium Infrastructure own the second and third largest in terms of capacity respectively.

Figure 2-13 PV Module Supplier OEMs and Owners of Ontario PV Systems 10 MW or greater



Source: SNL, ABB Energy Velocity, Navigant Analysis

- Capacity Factor. The average capacity factor of the operating solar fleet in Ontario according to data from the IESO is 16.3% (based on MW-AC). The relatively high capacity factor in the past 3 years is due to a higher overbuild ratio (on the range of 20% to 40%, the latter in more recent years), driven by the drop in panel prices. The capacity factor for new PV installations can be increased via higher DC-AC oversizing or introduction of axis tracker technology. The degredation rate of all systems is approximately 0.5% per year.

Table 2-1 Average Capacity Factor of Ontario's Operating PV Fleet

Year	Capacity Factor (based on MW-AC)
2014	15.4%
2015	17.4%
2016	16.0%
Average	**16.3%**

Source: IESO

- System Condition. As most operating systems are under 10 years old, the condition of the key components has not experienced much degradation, if any at all. Contracts typically include an O&M and lifecycle budget intended to maintain high performance conditions.
- O&M Practices. Preventative and reactive maintenance for ground-mounted PV systems usually includes panel cleaning, snow removal, lawn mowing and periodic verification of wiring and support integrity. O&M prices are only projected to increase with escalation in labor and other material costs. Inverter replacement requires additional O&M usually offered by the inverter manufacturer. Standard warranties are 5-10 years, with options to purchase extended warranties upfront (e.g., 20-year extended warranty).

Some companies that provide O&M services for utility-scale PV systems in Ontario include SMA, First Solar, Inc., SunEdison, NextEra Energy Canada ULC, SunPower, Canadian Solar, Inc., Enfinity, Northland Power, Inc., and EDF Renewable Energy, Inc.

Given the age of Ontario's solar fleet, most plants will not begin rolling off their twenty-year contracts until the early-to-mid-2030s, and most repowering will not occur until the mid-to-late 2030s. More information on repowering assumptions can be found in section 3.1.2.3.

2.2.2 Component Failure Rates and Operating Life

2.2.2.1 Gas

The generation performance and failure rate data of gas-fired plants is not publicly available and is generally held confidential by plant owners. It is reasonable to assume that performance and failure rates for Ontario plants will be like those of plants in Navigant's Generation Knowledge Services (GKS) data base. The GKS data base contains a broad and growing user and unit mix and currently has over 2,400 generating units representing over 527 GW of capacity, of which over 135 GW consists ofcombustion turbines and combined cycle units.

The following metrics were used in evaluating the Equivalent Availability Factor (EAF) and Equivalent Forced Outage Rate (EFOR), which are reasonable estimates of the performance of Ontario's gas fleet:

$$EAF = \left(\frac{AH - (EUNDH + ESDH)}{PH} \right) \times 100$$

EAF = Equivalent Availability Factor
AH = Available Hours
EUNDH = Equivalent Unit Derated Hours
ESDH = Equivalent Seasonal Derated Hours
PH = Period Hours

$$EFOR = \left(\frac{FOH + EFDH}{SH + FOH + ERSFDH} \right) \times 100$$

EFOR = Equivalent Forced Outage Rate
FOH = Forced Outage Hours
EFDH = Equivalent Forced Derated Hours
SH = Service Hours
FOH = Forced Outage Hours
ERSFDH = Equivalent Reserve Shutdown Forced Derated Hours

Based on the operating data for the Ontario gas-fired fleet, a peer group was developed that would be representative of the Ontario units, which was combined cycle units that were between 150 and 1000 MW with a NCF of between 10 to 40%. From that database, the media averages for units were as listed in Table 2-2 below.

Table 2-2 NCF, EAF and EFOR for Ontario Wind Fleet

	NCF	EAF	EFOR
Median	26.16%	83.94%	4.11%

The largest contributor to the EFOR rate was the steam turbine, which caused 11,688 forced outage hours, followed by the combustion turbines with 6,243 hours and the balance of plant (BOP) with 4291 hours. The combustion turbines and BOP contributed to a larger number of events, however (these tended to be of shorter duration than steam turbine events). This is demonstrated in Table 2-3 below.

Table 2-3 Breakdown of EFOR for Ontario Gas Fleet

Component	Total Hours	Percentage	Total Number of Events	Percentage
Boiler	758	3%	74	9%
Steam Generator	11,688	47%	142	17%
Generator	944	4%	53	6%
Balance of Plant	4,291	17%	194	23%
Combustion Turbine	6,243	25%	284	33%
Other	1,179	5%	110	13%

The highest number of steam turbine forced outage hours were due to events on the low-pressure turbine at 5,742 hours and the high-pressure turbine at 1,197 hours. This is due to the time required for system cooldown and to remove and reinstall casings. The control system had the largest number of events (49) but only contributed to a few forced outage hours (256), as control system issues are normally very fast to resolve. A summary of the causes of forced outages due to the steam turbine is provided in Table 2-4.

