Extending Pickering Nuclear Generating Station Operations

An Emissions and Economic Assessment for 2021 to 2024

Final Report

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STRATEGIC POLICY ECONOMICS

Executive Summary

Ontario's Minister of Energy recently indicated[1] that steps were being taken to commence a review of the province's 2013 Long-Term Energy Plan (LTEP). Two challenges will substantially impact the elements and investment decisions associated with the next version of the LTEP:

1. Expected doubling in greenhouse gas (GHG) emissions

   GHG emissions from Ontario's electricity sector are expected to more than double from current levels, reversing most of the reductions achieved since 2011. These reductions were made possible by the closure of the province's coal stations, with the last station ceasing operation in 2014. This is counter to the province's objectives outlined in the Premier's mandate letter to the Minister of the Environment and Climate Change, Ontario's Climate Action Plan and commitment to participate in a Cap and Trade program with Quebec and California - initiatives aimed at reducing GHG emissions[2].

2. A system reserve capacity gap equivalent to the Pickering Nuclear Generating Station (PNGS)

   Ontario's Independent Electricity System Operator (IESO) has identified a 2,000 to 3,000 megawatt (MW) gap in reliability reserve capacity that will occur with the scheduled closure of the Pickering Nuclear Generating Station (PNGS) in 2020. This gap is currently expected to persist through to 2032. Ontario will need to fill this gap to comply with the requirements of the North American Electricity Reliability Corporation (NERC) and the Northeast Power Coordinating Council Inc. (NPCC) that govern the integrated operation of Ontario's grid within the North American system.

This report examines the option of extending the operations of two Pickering A units for two years and four Pickering B units for four years to address these challenges and thus defer accordingly the need to construct 2,000 MW of new natural gas-fired generation plants[3] that are otherwise necessary in 2021.

Three categories of demonstrable benefits were evaluated for the four-year period of PNGS extended operations. The major observations are:

a) ***Lower GHG emissions*** – over 18 million tonnes (Mt) of CO_2 can be avoided, equivalent to avoiding a 55% increase in electricity system emissions and a 25% increase in overall provincial emissions from natural gas usage in all sectors of Ontario's economy. The PNGS option exemplifies Ontario's legacy of nuclear being practically responsible for Ontario's electricity system GHG emissions success.

b) ***Lower electricity system cost*** – potentially reduced by over $1.5 billion (B) due to PNGS operating cost advantages and avoidance of the risks of natural gas-fired generation dependence.

c) ***Positive Jobs and Gross Domestic Product (GDP) created –*** from the power of domestic spend

   - ***Jobs Sustained*** – 40,000 Person Year Equivalent (PYE) jobs.
   - ***Net New Ontario Domestic GDP*** – $7B enabled through replacing $4B of imported energy with domestic nuclear generation.

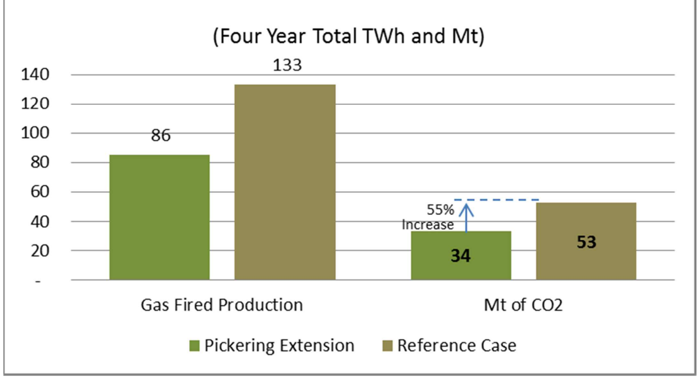
[1] OEA Energy Conference, 2015
[2] Government of Ontario, 2014. Wynne, 2014. Office of the Premier of Ontario, 2015
[3] IESO, October 2014

Detailed Description of the Three Benefit Categories

a) <u>*Reducing GHG emissions*</u> is an important policy objective to which extending the operations of the PNGS contributes in three ways:

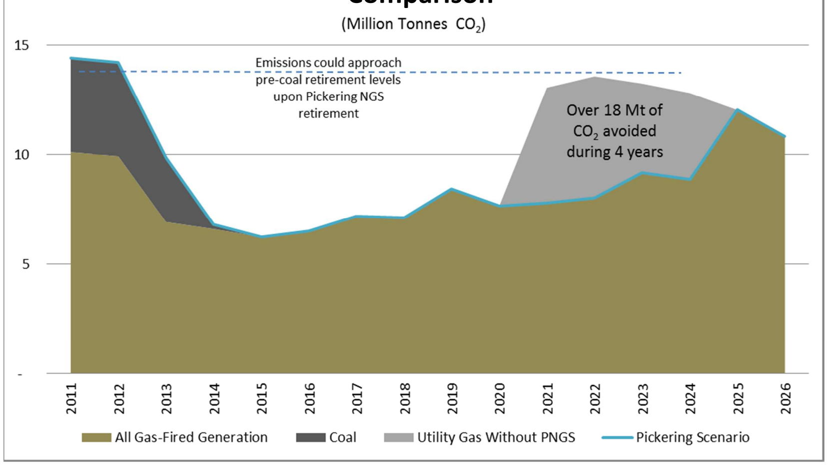
   i. Figure ES1 shows that extending PNGS operations for four years would reduce Ontario's natural gas-fired generation production from 130 tera-watt hours (TWh) to less than 90 TWh. This reduced reliance on gas-fired generation would eliminate the production of over 18 Mt of GHG emissions[4], equivalent to avoiding a 55% increase in emissions by the electricity system.

Figure ES1 – Gas Fired Generation and CO_2 Emissions



   ii. Figure ES2 highlights the reduced emissions profile of extended PNGS operation that sustains nuclear's GHG reduction success and defers a return to pre-coal retirement emissions levels[5].

Figure ES2 – GHG Historical Emissions and Projection Comparison



   iii. In a broader context, natural gas is not only used for the generation of electricty but also many other residential, commercial and industrial applications. Absent the PNGS, the province's overall emissions from the use of natural gas from all sectors will increase by 25%.

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[4] CO_2 emissions calculated based on a system-wide blended rate of approximately 400 kg/MWh.

[5] Near term CO_2 forecast is consistent with recently published IESO actual and forecast GHG emission data. All sources consulted indicate higher emissions throughout the forecast than suggested in the LTEP.

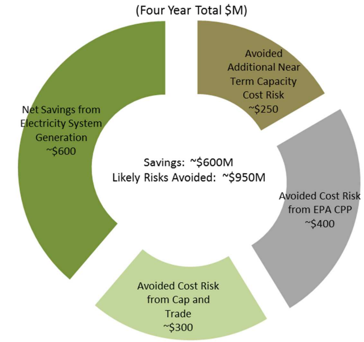
b) *Cost of electricity* to Ontario ratepayers could be reduced as shown in Figure ES3 by over $1.5B in two ways:

i. Avoid ~$600 million (M) in system cost reductions resulting from cost differences between PNGS and natural gas-fired generation.
   - Reduced system costs would avoid 4% and 1% rate increases for Class A industrial and Class B residential rate payers respectively.

ii. Avoiding over $950M in emerging costs risks emanating from the United States' Clean Power Plan, Ontario's Cap and Trade program and the province's need to contract additional capacity, all stemming from a growing dependence on natural gas-fired generation.

Figure ES3 – System Cost and Risk Reduction Benefits to Rate Payers

(Four Year Total $M)



c) *New domestic GDP* of over $7B generated through the power of domestic spend across four mechanisms as shown in Figure ES4:

i. Improves the Government of Ontario's fiscal position by almost $1.2B from taxes on the new gross domestic product (GDP) and cost savings from Ontario Power Generation (OPG).

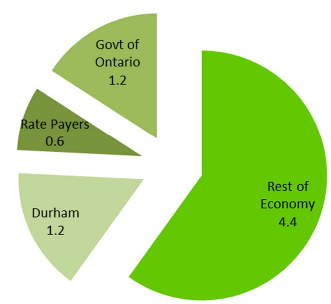
ii. Reduced electricity costs will enable ratepayers to inject over $600M back into the economy through indirect benefits.

iii. Continues a stimulus of $1.2B of economic activity to Durham Region where OPG is the largest employer.

iv. Adds approximately $4.4B to the rest of the provincial economy.

Figure ES4 – Share of Total Economic Benefit

(Four Year Total $B)



Economically, the province can only benefit by selecting the PNGS extension option. There is a high degree of domestic content embedded in Ontario's nuclear production. As a result, the observed benefits to Ontario are insensitive to the uncertainties in the input assumptions. For example, if PNGS costs proved to be higher than assumed, any impacts to rate payer benefits would be balanced by benefits from higher GDP and revenues for the Government of Ontario.

Recommendation:

The Ontario Government should direct the Minister of Energy, the IESO, and Ontario Power Generation to consult with the Canadian Nuclear Safety Commission (CNSC) for the purpose of securing approval for the longest possible period of continued safe operation of the PNGS beyond 2020 in order to:

(1) Sustain the substantial environmental and economic benefits that can accrue to Ontario for every year it operates; and

(2) Provide the government with the maximum time for assessing longer term options for the eventual replacement of the PNGS.

Table of Contents

List of Figures

List of Tables

1.0 Introduction

This study was undertaken to assess how extending the operations of the Pickering Nuclear Generating Station (PNGS) may impact on Ontario's publicly stated environmental and economic objectives.

Background

Ontario's Minister of Energy recently indicated[6] that steps were being taken to commence a review of the province's 2013 Long-Term Energy Plan (LTEP). Two challenges will substantially impact the elements and investment decisions associated with the next version of the LTEP:

1. Expected doubling in greenhouse gas (GHG) emissions

   GHG emissions from Ontario's electricity sector are expected to more than double from current levels, reversing most of the reductions achieved since 2011. These reductions were made possible by the closure of the province's coal stations, with the last station ceasing operation in 2014. This is counter to the province's objectives outlined in the Premier's mandate letter to the Minister of the Environment and Climate Change[7], Ontario's Climate Action Plan[8] and commitment to participate in a Cap and Trade program with Quebec and California[9] - initiatives aimed at reducing GHG emissions.

3. A system reserve capacity gap equivalent to the Pickering Nuclear Generating Station (PNGS)

   Ontario's Independent Electricity System Operator (IESO) has identified a 2,000 to 3,000 megawatt (MW) gap in reliability reserve capacity that will occur with the scheduled closure of the Pickering Nuclear Generating Station (PNGS) in 2020. This gap is currently expected to persist through to 2032. Ontario will need to fill this gap to comply with the requirements of the North American Electricity Reliability Corporation (NERC) and the Northeast Power Coordinating Council Inc. (NPCC) that govern the integrated operation of Ontario's grid within the North American system.

Objective

This report examines the option of extending PNGS operations to address the above challenges and considers three impacts this could have on Ontario:

1) Greenhouse Gas (GHG) emissions of carbon dioxide (CO_2)
2) Cost to the electricity system and rate payers
3) Economic implications to Ontario, including jobs and Gross Domestic Product (GDP)

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[6] OEA Energy Conference, 2015
[7] Wynne, 2014
[8] Government of Ontario, 2014
[9] Office of the Premier of Ontario, 2015

Approach

Strapolec modelled two scenarios of Ontario's electricity supply mix for the four year period from the beginning of 2021 to the end of 2024 inclusive:

1) ***Construct 2,000 MW of new gas-fired generation*** - the LTEP contemplated new Simple Cycle Gas Turbine (SCGT) generation as part of the assumed "planned flexibility" to address the capacity gap.[10]

2) ***Extend PNGS operations*** – the two-unit Pickering A Station extends operations for two years to 2022 and the four-unit Pickering B station for four years to 2024.

Structure of this document

This report provides a comprehensive description of the drivers, assumptions and outcomes of the assessment conducted regarding the benefits to Ontario of extending the operations of the PNGS to 2024.

Section 2 summarizes the characteristics of the emissions and reserve capacity challenges facing Ontario and why there is potential for considering the PNGS option as a solution. Section 3 presents the definitions of two scenarios created to contrast the emissions and economic impacts of extending the PNGS operations versus what may be the only alternative in a gas-fired generation solution.

Section 4 presents the detailed findings of the assessment of GHG emissions that would result from the two scenarios considered.

Section 5 discusses the cost implications for the electricity system, the cost assumptions that have been modelled, implications for rate payers, and the cost risks that should be considered.

Section 6 presents the findings of the economic impact assessment including how different stakeholder groups may be impacted. Section 7 expands on the benefits to the Government of Ontario.

Finally, Section 8 summarizes the findings and presents the recommendation that has emerged from this study.

The detailed assumptions that were compiled for building up the cost and economic parameters used in the analysis are provided in Appendix A and the sources consulted during the course of the research effort are listed in Appendix B.

[10] IESO, October 2014

2.0. Background

This project has evaluated the emissions and economic impacts of leveraging an extension of operations at the Pickering Nuclear Generating Station (PNGS) to support Ontario in addressing two major challenges:

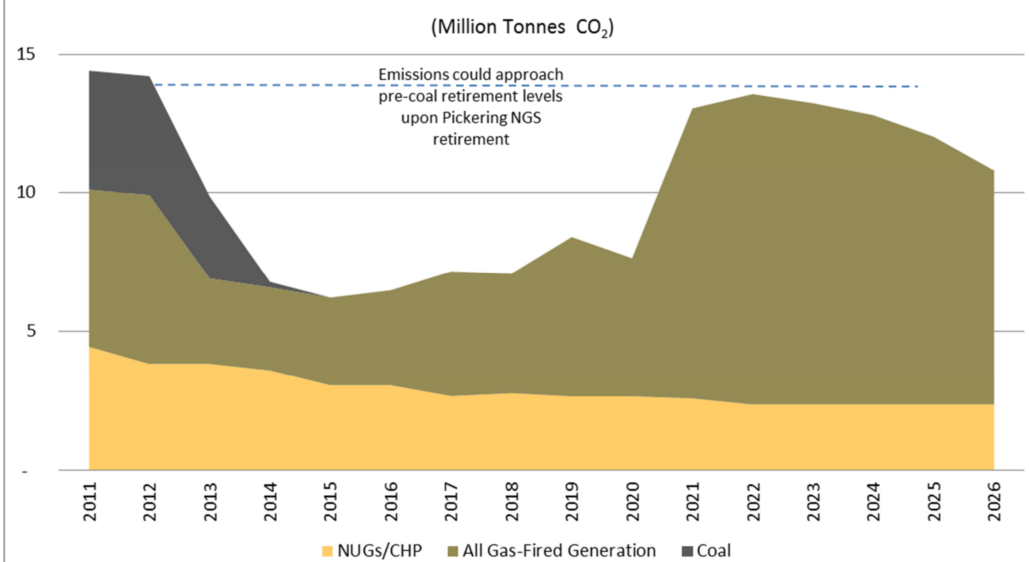
1. The GHG Emissions Challenge
2. Ontario's System Reliability Reserve Capacity Gap

This section describes the nature of these challenges to help explain how extending PNGS operations may contribute to their resolution.

2.1. The GHG Emissions Challenge

Ontario's electricity generation supply mix and production forecast has evolved to reflect the guidance contained in the 2013 LTEP. The forecast currently depends on natural gas-fired generation to support two conditions: (1) supplement nuclear electricity generation while Ontario's nuclear refurbishment program is underway; and (2) to replace the 3,100 MW of nuclear capacity when PNGS goes off-line after 2020. Figure 1 illustrates that GHG CO_2 emissions will, by 2022, be double 2015 levels[11]. This will return Ontario to emissions levels similar to 2011 and 2012, when Ontario had coal generating stations still in operation. The option to use natural gas-fired generation to compensate for lost nuclear generation will significantly erode the CO_2 emissions reductions achieved through the closure of the province's coal stations since then, a central strategy for the 2010 LTEP.

Figure 1 – Ontario Electricity System GHG Emission Projection



[11] Gas fired generation emissions are included for all of the Utility Gas generators, NUGs, and CHP sources. CO_2 emissions post 2020 calculated based on a system wide blended rate of approximately 400 kg/MWh

As elaborated more fully in Section 4, the associated growth in demand for natural gas usage within the electricity sector after the PNGS retires represents a 25% increase in the total emissions that arise from the use of natural gas across Ontario’s economy. This outcome is counter to the province’s climate change objectives and initiatives aimed at reducing GHG emissions.

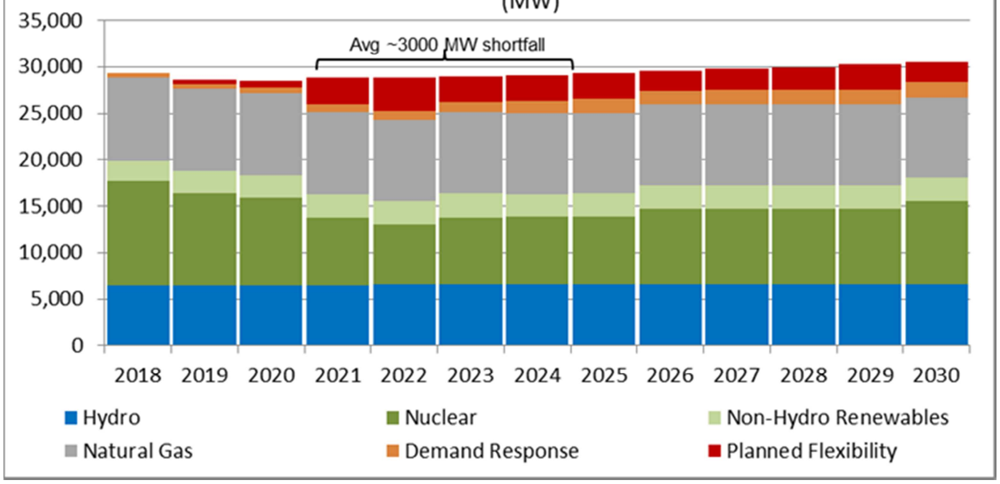
2.2. Ontario’s System Reliability Reserve Capacity Gap

Ontario’s 2013 LTEP identified the expected shortfall with respect to the peak capacity reserve capability that is necessary for Ontario to be a compliant member of NERC and NPCC. These two organizations govern the integrated operation of Ontario’s grid within North America. This shortfall has arisen directly from the need to refurbish Ontario’s nuclear fleet and the decision to retire the PNGS in 2020, the same factors cited above for causing the expected increase in GHG emissions.

