PICKERING EXTENDED OPERATIONS

1.0 PURPOSE

The purpose of this evidence is to discuss OPG's plan to extend the safe operation of Pickering ("Extended Operations") and to describe its associated costs and benefits. Under OPG's plan, as approved by the Province of Ontario, all six units at Pickering would operate until 2022, at which point two units would be shut down and the remaining four units would operate until 2024. Achievement of the plan is subject to the results of certain ongoing investigations and requires Canadian Nuclear Safety Commission ("CNSC") approval. While the activities comprising Extended Operations and their associated costs are discussed in this evidence, recovery of all costs discussed here is requested through the Nuclear OM&A and capital exhibits and associated tables presented elsewhere in this application.

2.0 OVERVIEW

The Pickering Nuclear Generating Station consists of six operating 540 MW reactors that were placed into service between 1971 and 1986 (see Ex. A1-4-3 for additional background information). OPG had planned to safely operate all six units until 2020; it now plans to safely operate six units until the end of 2022 and the remaining four units until 2024 as per the 2016-18 Business Plan.[1]

OPG has conducted assessments to demonstrate that extending operations is safe, technically feasible and has economic benefits for Ontario. These efforts build on the work OPG has successfully undertaken as part of the Pickering Continued Operations initiative to enable operation to 2020.[2]

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[1] The Business Case Summary (Attachment 2) shows Units 1 and 4 operating until the end of 2022 and Units 5-8 operating until the end of 2024, but confirmation of the planned shutdown date of each unit is subject to further testing and analysis.

[2] In EB-2010-0008, OPG presented the Pickering Continued Operations initiative aimed at operating the Pickering B Units for a further four calendar years (i.e., Units 5 and 6 to 2018 and Units 7 and 8 to 2020) by achieving 240,000 Effective Full Power Hours ("EFPH"). (See EB-2010-0008, Ex. F2-2-3). As part of the Pickering Continued Operations initiative and in association with other CANDU operators, OPG initiated the Fuel Channel Life Management ("FCLM") project in order to develop ways of managing technical risks associated with pressure tubes (fuel channels), which are seen as the life limiting component.

In EB-2013-0321, OPG filed an updated Pickering Continued Operation's Business Case, indicating that the FCLM project was revised to achieve high confidence that the fuel channels could attain an operational life of

Extended Operations involves incremental activities comprised of additional outage scope (inspections and maintenance), projects (plant modifications), work to respond to potential regulatory requirements and other necessary improvements. The estimated cost of this incremental work, above normal operating costs, is $307M over 2016-2020.[3] Normal operating activities and their associated costs will continue through to 2024 with amounts forecast for 2017 through 2021 included in the test period costs. The incremental investment will allow OPG to generate approximately 62 additional TWh over the remaining life of the plant, which equates to a levelized unit energy cost ("LUEC") of about 6.5 cents/KWh for the additional production.

The IESO has conducted an independent analysis for the Ministry of Energy that calculates the Ontario Electricity System benefits of Extended Operations at between $300M and $500M. Copies of the IESO's updated October 2015 and original March 2015 analyses are included as Attachment 1 to this exhibit. Extending the operation of Pickering mitigates capacity uncertainties during the refurbishments of the Darlington and Bruce stations. The overall system economic value is positive because Pickering's availability reduces the need to construct and operate more expensive gas-fired capacity. It is also projected to reduce CO_2 emissions by approximately 17 million tonnes over the 2021 to 2024 period. On January 11, 2016, the Government of Ontario announced the approval of OPG's plan to operate Pickering to 2024.

3.0 EXTENDING PICKERING OPERATIONS

3.1 The Decision to Extend Pickering Operations

In November 2015, the OPG Board of Directors approved Pickering Extended Operations.

247,000 EFPH. (See EB-2013-0321, Ex. F2-2-3, page 1). The Fuel Channel Life Management project was successfully completed in 2015 and provided the information necessary to enable a high confidence fitness-for-service statement for the Pickering fuel channels to reach 247,000 EFPH as the project intended. This work also underpinned OPG's successful application to the CNSC to allow Pickering to operate to 247,000 EFPH.

OPG subsequently commenced the Fuel Channel Life Extension ("FCLE") project. While the majority of the cost of the FCLE project relates to Darlington, not Pickering, the project did help to provide high confidence for Pickering Fuel Channels to achieve 261,000 EFPH, allowing all units to operate until December 2020 without life management outages. (See EB-2013-0321, Ex. F2-3-3, Attachment 1, Tab 11, page 3).

[3] Of this amount, about $290M is expected to be expended in the 2017-21 test period.

The Business Case Summary ("BCS") supporting Extended Operations is attached as Attachment 2 to this exhibit. The BCS included a partial release of $52M, of the $307M in costs to enable Extended Operations, primarily to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project, component condition assessments and to execute incremental maintenance and inspections during planned outages in 2017. OPG's Management will seek a full release of the remaining funds following completion of both the Fuel Channel Life Assurance Project and the Periodic Safety Review.

On January 11, 2016, the Minister of Energy announced that the Government had approved OPG's plan to pursue Extended Operations. Leading up to this announcement, the Ministry of Energy had been working with OPG and the IESO to analyze the technical feasibility, costs and benefits of Extended Operations.

3.2 CNSC Requirements

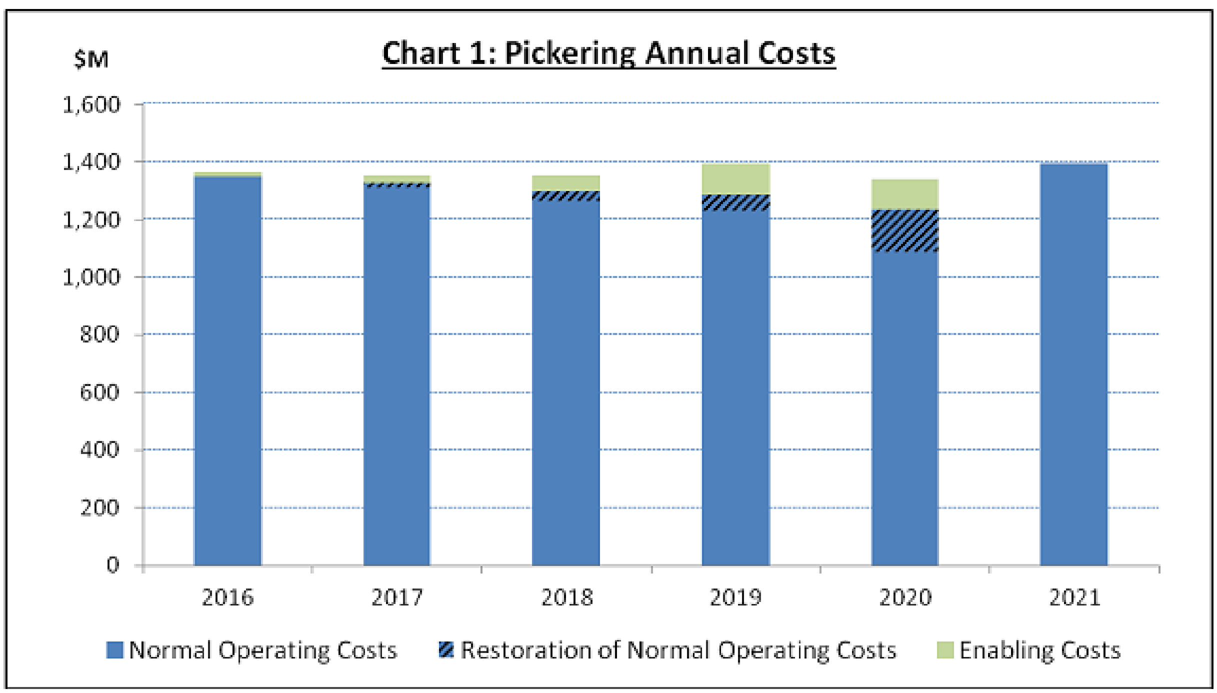
The current five-year power reactor operating licence for Pickering is set to expire August 31, 2018. Based on the success of OPG's Continued Operations project, in June 2014 the CNSC approved OPG's request to remove the hold point for operation past 210,000 Equivalent Full Power Hours ("EFPH"). By this action, the CNSC authorized operation up to 247,000 EFPH, which would allow the plant to operate to OPG's previously planned shutdown dates in 2020.

OPG's operating license requires it to provide written confirmation of the planned end-of-life date for Pickering to the CNSC by June 30, 2017. OPG will provide that confirmation in 2017 as part of the licence renewal application for the next operational period. OPG expects to request a 10-year licence renewal, which will take the units through both the end of commercial operations and the safe storage project period (i.e., until the units are in a safe stored state). OPG anticipates that the CNSC decision addressing operation beyond 2020 will occur as part of the Pickering licence renewal.

3.3 The Work Required for Extended Operations and its Cost

In order to achieve the operating lives in OPG's 2016-2018 Business Plan, certain work must be undertaken over the test period. This work is comprised of enabling actions required to extend operations and secure the necessary CNSC approvals. In addition, funds necessary to support the plant's normal operating activities have been included over the 2016-2021 period. The cost of these activities would have previously been forecast to decline when the plant was scheduled to shutdown in 2020.

Chart 1 below shows the estimated costs to enable Extended Operations and operate Pickering in each year of the test period. While this exhibit discusses these costs, they are recovered primarily through the base, project and outage OM&A exhibits (Exhibits F2-2-1, F2-3-1 and F2-4-1, respectively) with the relatively smaller amount of capital expenditures for Pickering projects and minor fixed assets recovered through Ex. D2-1-2. Thus, there is no additional revenue requirement request associated with this exhibit.