Table 2-4 Breakdown of EFOR for Ontario Steam Turbines

Steam Turbine	Total Hours	Percentage	Total Number of Events	Percentage
High Pressure Turbine	1,197	14%	10	7%
Low Pressure Turbine	5,742	69%	21	15%
Valves	50	1%	24	17%
Lube Oil	8	0%	8	6%
Controls	256	3%	49	35%
Miscellaneous (Steam Turbine)	1,012	12%	29	21%

The combustion turbine outages were driven by issues with the fuel and combustion system (2,634 hours over 120 events), as demonstrated in Table 2-5 below. This was principally due to dry low NOx combustion system issues and component failures.

Table 2-5 Breakdown of EFOR for Ontario Combustion Turbines

Combustion Turbine Component	Total Hours	Percentage	Total Number of Events	Percentage
Inlet Air System and Compressors	1,907	31%	27	11%
Fuel, Ignition and Combustion System	2,634	42%	120	49%
Turbine	426	7%	12	5%
Exhaust System	65	1%	16	7%
Auxiliary	152	2%	1	0%
Miscellaneous (Gas Turbine)	1,019	16%	69	28%

Balance of plant issues contributed to 17% of the total outage hours. The largest number were caused by issues with the electrical system (2,068 hours over 55 events). Issues with the condensate system and feed water systems were also important as shown in Table 2-6 below.

Table 2-6 Breakdown of Balance of Plant EFOR for Ontario Gas Fleet

Balance of Plant	Hours	Percentage	Events	Percentage

Condensing System	418	10%	29	15%
Circulating Water System	43	1%	5	3%
Condensate System	953	22%	18	9%
Feedwater System	554	13%	45	23%
Electrical	2,068	48%	55	28%
Auxiliary System	171	4%	21	11%
Miscellaneous (Balance of Plant)	84	2%	21	11%

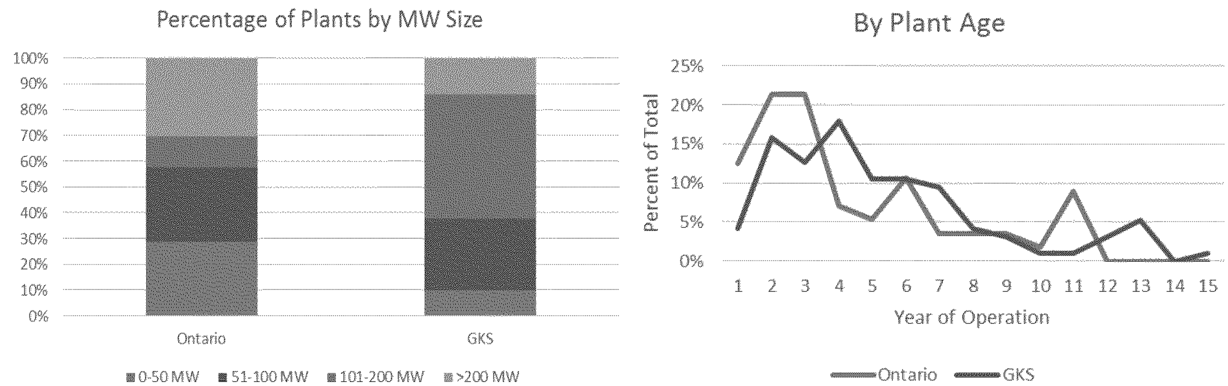
The heat recovery boilers and generators only accounted for a total of 7% of all outage hours with the generator accounting for 944 outage hours and the boiler accounted for 758 hours. The largest driver on the heat recovery boiler was tube leaks, while the generator was driven by a combination of cooling system and exciter issues.

While component failure rates increase with the age and use of natural gas plants, and heat rate degradation will tend to make the plants less completive in energy markets over time, plants following the proper maintenance and replacement regimes as outlined in section 2.1.1 should be able to continue operating over their forty-year expected life with acceptable outage rates.

2.2.2.2 *Wind*

Wind plant performance and failure rate data is not publicly available and is generally held confidential by plant owners. However, it is reasonable to assume that Ontario wind plants will have performance and failure rates similar to those of wind plants in Navigant's Generation Knowledge Service (GKS) wind database (Ontario has a slightly newer fleet, and fewer mid-size plants than the GKS averages, but they are similar overall). The GKS wind database includes data from approximately 8 GW of capacity from a variety of turbine models, plant sizes, ages, and O&M contract types. 95% of the MW capacity is in North America. Figure 2-14 shows the database distribution by plant size and age, which is similar to the size and age distribution of Ontario's wind fleet.