Figure 2 illustrates the capacity gap identified in the 2013 LTEP and shows that the average gap for the period from 2021 to 2024 is approximately 3,000 MW.[12]

Figure 2 – Summer Peak Capacity Availability for Reliability

(MW)



The 2013 LTEP included “Planned Flexibility” to address the capacity gaps Ontario must close in order to comply with the North American system reliability requirements. Planned Flexibility covered several elements: Conservation; Non-Utility Generator (NUG) re-contracting; coal station conversion to natural gas; new procurement; and electricity imports.

In its 2014 review of Ontario's interties[13], the IESO considered the feasibility of the import option and concluded electricity imports would not likely be available for 10 years, even if the pre-requisite transmission planning, approvals, and investments in interties were to commence immediately.

- Transmission infrastructure investments to allow for imports were estimated to approach $5B.

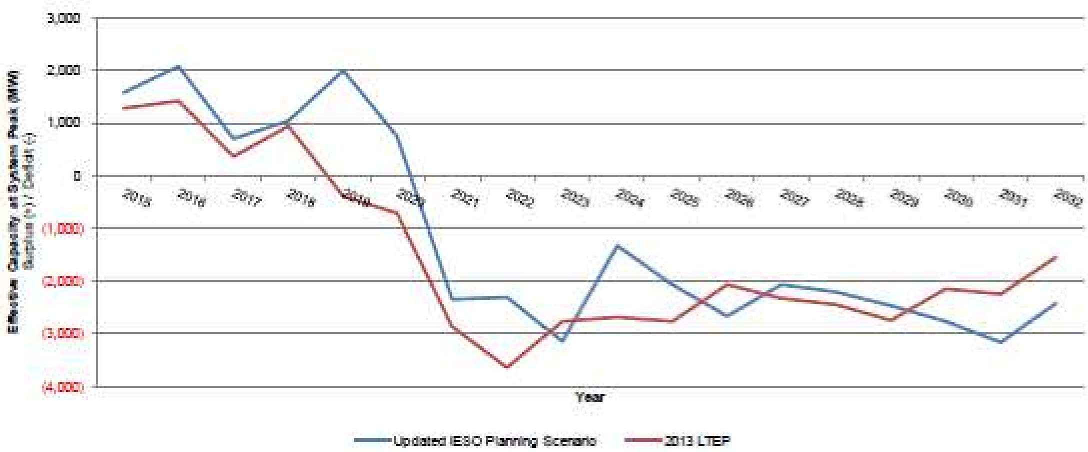
[12] IESO, 2014

[13] IESO, October 2014

- Importing electricity at the required levels could cost over $100/mega-watt hour (MWh).

The IESO has concluded that an unresolved capacity gap remains today for which Ontario continues to require a cost effective solution. Figure 3 replicates the data provided by the IESO in its September 2015 NUG framework assessment[14]. It includes an updated forecast for the capacity gap and shows how it compares to the 2013 LTEP assumptions. The IESO's report reflected the recently announced Ontario/Quebec capacity exchange agreement and other developments since the 2013 LTEP. While somewhat mitigated from the 2013 LTEP version, the current IESO estimated capacity gap remains similar in size to the PNGS's de-rated capacity and aligns with its retirement post 2020[15].

Figure 3 – IESO Current Reserve Capacity Perspective



Extension of the PNGS operations has been identified by the IESO as a potential contributing solution to the capacity reserve challenge. However, the IESO also noted that the technical and financial viability and implications were not yet known. An objective of this study is to help inform a better understanding of any potential implications.

2.3. Implications Summary

The GHG emissions and capacity reserve challenges are material issues for Ontario that require solutions. Both rate payers and taxpayers will expect the province to seek out cost effective and responsible strategies to address them. This report investigates the implications of extending the PNGS operations. The results are intended to help inform the province of the merits of this option, both for addressing the key issues and for the delivery of additional benefits for Ontario.

[14] IESO, September 2015
[15] IESO's updated capacity gap reduction in 2024 represents a refurbishment schedule altered from the LTEP, the details of which were not obtained.

3.0. Scenario Definitions

Assessing the implications of extending the PNGS operations is through a comparative analysis between two options. Two options or scenarios have been defined for evaluation that may represent the only viable alternatives that Ontario may have: (1) the PNGS scenario; and (2) a reference scenario that relies on natural gas-fired generation. The scenarios are to be compared on GHG emissions impacts and cost differences. This section addresses three elements of the scenario definitions:

1. Capacity Assumptions and Considerations

   Provides an overview of the characteristics used in the scenario analysis to enable an objective assessment of the options.

2. Scenario Production Differences

   Summarizes production differences between the scenarios that stem from of a stable PNGS baseload supply contrasted with the variable supply capability of natural gas-fired generation being deployed for a largely baseload operation. System supply mix production differences arise due to how these two supply types interact with the rest of Ontario's supply mix.

3. Impacts on Surplus Baseload Generation (SBG)

   Describes the SBG implications that stem from the scenario production differences.

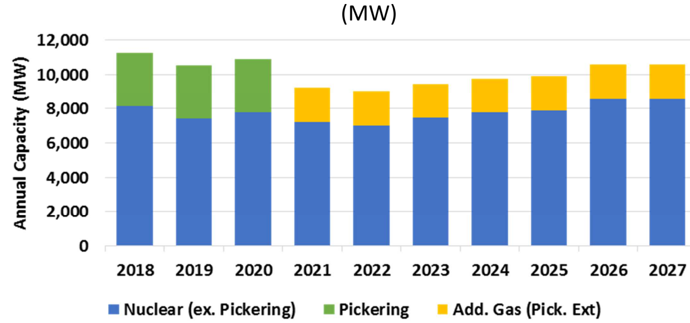
The following sections describe each of these topics to provide the basis for interpreting the environmental, financial, and economic outcomes presented in the latter sections of this report. The section closes with a summary of the implications of the assumptions.

3.1. Capacity Assumptions

Two scenarios have been defined to support a comparison of the production mix, emissions and cost over the four year period from the beginning of 2021 to the end of 2024.

The two scenarios represent: (1) a reference scenario reflecting Strapolec's view of the province's supply mix option from 2021 to 2024; and (2) a scenario to reflect the capacity changes representative of extending the operations of the PNGS. The capacity profiles of these two scenarios are illustrated in Figures 4 and 5.

Figure 4 – Reference Case Capacity Scenario
(MW)



1. Reference Case Scenario – LTEP Status Quo

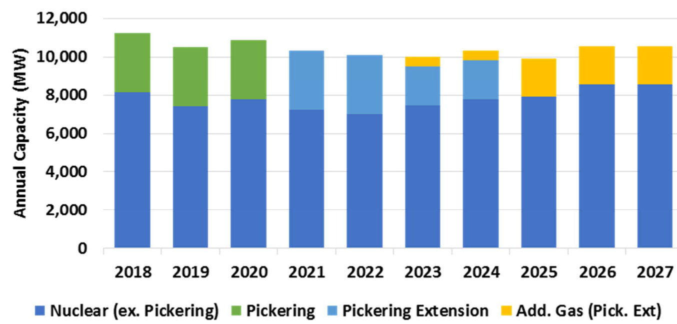
- 2,000 MW of natural gas-fired generation capacity to be commissioned in 2021 to coincide with the expected retirement of the PNGS and the capacity gap that result.

- This is chosen to reflect the minimum capacity that will be required to close the gap identified by the IESO. From a cost perspective, this is likely a conservatively low assumption as additional fixed costs could arise should more capacity be needed.

2. *Extended PNGS Operations Scenario*

- The PNGS 3,100 MW of capacity is extended.
    - Pickering is assumed to operate at a 75% annual operating factor due to planned maintenance outages throughout the year and hence the capacity is deemed comparable to the reference case gas-fired capacity plants for the simulation.

Figure 5 – Pickering NGS Capacity Scenario
(MW)



- As illustrated in Figure 5, the PNGS scenario has all six units operating for the first two years and then only the four "B" units operating for the next two years.
- 500 MW of gas-fired generation capacity is added in 2023 to compensate for the retirement of the PNGS "A" units, again to retain similar reserve capacity profiles to that of the reference case.

All assumptions on capacity, productivity and regulated/contracted pricing for all other sources of supply in the provincial supply mix are the same between the two scenarios. Although not part of this analysis, after 2025 both scenarios would have identical assumptions regarding 2,000 MW of gas-fired generation.

3.2. Scenario Production Differences

The expected generation levels of the PNGS extended operations is central to a consistent set of assumptions that align capacity, supply mix characteristics and the cost assumptions. Generation has been modelled as 20 tera-watt hours (TWh) per year from the six PNGS units in 2021 and 2022 and then 14 TWh per year from the Pickering B units in 2023 and 2024. These selections are based on rounded 2013 PNGS production levels and reflect a 75% operating factor.

The electricity system impact analysis was conducted using Strapolec's proprietary model of Ontario's electricity system[16]. This model assesses the full daily, weekly and seasonal demand, supply, and pricing dynamics using hourly generation estimates to compile a full annualized representation of the production from Ontario's supply mix. The model determines the impacts of capacity changes on the need for imports, natural gas-fired generation, and curtailment of other supply sources. It also forecasts

[16] Strapolec, 2013

the Hourly Ontario Electricity Price (HOEP), and the total electricity system cost. Strapolec's system model applies normally expected production assumptions to all supply sources and then adjusts any variable supply production amounts to meet demand on an hourly basis. The net effect of all the hourly results yields the resulting mix of supply in a year.

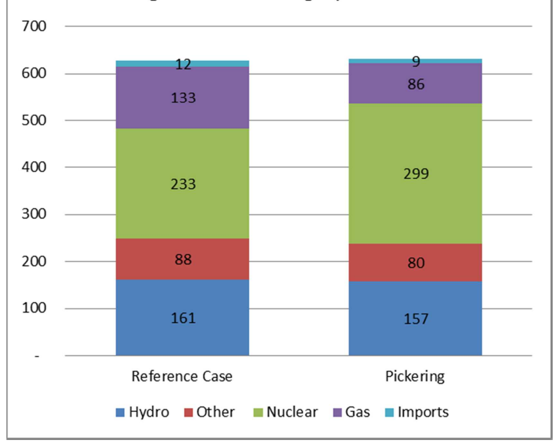
Figure 6 compares the total four year generation from all supply sources. The generation production results show that retaining PNGS capacity increases nuclear production by 66 TWh and:

- Reduces the need for imports by 3 TWh.
- Displaces 47 TWh of gas fired generation or about 37% of that generation.
- Displaces 8 TWh of other generation and 4 TWh of hydro

The total useable generation from the PNGS is 62 TWh. The remaining 6 TWH of the 68TWh of PNGS production consist of 2 TWh of curtailed nuclear energy and a need to export an additional 4TWh of SBG.

Figure 6 – Scenario Generation Mix Comparison

Existing Plan vs Pickering 4 year Total TWh



3.3. Impacts on Surplus Baseload Generation (SBG)

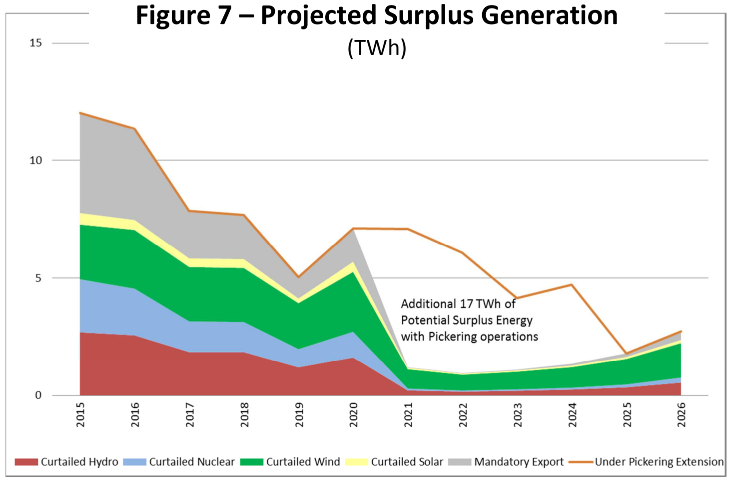
The presence of SBG resulting from Ontario's supply mix is well known and understood. Figure 7 shows the components of SBG for the reference case and highlights that 17 TWh of new SBG is created by the extended PNGS scenario. The PNGS induced SBG includes the 2 TWh of surplus PNGS production and 4 TWh of exported SBG mentioned above, as well as the 12 TWh of hydro and other generation that is displaced (the totals do not equate due to numerical rounding). The total of 17 TWh is 25% of expected PNGS production.

Even within the PNGS extended operations, the forecast SBG will continue to decline from the levels that the system is producing today.

- The low SBG forecast for the reference scenario in 2021 to 2024 reflects that natural gas-fired generation can adjust rapidly to demand changes.
- Figure 7 also illustrates that the ongoing surplus wind generation remains even without PNGS continued operations.

Figure 7 – Projected Surplus Generation

(TWh)



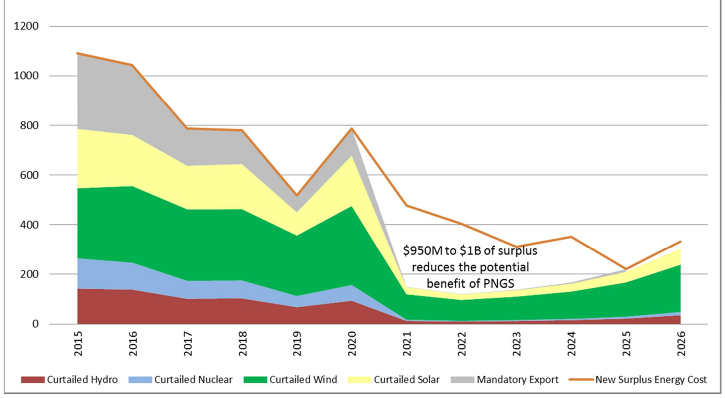
The surplus energy illustration is based on a curtailment assumption within the Strapolec simulation that curtails the highest contractual cost supply first. This allowed for the calculation of the cost impact when the renewables were added. It is understood that the IESO may be moving to a similar curtailment strategy and away from the current strategy that curtails hydroelectric and Bruce nuclear output before variable renewable output.

Figure 8 summarises the cost implications of SBG under the two scenarios. The PNGS extension scenario will have an additional $950M to $1B in SBG. The cost of the additional SBG is computed using the expected PNGS unit cost of production.

The net costs of the produced "surplus" energy are reflected and included in the total cost depictions compared in Section 5.

Figure 8 – Comparing Cost of Surplus Generation

($M)



3.4. Implications Summary

Contrasting the two scenarios of stable nuclear supply versus flexible natural gas-fired generation is a trade-off of the production of one for the other. However, since PNGS production is not flexible by its nature, additional surplus energy will be created. Due to the cost advantages of the PNGS operation, the cost of the surplus energy is absorbed by the system and still enables the net energy cost benefit to rate payers described in Section 5.

4.0. Electricity System GHG Emissions of CO_2

This section presents the results of the GHG emissions comparative analysis, specifically as it pertains to CO_2 emissions. The context for why these emissions are important to Ontario and how the province plans to address them is provided in Section 2. The findings of this section suggest that Ontario's GHG emissions forecast may be improved by extending the operation of the PNGS. Four topics are discussed:

- Forecast Emissions

  The forecasts for the two scenarios are presented, compared, and related to the natural gas-fired generation that drives them.

- History of Emissions and the Nuclear Symbiosis

  The history of emissions reductions in Ontario is presented along with the compelling evidence that shows Ontario's achievements are almost entirely due to the contribution of nuclear generation.

- Forecast Use of Natural Gas in Ontario

  The broader context of the role natural gas plays in Ontario for residential, commercial, and industrial applications in addition to electrical generation is discussed along with an observation of how the usage mix may change absent PNGS.

- US Shale Gas GHG Emissions Footprint

  Emerging research is showing United States (US) shale gas sources to be worse emitters than traditionally assumed for natural gas.

4.1. Forecast Emissions

Measured GHG emissions in Ontario's electricity system today stem from the production of electricity by natural gas-fired generating plants. These plants include the NUGs, many of which are co-generation facilities, as well as the Combined Heat and Power (CHP) facilities initially under contract with the Ontario Power Authority (OPA) but now with the IESO. All of these sources are treated collectively but with the system simulation attributing the appropriate duty cycles to their individual operations (e.g. NUGs operate virtually continuously in support of their co-generation function). This analysis establishes that reductions in GHG emissions are directly correlated with the degree to which natural gas-fired generation is displaced by PNGS.

The production profiles of Ontario's natural gas-fired generation fleet for the two scenarios are illustrated in Figure 9. Under the PNGS scenario, the forecast natural gas-fired generation reduces from 130 TWh to less than 90 TWh in the four year period studied. As would be expected, the four year profile shows how more gas-fired generation is displaced when all six PNGS units are operating. In Figure 9, the displaced generation is the difference between the production levels of the two scenarios.

The annual benefits decline as the Pickering A units are retired in 2022 as there is less nuclear production available to offset the natural gas-fired generation.