3.3.1 Enabling Work and its Associated Cost

In advance of recommending Extended Operations, OPG completed an initial technical assessment of the Pickering units' continued ability to operate to the proposed shutdown dates. OPG has determined that the technical feasibility of operation to 2022/2024 is sufficient to support proceeding with Extended Operations as the planning basis for operational and investment purposes. The technical assessments completed also produced the scope of work required to demonstrate fitness-for-service to the proposed shutdown dates. The main elements of this scope of work are: 1) the Periodic Safety Review; 2) the Fuel Channel Life Assurance project; and 3) component condition assessments.

Based on discussions with the CNSC, an update to the Periodic Safety Review is required in advance of the 2018 Re-licensing Hearings to support OPG's plans to extend Pickering operations beyond 2020. A Periodic Safety Review evaluates an existing plant and the programs used in its operation against the modern codes and standards that would apply to a new nuclear plant. Potential safety enhancements are then assessed to identify the alternatives that can be reasonably and practicably implemented to improve safety during the four years of additional operations. Work on the update to the Periodic Safety Review began in 2015 and will be completed in early 2017 so that the information confirming that Pickering is safe to operate will be available prior to OPG's licence application to the CNSC.

The major limiting component for Extended Operation of Pickering is the life expectancy of the fuel channels where the pressure tube dimensional changes that occur over time have the potential to restrict operations. Technical work on the fuel channels' fitness-for-service will continue through the Fuel Channel Life Assurance project and ongoing inspections. The work program consists of analysis and research and development work to assess fuel channel fitness-for-service for the planned operating durations and to develop methods for assuring that each Pickering Unit can meet its extended service life target. As noted in section 3.3.1 number 2 above, this work program builds on the Fuel Channel Life Management and Fuel Channel Life Extension projects that OPG undertook as part of Pickering Continued Operations.

While the technical fitness-for-service of other major components is not considered life limiting, component condition assessments will validate their fitness-for-service to the planned operation dates. Planned outages will involve maintenance and inspection of steam generators, feeders, 'balance of plant' components (including fueling machine maintenance). Examples of the work expected to be performed include spacer location and relocation work, additional steam generator water-lancing and feeder replacements.

The costs to enable Extended Operations are forecast to be $307M from 2016 to 2020. These costs include those to complete the Periodic Safety Review, the Fuel Channel Life Assurance project, component condition assessments, incremental outage inspections and maintenance programs and potential modifications that are required to demonstrate fitness-for-service beyond 2020 and maintain safe, reliable operations. Chart 2 below shows the breakdown of these costs.

Chart 2: Pickering Extended Operations – Enabling Costs ($M)

Line No.	Cost Item	2016	2017	2018	2019	2020	Total	Reference
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Base OM&A**	11.0	1.0	0.0	0.0	0.0	12.0	Ex. F2-2-1 Table 1
2	**Outage OM&A:**							
3	**Pickering Station**	0.0	12.2	11.6	20.8	22.8		Ex. F2-4-1 Table 1
4	**Nuclear Support**	0.0	9.9	25.7	67.9	62.8		Ex. F2-4-1 Table 1
5	**Total Outage OM&A**	0.0	22.1	37.3	88.7	85.6	233.7	
6	**Project OM&A**	4.0	2.5	18.0	18.4	18.7	61.6	Ex. F2-3-1 Table 1
7	**Total Pickering Extended Operations**	15.0	25.6	55.3	107.1	104.3	307.2	

3.3.2 Normal Operations and their Associated Cost

With shutdown previously anticipated in 2020, ongoing operations and their costs were set to decline starting in 2017. With Extended Operations, OPG needs to restore on-going operating and maintenance programs to normal levels for the 2017 to 2020 period. For example, outages requirements set to decline under the previous plan will now need to be reinstated. As well, both OM&A and capital projects need to be restored to the levels required to continue to operate safely for four additional years and to maintain or improve plant reliability during that time. The costs in this category shown in Chart 1 are those required to restore on-going operating and maintenance programs back to normal resource levels over the 2017-2020 period.

The 2021 normal operating costs are those required to maintain ongoing base operations, project and outage OM&A work as well as the capital projects necessary to continue the safe operation and maintenance of the plant. These costs also include funds for a scheduled Vacuum Building Outage in 2021.

3.4 The Benefits of Extending Pickering Operations

For the Ontario Electricity System, extending the operation of Pickering will mitigate capacity uncertainties during the refurbishments of the Darlington and Bruce stations. The overall system economic value is positive because having Pickering available reduces the need to operate more expensive gas-fired capacity and the costs associated with siting and building additional gas-fired generation, and possible carbon pricing costs. Extended Operations also reduces the need for imports and reduces CO_2 emissions by approximately 17 million tonnes over the 2021 to 2024 period.

The IESO completed an updated assessment of Extended Operations in October 2015 (see Attachment 1). This assessment shows a present value benefit ranging from $300M to $500M ($2015). The IESO's assessment closely corresponds to OPG's internal assessment, which shows benefits ranging from $500M to $600M, with the difference arising primarily because the IESO uses a lower real discount rate (4 per cent versus approximately 5 per cent used by OPG) and different system assumptions for items such as load growth and the price of gas-fired generation.

For electricity customers, the primary benefit is to moderate the rate impacts, prior to rate smoothing, which would otherwise occur during the height of the Darlington refurbishment following shutdown of the Pickering units (See Ex. A1-3-3). This is made possible by increased nuclear generation after 2020, which results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs being placed into the rate base.

OPG expects to incur severance and related costs following the eventual shutdown of Pickering. Extended Operations will defer the costs associated with closure of the station. Delaying the incurrence of these costs by up to four years reduces their present value. This is true even if there is no change in their nominal value. Additional deferral benefits come from delaying the costs to place the Pickering Units in a safe-stored state and eventually dismantling the units. Extending the time before these costs are incurred also permits additional growth in the decommissioning funds.

4.0 VARIANCE ACCOUNT

Differences between forecast and actual Extended Operations spending, including amounts spent in 2016 where no forecast was incorporated in the 2014-15 approved payment amounts, will be included in the Capacity Refurbishment Variance Account for disposition in a future proceeding. This variance account is discussed in Ex. H1-1-1, section 5.6.

ATTACHMENTS

Attachment 1: IESO Analyses: "Assessment of Pickering Life Extension Options: October 2015 Update" and "Assessment of Pickering Life Extension Options" - March 9, 2015

Attachment 2: Pickering Extended Operations Business Case Summary

Note: Attachment 2 is marked "Confidential" or "Internal Use Only", however, OPG has determined it to be non-confidential in its entirety.

Assessment of Pickering Life Extension Options: October 2015 Update

Prepared for discussion with Ministry of Energy

Power System Planning

October 30, 2015
Updated November 4, 2015

Independent Electricity System Operator

Overview

- In March 2015, upon Ministry of Energy request, the IESO provided an independent assessment of the integrated power system impacts of various Pickering life extension scenarios between 2018 and 2024 (see Appendix 2)
  - Technical and economic information concerning Pickering was provided to the IESO by OPG between December 2014 and January 2015 for each scenario assessed

- IESO's March 2015 assessment concluded that, while not without its potential pitfalls, extended Pickering operation holds potential benefit and merits further exploration. In particular, the scenario of Pickering operation to 2022/2024 appeared most promising among the extension options assessed.
  - Feasibility of Pickering extension beyond 2020 from a regulatory perspective has yet to be shown

- In April 2015, the Ministry of Energy, OPG, and IESO developed a joint work plan identifying activities to increase the economic, technical, and regulatory confidence with respect to Pickering life extension (see Appendix 3), including providing an update on the economic merits of life extension in Q4 2015.

- In October 2015, the IESO updated its evaluation of the merits of Pickering extension, with focus on the extension to 2022/2024 option in particular, in light of updated technical and economic information from OPG and changes to the electricity planning context since the March study.

- The IESO's updated assessment is presented in the following slides.

Summary of results

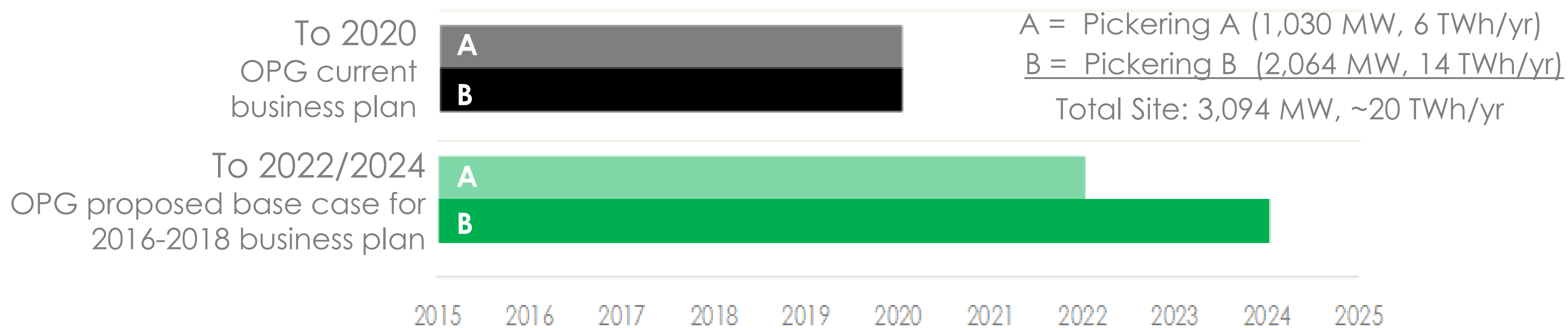
- The conclusions of the IESO's updated assessment of Pickering life extension to 2022/2024 are consistent with the IESO's March 2015 evaluation:
  - Defers timing of capacity needs by two to four years, providing more time for exercising procurement decisions in light of evolving electricity sector trends
  - Potential for cost savings although these depend on the outlook for Pickering production and operating costs (which have a lower degree of uncertainty and can be controlled to some degree) and natural gas/carbon prices (which have a higher degree of uncertainty and limited opportunity to control)
    - It shows value when natural gas or combined natural gas/carbon prices are above \$4.2-\$4.7/MMBtu
    - It shows a disbenefit when Pickering capital/operating costs are 15-22% greater than the estimates provided by OPG
    - Value of Pickering extension decreases as Pickering's energy production decreases. Value of life extension could also be lower if Pickering were unavailable at the time of system peak demand (due to extended outages for example).