Figure 2-14 Plant Size and Age Distribution in GKS Wind Database



Source: Navigant GKS Wind Database

The following are median values of selected performance metrics in the GKSwind database, which are reasonable estimates of performance of the Ontario wind fleet:

- Availability. The most common measure of availability used in the wind industry is equipment equivalent availability factor (EEAF). EEAF does not penalize the plant for hours when there is no wind. Median EEAF = 95.6%.

$$EEAF = \frac{[PDTH - (FTH + MTH + PTH)]}{PDTH} \times 100$$

  - PDTH = Period Turbine-Hours = (total hours in the period) *(number of turbines)
  - FTH = Forced Turbine-Hours = (forced outage hours per turbine) *(number of turbines)
  - MTH = Maintenance Turbine-Hours = (maintenance outage hours per turbine) *(number of turbines)
  - PTH = Planned Turbine-Hours = (planned outage hours per turbine) *(number of turbines)

- Forced Outage Rate. The most common measure of forced outage rate used in the wind industry is equipment equivalent forced outage rate (EEFOR). Median EEFOR = 2.7%.

$$EEFOR = \frac{FTH}{(CTH + FTH + RUTH)} \times 100$$

  - CTH = Contact Turbine-Hours
  - RUTH = Resource Unavailable Turbine-Hours

- Major Failures. Navigant defines major failures as events which either (a) require a crane to repair or replace a system or (b) require the replacement of a major component within a system, resulting in a cost greater than 5% of the installed cost of the turbine. Table 2-7 below is a summary of average major failure rates in the GKS wind database, both for the most recent benchmark year (2015) and the cumulative rate for the life of the plant. Also, shown in the far-right column of Table 2-7 below are industry average failure rates as reported in a 2013 United States National Renewable Energy Laboratory (NREL) study.[6]

- 2015 Major Failure Rate = (# of Major Failures in 2015) / (# units)
- Cumulative Major Failure Rate = (# of Major Failures through 2015) / (# units) / (years since COD)

Table 2-7 Major Failure Rates by System

System	2015 Major Failure Rate	Cumulative Major Failure Rate	Industry Average Failure Rate
Blade	0.2%	0.5%	0.67%
Gearbox	1.1%	1.3%	5.0%
Generator	2.1%	2.1%	3.5%
Main Bearing	0.6%	0.5%	2.0%
Generator Bearing	0.3%	0.4%	n/a
Transformer	0.1%	0.04%	n/a

While component failure rates do increase with age, the plants continue to maintain acceptable operating profiles over the course of their identified useful life (albeit with capacity factor degradation and O&M escalation). Beyond the identified useful life, the plants would see accelerated component failures which eventually make continued operation untenable (see section 3.1.1.2).

2.2.2.3 *Solar*

The operating life of PV systems is usually monitored by the system owner. In the solar industry, the rate at which the system is fully functioning (and available to generate power) expressed as a function of the total time considered, is referred to as the availability rate. For solar, the availability rate is relatively high, approximately 98% to 99%[7] based on the information that we have reviewed, compared to other technologies. This is because components are connected in strings, meaning that should something fail, only a single string or portion of the system will experience an outage, while the rest of the system continues to generate power. It is unlikely for all to fail at once.

- Panels most often experience an outage or failure due to coverage (snow, soiling, or other shading) or a wiring fault. However, the way panels are connected electrically, when one stops generating power, the others continue.
- Inverters for utility-scale systems are usually 1 MW. For a 10 MW system, the typical design is ten (10) 1 MW inverters. This means that if an inverter fails, only one-tenth of the system would power down. Inverters typically last 10-12 years, but it is possible that an outage can occur sooner than that.
- Racking systems are typically tested and rated to handle expected snow and wind loads plus a factor of safety. Therefore, the warranty from the manufacturer covers damage from these occurrences. Should the structural integrity of the racking system be compromised, it is again likely that only the module(s) related to one string would need to be taken offline to repair, not the whole PV system.

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[6] NREL, Lantz, E., Operations Expenditures: Historical Trends and Continuing Challenges, 2013

[7] DBRS reported that the independent engineer for the 100 MW (AC) Kingston Solar project assumed inverter availability of 99%.

- Wiring is required to be protected up to codes and standards to limit the potential for damages.

Overall, over the modeled twenty-five-year life, it is unlikely that the component failure rates would cause an unacceptable operating profile for the solar fleet.

2.3 Leasing, Regulatory, and Contract Issues

2.3.1 Leasing Structure

When constructing a gas-fired power station it is typical for the owner to purchase the land that is used for the site. All the gas-fired plant owners that Navigant could interview owned the site land; therefore, no leasing issues were identified for extending the life of gas-fired plants.

The terms of land leases for wind plants vary. The minimum length is 20 years, but up to 50 year leases are not unusual. In all cases, there will be an option for the plant owners to extend the lease for an additional 15 years or more. Leases are contracts between the plant owners and landowners, and they are generally written to be more favorable to the plant owners. For example, plant owners can typically construct, erect, use, install, reinstall, replace, relocate, maintain and remove equipment from time to time, without limitation. No approvals to modify or extend leases are needed by local jurisdictions, community or aboriginal partners, unless they have such approval rights due to having partial ownership in the wind plant. Typically, limited partners do not have approval rights for minor items such as lease extensions.

Most 10 MW+ solar farms are sited on farmland and have a minimum 20-year lease. Some may go as high as 50 years and/or there might be options to extend the lease. Counterparties include private landowners, First Nations, and municipalities. Leases usually have two cost components as follows: (1) a fixed component and (2) a variable component where the variable component is equal to a percentage of revenue generated from the asset (e.g., 3%). No leases require third party approvals such as local jurisdictions, community, or aboriginal partners, unless those parties are partial owners in the project.