Figure 9 – Gas-Fired Generation Emissions Comparison

(TWh/year)

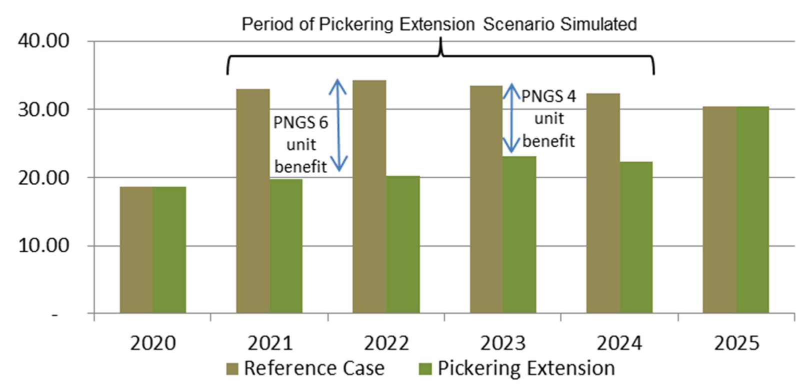
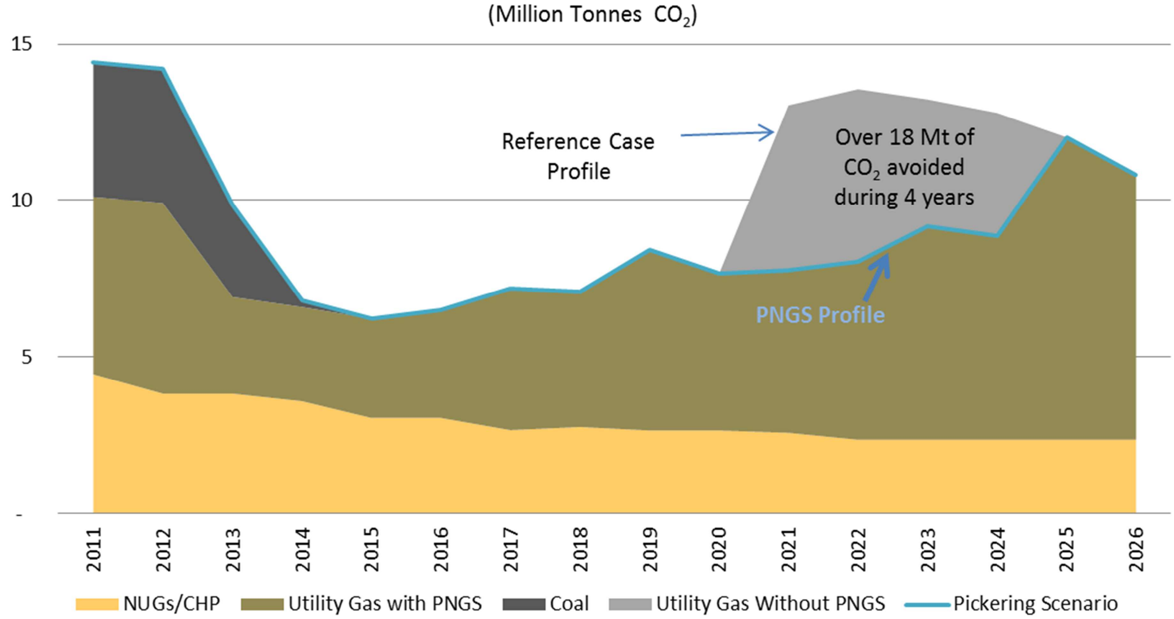


Figure 10 illustrates the fifteen year context for the emissions implications that stem from the differing natural gas-fired generation production levels of the two scenarios. By reducing the need for natural gas-fired generation, continued PNGS operations avoids 18 million tonnes (Mt) of GHG emissions. This is equivalent to avoiding a 55% growth in emissions that will otherwise arise from Ontario's growing dependence on natural gas-fired generation.

It is clear from Figure 10 that extending the operations of the PNGS will effectively defer if not largely avoid a return to the pre-coal retirement emission levels.

Figure 10 – GHG Emissions Projection Comparison

(Million Tonnes CO_2)

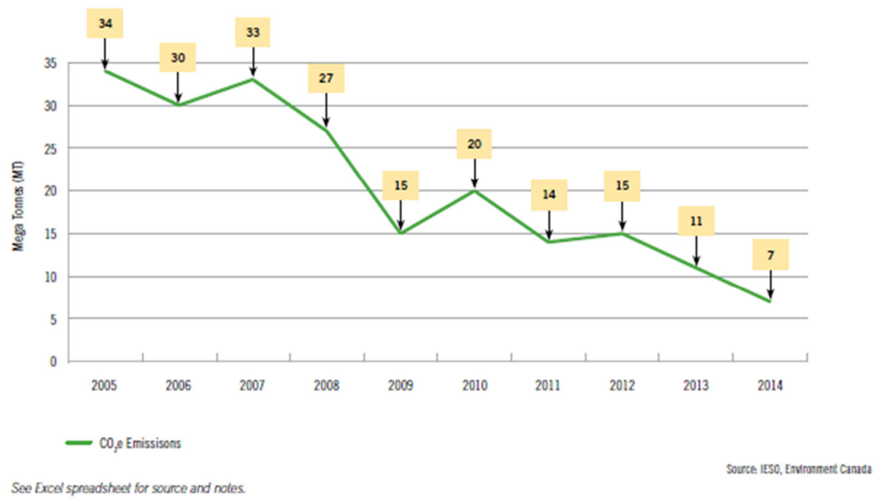


4.2. History of Emissions and the Nuclear Symbiosis

The historical perspective presented in this section examines how Ontario has achieved its GHG emission reductions. There are several enablers that allowed Ontario's coal stations to be retired and to also limit rising production of natural gas-fired generation in its place. The discussion focusses on CO_2 emissions, as documented by the IESO, and then examines both capacity and generation additions that have occurred between 2002 and 2014. This historical perspective on CO_2 emissions shows that the GHG emission reduction achieved by Ontario has been driven by increased nuclear generation.

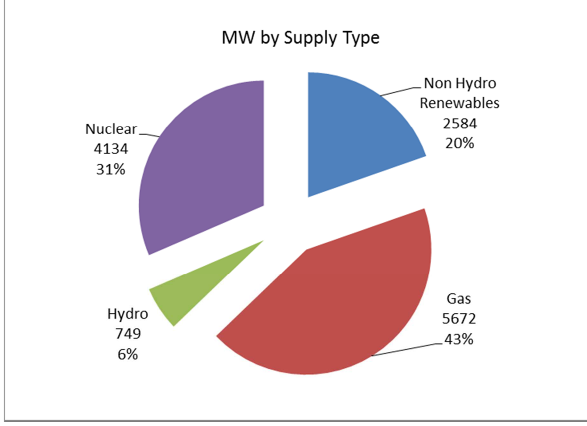
The IESO, in its quarterly Ontario Energy Outlook, reports on the CO_2 emissions from Ontario's electricity sector. Figure 11 is an excerpt from the IESO's Q4 2014 report which shows how emissions of CO_2 have declined from 34 Mt in 2005 to 7 Mt in 2014.[17]

Figure 11 – CO_2 Emissions for the Ontario Electricity Sector
(Mt)



Many point to the significant capacity increase in natural gas and non-hydro renewables generation as being the enablers that allowed for the retirement of coal fired generating plants and the associated reduction in GHG emissions[18]. Figure 12 summarizes the total capacity additions that have been made in Ontario since 2002. In that time frame, over 7,500 MW of coal capacity was retired. This capacity was replaced by 5,600 MW of natural gas-fired generation, 2,600 MW of non-hydro renewables, 4,100 MW of nuclear and 750 MW of hydro.

Figure 12 – Capacity Change Since 2002

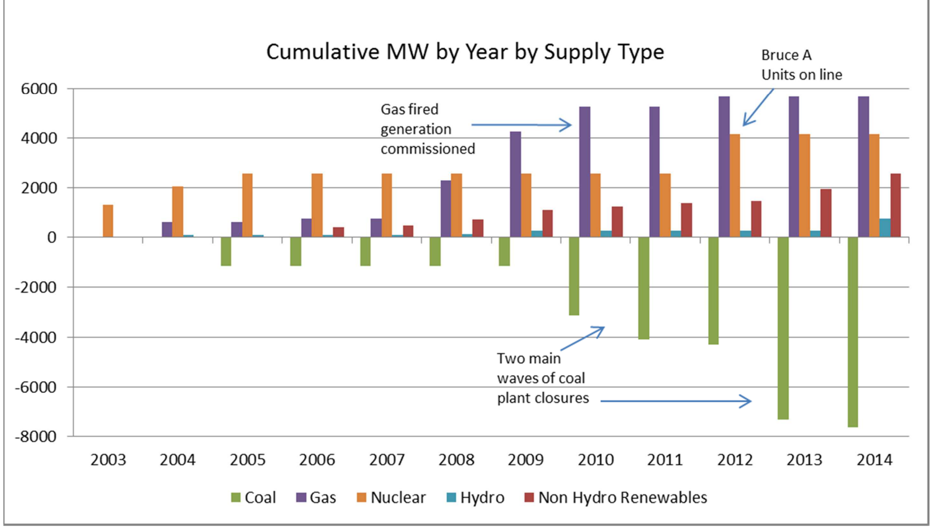


[17] IESO, 2014. Note that these IESO reported actuals are materially higher than forecast by the 2013 LTEP, a bias that Strapolec's forecast suggests will hold throughout the period being analyzed.
[18] Ontario Ministry of Energy, 2013

Natural gas and renewables generation accounts for 63% of the new capacity additions since 2002, while nuclear accounts for 31%.

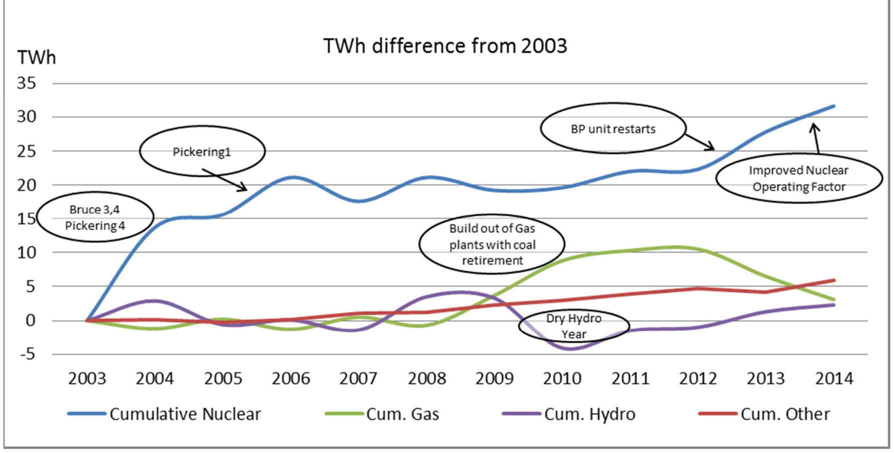
Figure 13 presents the timeline of the capacity additions and retirements since 2002. Correlating the annual capacity additions with the coal capacity retirements shows that the coal plant closures occurred in two phases: (1) the initial closures occurred the year after new gas-fired generation was commissioned in 2010/2011; and (2) the latter coal plant closures coincided with the year following the return to service of the refurbished Bruce A nuclear units which came on line 2012.

Figure 13 – History of Capacity Additions



However, it is the source of actual power generation, not the presence of alternative capacity that drives emissions down. Figure 14 shows the net cumulative increase in generation from all supply sources. Compared to 2002, most supply types today have only marginally increased their generation levels, with the very notable exception of nuclear generation. It is also evident that the increased natural gas-fired generation production in 2010 was in part due to the 7.5 TWh drop in hydro production that occurred in that year.

Figure 14 – Changes in Generation by Supply Type



The subsequent ramp down of gas-fired generation going into 2014 is clearly associated with the increased production from nuclear after the Bruce A units came online and the recovering hydro production. Since 2010 and the first coal plant closures, non-hydro renewables have only marginally increased production.

Figure 15 illustrates the history of CO_2 emissions from 2003 to 2014 and highlights relevant major events alongside the CO_2 emission profile. The portrayal shows how sustained achievements in GHG reductions correlate with increased nuclear generation events in the last 12 years.

Figure 15 – GHG Emissions 2003-2014

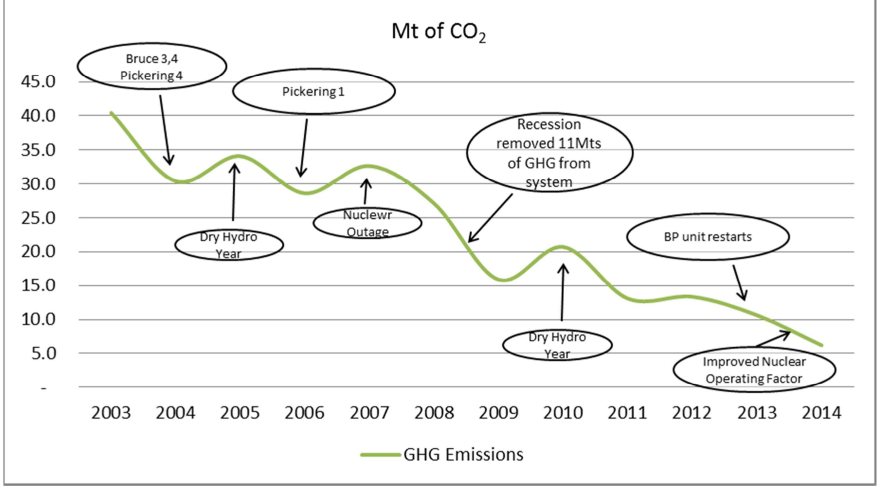
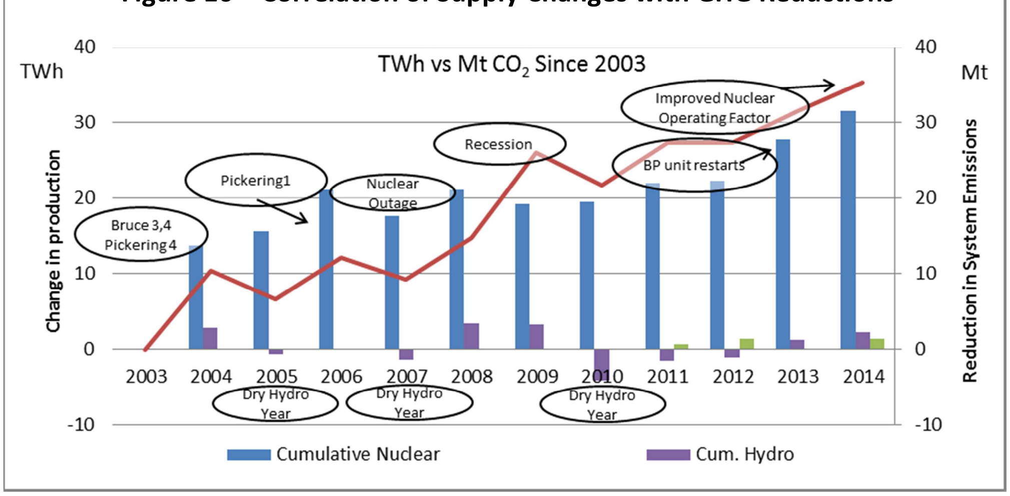


Figure 16 summarizes the net annual production change by supply type that has occurred since 2003 and contrasts that with changes in CO_2 emissions. When cumulative GHG emission reductions are compared to cumulative changes in generation by supply type, the role of nuclear is evident. Trends are clear that every time hydro or nuclear generation has decreased, GHG emissions have risen and vice versa. Noteworthy is the sustained decrease in demand resulting from the 2008 recession. The recession led to a marked drop in coal-fired generation and an 11 Mt reduction in CO_2 emissions.

Figure 16 – Correlation of Supply Changes with GHG Reductions



During the time frame when Ontario's coal stations were being retired, overall nuclear production increased by 32 TWh and CO_2 emissions decreased by 35 Mt. While nuclear capacity remained flat from 2005 through to 2012 (ref. Figure 13), generation was steadily increasing as nuclear operating performance continued to improve. Nuclear is the only low carbon energy supply that has materially increased since 2003.

The strong relationship between emissions reductions and nuclear generation growth is as evident in the last five years as it is for the entire period since 2002. The coal retirements began in 2010 amidst an offsetting increase in gas-fired production and a drop in hydro production as the 2010 LTEP was being rolled out. During this period, wind and solar capacity more than doubled. However, the generation impacts since 2010 are starkly different:

- Nuclear generation has grown by 12 TWh.
- Hydro output grew by over 6 TWh, recovering from previous dry years but still remaining less than 2004 levels despite capacity additions in 2014.
- By contrast, emission offsetting production from non-hydro renewables has only grown by 1.5TWh since 2010, when discounting the contribution of these sources to surplus baseload generation.[19]

Nuclear generation is responsible for offsetting the generation from the retiring coal plants and new natural gas-fired generation plants built to replace them. Nuclear generation accounts for over 87% of the clean or low carbon energy generation that has grown over both time frames measured and discussed above: since 2003; and similarly since 2010.

4.3. Forecast Use of Natural Gas in Ontario

This section examines the degree to which changes in the use of natural gas fired generation in the electricity sector may impact the emissions profile for the total use of natural gas across all sectors of Ontario's economy. The relevant conclusions of this section are that, absent a PNGS extension, natural gas use in Ontario will rise by more than 25% over the relevant period and may also produce greater than historical emissions per unit of energy produced due to the shift of Ontario's natural gas supply to shale gas resources from the US.