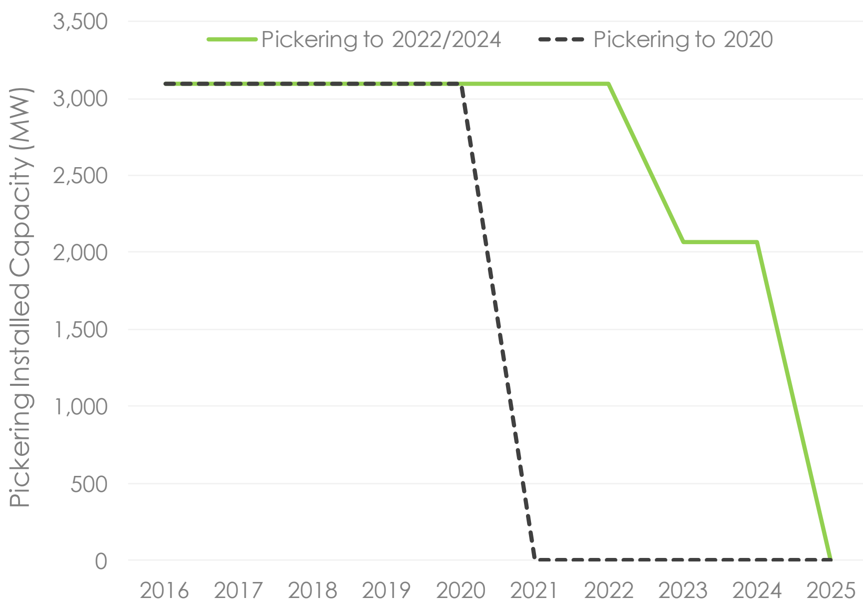
- Extending Pickering operation beyond 2020 continues to defer some supply and transmission investments that would otherwise be required, defers decommissioning and severance costs, offsets production from natural gas-fired resources, increases export revenues and reduces carbon emissions

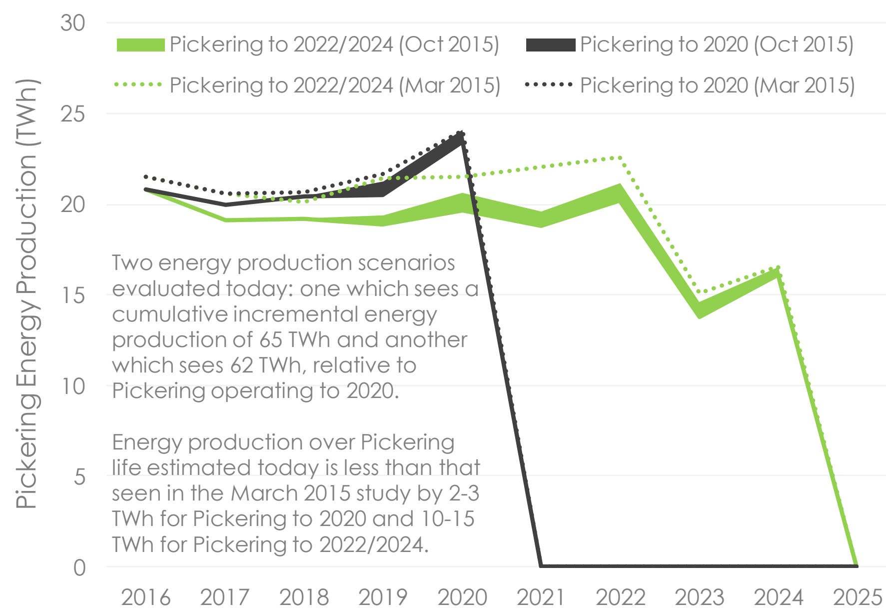
- Extending Pickering operation defers the increase in the total electricity costs that eventually takes place, generally leading to lower electricity costs for consumers in the period prior to 2024 and higher costs for a few years thereafter

- The IESO's assessment is illustrated in the following slides. Additional details can be found in Appendix 1.

Two Pickering scenarios assessed: one features Pickering operations to end of 2020 per OPG's more recent business plan, the other features additional years of operation to 2022/2024. Approximately 3,100 MW and 20 TWh is provided by Pickering for each year of operation.







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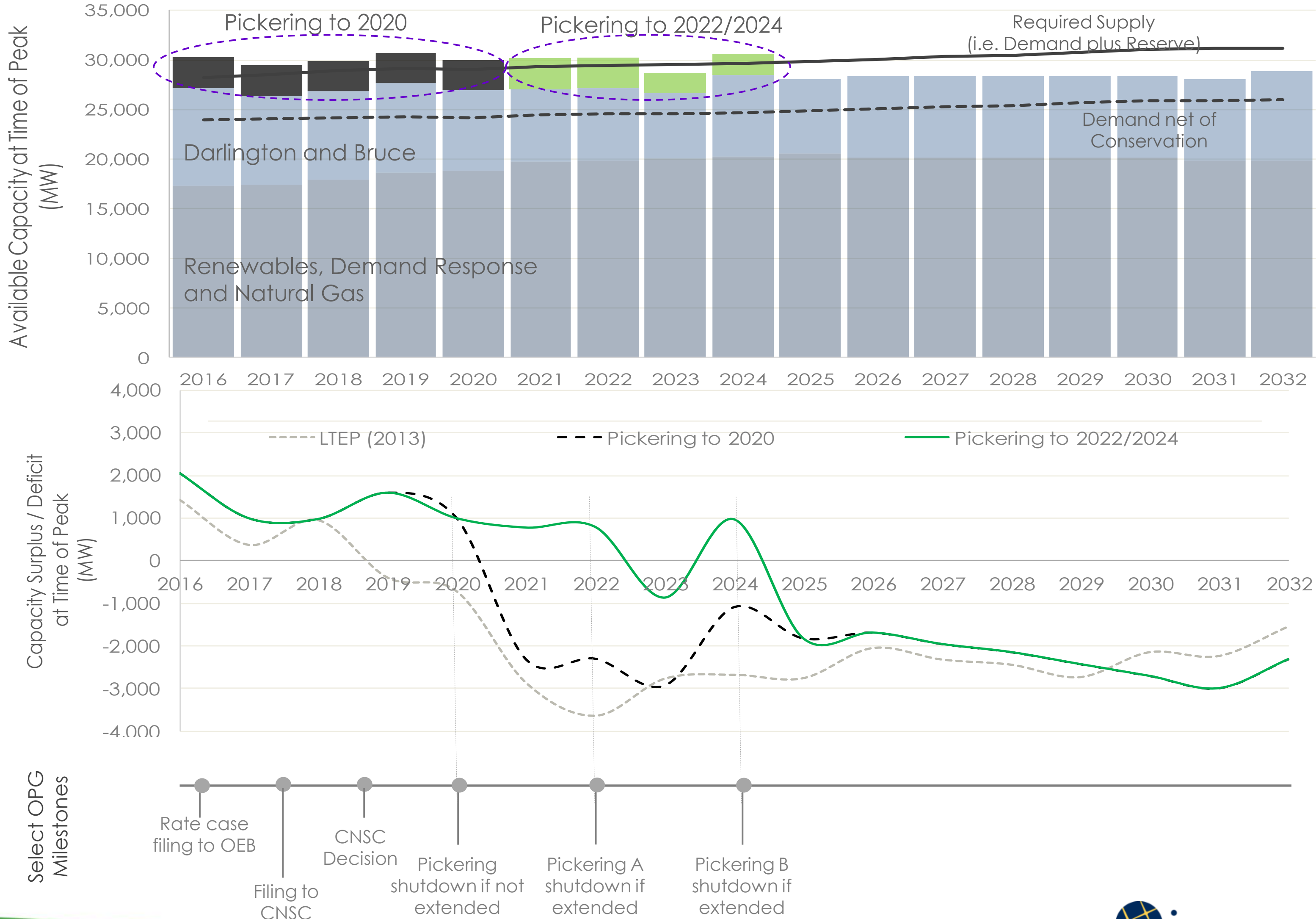
Ontario's existing, committed and directed resources will provide adequate supply for the next few years, after which time additional resources will be required. With Pickering operating to 2020, capacity needs begin to emerge in about 2021 and are on the order or 2,000 MW to 3,000 MW. Extended operation at Pickering to 2022/2024 would defer this need for additional supply by a few years. Although life extension defers procurement decisions, confirmation of its viability arrives late and on the cusp of possible transition from surplus to deficit.