2.3.2 Regulatory Issues

No regulatory issues were identified for lifetime extension of gas or solar plants.

For partial repowering of wind plants (replacing the drive train and rotor with similar size components), regulatory approvals would generally not be required. The noise profile of the new turbine will generally be less (quieter) than the original turbine and therefore would not need to be remodeled. The rotor diameter will typically be the same as the original in a partial repowering, so a revised permit for increased tip height generally will not be needed. One wind plant owner reported having a permit from the municipality that includes a road allowance for the distribution lines. The city can impose reasonable conditions but cannot deny an extension of the permit.

Regulatory approvals would likely be required for full repowering of wind plants (replacing the turbines with larger components). Existing building and operating permits would generally not cover the significant construction work and changes in plant configuration that is associated with full repowering. However, repowering could offer the possibility for expedited permitting because development is occurring at a previously permitted site and these sites have a much longer track record of historical environmental data. Existing plants also tend to have increased local familiarity, which might also facilitate the permitting process. On the other hand, if endangered species are found to be in the proximity or other environmental damage has occurred, permitting would likely be more complex and drawn out, or local siting requirements may become more stringent over time.

3. COST OF LIFETIME EXTENSION AND REPOWERING

This section outlines the costs of lifetime extension that would be borne by ratepayers. Calculation of these costs is essential to calculating the annual Fair Allocation Amount, to ensure that all costs are spread over the extended lifetime of the generating units. After considering the various options available, Navigant included full repowering of the wind and solar fleet and partial repowering as needed for the gas fleet in the status quo and Fair Allocation Amount scenarios as the most cost-effective repowering options.

3.1 Repowering and Extension Options

3.1.1 Life Cycle of Plants under normal O&M schedule with minimal investment

3.1.1.1 *Gas*

As discussed previously, a combustion turbine power plant can operate for at least 40 years if the owner follows prudent operating practices and recommended outage schedules for the combustion turbine, generator, steam turbine and heat recovery boiler. In general, the O&M for gas-fired plants will increase with the escalation terms within the service contracts for the associated equipment.

Combustion turbine outages are driven by the hot section and combustion components. Manufactures have improved this technology so outages are now not required until either 24,000 factored fired hours or 900 factored starts are reached. When the hot section components are removed, they can be repaired from two (2) to four (4) times depending on the component and the manufacture's recommendations.

Electrical generators and steam turbines are generally linked to scheduled inspection intervals of 6 years or 48,000 operating hours. Following best practices owners and operators have managed to extend those intervals to between 10-12 years or 80,000 to 96,000 operating hours.

Heat recovery steam generators with proper maintenance have operated for 15-20 years without major capex being spent. Replacement parts are most commonly needed in the heat-affected zones of the super-heaters or the high flow areas of the economizers.

Maintenance spending increases with the number of starts of a combined cycle power plant. As discussed earlier, units are now designed for 150-250 starts per year. This spending is normally associated with BOP equipment and does not materially impact the overall cost of operations.

Depending on the operating profile of the facility, reliable operations after 20 years would most likely require capital expenditures for the HRSGs, electrical generators, steam turbines and combustion turbines. If no investments are made it would be expected that the units would suffer from forced outages and decreased availability.

3.1.1.2 *Wind*

As previously discussed, the physical lifetime of a wind plant is generally considered to be 20 to 25 years. Historically an assumption of 20 years was used in analyses to match the financial life, but an increasing number of plant owners are using 25 years due to technological advancements that have led to improvements in plant reliability and longevity.

If a wind plant were to continue to be operated beyond the physical lifetime without significant investment, O&M costs would increase at an accelerated rate and availability would drop at an accelerated rate. Wind plants generally have capacity factor degradation of about 1.6% per year, and so provide far less clean energy benefit if operated beyond 25 years. Ultimately the plant owners will decide that operating the plant has less value than another option. Options considered include full repowering, partial repowering, and decommissioning, which are discussed in Section 3.2.

3.1.1.3 *Solar*

As previously discussed, the physical lifetime of a ground-mounted PV system is 20 to 25 years. The modules and racking typically come with 10-year product warranty (defects in materials and workmanship) and a 25-year performance warranty. Inverters typically have a 10-year product warranty and last 10-12 years. Wiring typically lasts 10-12 years. Therefore, inverters and wiring would need to be replaced at least once on average over a 20-year lifetime.

If a PV system were to continue to be operated beyond the physical lifetime without significant investment, O&M costs would remain the same, only increasing with inflation and the price of any material costs involved in maintenance. Replacement of inverters and wiring are separate from general O&M and would require minimal investment. Inverters do typically fail after year 10 so most installers opt into an extended warranty where available, which is an upfront cost at the time of installation. With the standard warranty the cost of the inverter would just be incurred later, at the time of the replacement.

PV modules, and therefore, systems, are projected to degrade by 0.5% each year, which is usually how the capacity factor and system performance is forecasted at the time of installation. The capacity factor of the system can be determined based on the number of years since the components were replaced. If a PV system operated beyond the typical 20-year term, the capacity factor of year 21 would be that much lower than if a whole new system were installed in its place.