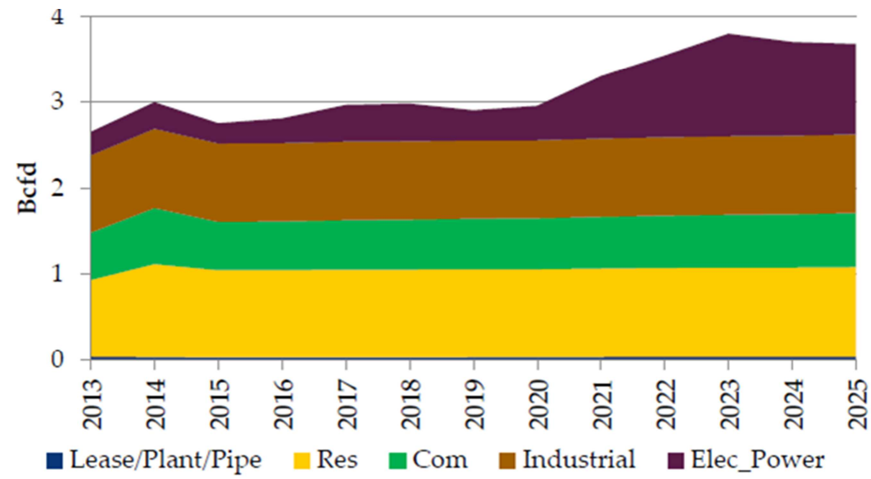
Natural Gas Usage

Figure 17 replicates the forecast usage of natural gas in Ontario produced by Navigant Consulting in a report to the OEB[20]. The forecast shows natural gas consumption by the electricity sector will triple soon after the PNGS is retired. Natural gas use in Ontario has been typically dominated by residential heating

[19] Computed using Strapolec's production forecast model
[20] Navigant Consulting, December 2014

and industrial users. Forecast natural gas-fired electricity generation will increase Ontario's overall consumption of this fuel by more than 25%, making electricity the largest source of consumption.

Figure 17 – Ontario Natural Gas Demand by Usage



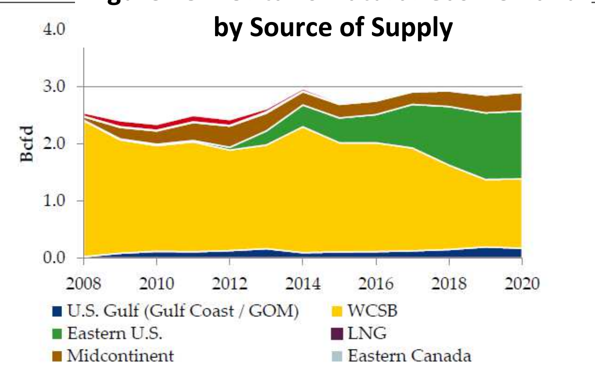
Source: Navigant Mid-Year 2014 Outlook

As a result, at a minimum, the change in usage by the electricity sector will cause an equivalent 25% increase in GHG emissions from that fuel source. Decisions to further increase the use of gas-fired generation will consequently have a material impact on Ontario's ability to meet its overall climate change objectives.

Natural Gas Supply

In the same report, Navigant forecast that Ontario will dramatically shift its source of natural gas supply from Alberta, or specifically the Western Canadian Sedimentary Basin (WCSB), to US shale gas reserves. This shift is illustrated in Figure 18 where the forecast supply growth from the Eastern US is highlighted. As a result, Ontario can expect that on the margin, natural gas required to fuel the replacement of the PNGS generation with natural gas-fired generation will be from the US shale gas resources.

Figure 18 – Ontario Natural Gas Demand by Source of Supply



Source: Navigant Mid-Year 2014 Outlook

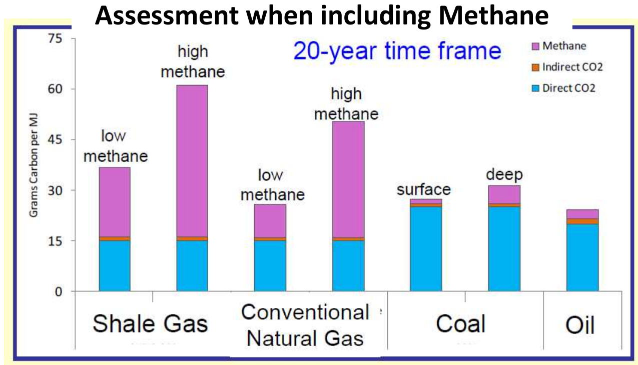
4.4. US Shale Gas GHG Emissions Footprint

Analysis by Howarth[21] of several shale gas emissions studies indicates that US shale gas may have a higher GHG emissions footprint than not only traditional natural gas supply sources, but also that of coal. As a result, although not modelled in this analysis, the move to the US shale gas supply may come with the risk of higher life cycle GHG emissions.

It is well accepted that natural gas produces roughly half the CO_2 of coal. However, leakage in the production system used to extract and deliver natural gas may make the overall lifecycle emissions potentially higher than coal.

Figure 19 replicates the findings of the Howarth study regarding the contribution of methane leakage to the life cycle emissions forecast of various gas and coal reserves. The Howarth study suggests that leakage from the shale gas production system, due to the extraction technology, could be putting more methane into the atmosphere. Methane is a stronger accelerator of climate change than CO_2, albeit a shorter lived one. Methane dissipation from the atmosphere is measured in decades while CO_2 dissipation is measured in centuries.

Figure 19 – Recent Emissions Assessment when including Methane



The shift towards use of US shale gas potentially represents an unquantified upward risk to Ontario's GHG emissions as the province embarks on its climate change actions and initiatives.

4.5. Implications Summary

Increased reliance on natural gas-fired generation to replace production from the PNGS post 2020 could reverse the GHG emission reductions achieved since 2011 through the closing of Ontario's coal stations. The province's forecast supply dependence on US shale gas could exacerbate this challenge.

The upcoming review of Ontario's 2013 LTEP provides an opportunity for the province to select options that continue to support GHG reduction objectives. As shown by this analysis, extending the operation of PNGS can ensure that Ontario continues to benefit from the GHG emission reductions achieved so far in the province's electricity sector.

[21] Howarth, 2014

5.0. Cost to the Electricity System and Rate Payers

This section presents the cost implications to Ontario's electricity system and rate payers that are expected to arise from continuing the operations of the PNGS. The energy sector underpins Ontario's economic competiveness, yet residential and industrial electricity rates have been steadily rising over the last decade. Industrial rates have risen 16% since 2013 and are expected to rise 13% over the next five years.[22] As a result, any cost increases resulting from future decisions regarding electricity supply options are important considerations.

The following cost discussion addresses five topics:

- Forecast Electricity Generation Costs

  An overview is provided of the cost differences between the scenarios and the anticipated benefit.

- Rate Payer Implications

  How the HOEP, Class A Industrial rates, and Class B residential rates are expected to change is illustrated along with the impact on the affected stakeholders and rate payers.

- Unit Cost Comparison

  The unit costs of PNGS extended operations are compared to the equivalent unit costs of natural gas-fired generation including the combined fixed and variable elements.

- Cost Risks

  The risks presented by evolving energy policies in Ontario and the US are discussed. On balance, these policy induced risks suggest the PNGS option may have a greater cost advantage than shown by this analysis.

- Other Benefits & Considerations

  A summary is provided of other factors uncovered during research efforts that may be relevant to the decision to extend PNGS operations.

The section closes with a summary of the key implications of the findings of this section of the report.

5.1. Forecast Electricity Generation Costs

Section 3 summarized the production implications of the two scenarios. When the costs are applied to those production levels, the net financial impact on the electricity system can be determined. From a

[22] Ontario Chamber of Commerce, 2015

supply mix perspective, there are two stages to the PNGS extension scenario that impact on the cost results:

1. Both PNGS Stations A and B will operate for the first two years, and only station B for the last two.
2. The capacity of the nuclear units under refurbishment decreases in 2023, the last two years of the PNGS scenario, which increases the base "other" costs.

Figure 20 illustrates the total cost of electricity generation expected in 2022 and 2023, the years before and after the mid-point in PNGS' extended operations. The changing supply mix leads to overall cost increases from 2022 to 2023 for both scenarios.[23] The cost of extending PNGS operations is expected to be approximately $170M less than the reference scenario in 2022 and approximately $210M less in 2023.

Figure 20 – Total System Cost Comparison by Scenario

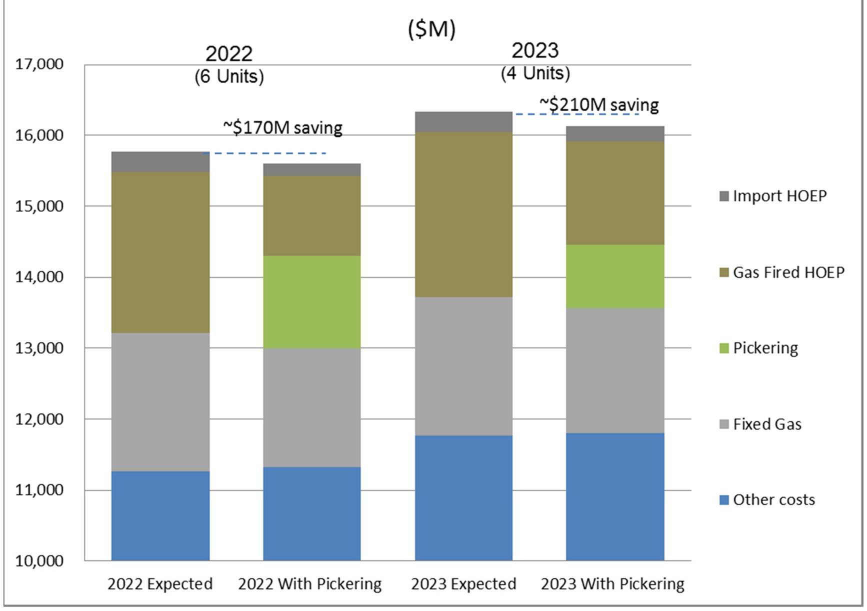
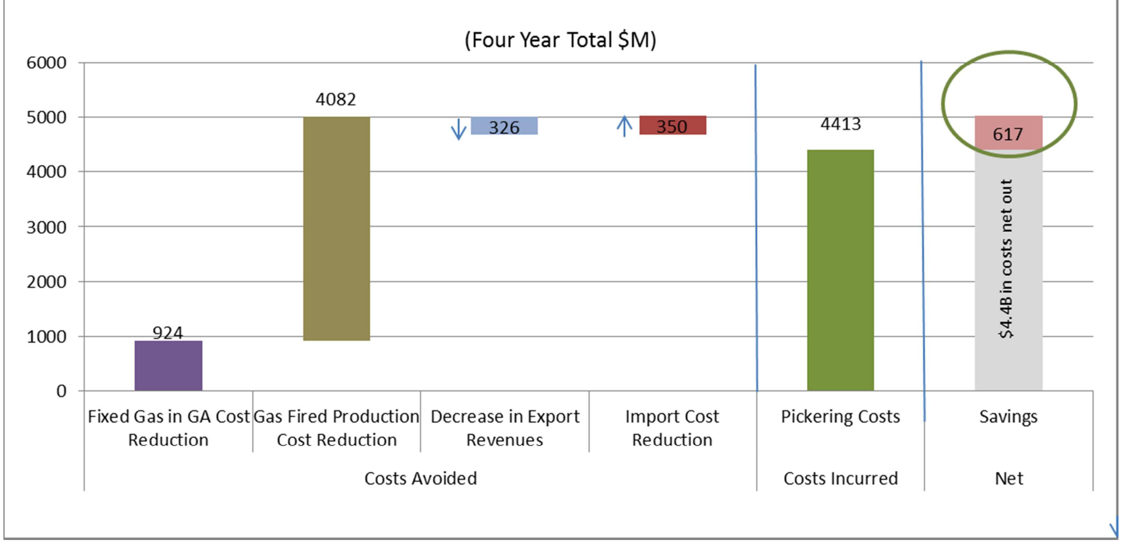


Figure 21 shows the cost elements that differ between the two scenarios. The figure frames the costs in the reference scenario that are avoided if the PNGS extended operations option is selected and contrasts them against the PNGS costs that would be incurred. Over the full four year period of PNGS extended operations, Ontario's electricity system cost is forecast to be over $600M[24] less than may be incurred if natural gas-fired generation is used to replace PNGS capabilities.

[23] In simulation, gas-fired generation and import costs driven by the HOEP forecast model. Costs in nominal dollars

[24] Throughout this report, numerical values have been rounded down from the values in the exhibits. This is done for two reasons: (1) to avoid connotation of false precision and (2) to add a degree of conservatism to the findings.

Figure 21 – Savings from Electricity System Generation



Cost savings are realized by the lower cost PNGS generation displacing the higher cost natural gas-fired generation and capacity. Avoiding the gas-fired generation removes $5B of cost from the system. The sources of this saving include:

- Avoided need to recover natural gas-fired generation plant fixed costs of over $900M in the four year period as contracting of new plants is deferred.
- $4.1B cost reduction in variable natural gas-fired generation due to the reduced volume of fuel required.
    - The decrease in natural gas-fired generation also has the effect of reducing the HOEP to the benefit of industrial rate payers which is discussed in a subsequent section.
    - The reduction in natural gas-fired generation variable costs is partially offset by a $325M reduction in export revenue stemming from the lower HOEP that occurs when natural gas-fired generation is not on the margin.[25]
- Avoided $350M in the costs of electricity imports as the need for these imports will be reduced.

The $5B in avoided costs of natural gas-fired generation will be offset by the approximately $4.4B in PNGS operating costs that will be required for the 4 years of extended operations:

- The costs reflect two years of Pickering A operations and four years of Pickering B operations.
- A blended rate of $63/MWh is derived based on the modelled 68 TWh of generation.

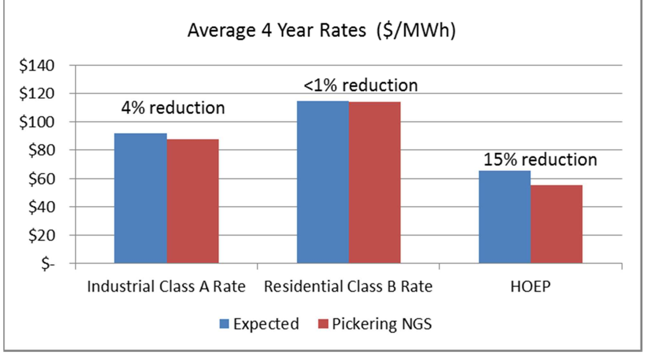
The benefit to the electricity system is the difference between the costs avoided and the costs incurred. The analysis suggests over $600M in savings to rate payers will result from the four year period studied.

[25] Voluntary export volume assumptions are held constant for both scenarios

5.2. Rate Payer Implications

The forecast lower total system costs associated with the PNGS option will result in reductions to consumer electricity rates. Figure 22 summarizes the rate impacts for both industrial and residential consumers and also indicates the impact on the HOEP.

Figure 22 – Rate Payer Cost Comparisons



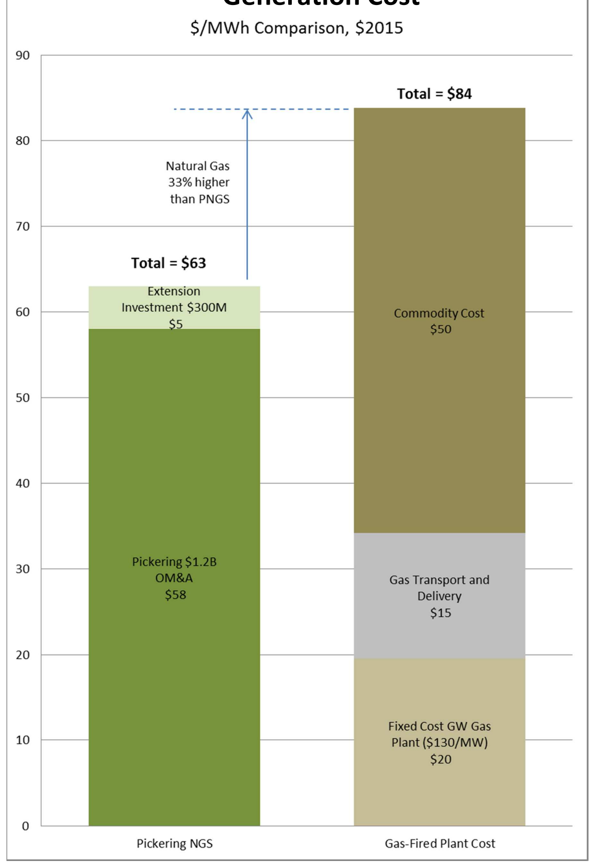
The analysis indicates that Industrial rates could drop by 4%, a benefit for Ontario's recovering manufacturing sector. Residential rates are only expected to be marginally affected. Of note is the 15% expected decline in the HOEP portion of the costs of the electricity system.

Differences in expected rate benefits between industrial and residential rate payers stem from the method used by the OEB to determine the Class A and Class B rates. Class A industrial rates are more heavily weighted to the value of the HOEP than residential rates.

5.3. Unit Costs of Generation

This section summarizes the cost assumptions applied to the PNGS and natural gas-fired generation options and compares them on an equivalent $/MWh basis. Figure 23 summarizes the results.

Figure 23 – Pickering NGS vs Gas-Fired Generation Cost



PNGS Cost Assumptions

The costs for continuing the operations of the PNGS were derived from Ontario Power Generation (OPG) disclosures to the OEB regarding PNGS extensions[26]. The costs presented by OPG in its business cases reflect the incremental costs to the corporation as compared to the PNGS retirement scenario. The incremental costing approach explicitly considers the net impact on OPG should the PNGS option be implemented:

- Under a PNGS retirement scenario, OPG will retain some fixed costs to support the Darlington NGS (DNGS)

[26] Ontario Power Generation, September 2013

operations that had been previously allocated in a split manner to both the PNGS and DNGS stations.

- Taking an incremental approach vis-a-vis these costs results in lower than the fully attributed costs represented during the 2014 OEB decisions.
- OPG has taken this approach in their 2010 and 2012 OEB submissions on this matter.

Strapolec believes this to be a prudent and fiscally responsible approach.

2013 production levels were assumed at 20 TWh for the A and B units and 14 TWh for only the PNGS B units. The total PNGS costs to be recovered were modelled as $63/MWh (2015 dollars) which includes two components:

- $58/MWh in 2015 dollars is required to recover the approximately $1.2B/year of PNGS Operations, Maintenance and Administration (OM&A) costs for the six units.
- A $5/MWh adder is included to recover $300M of investment which Strapolec has assumed would be required to enable the extended operations. The investment estimate is based on the $200M discussed in the previous OPG submissions to the OEB, but with margin and escalation added to provide a conservative value.