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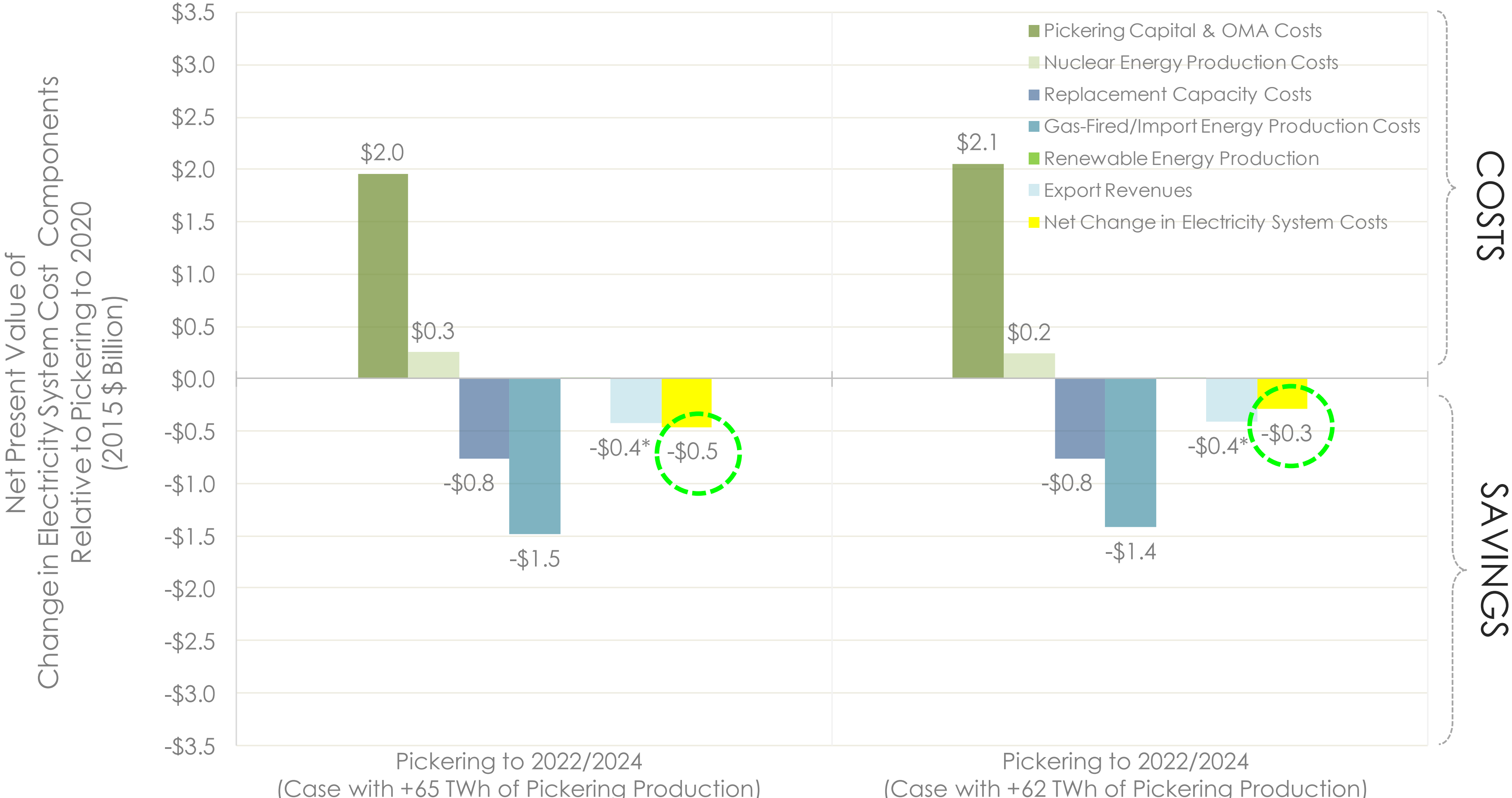
Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B-$0.5B vs $0.6B in the previous study (NPV from 2016-2032 in 2015 $, includes impact of Pickering severance costs, excludes benefit associated with deferring decommissioning liabilities and transmission investments). Cost savings from extending Pickering operations are driven by reductions in replacement capacity and energy costs from gas-fired resources and energy imports. These savings offset Pickering capital and operating costs, which comprise the largest cost components of Pickering extension. Value of extension could be lower if Pickering's production or availability at time of peak demand decreases, if Pickering's operating costs increase, or if natural gas/carbon prices decrease (see Appendix 1 for further details).



*Export revenues increase.
NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

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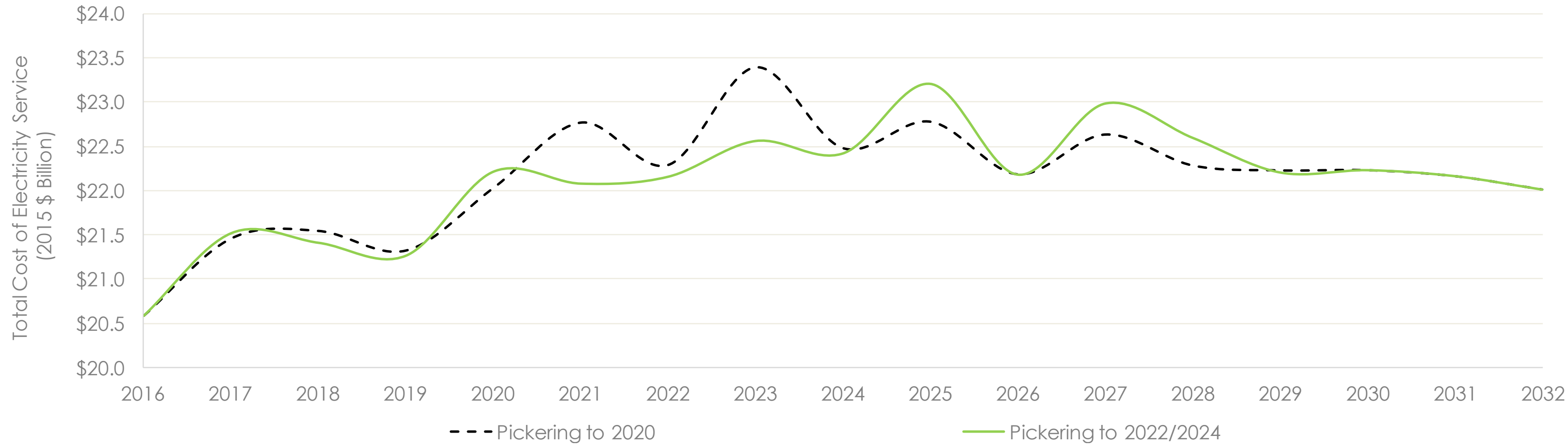
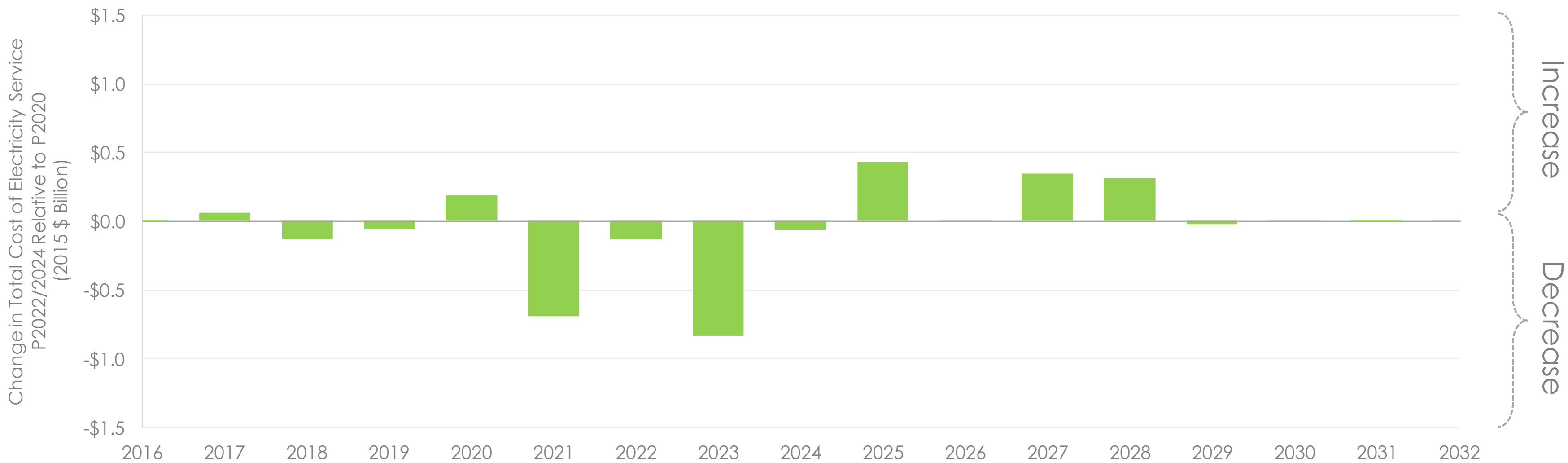
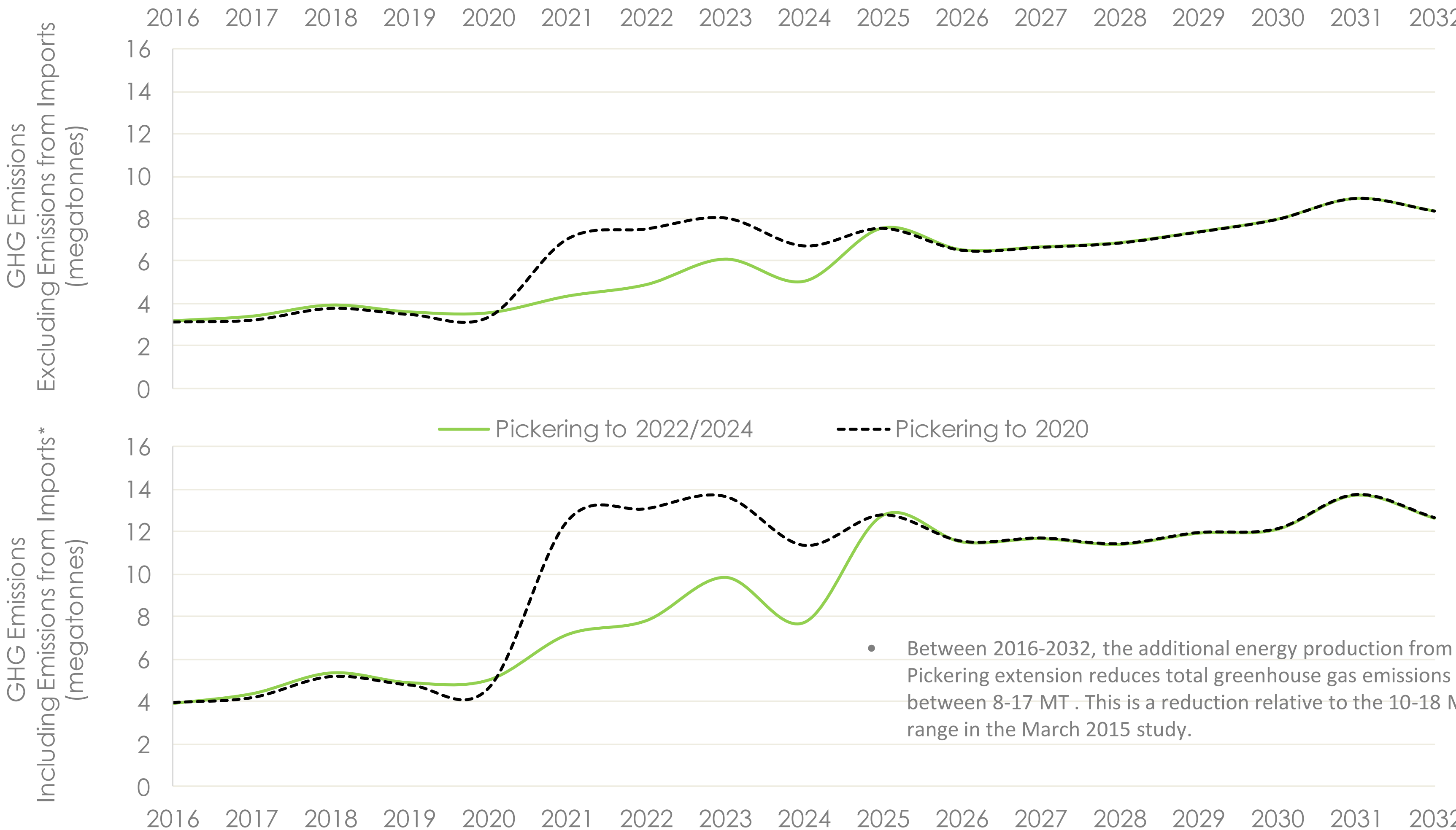
Extending Pickering operation beyond 2020 defers the increase in the total cost of electricity service that eventually takes place. Relative to Pickering operating to 2020, extending Pickering life to 2022/2024 generally leads to a lower cost of electricity service in the period prior to 2024 and generally a higher cost of electricity service for a few years post 2025.