3.1.2 Cost of Repowering for lifetime extension

3.1.2.1 *Gas*

As discussed above the limiting factor on the combustion turbine would be the turbine rotor that requires a major inspection and potential replacement of turbine wheel at 200,000 factored hours or 5,000 factored starts. The rotor must be removed and sent to a qualified repair shop for disassembly, inspection and repair and/or replacement of the rotor disks. In addition, there would likely be requirements for replacement of super-heater or economizer sections of the HRSGs.

The costs for the turbine life extension would be in the range of CAD$16.2M for the inspection and repair/replacement of hot section components. The other work required on the heat recovery steam generators would be in the range of CAD$4.05M.

The balance of plant equipment would normally be covered during the routine maintenance at the facility. This would include the rebuilding or replacement of pumps, including the boiler feed pumps, and the repair and replacement of motors. It would also include the replacement of any catalysts that are required for emissions control.

Steam turbines and electrical generators should be able to operate for the life of the plant with routine inspections and maintenance, assuming there are no incidents with the equipment.

Long-term equipment replacement costs were modeled in fixed O&M for the purposes of calculating the Fair Allocation Amount, with rotor replacement modeled as a partial repowering.

3.1.2.2 *Wind*

Wind plant owners face the following options when a plant reaches the end of its physical lifetime:

- *Full repowering*, which is defined as the complete dismantling and replacement of turbine equipment, including the tower and foundation. With full repowering, some of the existing project infrastructure (e.g., roads, buildings, and interconnection equipment) is assumed to be utilized in the new project. There is also the potential to offset repowering costs by recycling or selling the older equipment.
- *Partial repowering*, which is defined as installing a new similar sized drivetrain and rotor on an existing tower. Some peripheral components, such as the power convertors and electronics, may also be replaced. Partial repowering allows existing wind power projects to be updated with equipment that increases energy production, reduces machine loads, increases grid service capabilities, and improves project reliability.
- *Decommissioning*, when the plant is fully disassembled and the land is returned to its original use. The equipment is sold for reuse or scrapped.

Repowering (either full or partial) is a major undertaking that requires substantial capital investment and planning, similar to the development of a greenfield plant. The major benefits of repowering are increased plant availability, the return of O&M costs to normal levels, and an extended plant lifetime. Performance improvements associated with partial repowering are assumed to be less than under full repowering but greater than the original design of the machine.

Navigant's costs of repowering were developed from a case study of a wind plant with the following characteristics of an average wind plant in the current Ontario fleet:

- 40 Siemens 2.3 MW WTGs, with a total plant capacity of 92 MW;
- Commercial Operation Date and Year 1 of operations in 2015;

Three scenarios were considered, including decommissioning the plant after 25 years of operation, in 2040, and full or partial repowering, both occurring after 25 years, in 2040, followed by decommissioning after an additional 25 years, in 2065.

Table 3-1 is a summary of key assumptions of the case study, which were also used to calculate the Fair Allocation Amount. Capital and O&M cost assumptions are from a 2013 NREL repowering study,[8] escalated to 2017 USD at 2.5% per year and converted to CAD at a rate of 1.35 CAD = 1 USD. All O&M costs were converted to fixed O&M for modeling purposes. Fully repowered plants are assumed to have slightly lower (5%) total installed capital costs because of the ability to reuse or repurpose existing equipment. Partial repowering is estimated to result in an approximately 15% lower capital cost because of reusing existing equipment including towers and foundations. In all scenarios, it is assumed that

[8] NREL, Wind Power Project Repowering: Financial Feasibility, Decision Drivers, and Supply Chain Effects, December 2013, http://www.nrel.gov/docs/fy14osti/60535.pdf

decommissioning cost (occurring in year 26) equals the resale or scrap value of the components (i.e., net zero cost).

NCF growth assumptions are based on projections from NREL's 2016 Annual Technology Baseline report, but are benchmarked to average Ontario fleet values from IESO. Larger rotors and taller towers, along with other technological advancements, have resulted in significant increases in net capacity factors for utility-scale wind plants over the past 15 years. These advancements are expected to continue for the foreseeable future, albeit at a slower pace. NCF for this case study is assumed to be 37% for full repowering in 2040, which is a 5% improvement over the project's initial 32% NCF in 2015, reflecting the technological advancements that are expected during this 25-year period. As defined here, partial repowering was estimated to achieve about 50% of the energy production improvements associated with full repowering. Full repowering was assumed for all wind plants. The higher capacity factors from full repowering allowed a greater percentage of total plant costs to be assigned to the repowered asset (in the later part of the analysis period), which meant full repowering allowed significantly more clean energy benefits with relatively little increase in clean energy costs relative to partial repowering.