It was assumed that when PNGS A closes, the same rate of $63/MWh would continue to apply for the ongoing generation from the B units. This represents an assumption that 70% of the OM&A costs would continue after PNGS A units are retired, which may be a conservatively high cost assumption.[27]

Gas-Fired Generation Cost Assumptions

Strapolec's market model of Ontario's hourly production and the pricing dynamics behind the HOEP was used to compute the variable costs of natural gas-fired generation. However, an illustration of comparative unit rates is useful in interpreting the results. The illustrative comparable rate is $84/MWh as shown in Figure 23 and is comprised of the following:

- *Fixed monthly costs*

  The fixed costs of natural gas-fired generation are based on LTEP 2013 assumptions which have been escalated to a 2015 dollar value of $132,000/MW per year. This value is applied to the 2,000 MW of SCGT assumed in the reference case. The equivalent cost of the fixed monthly payments on a per MWh basis is calculated from the natural gas-fired production displaced by PNGS operations as determined by Strapolec's simulation. The full fixed annual cost is included in the comparative analysis as the need for contracting the gas capacity is deferred beyond the period of the PNGS extended operations. Strapolec analyzed the cost of building a new SCGT based on values obtained from the EIA 2015 AEO. At $132,000/MW/year, very little variable costs can be recovered by those payments.

[27] Based on a number of units criteria, removal of two PNGS A units could reduce the costs by a third to 67%, potentially a 5% reduction from the costs assumed for PNGS B.

- *Variable costs*

  To illustrate a comparative rate, Strapolec developed an estimate using forecasts of Henry Hub gas prices, Dawn Hub premiums, heat rates, exchange rates and the costs of delivering natural gas in Ontario. The comparative estimate is based on the costs at the margin. Specifically, the additional production required to replace PNGS from the existing fleet will cause the plants to operate at higher utilization factors than they are today. At the margin, full transportation and delivery costs are expected to contribute to the future value of the HOEP.

These assumptions suggest that the equivalent costs of natural gas-fired generation on a per MWh basis are about 33% more than the PNGS unit costs. As mentioned in Section 3, part of this saving is not realized due to the contribution of SBG.

5.4. Cost Risks

This section examines the degree of conservatism deployed in this analysis as well as the risks and other cost sensitivities inherent in the modelled assumptions and discusses how they may impact the findings. An overview of the estimated cost impact of some of the risks is provided below followed by individual sections on the broader North American trends that may potentially impact the future cost of natural gas supply. These trends are largely related to the US Environmental Protection Agency's (EPA) Clean Power Plan (CPP) and which could also impact on the outcomes related to Ontario's Cap and Trade initiative.

Forward Looking Risks on the Cost of Natural Gas

To characterize the degree of conservatism used in this analysis, the modelled assumptions can be compared to other third party estimates of future costs. Three factors suggest the assumptions used in this analysis are conservative:

1. Assumptions have been conservatively informed by current industry data[28]:
   - Strapolec developed its own estimate based on Henry Hub forecasts, Dawn Hub premiums, heat rates, exchange rates and costs of delivering natural gas in Ontario, and recovery of monthly fixed costs.
   - PNGS cost rate of $63/MWh is based on previous OPG incremental cost business cases submitted to the OEB and an assumed $300M investment to prepare the PNGS for the extension.
2. Other sources point to alternatives that would have higher costs:

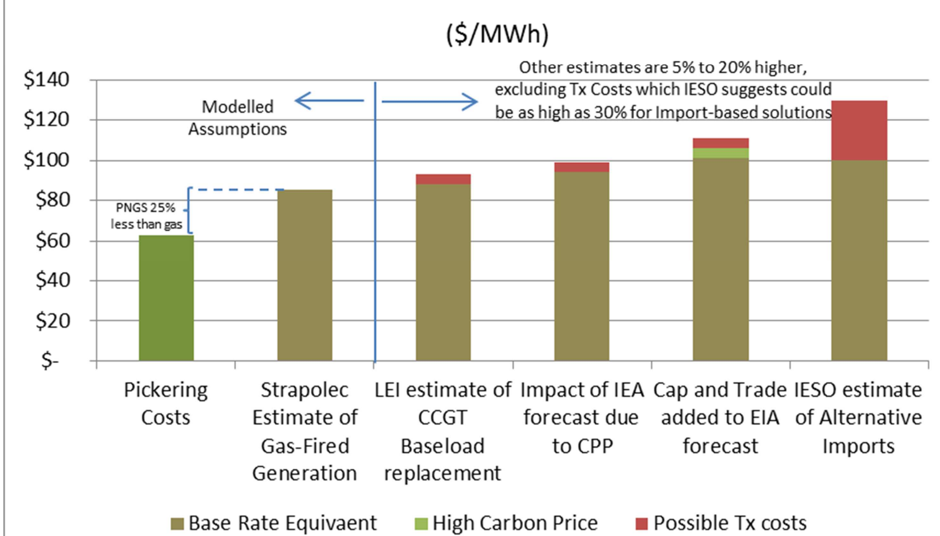
[28] See appendix A for the detailed assumptions

- London Economics International (LEI) has produced an estimate for a baseload Combined Cycle Gas Turbine (CCGT) installation in Ontario. A CCGT may be an alternative to the lower cost SCGT if the expected operational duty cycle is reasonable for a CCGT. The LEI estimate for a CCGT is 5% higher than the costs of natural gas-fired generation assumed here but predicated on a 6% lower fuel price than the Energy Information Administration (EIA) is currently forecasting.[29]
- The IESO's assessment of Ontario's interties[30] and their ability to accommodate increased imports, indicates that the volume of required electricity imports will likely cost $100/MWh. The IESO also suggested that there may be a need for up to an additional $30/MWh for transmission investments.

3. Emergent cost risks stem from the CPP and Ontario's Cap & Trade program objectives:
   - The EIA 2015 assessment of the CPP forecasts natural gas price in the timeframe of the PNGS extended operations could be on average 10% higher than assumed.
   - The Ontario Cap and Trade program will add at least 8% to the cost based on the assumption that Ontario's price will reflect the current carbon price of $12/tonne in Quebec and California and escalated by 5%/year in accordance with regulatory requirements of these two jurisdictions. If industry forecasts resulting from the CPP are realized, the impact on the cost of natural gas-fired generation could be 15% higher.

Figure 24 summarizes the impacts of the potential risks identified and compares them to the baseline cost assumptions used here. This comparison shows that a natural gas-fired generation option could cost 40% to 60% more on a per MWh basis than extending PNGS operations. In a worst case of relying on imports, the costs of alternatives could be double that of the PNGS extension.

Figure 24 – Risks and Conservatism in Cost Estimates



[29] LEI assumed the cost of natural gas from the EIA AEO 2014 report. EIA AEO 2015 forecasted Henry Hub prices are 6% higher than when IESO and LEI provided their estimates.
[30] IESO, 2014.

Cost Sensitivity of Findings to PNGS Assumptions

Figure 24 addresses the perceived risks that could increase the cost of natural gas-fired generation. Based on research, Strapolec did not uncover any evidence suggesting that a different planning reference for the cost of natural gas should be used that could be materially lower than assumed. Similarly, Strapolec believes it is unlikely that the PNGS cost assumptions used could be materially low. For the identified $600M benefit to be reduced to a breakeven condition, the future price of natural gas would have to be 15% less than forecast. On the nuclear side, costs would similarly have to be over 15% higher than assumed. For reference, Strapolec has derived from the OEB 2014 decision that the fully allocated PNGS rate is $62/MWh (or 8% higher). At this stage in the life of PNGS operations, one would expect the OPG estimates for PNGS OM&A costs to be mature.

Furthermore, given the substantial provincial domestic content contained within the costs of nuclear production, the overall observed benefits to Ontario are insensitive to the uncertainties within the nuclear input assumptions. For example, if the PNGS costs proved to be higher than assumed, some of the $600M in identified rate payer benefits may be reduced. However, additional GDP and revenues for the Government of Ontario would then arise, balancing the overall result of economic benefits from the PNGS option. Section 6 provides additional details regarding these cost sensitivities.

The next sections provide an overview of the major implications to Ontario that could emanate from the US EPA CPP initiative and Ontario's intentions to participate with Quebec and California in a cap and trade program.

5.4.1. CPP Impact on the Price of Natural Gas Supply

Based on the EIA assessment of the CPP, future conditions in the US can be expected to place further upward pressure on natural gas prices during the expected period of the PNGS extension.

The CPP was developed in response to President Obama's Climate Action Plan[31]. The CPP can be expected to further increase demand for natural gas over and above what the EIA assumed in its recently released 2015 Annual Energy Outlook (AEO).

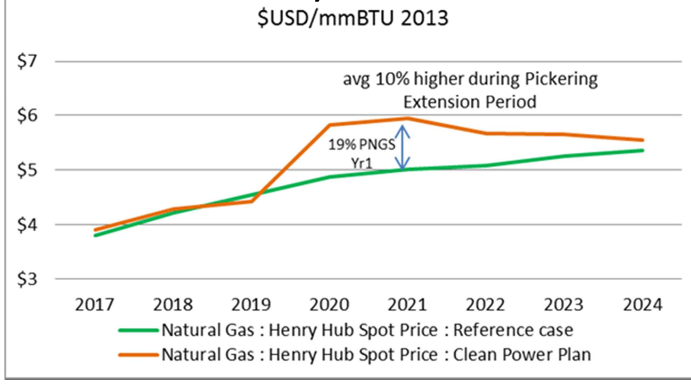
EIA's analysis of the EPA's proposed CPP rule forecasts major changes in the fuel mix used to generate electricity in the United States. [32] The EIA noted that "Under the proposed Clean Power Plan, natural gas, then renewables, gain generation share". The EIA's analysis uses the Annual Energy 2015 AEO Reference Case as its baseline for assessing CPP implications. Under the CPP Base Policy case, the EIA suggests that the main compliance strategy to lower GHG emissions rates is to increase natural gas-fired generation to displace and ultimately surpass coal-fired generation. As a result, the EIA now says that natural gas

[31] Executive Office of the President, 2013
[32] U.S. Energy Information Administration, May 2015

demand in the electricity sector will be almost 25% higher in 2020 than predicted in the 2015 AEO forecast and almost 10% higher in 2030 than the 2015 AEO forecast.

The timing of the CPP will create a peak capacity challenge during the anticipated PNGS extension horizon. Figure 25 illustrates the EIA's CPP based forecast that has the cost of gas rising by an additional 19% at the start of the proposed PNGS extension, when all six PNGS units will be operating. Over the four-year PNGS extension period, the increase in the cost of natural gas is forecast to average 10%.

Figure 25 – EIA Projected Impact of CPP on Henry Hub Price



Canada's National Energy Board (NEB)[33] notes that the natural gas markets in Canada and the United States operate as single integrated market. Ontario can expect that these price increases will likely make their way to Ontario and be amplified by the province's expected increased reliance on US natural gas supply and the typical trends observed between Dawn and Henry Hub prices exhibited when supply constraints occur.

5.4.2. CPP Impacts on Reliability Reserve Requirements

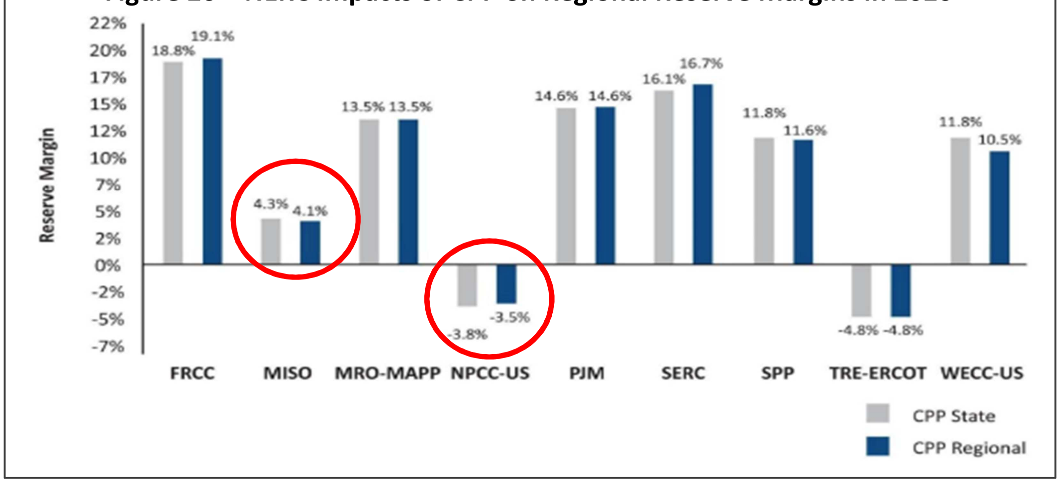
The North American Electricity Reliability Corporation (NERC) has also assessed the implications of the CPP on the North American grid and its reliability reserve capabilities.[34] It concludes that with the forecast changes to the generation mix that are anticipated to result from the CPP, resource adequacy is likely to be negatively impacted by two factors:

1. Uncertainty and variability of renewable resources (such as wind and solar) will need to be accounted for in establishing new target reserve margins. This means the future margin requirements will likely be higher
2. Higher forced-outage rates would also result in higher reserve margin targets, as each electricity system area would need to carry more reserve capacity to balance the uncertainty.

Figure 26 replicates the NERC findings that show how certain jurisdictions – particularly the Northeast Power Coordinating Council (NPCC-US), to which Ontario is a member, and the Midcontinent Independent System Operator (MISO) that border Ontario, will face the most significant resource adequacy concerns in 2020, the time when PNGS is scheduled to go off line.

[33] National Energy Board, 2011
[34] North American Electricity Reliability Corporation, November 2014

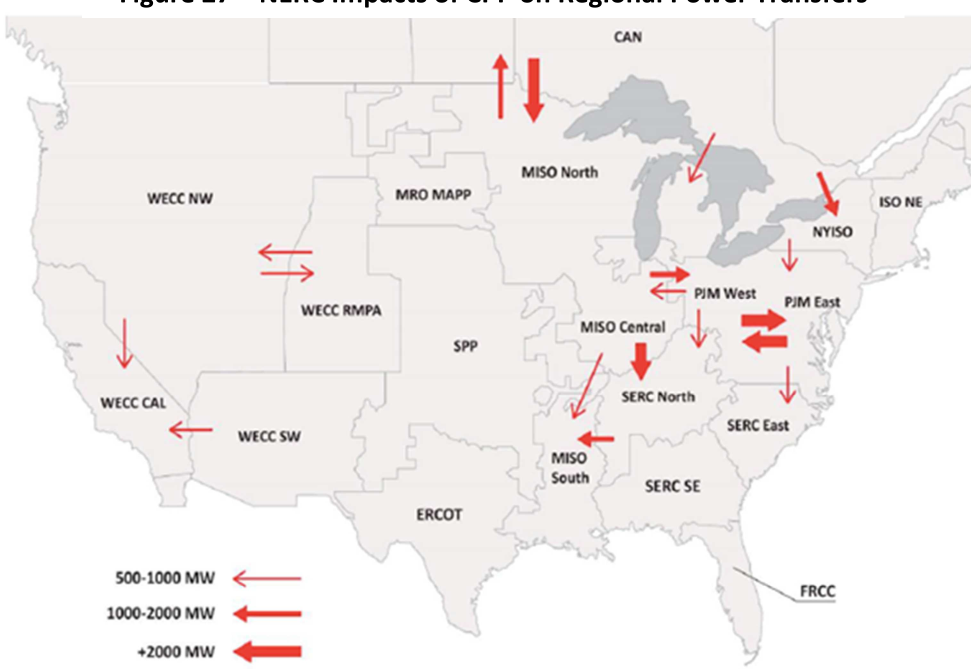
Figure 26 – NERC Impacts of CPP on Regional Reserve Margins in 2020



In addition, reliability could be impacted by other factors, for example, when the timing of forecasted inadequate resource events occurs in certain electricity system areas. In regional trading cases, areas with lower incremental CO_2 reduction options can displace higher-cost options in adjoining states or power pools. Overall, net transmission flow activity between regions is expected to increase by 19,230 MW under the state compliance plan (versus no CPP).

According to NERC, the CPP can be expected to change the power flows in many major power areas. Power flow changes anticipated by NERC are illustrated in Figure 27 which replicates the depiction created by NERC. These power flow changes, both in direction and volume represent potential challenges in the planning and operation of the US NERC Bulk Power System (BPS).

Figure 27 – NERC Impacts of CPP on Regional Power Transfers



The CPP will impact intertie flows and demand for energy from Ontario. Canada is anticipated to export three times more power to the United States, mainly to states in the NPCC and MISO grids. Absent the PNGS, very little low carbon on peak power will be available from Ontario as it will be needed to serve Ontario's needs.

This result would further compromise any alternative supply options that Ontario may be contemplating with regards to accessing US generation for electricity imports into Ontario. New capacity is going to be required across the NPCC/MISO grids. By extending PNGS operations, Ontario may mitigate the risks associated with the peak constraints that have been identified by the EIA and NERC.

5.4.3. CPP Impact on Carbon Prices

The impetus behind the CPP is to reduce the consumption of carbon emitting fossil fuels in the United States. In general, carbon pricing is expected to increase as climate change pressures mount in North America. The US federal government currently uses carbon prices ranging from $11 to $57 (2013 USD/short ton) for their long range planning purposes. [35] The CPP is expected to put further upward pressure on carbon prices.

Synapse Energy Economics assessed several studies that reviewed the implications of the CPP on carbon prices. These studies included those by the various market operators (e.g. peers of the IESO). Collectively the studies suggest carbon prices could be in the range of $20 to $40/short ton of CO_2 (USD) as shown in Figure 28.

Synapse used these analyses to develop their own forecast shown in Figure 29 (converted by Strapolec to CAD per tonne). The average price of carbon during the PNGS scenario is $30/tonne or $12/MWh.