Over the planning period, the additional energy production from Pickering operation to 2022/2024 also reduces total greenhouse gas emissions by between 8 megatonnes (excluding emissions from imports) and 17 megatonnes (including emissions from imports)



- Between 2016-2032, the additional energy production from Pickering extension reduces total greenhouse gas emissions by between 8-17 MT . This is a reduction relative to the 10-18 MT range in the March 2015 study.

*CCGT emission rates used for import emissions rates as a proxy.

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Looking ahead

- While Pickering is currently scheduled to shut down in 2020, the IESO's updated assessment indicates, on balance, Pickering extension to 2022/2024 is an option worth continuing to explore on the basis of:
  - Defers timing of need and the supply/transmission investments that would otherwise be required
  - Defers procurement decisions with respect to new resources, providing more time in exercising options while reducing risk of over investment during a period of supply/demand uncertainty
  - Provides insurance supply in some years in case of nuclear refurbishment delays
  - Defers Pickering decommissioning and severance costs
  - Offsets production from natural gas-fired resources
  - Increases export revenues and reduces carbon emissions

- Over the next few years, OPG will seek to demonstrate the technical feasibility of extended Pickering operation to 2022/2024, develop the business case, and pursue regulatory approvals at the Ontario Energy Board and Canadian Nuclear Safety Commission (CNSC).
  - Discussions between OPG and the CNSC would begin prior to OPG's CNSC filing to determine regulatory requirements for extending operation beyond 2020. Additional work will follow for inclusion in OPG's submission.
  - OPG's filing to the CNSC would take place in 2017. CNSC decision would be received by late 2018.

- The timing and extent for additional resources is a moving target and will be influenced by factors such as electricity demand, refurbishment progress, conservation achievement, performance of existing fleet, and others. Prospect of Pickering extended operation introduces another moving piece and confirmation of its viability arrives late and on the cusp of possible transition from surplus to deficit.

Next steps

- The IESO re-emphasizes the importance of achieving the milestones laid out in the April 2015 work plan in a timely manner given the tightness of the overall discovery and decision timeline – in light of the current supply/demand outlook and implications on the need to develop/initiate alternative resource solutions

- In the meantime, in the event the Pickering extension option does not materialize, preparations must be made in a manner that preserves the ability to take advantage of the extension opportunity should it prove viable while not being caught short should it not:
  - Preserving ability to take advantage of the extension opportunity includes not over-committing, in the meantime, to other supply sources that would become redundant/stranded should the extension opportunity prove viable (i.e. feasible and cost-effective) and/or that would erode the economic value otherwise offered by Pickering extension
  - Not being caught short includes achieving timely decisions and maintaining the ability to implement resources in the quantities, capabilities and timelines required in the event, by 2017/2018, the extension option is proven unviable

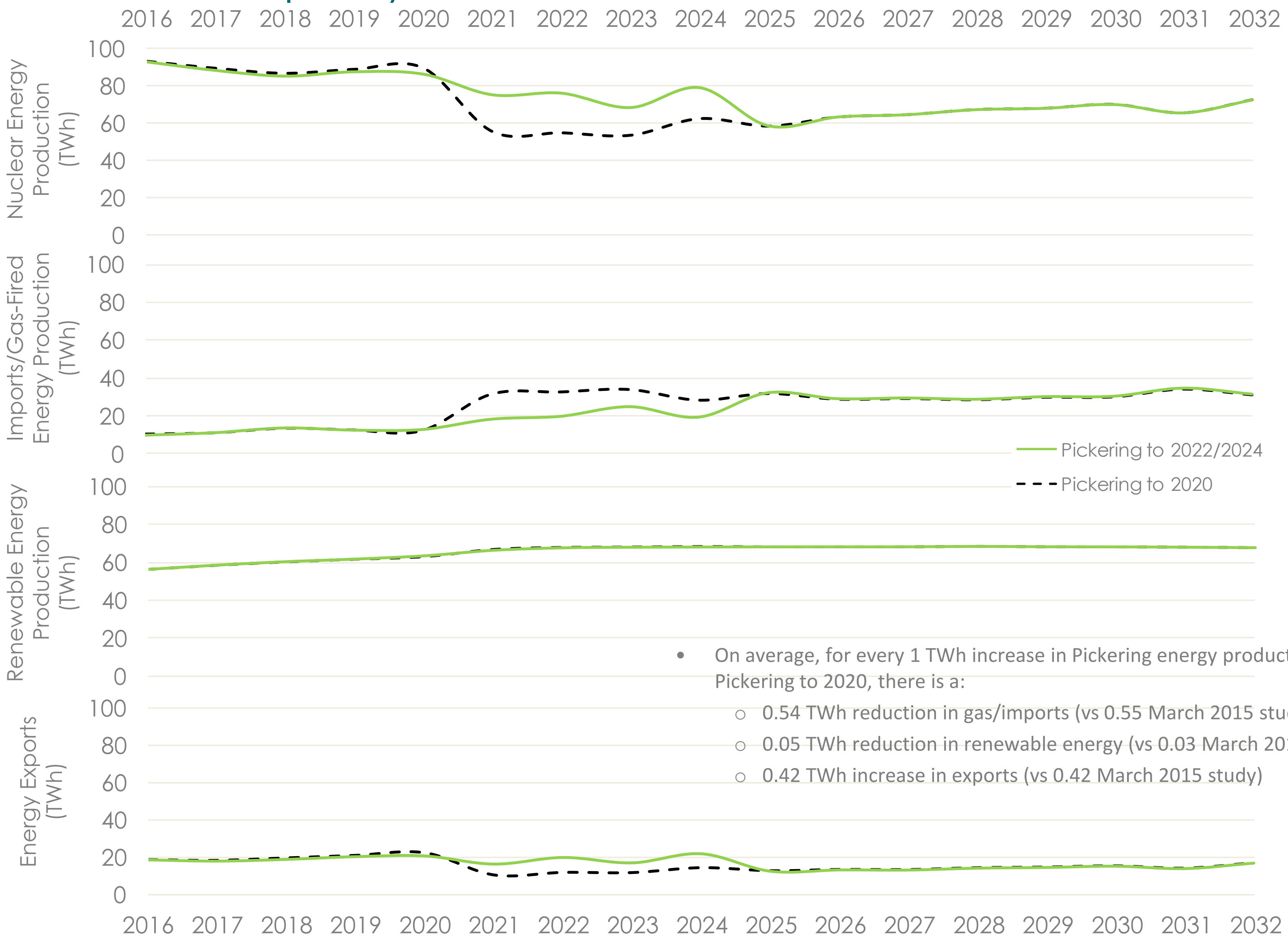
- Elements of our approach within this context include:
  - Frequent monitoring of progress on Pickering extension development work and approvals
  - Ongoing assessment of Pickering extended operations
  - Ongoing assessment of alternatives to Pickering extension and their implementation requirements
  - Routine updates to the Ontario supply/demand outlook
  - Ongoing contingency planning in case Pickering extended operations does not proceed
  - Continued development of mechanisms to secure supply and demand-side resources

- Work on these and other fronts is underway as part of a broader integrated planning initiative. Updates on progress will be brought forward as applicable.