Table 3-1 Wind Repowering Case Study Key Assumptions and Results

	units	Original Plant	Full Repowering	Partial Repowering
Year 1	-	2015	2040	2040
Capital cost	2017 CAD/kW	2,844	2,291	2,049
Fixed O&M in year 1	2017 CAD/kW-year	19.04	19.04	19.04
Variable O&M in year 1	2017 CAD/MWh	9.32	9.32	9.32
O&M increase per year	Real %/year	2.0%	2.0%	2.0%
NCF in year 1	%	32%	37%	34.5%
NCF decrease per year	%/year	1.6%	1.6%	1.6%

3.1.2.3 *Solar*

Table 3-2 shows some of the key assumptions related to life extension of solar projects

Table 3-2 Solar Repowering Case Study Key Assumptions and Results

	units	Original Plant	Full Repowering	Partial Repowering
Year 1	-	2017	2038	
Capital cost	$/W-DC	$1.80	$0.95	
PV Module Cost	$/W-DC	$0.54	$0.24	
Fixed O&M	$/kW-DC	$27	$27	$27
O&M increase per year (Inflation)	%/year	2.5%	2.5%	2.5%
Capacity Factor (based on MW-AC)	%	16.3%	16.3%	16.3%
Capacity Factor decrease per year	%/year	0.5%	0.5%	0.5%

As mentioned in Section 3.1.1.3, to extend the life cycle of a ground-mounted PV system to 30 years, the major equipment that would need to be replaced are the inverters and the wiring. These two components have a technical lifetime of 10-12 years and so they are replaced at least once in a typical 20-year contract. The expected operating life after replacement of the inverters and wiring would be another 10-12 years.

Attention should be paid to the lifetime and replacement of the PV modules. Panel technology is improving at a much faster rate than other renewable technologies, such as wind, and other key solar components such as racking and inverters. In parallel, module prices have significantly dropped over the past 10 years and are projected to continue to decrease for the next 10 years. If modules are replaced 20 years from now, they may have a much higher efficiency and much lower costs that what exists today.

Therefore, even if the O&M price and the cost to replace inverters and wiring does not require significant CAPEX to extend the life of the PV system, the module efficiency and price at the end of the original 20-year contract may prove to be more economical. Replacing panels would extend the life of the system an additional 20-25 years, or perhaps longer based on the technical lifetime of panels at the time.

The capacity factor in Table 3-2 is constant from 2017 to 2038. While panel efficiency will continue to increase during this period, that does not impact capacity factor (it does impact power density). Capacity factor is increased by using tracker technology, but for this analysis, we assume a constant split between fixed tilt and tracker in both 2017 and 2038. By contrast, wind farms have could increase capacity factor by increasing the hub heights and reaching better wind regimes. Full repowering was assumed for all solar plants.

3.2 Leasing, Regulatory, and Other Costs

The owners of gas-fired facilities would have to renegotiate new contracts for repair and replacement of combustion turbine parts. This may result in cost savings as there have been third party entrants into the parts supply and repair markets.

Leasing, regulatory, and other development costs are low relative to the total capital expenditures associated with modern wind facilities. These costs are generally assumed to be the same as those required for a greenfield development wind project.

Because the technical lifetime of PV systems, specifically the modules, is expected to outlast a 20-year PPA, some owners expect the system to run for an additional 5-10 years beyond the PPA and original lease. However, plans to extend the land lease are typically not put in place until closer to year 20, as refinancing the lease early would result in penalties.

At the time of the installation of a PV system, there is usually a budget set aside for decommissioning. If the system were to be decommissioned later than originally intended, there would be no extra costs, and the original budget should cover decommission at year 25 or 30.

4. CALCULATION OF FAIR ALLOCATION AMOUNT

4.1 Financing Assumptions and Methodology

As discussed previously, the Fair Allocation Amount was calculated for the modeled asset classes assuming gas plants last for forty years (with no or partial repowering), wind and solar plants last for fifty years (with one full repowering), and conservation and coal retirement benefits accrue over fifteen years. Capacity factor degradation is assumed to reset with full repowering for wind and solar assets. The benefits associated with clean energy generation assets are tied to (i) when they produce power, and/or (ii) when they are available to produce power. Similarly, the benefits associated with conservation and the early retirement of coal generation are tied to the avoided generation and the avoided emissions from coal generation, respectively. For modeling purposes, Navigant assumed that benefits from wind and solar generation are proportional to the energy generated from these assets (which declines over time with capacity factor degradation), while benefits from gas are proportional to the availability to provide energy to the grid. This is consistent with both the key function that these respective asset classes serve in the Ontario wholesale energy market and the way in which contracts for the respective asset classes are currently structured.

The Fair Allocation Amount for the asset classes is calculated to smooth the costs incurred over the life of an asset (current contract costs, O&M, and repowering costs) proportionally to the benefits provided by the assets over that life. Going-forward costs for gas units were estimated on a plant-by-plant basis, while the assumptions for wind and solar units are shown in Table 3-1 and Table 3-2, respectively. Conservation expenditure was assumed to escalate with inflation from the 2015-2017 average. The Fair allocation amount was calculated assuming a both a 4.5% discount and borrowing rate[9], with annual inflation at 2%. Rate reductions in $/MWh terms were calculated assuming 72 TWh of Regulated Pricing Plan (RPP)-eligible load. To ensure that all costs are included in the analysis period, all investments were financed so that they are paid back by the end of the expected life of the investment or 2050, whichever is earlier. Fair Allocation Amount payments for gas, wind, and solar were structured as the contracts for these assets currently are currently structured, with gas denominated in $/MW-year and solar and wind denominated in $/MWh (as discussed above, this is also proportional to how the benefits of these assets are allocated, and causes wind and solar costs to decrease with capacity factor degradation). Gas and wind costs are escalated at 20 percent of inflation, as the contracts are currently structured, while solar is not escalated. Conservation and coal retirement costs are allocated proportionally over the fifteen-year benefit life without degradation or escalation.