Figure 28 – Summary of CPP CO_2 Price Estimates
($2014/short ton)

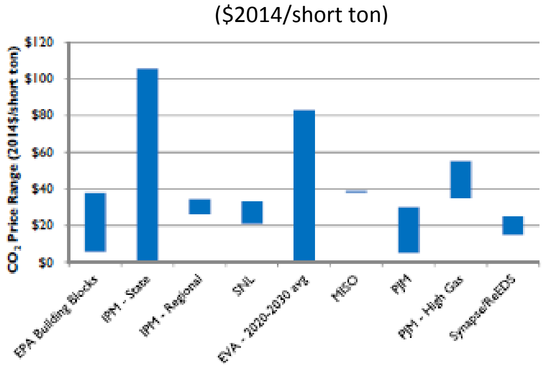
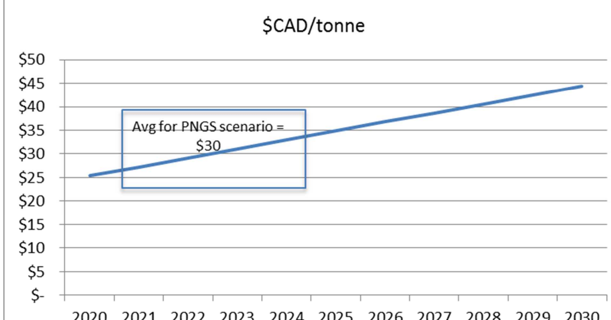


Figure 29 – US Carbon Price Forecast



[35] Synapse Energy Economics, 2015

5.4.4. Cap and Trade and Premium on Gas-Fired Production

The potential impact of the CPP on carbon prices is relevant to Ontario given its signalled participation in a collaborative Cap and Trade program with Quebec and California. Carbon prices in California are set through an auction mechanism[36]. Figure 30 shows how the California prices have recently hovered around $12/tonne of CO_2. Both California and Quebec have instituted a minimum auction price which is to escalate by 5%/year[37]. For Quebec, the result is in an average price of $17.25/tonne during the proposed PNGS extended operations as shown in Figure 31.

Figure 30 –Carbon Trading Prices in California

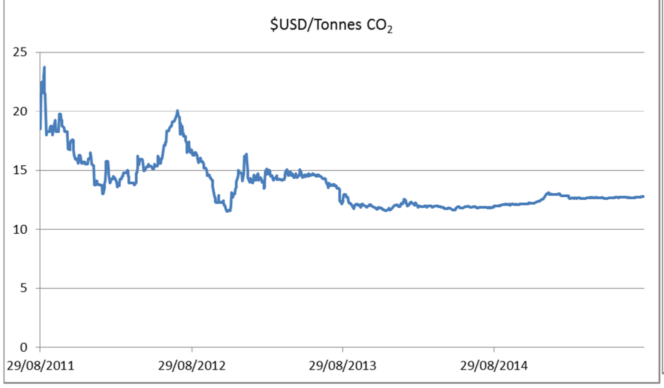
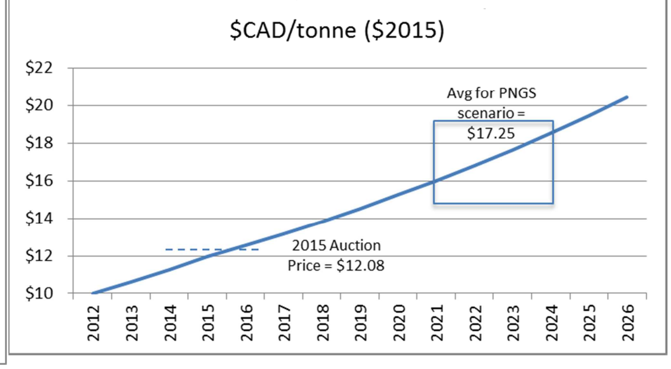


Figure 31 – Minimum Carbon Price Forecast Quebec



Since over 25% of the forecast increase in provincial carbon emissions from natural gas will be coming from natural gas-fired electricity generating plants, it is assumed that Ontario's participation in the cap and trade programs would lead to the carbon prices becoming reflected in the province's electricity costs. Assuming further that Ontario's participation in the collaborative cap and trade program will result in matching the Quebec minimum price of $17.25/tonne, this would equate to per unit cost of about $6.90/MWh (400 kg/MWh) or an 8% premium on the full recovery blended unit cost rate assumed in this study.

The forecast impacts on carbon prices resulting from the CPP suggest that this 8% annual increase in the cost of natural gas-fired generation derived from the Quebec minimum auction price is conservative. Given that there is a single North American market for natural gas, carbon prices could coalesce around the higher 15% US premium implied in Figure 29 as the cap and trade programs mature.

5.5. Other Benefit Considerations

Other benefits that may result from the PNGS option include the following:

1. Existing risks to system planning or reliability may be avoided:

[36] California Carbon Dashboard, 2015
[37] California Air Resource Board, 2014

- Timeline for developing and obtaining the social license for new natural gas fired generation plants.
- Environmental assessment and process for siting new natural gas-fired generation plants.
- Cost of transmission connections for new natural gas-fired generation plants.

2. Avoided additional reserve capacity costs that would only be needed for a short time:

- An additional 1,000 MW of capacity (for a total of 3,000 MW) could be occasionally required during the 2020 to 2024 time horizon.
- Given electricity system requirements in neighboring jurisdictions and the intertie limits, this capacity will likely have to be built.
- This could result in an additional $2.6B+ commitment over 20 years if an additional 1000 MW of gas capacity needs to be built.

3. Benefit of stable supply:

- Lower reserve capacity required with the benefit of costs saved.
- Ontario protected from cost risk associated with natural gas price volatility as the world moves to low carbon generation options.

4. Potential to support the Ontario Cap and Trade Initiative and CPP:

- The additional baseload nuclear generation could be linked to Ontario's Cap and Trade program to develop new low cost zero emission electricity offers in off-peak hours.
- The spare baseload capacity, currently modelled as producing SBG, may support off peak needs in the US as the coal plants are retired in that critical timeframe.

5. Benefits previously recognized by OPA:

- *"Hedge against factors including increased demand, delay in achieving conservation targets, higher natural gas prices or carbon prices, nuclear refurbishment delays, or delays in the in-service of directed resources"*[38].

5.6. Implications Summary

Extending PNGS operations instead of constructing 2,000 MW of new gas-fired generating plants is estimated to reduce the cost of electricity to Ontario rate payers by between $600M and over $1.5B over the four-year period. Figure 32 describes the major elements of the potential $1.5B in savings discussed in this section. The savings arise because PNGS operations are $600M less costly than natural gas-fired generation.

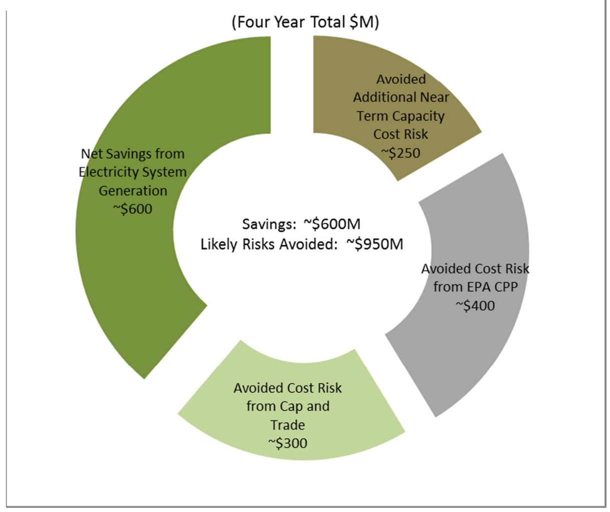
[38] Ontario Power Authority, April 2012

$950M of cost risks associated with being reliant on natural gas as a fuel are also avoided. Three factors contribute to the over $950M in avoided cost risks:

- Clean Power Plan ($400M)
- Ontario Cap and Trade program ($300M)
- Potential need for contracted reserve capacity in 2021/22 ($250M)

Lower electricity costs and avoided risks will ease the cost increases that Ontario's rate payers have experienced. Strapolec believes that the assumptions used in this study are conservative and valid for planning guidance purposes.

Figure 32 – System Cost and Risk Reduction Benefits to Rate Payers



6.0. Economic Implications to Ontario

This section describes the results of the economic impact assessment of the PNGS option versus the natural-gas fired generation alternative. Considerations addressed in this section include measures of jobs and provincial gross domestic product (GDP).

By the end of 2013, Ontario had shed 290,000 jobs in the manufacturing sector since the recession with only 11% of the Ontario workforce being employed in manufacturing compared to 18% in 2000. Additionally, Ontario's historical workforce of steady full-time jobs is shifting to more part-time, lower paying positions. Since 2000, part-time positions increased by 25% compared to an increase of 16% in full-time positions.[39] The energy sector has been an important element of Ontario's economy, with nuclear energy in particular providing over 20,000 direct, well paying, full time jobs.[40]

As such, the benefit to the economy should be a major consideration when comparing a domestically based energy supply such as nuclear to an energy import based option like natural gas-fired generation. This section provides an overview of the findings and description of the assumptions associated with the following:

- Framework for Economic Impact Assessment
- Job Implications
- GDP Implications
- Benefits to Durham Region

Benefits to the Province of Ontario are detailed in Section 7.

6.1. Overview of Forecast Economic Impacts

Extending PNGS operations will result in three primary economic benefits:

1. Jobs: *almost 40,000 direct, indirect and induced Person Year Equivalent (PYE) jobs over the four year period*
    - Direct jobs include approximately 4,000 incremental annual PYE jobs at OPG as well as others within Ontario's nuclear supply chain.
    - Multipliers used in the industry (CME 2012, and NEI) have been applied to determine indirect and induced jobs.[41]
2. GDP: *up to $7B net new growth for Ontario*

[39] Tiessen, March 2014
[40] Canadian Nuclear Association, October 2012, OCI, Strapolec analysis
[41] Canadian Manufactures and Exporters, 2012

- By displacing electricity imports and natural gas purchases with domestically sourced energy, the direct, indirect and induced GDP of Ontario could be increased over the four years by ~$7B.
- GDP growth in Ontario is realized in three ways:
    - Indirect spend by rate payers who have new disposable income
    - Income and supply chain direct, indirect, and induced spend in the region of Durham
    - Income and supply chain direct, indirect, and induced spend in the rest of the province
- Figure 33 summarizes the GDP benefits expected and how these benefits will be distributed.

3. Durham Region: *30% of the jobs along with associated economic benefits*

- OPG is among the largest employers in the region with many of the employees living in Durham.
- Figure 34 summarizes the direct and indirect jobs expected in the first year of the PNGS extended operations and the split between Durham Region and the rest of the province.

Figure 33 – Incremental GDP Created by Extending Pickering NGS Operations

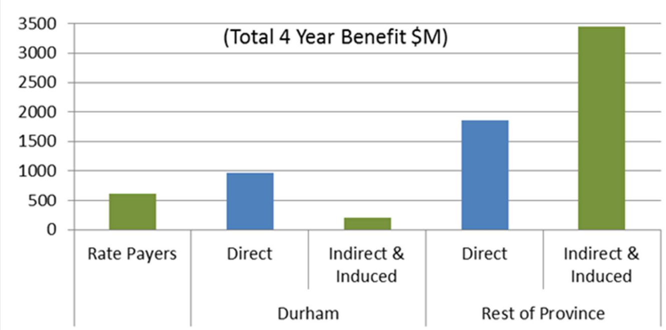
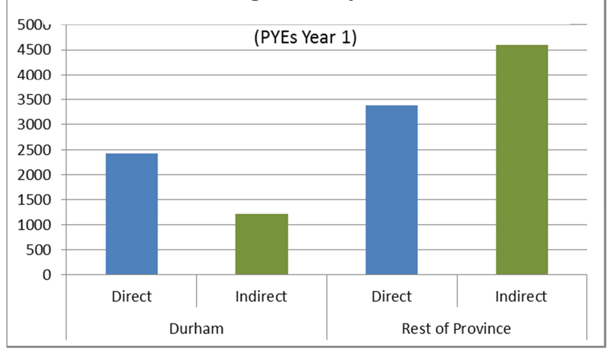


Figure 34 – Jobs Sustained by Extending Pickering NGS Operations



6.2. Framework for Assessing Economic Impact

A comparative framework is used as the basis for estimating the economic impact of a potential extension of PNGS operations. Three factors have been considered in assessing the GDP impacts:

1) Labour income and domestic supply chain purchases are the relevant factors used to compute GDP contributions.

2) The purchases of imported supplies, goods or services do not add to GDP and in fact represent a leakage out of the province.

3) The financial recovery components of a utility's revenue do not contribute to GDP. For example, capital recovery mechanisms (depreciation, amortization and interest expenses) are paying for investments for which the GDP would have been accounted for when the associated capital projects

were implemented. Profits may be returned to shareholders, perhaps not in Ontario, and may not be invested in new capital projects in Ontario. While corporate profits do in general result in some induced GDP contribution, that level of fidelity has not been considered in this study.

The two scenarios can be compared across these three dimensions.

6.2.1. GDP Driving Characteristics – The Power of Domestic Spend

Economic benefits to Ontario are stimulated by:

1. Avoiding the GDP leakage represented by the cost of imported electricity and the cost of purchased natural gas supply. The avoided leakage is turned to economic advantage by applying the funds to the PNGS operations and creating new GDP.
2. Reducing the overall cost of the electricity system and stimulating the broad based indirect GDP benefits resulting from rate payer savings.

Five unique characteristics drive the predicted economic benefits of the traded-off scenarios:

1) Incremental Cost to Extend PNGS

   PNGS extended operations is economically assessed on an incremental activity addition basis with respect to the existing plans. This has been advocated by OPG to the OEB.

2) PNGS Operating Costs are Domestic

   PNGS incremental operating costs are 60% labour with 80% of the remainder being spent on Ontario domestic supply chain resources.

3) Natural Gas Variable Costs are Imports

   Natural gas-fired generating plant variable operating costs are dominated by the purchase of fuel from outside the province. This purchase represents a $3.6B GDP leakage.

4) Natural Gas Fixed Costs are Financial

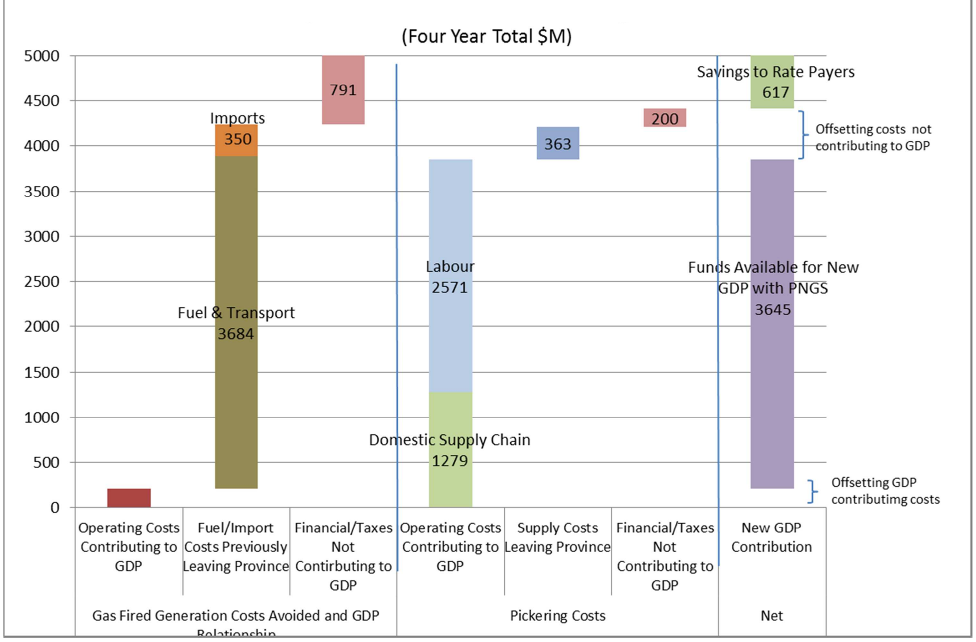
   The monthly fixed costs to the electricity system of new natural gas-fired generating capacity are avoided by deferring construction of new plants. The monthly payments avoided are largely financial recoveries that would otherwise contribute very little to GDP.

5) Avoiding Electricity Imports

   Imports of electricity entail spending outside of the province representing $350M in GDP leakage.

Several of the costs within both options fall into the non-contributing GDP factors previously described. Figure 35 categorizes the cost components of each scenario into the GDP contributing vs non-contributing categories. The figure illustrates the relationships between these costs in a comparative manner. Collecting the common GDP contributing factors as well as the non-GDP contributing factors, and characterizing them as GDP leakage or financial factors, highlights where the GDP contributing costs will arise from. Aligning those items with common GDP impacts and then removing the amounts from each scenario that overlap graphically demonstrates the incremental approach used to identify the impacts that differentiate the two options. This approach ensures that the economic contributions of the natural gas-fired generation scenario are recognized in the comparative analysis.

Figure 35 – Comparison of GDP Contributing Factors



As mentioned earlier in this report, the economic impact of constructing new natural gas-fired generating plants has not been considered in this portion of the analysis. While the relevant plants will still need to be built, their commissioning is only slightly deferred until the eventual retirement of the PNGS. These investments will still occur within the time frame of the scenarios analysed and hence does not represent an incremental factor.

The results of this approach to the comparative analysis shown in Figure 35 demonstrates that there are net new funds of about $3.6B that are available to pay for the PNGS operations and create net new economic benefit. The rate payers' savings benefit of ~$600M also results from what would otherwise be non-GDP creating financial cash flows for the natural gas-generation fixed assets. The resulting net economic contribution of the PNGS is approximately $4.2B before considering the indirect and induced factors associated with the PNGS operations.

A discussion of the economic assumptions for each scenario is provided in the next two sections.