APPENDIX 1:

Additional details of IESO's October 2015 Updated Assessment of Pickering Life Extension Options

Energy production from Pickering extension displaces production from gas-fired resources, reduces energy imports, and increases energy exports in the period between 2021 and 2024 (i.e. the life extension period)



- On average, for every 1 TWh increase in Pickering energy production, relative to Pickering to 2020, there is a:
  - 0.54 TWh reduction in gas/imports (vs 0.55 March 2015 study)
  - 0.05 TWh reduction in renewable energy (vs 0.03 March 2015 study)
  - 0.42 TWh increase in exports (vs 0.42 March 2015 study)

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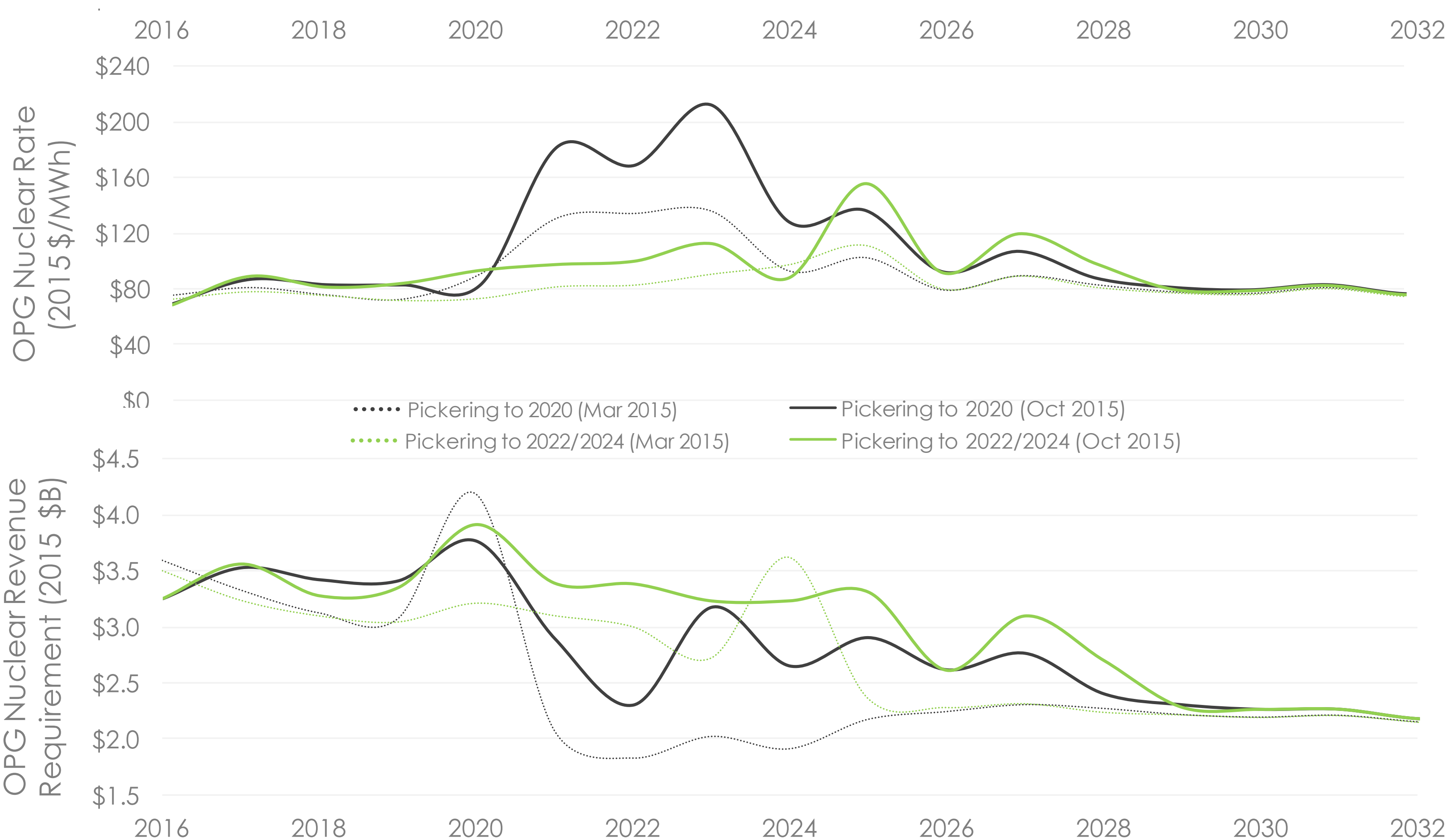
OPG's total nuclear rate will increase as OPG nuclear production decreases. Life extension at Pickering increases OPG's annual nuclear production and tends to reduce OPG nuclear rates to 2024. OPG's nuclear program will cost between $2.2 billion and $3.9 billion (2015 $) per year between now and 2032.



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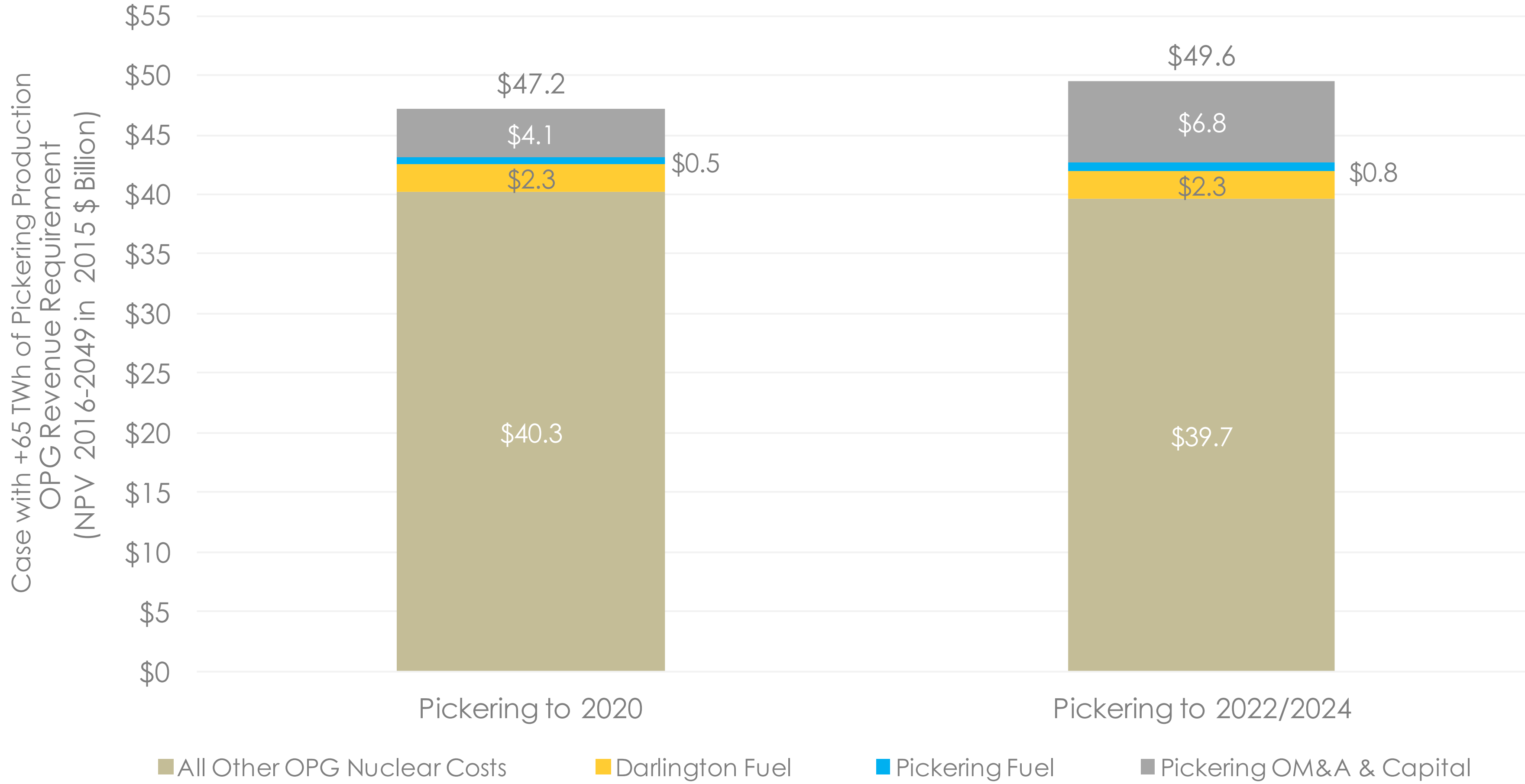
Pickering extension sees OPG's total nuclear revenue requirement increase by $2.3B (NPV in 2015 $).



NPV evaluated at a 4% real discount rate.