After the annual Status Quo and Fair Allocation Amount payments were calculated, the historical difference (2005-2016) between the Status Quo and Fair Allocation Amount was calculated as well. Since the Status Quo exceeds the Fair Allocation amount over this period, a schedule was calculated to provide rate relief by reducing the GA until this overpayment amount is exhausted, after which ratepayers pay the Fair Allocation amount over the remainder of the contract.

[9] The current estimated OPG cost of capital. By assuming a consistent discount rate and borrowing rate, the financing plan precludes the possibility of value being created through interest rate arbitrage, and limits benefits to those strictly tied to the useful life of the facilities in question.

4.2 Financing Plan

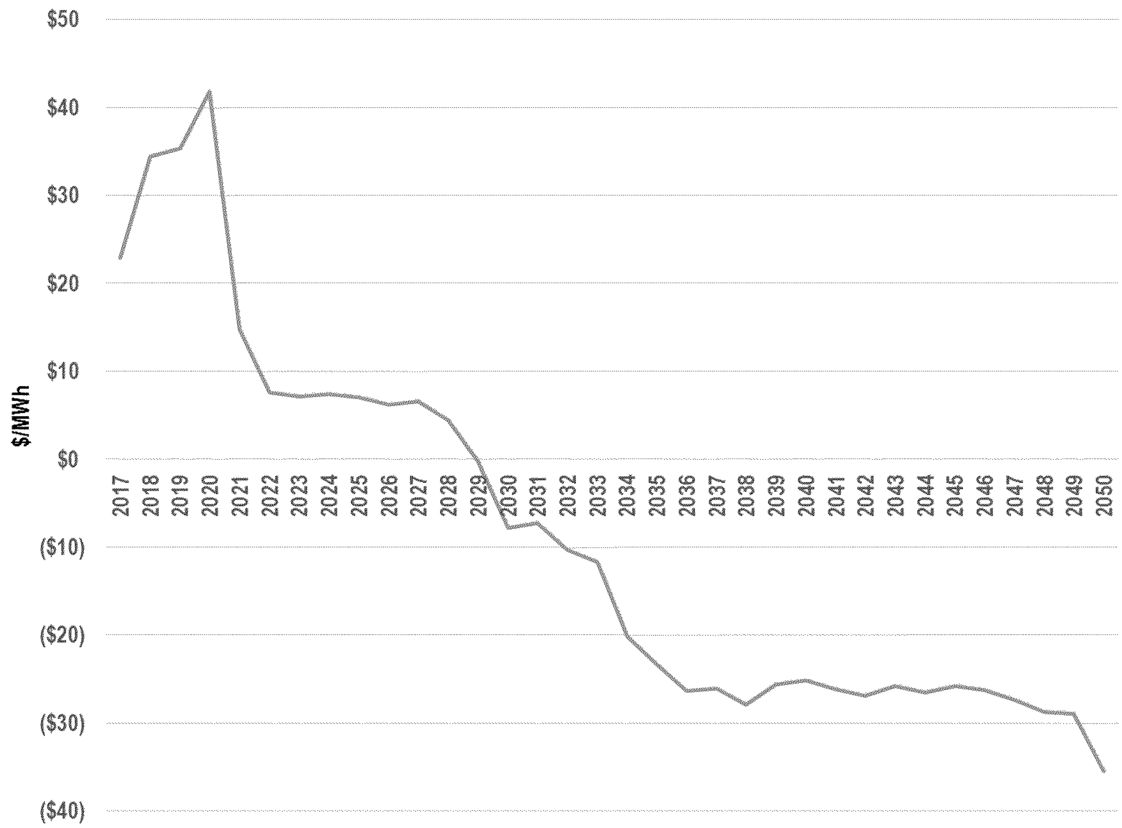
The annual difference between the Status Quo, the Fair Allocation Amount, the Fair Allocation Amount from 2017, and the Fair Allocation Amount with Customer Rebates of the financing plan are shown in Figure 4-1.

Figure 4-1 Annual RPP-Eligible Customers Payments for Modeled Asset Classes by Scenario

Source: Navigant Analysis

Overall, eligible ratepayers paid $5.7 billion more for the contracts in 2005-2016, which is equal to $6.7 billion in 2016 with accrued interest. This quantity, combined with the difference in costs in 2017 and 2018 between the Status Quo and Fair Allocation Amounts, mean that ratepayer GA contributions can be reduced by $1.631 billion in 2017 ($22.93/MWh), $2.481 billion ($34.46/MWh) in 2018, $2.546 billion ($35.37/MWh) in 2019, $3.015 billion ($41.88/MWh) in 2020, and $1.069 billion ($14.84/MWh) in 2021. Over the course of 2022-2028, ratepayers can enjoy an additional savings of $3.662 billion (on average, $6.67/MWh) by paying the Fair Allocation Amount, after which rates would increase from the status quo so that costs are proportional to benefits for the contracted assets (ratepayers pay a total of $35.213 billion more with the Fair Allocation Amount than the Status Quo from 2029-2050, or on average $22.23/MWh). Annual net rate reductions from 2017-2050 are shown in Figure 4-2.