6.2.2. Natural Gas-Fired Generation Economic Impact Assessment Assumptions

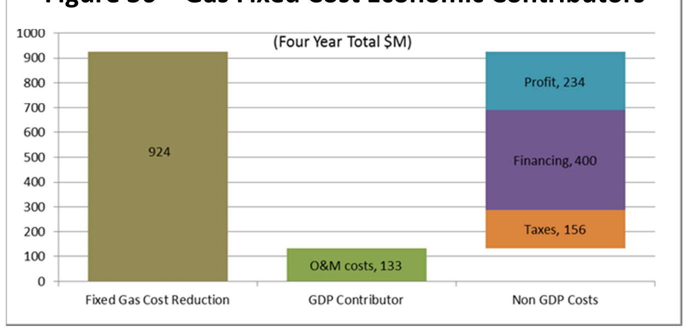
Figure 35 showed how $5B of natural gas-fired generation costs would be displaced by extending PNGS operations. Natural gas-fired generation costs in Ontario have two major and distinct components within the overall cost structure of the electricity system. These components pertain to the Global Adjustment (GA) and separately to the HOEP. Elements of both cost components are subject to displacement by PNGS operations.

1) Monthly fixed costs recovered through the Global Adjustment (GA) ($920M 4-year total reduction):

   IESO indicated that the LTEP had assumed monthly fixed costs of $130,000/MW/year or $260M/year for the 2,000 MW modelled in this analysis. These fixed monthly charges cover primarily the financial returns of the plant and the relatively small fixed operating costs of a peaking supply plant.

   Figure 36 shows the components of these monthly fixed costs and how they may contribute to GDP. Only the ~$130M fixed operations and maintenance (O&M) costs contribute to GDP[42]. The remainder of the costs, or ~$800M, are funds that can be converted from non-GDP contributing to GDP contributing costs with the PNGS option.

Figure 36 – Gas Fixed Cost Economic Contributors



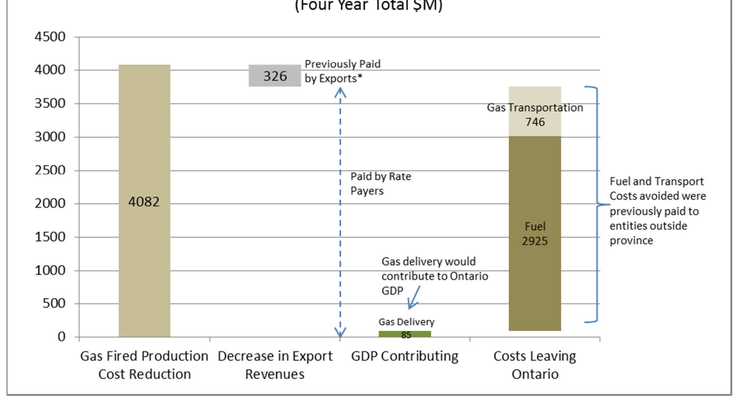
* GDP impacts of previous exports is not material to study given 95% import content of supply

2) Variable costs of production recovered through the HOEP ($4B 4-yr total reduction)

   The variable costs of production dwarf the fixed cost payments by a factor of four. Figure 37 shows how the majority of these costs are for fuel and the costs of the national pipeline systems that deliver the natural gas to Ontario[43].

   Only ~$85M of the costs would contribute to Ontario's GDP through the local delivery

Figure 37 – Gas-Fired Generation Economic Components



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[42] The economic impact benefits of new gas-fired facility construction has been excluded from this analysis as the need for the facilities is merely deferred by 2 to 4 years in the simulation and will likely still occur within the time frame being assessed. The net present value (NPV) benefit due to the deferrals is considered immaterial to the findings in this report.

[43] Details are provided in appendix A

charges of Enbridge and Union Gas. The remaining $3.6B in fuel and transportation costs leave the province.

The share of gas-fired generation in exports is lower with PNGS, reducing export revenues. The lower export revenues offset the cost savings of reduced production by $325M. These are not a lost GDP opportunity as 95% of the underlying variable costs are for imported supplies. The material difference between the PNGS and reference case aspects of this topic therefore net to a zero sum impact on Ontario's trade balance and GDP.

The GDP contributing elements from the gas plants that arise from the fixed cost O&M and local delivery costs are likely less than $300M over the four years. In the incremental analysis approach, these are offset against PNGS generation O&M costs. The remainder of the natural gas-fired generation costs arising from both the $800M in fixed financing costs and from the $3.6B in imported fuel costs are non-GDP generating. Displacing them represents $4.4B in electricity system costs that can be directed to support the costs of the PNGS extended operations and create net new GDP.

6.2.3. PNGS Economic Impact Assessment Assumptions

PNGS costs of $4.4B stimulate almost $4B[44] in GDP contributing activities over the four years. The incremental costing approach discussed in Section 4 considers the costs and employment that will remain at OPG upon PNGS retirement in order to conduct the operations at the Darlington NGS.

The incremental impact approach is also justified for use in the economic impact analysis for the following reasons:

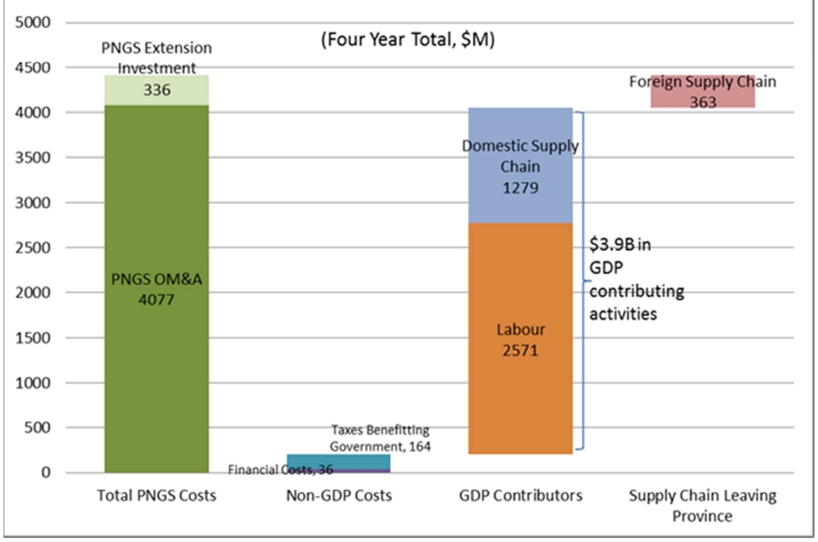
- The retirement of PNGS is being deferred only for a short time,
- Any operational ramp downs that may be planned, will simply be deferred,
- The economic impacts that may arise from decommissioning activities are simply being deferred.

The incremental approach simplifies down to evaluating the impact of four years of PNGS operations activity.

The breakdown of PNGS operating costs discussed earlier provides the basis for identifying the economic impacts. Figure 38 summarizes the cost components that make up the investment and OM&A costs of extending the PNGS operations. Furthermore, as the plant is already depreciated, one advantage of continued operations is that only a small portion of the costs are for financing purposes, i.e. those related to the extended operations preparatory investments. Almost 90% of the $4.4B rate base, or $3.9B over the four year period, contributes to jobs and GDP.

[44] Note: Impact due to timing of cash flows has not been rigorously considered

Figure 38 – Incremental PNGS Extended Operations GDP Contributors



Note: Simulation costs are prorated based on composition of OM&A and investment cost elements

6.3. Jobs Implications

Extending the operations of the PNGS is forecast to generate almost 40,000 PYEs of employment over the four year term studied. This number of PYE jobs is derived from two factors: number of personnel employed at OPG in support of PNGS operations; and (2) the number of Ontario domestic jobs sustained in the supply chain that would continue to provide products and services to the OPG PNGS related activities.

The derivation of the jobs that are sustained by the PNGS option is summarized in Table 1. OPG incremental employed personnel quantified as Full Time Equivalents (FTEs) is estimated at 4,000 per year when all six units are operating. Strapolec has assumed this will reduce by 30% when PNGS A operations are discontinued. The OPG labour composition assumptions are described more fully in appendix A.[45]

Direct jobs in the nuclear supply chain have been estimated based on the PNGS supply chain spend prorated against the size of the nuclear industry's supply chain employee base and estimates of the supply chain's other revenues. Total industry jobs and their distribution across the country have been obtained from the Organization of Canadian Nuclear Industries (OCI).[46]

[45] Ontario Power Generation, 2013; Strapolec analysis
[46] OCI, 2013

The total number of jobs also includes indirect and induced jobs. The multipliers used have been obtained from the Canadian Manufacturers and Exporters (CME) association studies conducted for the Canadian Nuclear Association (CNA) in 2012.

Table 2 shows how the annualized values of Table 1 will produce 40,000 direct, indirect and induced jobs when spread over the four year period of the PNGS option.

Table 1 - Summary of Approximate Job Impacts (FTEs/Year)				
	Direct Jobs	Indirect Multiplier	Indirect Jobs	Total
Pickering Incremental for OPG	4,000	1	4,000	8,000
Supply Chain jobs	1,800	1	1,800	3,600
Total Jobs	5,800		5,800	11,600
Notes:	Supply chain job estimates based on CME reported OCI jobs			
	OCI data prorated based on expected Pickering supply chain spend			
	Multipliers using CME factors per CNA			

Table 2 - Net Job Impact of Assessed PNGS Extended Operations				
Total Job Impacts	% Jobs Included	Per Year Jobs	# of Years	Total Jobs
6 Unit operations	100%	11,600	2	23,200
4 Unit operations	70%	8,120	2	16,240
Total				39,440
Notes:	Jobs scaled similar to expected costs per TWh assumption			
	Jobs are in terms of Person Years of Employment (PYEs) or Full Time Equivalent jobs (FTEs), both used synonomously in this report			

The above jobs analysis is conservative as it does not reflect any induced jobs benefits resulting from the $600M savings that would be realized through rate payers. Induced jobs could be as high as 3,000 PYEs, or 8% higher than the total of approximately 40,000 PYE jobs noted above. Based on the estimated $600M in benefits mostly accruing to industrial rate payers, additional job growth should be anticipated in the province's industrial sector. After tax, these job creating benefits could be approximately $400M based on CME's estimate of the total corporate tax burden in Ontario (approximately 30%). CME's assessment of the contribution to job creation by after tax corporate profits suggests that about 8,000 jobs are created for every billion dollars in after tax profit.[47] As a result, the rate payer savings could generate 3,000 additional induced jobs.

[47] Canadian Manufacturers & Exporters, 2011; Strapolec analysis

6.4. GDP Implications

GDP estimates have been developed based on several assumptions recently used in the nuclear sector. The fundamental economic multipliers and principles described in the CME's 2012 study (referred to in the 2013 LTEP) have been applied here. Income has been based on total labour costs at OPG, less a burden of 40% over salary for fringe benefits, etc., applied here as a rule of thumb by Strapolec.

Table 3 shows the breakdown of the approximately $7B in GDP benefits that could arise in Ontario by extending the PNGS operations by four years.

Table 3 - Calculation of GDP Benefits ($M over 4 years)				
	Direct	Indirect Multiplier	Indirect GDP	Total GDP Impact
Labour Income	1,836	1.4	2,571	4,407
Supply Chain (net of Gas O&M)	983	1.1	1,082	2,065
Rate Payer Savings			617	617
Total	2,820		4,270	7,089
Notes:	Labour multiplier is 1.4 times income per CME			
	Income ~ 70% of labour costs (typical overhead)			
	Supply Chain multiplier based on CME report			

6.5. Benefits to Durham Region

The important role that OPG plays in the economy of the Durham Region is widely recognized. In their submissions to the OEB, OPG continually reiterates that the PNGS is a major employer within the Durham Region with 2,700 people directly employed at the PNGS stations in 2009. Based on the locations where PNGS related employees live[48], Strapolec estimates that approximately 2,400 direct jobs are filled by residents of the Durham Region.

OPG's nuclear operations, of which the six PNGS units represent the largest operation, have "attracted nuclear related businesses, helping to establish a Durham Energy Industry Sector cluster (e.g. Eastern Power, Eco-Tech, Black and MacDonald, AREVA, New Horizons Systems Solutions, etc.)."[49]

The annualized economic contribution to the region is summarized in Table 4. Over the four-year period, more than 12,000 jobs and almost $1.2B of direct, indirect, and induced local GDP will be

[48] Gartner Lee, 2000, OCI, 2013, PWU, Strapolec analysis
[49] Ontario Power Generation, 2013

sustained. Local multipliers used for this analysis have been based on the Nuclear Energy Institute (NEI) report[50]. These multipliers are typical of those observed in the US.

Table 4 - Summary of Approximate Economic Relevance to Durham Region					
Annualized	Direct	Multiplier	Indirect & Induced	Annual Total	4 Year Total
Supply Chain Output ($M)	17	4%	1	17	GDP
Income ($M)	267	22%	59	325	1,165
Jobs (PYEs)	2,424	50%	1212	3,636	12,362
Sources:	Nuclear Energy's Economic Benefits - Current and Future, 2014,Nuclear Energy Institute (NEI)				
	Applied NEI ratios to national CME assumptions				

6.6. Implications Summary

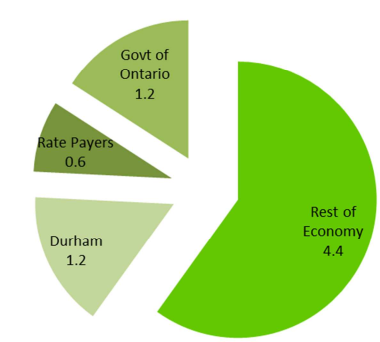
The PNGS option represents a significant opportunity to provide over $7B of economic benefits for a range of Ontario stakeholders.

Figure 39 summarizes the elements of the $7B in benefits that arise by extending the operations of the PNGS, mostly enabled by the power of domestic spend arising from the displacement of $4B in energy imports. The benefits identified include:

- Reduced electricity costs of over $600M to Ontario ratepayers.
- Continued $1.2B in economic stimulus for the Durham Region.
- Improved the Government of Ontario fiscal position of almost $1.2B.
- Adds approximately $4.4B to the rest of the provincial economy.
- Sustains 40,000 person year equivalent direct, indirect and induced jobs.

Figure 39 – Share of Total Economic Benefit

(Four Year Total $B)



The next section discusses the direct benefits to the Government of Ontario.

[50] Nuclear Energy Institute, April 2014

7.0. Benefits to Government of Ontario

Extending the operations of the PNGS by four years would improve the fiscal position of the Government of Ontario by over $1.1B (cumulative).

Incremental tax revenues, estimated at over $900M and representing 13% of the new GDP created, is the largest contributing factor. The 13% share of incremental GDP is an approximation based on research that indicates most economic impact studies identify Ontario provincial government revenues as being 12% to 14% of incremental GDP created. [51] By contrast, overall government revenues are greater than 16% of Ontario GDP and so the 13% assumption may be conservatively low.

Two additional benefits have been included that would accrue to the Ontario government as a result of its shareholder stake in OPG operations. These have been previously identified by the OPA and include:

1. Operating income of OPG to the Government of Ontario.
2. Severance costs deferred and savings from deferring the decommissioning activities, which allows more time to potentially increase the value of the decommissioning liability funds.

The benefits that will accrue to the Government of Ontario are summarized in Table 5.

Table 5 - Benefits to Ontario Government ($M over 4 years)		
Total GDP	7,089	
Taxes from GDP	922	13%
Income from OPG	45	net of lost gas plant tax revenue
Deferred Decommisioning	201	per OPA assessment 2012
Total Ontario Benefit	**1,168**	

These benefits suggest that extending the operations of the PNGS will sustain an Ontario budget contribution to the Province of almost $300M/year for the four-year period instead of creating an equivalent deficit in the provincial budget for those years.

Implication Summary

Extending the operations of PNGS represents a significant opportunity for the Ontario Government to positively support its fiscal position while simultaneously reducing the cost burden of its taxpayers and electricity rate payers. Besides enhancing Ontario’s fiscal position by over $1.1B, the PNGS option enables the province to achieve further substantial reductions in GHG emissions while also meeting the province’s reliability capacity reserve gap.

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[51] Conference Board of Canada, 2012; Dungan, 2014; Ontario Ministry of Finance, 2015

8.0. Summary and Recommendation

The emissions and economic benefits of extending the PNGS operations are clear and compelling. The PNGS option helps address two significant challenges facing the province: (1) it supports achieving Ontario's GHG reduction objectives by avoiding an increase in GHG emissions of 55%; and (2) helps mitigate Ontario's near term reliability reserve capacity gaps. The benefits of extending the PNGS operations include:

- ***Lower GHG emissions*** – over 18 million tonnes (Mt) of CO_2 avoided, which is avoiding both a 55% increase in electricity system emissions and a 25% increase in the total provincial emissions from natural gas usage across all of Ontario.
    - The PNGS option exemplifies Ontario's legacy of nuclear being practically responsible for Ontario's electricity system GHG emissions success.
- ***Lower electricity system cost*** – potentially reduced by over $1.5 billion (B) due to PNGS operating cost advantages and avoidance of the risks of natural gas-fired generation dependence.
    - $600M cost reduction to Ontario's electricity rate payers.
    - Mitigation of almost an additional $1B in costs risks that can potentially arise from far reaching developments in the U.S. electricity system that could significantly increase natural gas prices and reserve capacity requirements in Ontario.
- ***Positive Jobs and Gross Domestic Product (GDP) created –*** from the power of domestic spend
    - Over $7B dollars of benefits will accrue to rate payers, the Government of Ontario, and, significantly, to the provincial economy.
    - ***Jobs Sustained*** – 40,000 Person Year Equivalent (PYE) jobs.
    - ***Net New Ontario Domestic GDP*** – $7B enabled through replacing $4B of imported energy with domestic nuclear generation.
- ***Allowance for more time*** to develop a solution to Ontario's longer term grid reliability and emissions challenges.

Recommendation:

Given these significant benefits, the Ontario Government should direct the Minister of Energy, the IESO, and OPG to consult with the Canadian Nuclear Safety Commission (CNSC) for the purpose of securing approval for the longest possible period of continued safe operation of the PNGS beyond 2020 in order to:

- Sustain the substantial economic and environmental benefits that accrue to Ontario for every year the PNGS continues to operate.
- Provide the government with the maximum time for assessing longer term options for the eventual replacement of the PNGS.