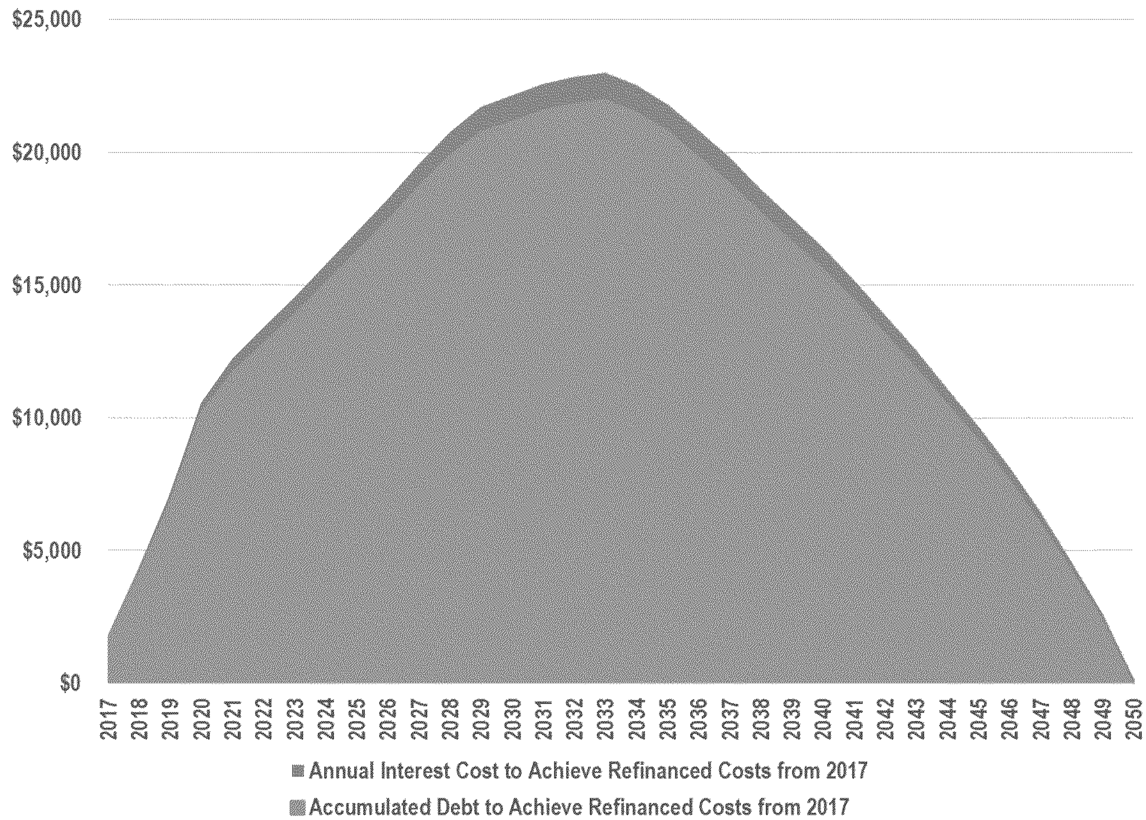
Figure 4-2 Annual Net Rate Reduction, 2017-2050



Source: Navigant Analysis

Over the life of the financing plan explored in this report, the province takes on a peak accumulated debt of $22.028 billion in 2033, and pays a total of $21.089 billion in interest from 2017-2050, as can be seen in Figure 4-3. Because the discount rate is assumed to be equal to the borrowing rate, the NPV of the Status Quo, the Fair Allocation Amount, and the Fair Allocation Amount with Customer Rebates scenarios are all identical from 2005-2050, with the Status Quo equal to the Fair Allocation Amount with Customer Rebates from 2017-2050.

Figure 4-3 Accumulated Debt and Interest Under Financing Plan, 2017-2050



Source: Navigant Analysis

Navigant's calculation of the Fair Allocation Amount, and by extension the financing plan, is contingent on the financial assumptions in Table 1-1 and Table 1-2. A summary of risks in the financing plan is provided in Table 4-1.

Table 4-1 Key Risks to Modeling Assumptions

Risk	Effect
Interest Rate Increase	If long-term borrowing rates rise above the projected 4.5% (based on OPG cost of capital), increased interest costs will require later-year payments to be higher than the calculated Fair Allocation Amount.
Technology Improvement	If technology improvement is slower than expected (either due to higher repowering costs or lower capacity factors), repowering costs will be higher and/or benefits lower in the longer term, which will cause long-term rate increases.

Degradation and O&M costs	If long-term O&M growth (due to component failure rates or costs) or capacity factor degradation is higher than expected, costs will be higher and/or benefits lower in the longer term, which will cause long-term rate increases.

5. REFERENCES

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