Appendix A - Scenario Cost Assumptions

This appendix summarizes the detailed cost related parameters that have been used in the economic assessments. Four specific areas are described in this appendix:

- Basis of Derivation of Pickering Cost Assumptions
- Natural Gas-Fired Generation Fixed Plant Costs
- Variable Costs for Gas-Fired Generation
- Expected cost of natural gas as a fuel for gas-fired generation.

A.1. Basis of Derivation of Pickering Cost Assumptions

Pickering costs were developed based on an incremental cost approach. This means that the costs to extend PNGS operations are those that would be incurred as additional to OPG's baseline assumptions of only the Darlington NGS (DNGS) being operated post 2020 as per the LTEP. These costs are not incremental to the decommissioning program which is simply deferred. The benefits of that deferral are discussed as benefits to the provincial government in Section 7.

This incremental costing approach is the method OPG used in their OEB submissions in 2010 and 2013 in support of the PNGS continued operations post 2015.

Since a total system cost model is being used that factors in the DNGS cost rates assumed in the LTEP, the incremental cost approach is legitimate for this simulation as all costs are properly captured for comparison purposes.

A summary of the assumptions that build up the $63/MWh rate used to depict the PNGS costs in this analysis is provided in the table below.

Mock-up for Incremental Pickering Business Case Assumptions to Support Economic Impact		
Cost Element	**Cost ($M)**	**Notes**
Fuel	126	Average of 2017 to 2019 in 2013 Bus Case, escalated to 2015$
O&M Labour	690	Computed based on 2015 average compensation and 4000 FTEs
O&M Supply Chain	298	Estimated based on remainder of costs from total estimated
Financing	0	Assume that Pickering will have been fully depreciated
Income (EBIT) & Prop Taxes	47	Added to reflect return required in consumer rates
Total	1160	
Rate Calculation		
Assumed TWh	20	In 1st and 2nd year, 3rd and 4th years will reduce to 14
Assumed Rate ($/MWh)	$ 58	
Investment Recovery ($/MWh)	$ 5	$300M recovered over 68 TWhs over 4 years
Total Rate ($/MWh)	**$ 63**	
Notes	Rate is held constant for simulation assuming a proration of costs when Pickering A operations end and B continue at 14 TWh/year	
	Fuel and supply chain costs are treated similarly for economic impact assessment	

The incremental business case cost assumptions have been developed primarily through leveraging the OPG data provided in support of the OEB submissions as follows:

1. OPG cost estimates from the OEB submissions were obtained and escalated to 2015 dollars.
2. OPG's staffing plan was obtained from OEB submissions.
3. Staffing and FTE assumptions were developed based on OPG representations of incremental costs for support and corporate services as stated in the OEB submissions.
4. Labour costs for the economic impacts were estimated from the expected FTE counts and the average salaries identified in the OEB record of decision.
5. Fuel and supply chain costs were estimated from the average fuel costs in the 2013 OPG business case with the supply chain expenditures accounting for the rest.
6. It is assumed that the Pickering asset has been completely depreciated prior to the extension and that any new capital expenditures will be paid for through rates applied during the extension period.
7. A 4% surcharge was also assumed in the rate to reflect the typical income for OPG's shareholder.

Estimating Incremental Pickering NGS Costs for Extending Operations			
Cost in 2017	Incremental costs ($M)	Cost in 2015$	Average of Estimates
2010 Business Case (2010$)	1060	1159	1114
2013 Business Case (2012$)	1013	1069	
Notes	2017 picked as a Reference year as it appears to capture the full annual operating costs		
	Total OM&A & Capital includes station OM&A (base, outage, projects) and sustaining capital projects and the stations share of incremental allocated nuclear and corporate support costs. These costs do not include severence costs associated with each scenario		
Source	OPG business cases submitted to OEB in 2010 and 2013		

For reference, Strapolec has derived from the OEB 2014 decision that the fully allocated PNGS rate is $62/MWh excluding considerations for the $300M extension investment. This is only 8% higher than the $58/MWh for PNGS OM&A costs assumed based on the incremental approach.

Estimated Annualized FTE Jobs from Extending Pickering NGS Operations				
	Estimated Current FTE Allocation	% Jobs Retained with Extension	Jobs Retained (FTEs)	Scenario with Incremental Costs Weighted More on Labour
Nuclear Support	2130	68%	1449	1585
Corporate Staff	1888	28%	529	801
Pickering NGS Staff	1,830	100%	1,830	1,830
Total Staff	5849		3807	4216
Source:	FTEs from OPG Nuclear Resources Staffing Plan and JPSCA analysis cited in OEB Decision 2014 based on EB-2013-0321			
	% costs retained assumption from OPG Pickering Business case in EB-2013-0321			
Notes	Current staff estimated based on a 60%-40% Pickering to Darlington ratio based on number of units. Strapolec created reference to assess possible range			

Estimated OPG 2015 Labour Costs			
	FTEs	Compensation ($/year)	Labour Cost ($M)
Management	1076	$ 205,914	222
Society	2965	$ 176,508	523
PWU	5300	$ 163,458	866
Total	9341		1611
Assumed for Pickering Business Case			
	4000	$ 172,491	690
Source:	OEB Decision with Reasons, 20 November 2014		

A.2. Natural Gas-Fired Generation Fixed Plant Costs

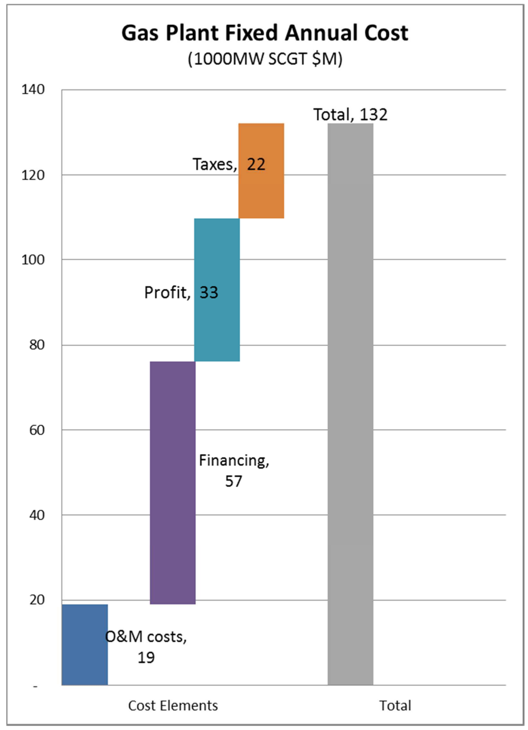
Strapolec developed a financial model of the fixed portion of a new 1,000 MW Simple Cycle Gas Turbine (SCGT). Cost assumptions have been obtained from the EIA 2015 AEO. Comparing the required financial returns to a fixed cost payment of $11,000/month per MW of capacity shows that this level of budget is mostly attributable to financial cost and return recoveries.[52]

The financial assumptions are summarized in the table below with the financial model outputs depicted in the accompanying figure. Only 15% of the annual $132M payments, or $19M of the on-going cost, is for operating and maintenance activities that contribute to GDP.

Based on the financial mock-up of parameters, there is little room within the assumed fixed cost payments to address any of the variable cost components.

52 IESO, October 2014; Ontario Ministry of Energy, 2013; EIA, April 2015; Strapolec Analysis

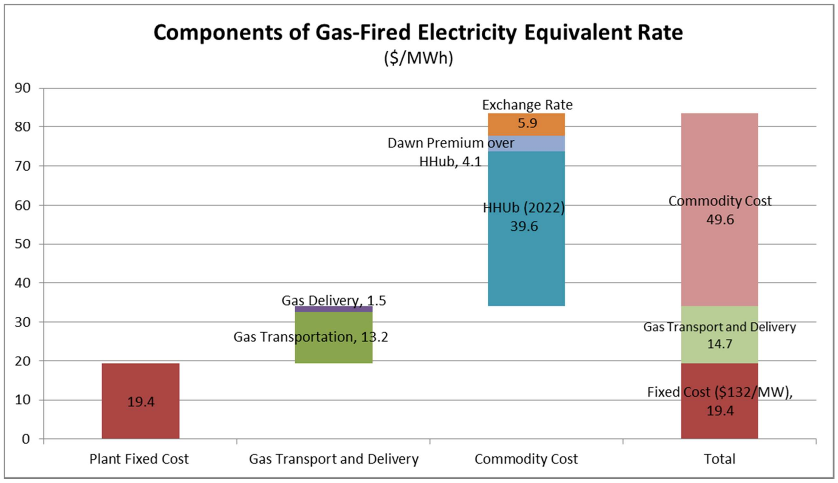
Assumptions		
Financing leverage		60%
Debt interest rate		6%
After tax return on equity		15%
Income tax rate		40%
Nameplate Capacity (MW)		1,000
Fixed revenues($/MW/Month)	$	11,000
Capital cost ($M)		750



A.3. Variable Costs for Gas-Fired Generation

The breakdown of costs that have been used to estimate an equivalent rate for 2022 (in 2015 dollars) is illustrated in the figure below. The predicted variable costs are $65/MWh which includes $49.60/MWh for the commodity and $14.70/MWh for transportation and delivery of the natural gas fuel to the gas-fired generating plants.

The basis for this breakdown of the comparative unit costs stems from the perspective that in the reference scenario, the natural gas-fired generation fleet will be operating at higher operating factors than seen recently. As such, for the purposes of PNGS comparison the incremental variable costs will be occurring on the margin of this higher capacity. It should therefore be expected that all of the variable costs of generation will be impacting on and reflected in the HOEP.



Many inputs have been used to establish the assumptions underscoring the predicted $66/MWh:[53]

- Delivery and transportation costs: are currently 7 cents/cubic meter = ~$2/ per million British Thermal Units (mmBTUs) based on Enbridge Class 125 rates. This consists of approximately 6 cents/m^3 NEB regulated rate for transportation and approximately 1 cent/m^3 for local delivery.
  - Note that the Enbridge cost of transportation is much higher than that for Union Gas in southwestern Ontario, where the Dawn Hub is located. The Enbridge rate has been used for this analysis on the assumption that the natural gas-fired generation plants most likely to be called upon to replace PNGS generation would be those in the GTA, the source of the demand for PNGS.
- Heat Rate: Analysis assumed a value of 7.54 BTU/Wh based on the relationship of observed actual production and coincident GHG emissions combined with the assumption that the future gas generation mix will reflect the same composition of supply as there are generators. In contrast, the EIA stated value for 2014 of the average US heat rate is 7.95 BTU/Wh. As a result, the heat rate assumption used here is potentially conservative, particularly if SCGT supply contributes to the production, which is likely.
- Henry Hub price is based on the average price forecast (2013 dollars) of $5.20 per EIA 2021-2024.
- Dawn premium over Henry Hub is assumed at 9% based on historical relationship prior to the weather and constrained supply events of 2014 and 2015.
- Long term USD vs CAD exchange rate premium = 15%.
- Note that the EIA average forecasted US delivery cost to the electricity sector is 18% of commodity costs in the relevant time frame. Transportation and delivery costs for Ontario are estimated in this analysis to be 23% of the fuel costs. Part of the difference between US and

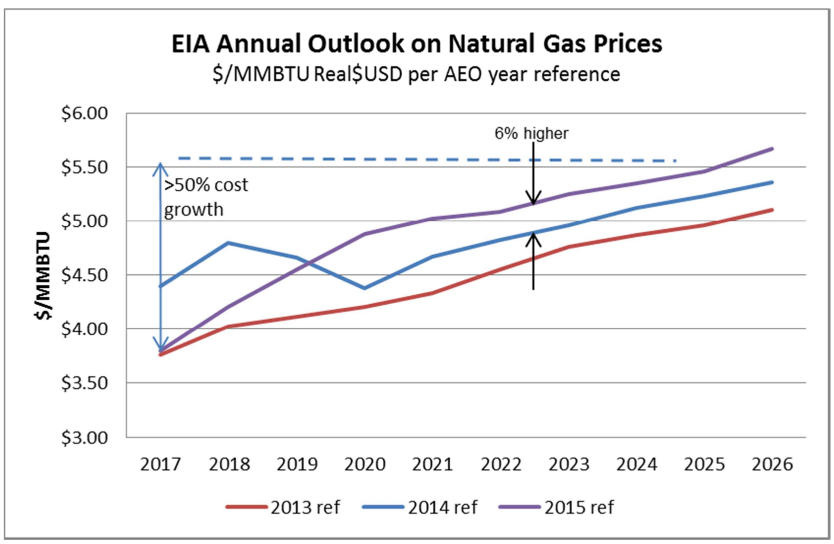
[53] Strapolec analysis; IESO, October 2014; Ontario Power Authority, April 2012; U.S. Energy Information Administration, 2015; Ontario Energy Board, 2015; National Energy Board, 2011; Enbridge, 2015; Union Gas, 2015; Bloomberg, 2015

Canadian transportation costs is that the costs of natural gas transportation to Ontario have been rising in the last decade as demand for natural gas in this province has been declining.

A.4. Forecast Cost of Natural Gas

The cost of natural gas fuel represents the largest component of the cost of gas-fired generation and hence assumptions about the fuel price are critical to understanding the sensitivities of any resulting analysis. There are two main components to the cost of fuel in Ontario: (1) The benchmark North American reference of the cost of natural gas as obtained from the Henry Hub in Louisiana; and (2) A cost differential that exists between the Henry Hub and the Dawn Hub that supplies Ontario.

The source of the forecast Henry Hub price is the EIA 2015 Outlook. The last three EIA forecasts have predicted increasingly higher future commodity prices as illustrated in the figure below. In the period of interest for this study, the EIA's 2015 AEO forecast is 6% higher than the forecast in the previous 2014 AEO. The latest average for 2021 to 2024 is $5.20/mmBTU in USD.

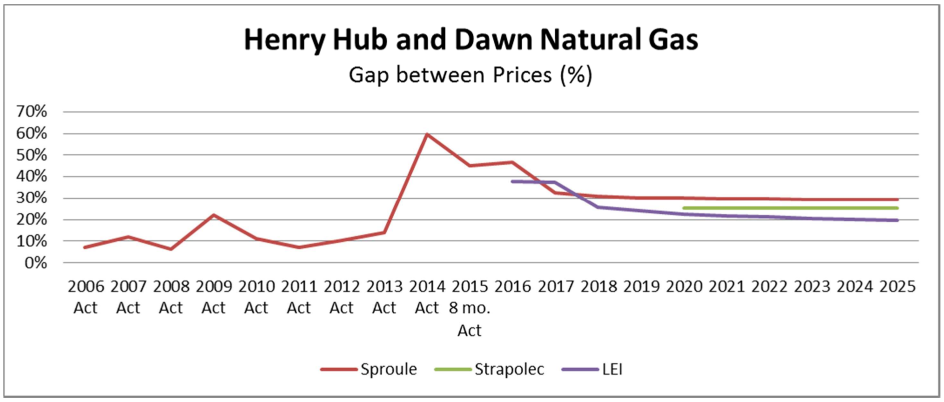


Ontario acquires natural gas from the Dawn Hub in southern Ontario. The Dawn price differs from Henry Hub due to system and market costs for transporting the fuel to Ontario[54]. The Strapolec forecast is based on a 9% observed historical price premium at Dawn up to 2013. The premium price difference was much higher than 9% in 2014 and 2015 due to a number of environmental and gas system constraint issues.

Two sources were consulted regarding the long term price difference between Henry Hub and Dawn. Sproule and LEI both offer long term gas price forecasts of Dawn and Henry Hub. These have been

[54] Energy Information Administration, 2013, 2014, 2015; Sproule, 2015; London Economics Institute, 2015; Strapolec analysis

illustrated in the figure below alongside the assumption used by Strapolec in this analysis. Strapolec has assumed a 1.15 CDN/USD long term exchange rate post 2020 which has also been applied to the LEI forecast illustrated below.



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Appendix C - List of Abbreviations

AEO – Annual Energy Outlook
BCFD – Billion Cubic Feet per Day
BPS – Bulk Power System
BTU – British Thermal Unit
CBoC – Conference Board of Canada
CCGT – Combined Cycle Gas Turbine
CHP – Combined Heat and Power
CME – Canadian Manufacturers & Exporters
CNA – Canadian Nuclear Association
CNSC – Canadian Nuclear Safety Commission
CO_2 – Carbon Dioxide
CPP – Clean Power Plan
DNGS – Darlington Nuclear Generating Station
EIA – U.S. Energy Information Administration
EPA – U.S. Environmental Protection Agency
FTE – Full Time Equivalents
GA – Global Adjustment (36)
GDP – Gross Domestic Product
GHG – Greenhouse Gas
HOEP – Hourly Ontario Energy Price (wholesale market)
IESO – Independent Electricity System Operator
LEI – London Economics International
LTEP – Long Term Energy Plan
MISO – Midcontinent Independent System Operator
mmBTU – million British Thermal Unit
Mt – Million Tonnes
MW – Mega-watt
MWh – Mega-watt Hour (one million watts being produced for 1 hour, enough to power ten thousand 100W light bulbs for one hour)
NEB – National Energy Board
NEI – Nuclear Energy Institute
NERC – North American Electricity Reliability Corporation
NPCC – Northeast Power Coordinating Council Inc
NPV – Net Present Value
NUG – Non-Utility Generator
O&M – Operations and Maintenance
OCI – Organization of Canadian Nuclear Industries
OEA – Ontario Energy Association
OEB – Ontario Energy Board

OM&A – Operations, Maintenance and Administration
OPA – Ontario Power Authority
OPG – Ontario Power Generation Inc.
PNGS – Pickering Nuclear Generating Station
PYE – Person Year Equivalents
SBG – Surplus Baseload Generation
SCGT – Simple Cycle Gas Turbine
StatsCan – Statistics Canada
TWh – Tera-watt Hour (one trillion watts being produced for 1 hour)
US – United States
WCSB – Western Canada Sedimentary Basin

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