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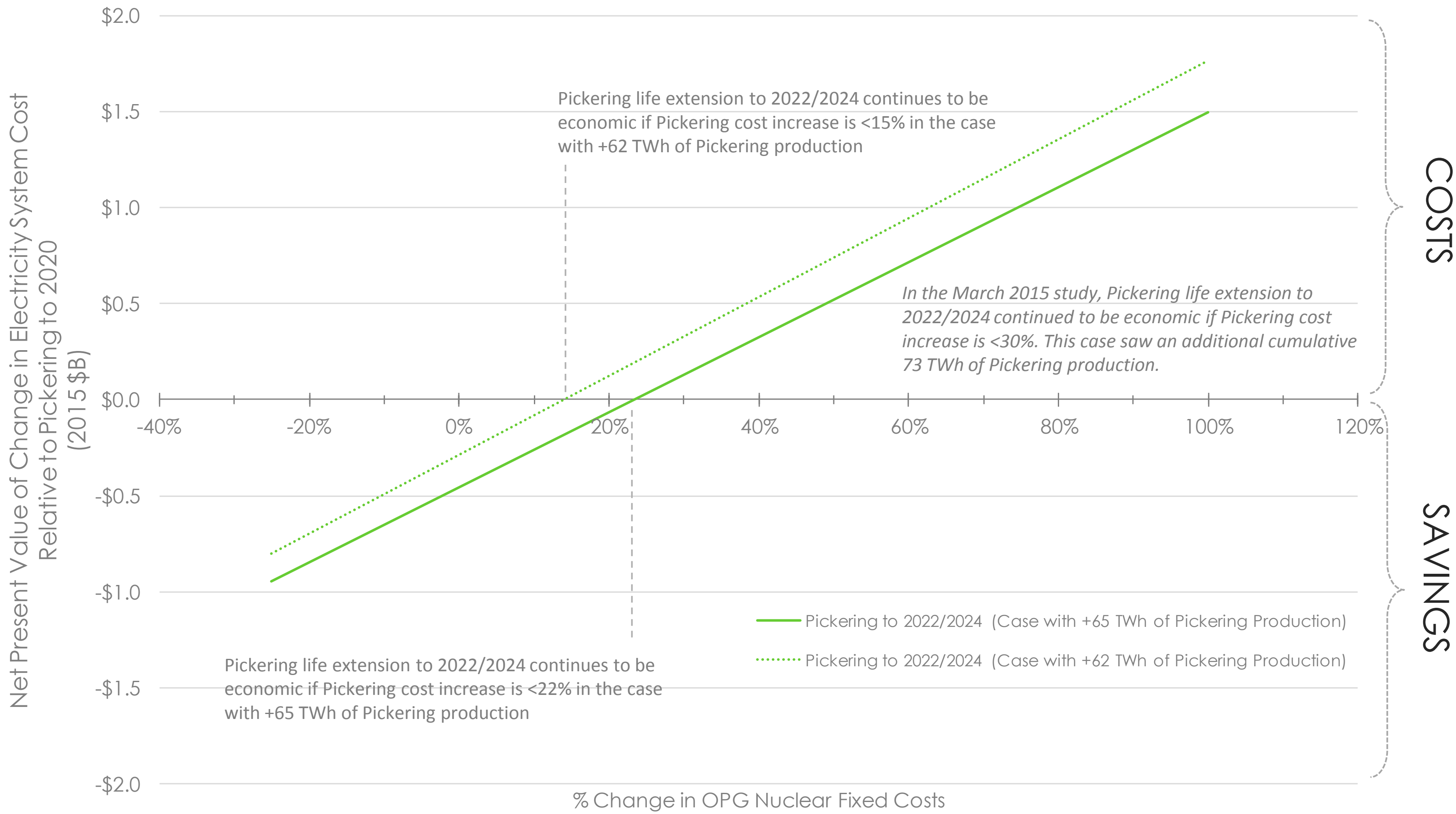
Pickering extension to 2022/2024 yields a net benefit in the range of $0.3B (in the case which sees a cumulative increase in Pickering production by 62 TWh) to $0.5B (in the case which sees a cumulative increase in Pickering production by 65 TWh) (NPV 2016-2032 in 2015 $). This is a reduction relative to the March 2015 study which saw a net benefit of about $0.6B (for a cumulative increase in Pickering production by 73 TWh).

NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

The economic proposition of Pickering extended operations to 2022/2024 is sensitive to Pickering capital and operating costs. As these costs increase, the value of extending Pickering life to 2022/2024 decreases. As production from Pickering decreases, the ability to tolerate cost increases also decreases.



NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

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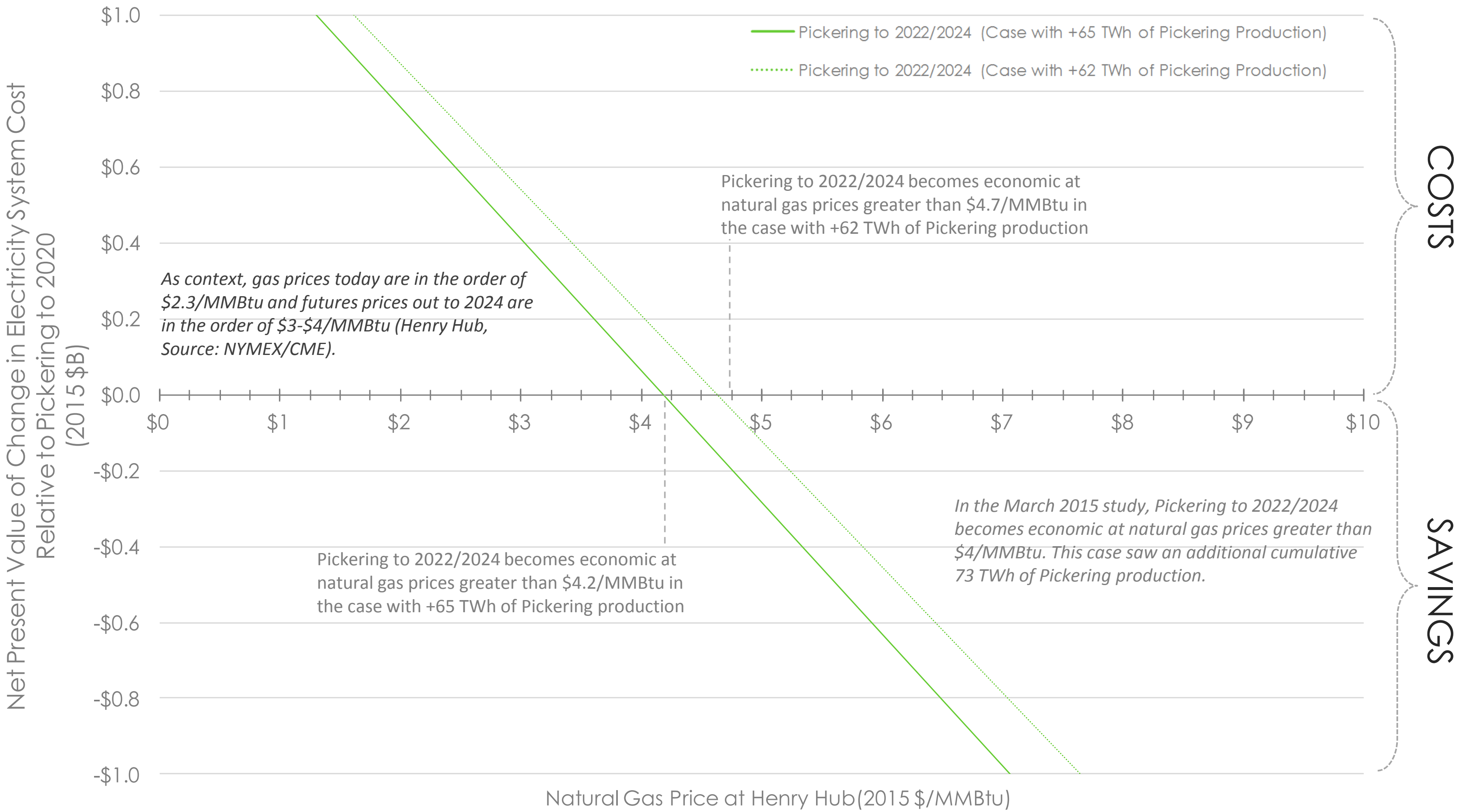
Benefits of extended Pickering operations are also sensitive to natural gas prices. Higher natural gas prices (or combined natural gas/carbon prices) result in greater value from extended operations. Lower prices result in lower value. As production from Pickering decreases, the natural gas price at which Pickering life extension becomes economic also increases.



NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

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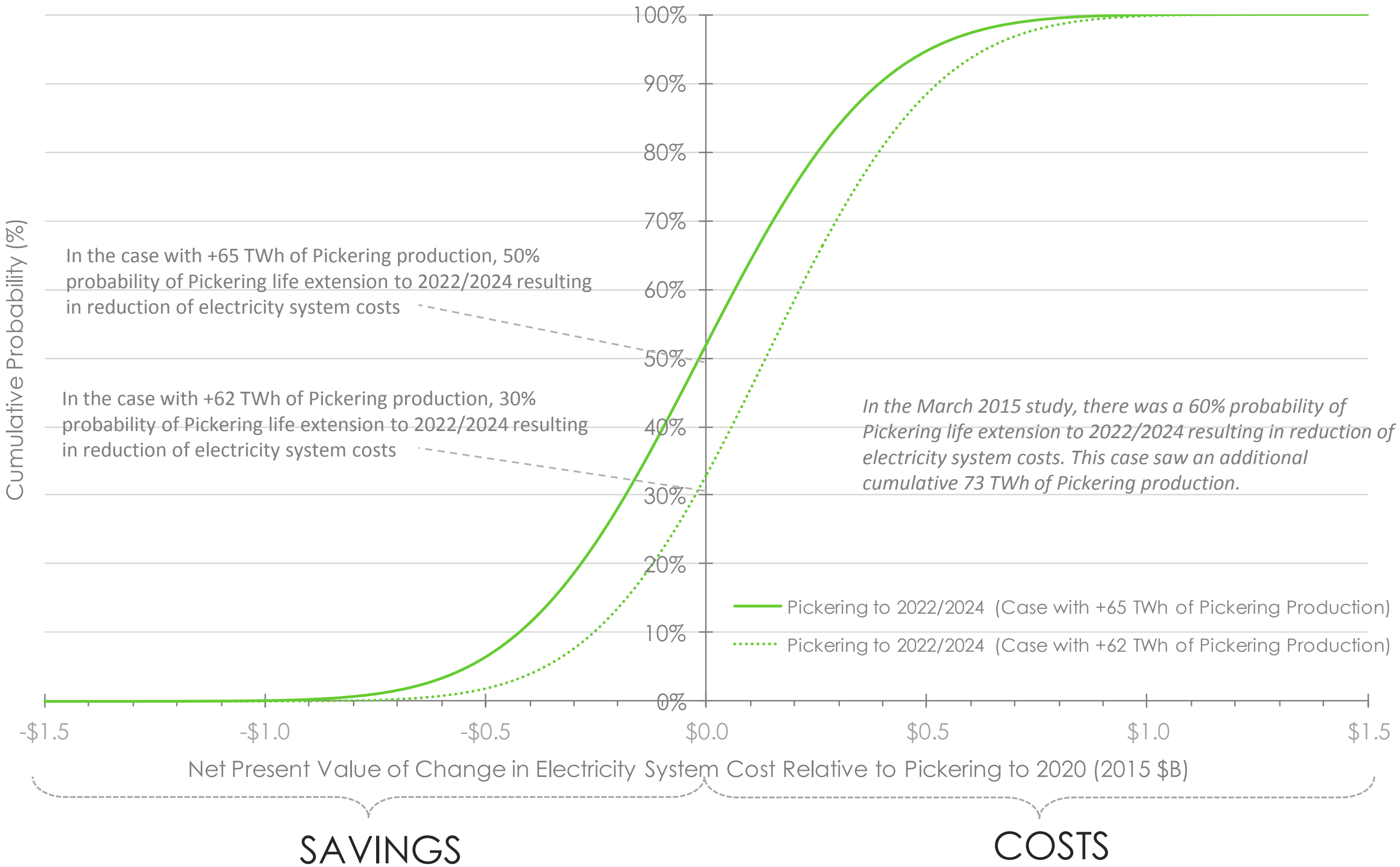
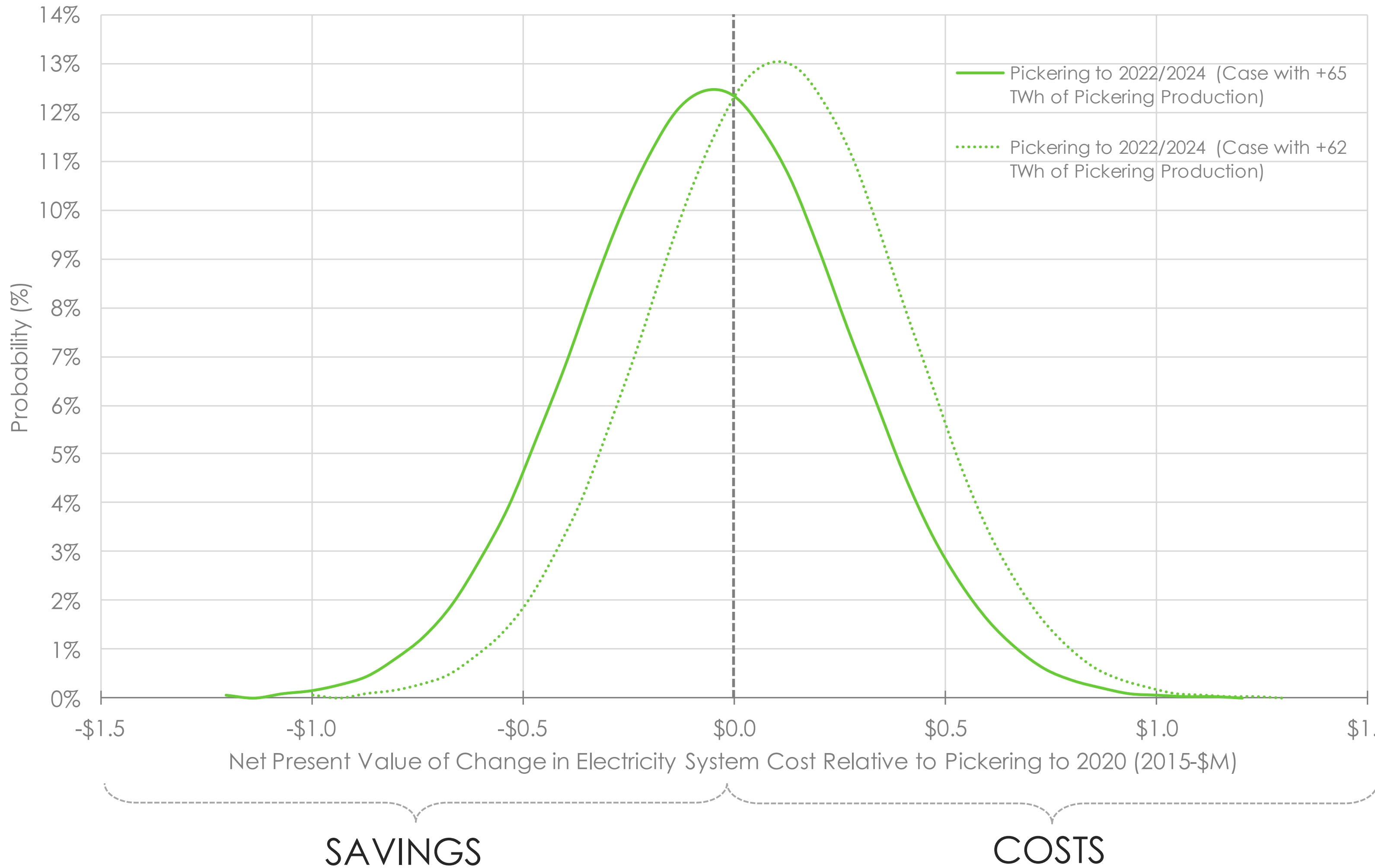
Consideration of the historical gas price distribution between 2010 and 2015 adds insight into the cumulative probability of change in electricity system cost as a function of natural gas price under various Pickering extension scenarios. Pickering life extension to 2022/2024 offers moderate probabilities for savings. As production from Pickering decreases, the likelihood of achieving savings also decreases.



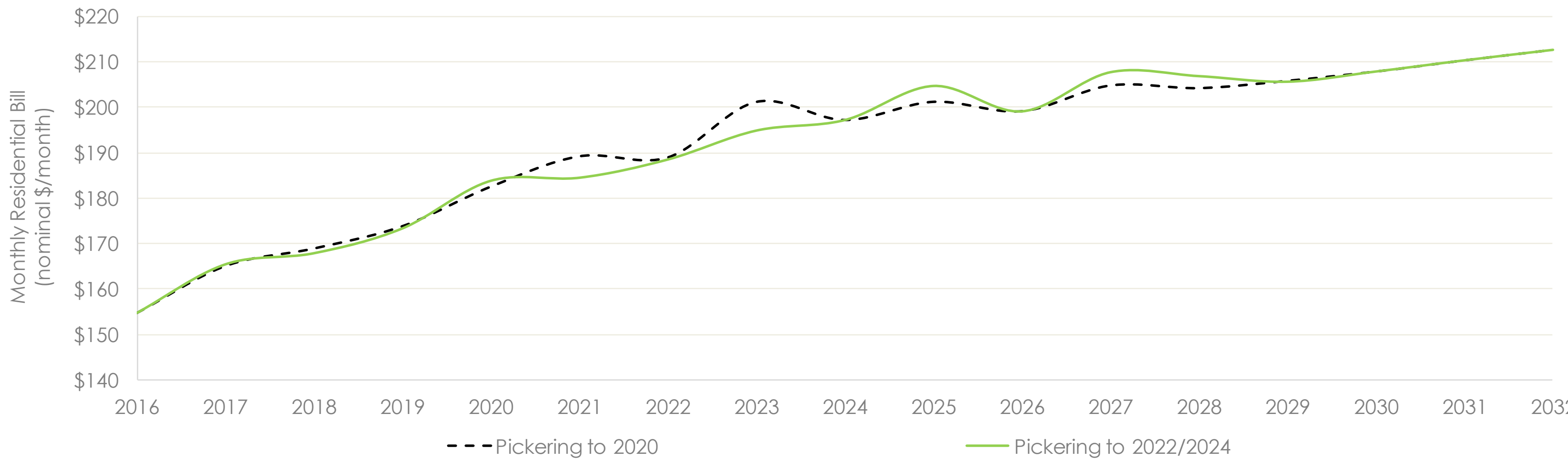
NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

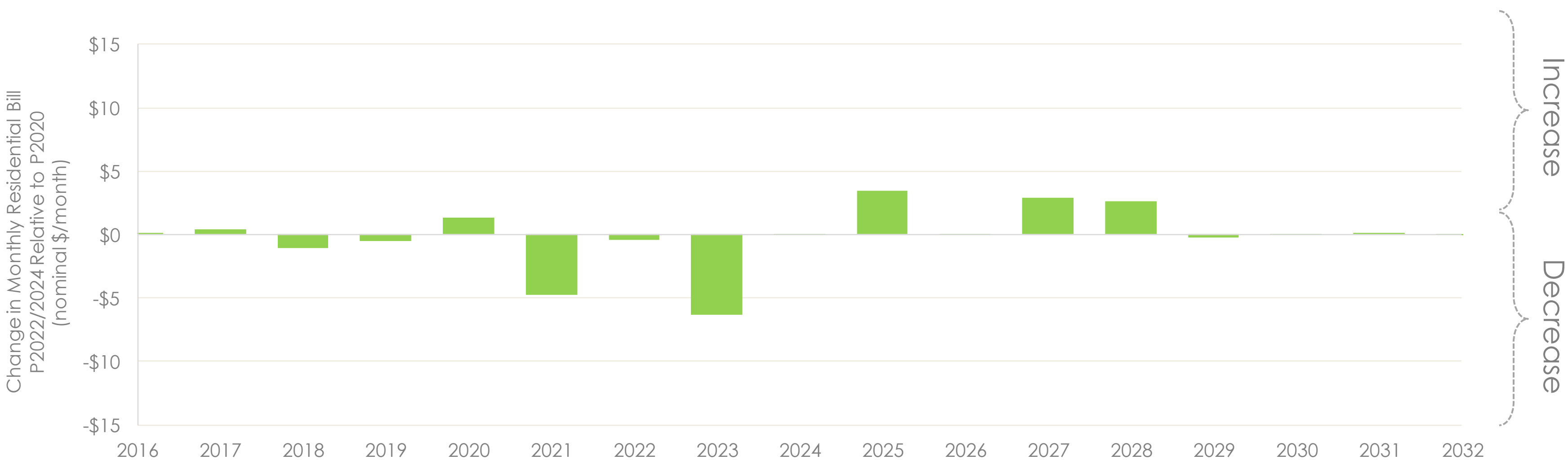
Viewing the same results as a set of NPV distributions illustrates the overlap of possibilities among the Pickering production scenarios as well as the variability within each distribution. As the additional production form Pickering life extension decreases, the NPV distribution shifts further towards life extension being a net cost.



NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

Extending Pickering operation to 2022/2024 generally leads to a reduction in residential electricity bills between 2016 and 2024 compared to Pickering operating to 2020. Residential electricity bills increase for a few years thereafter.





Residential electricity bill illustrated assumes a typical residential consumption of 800 kWh/month.

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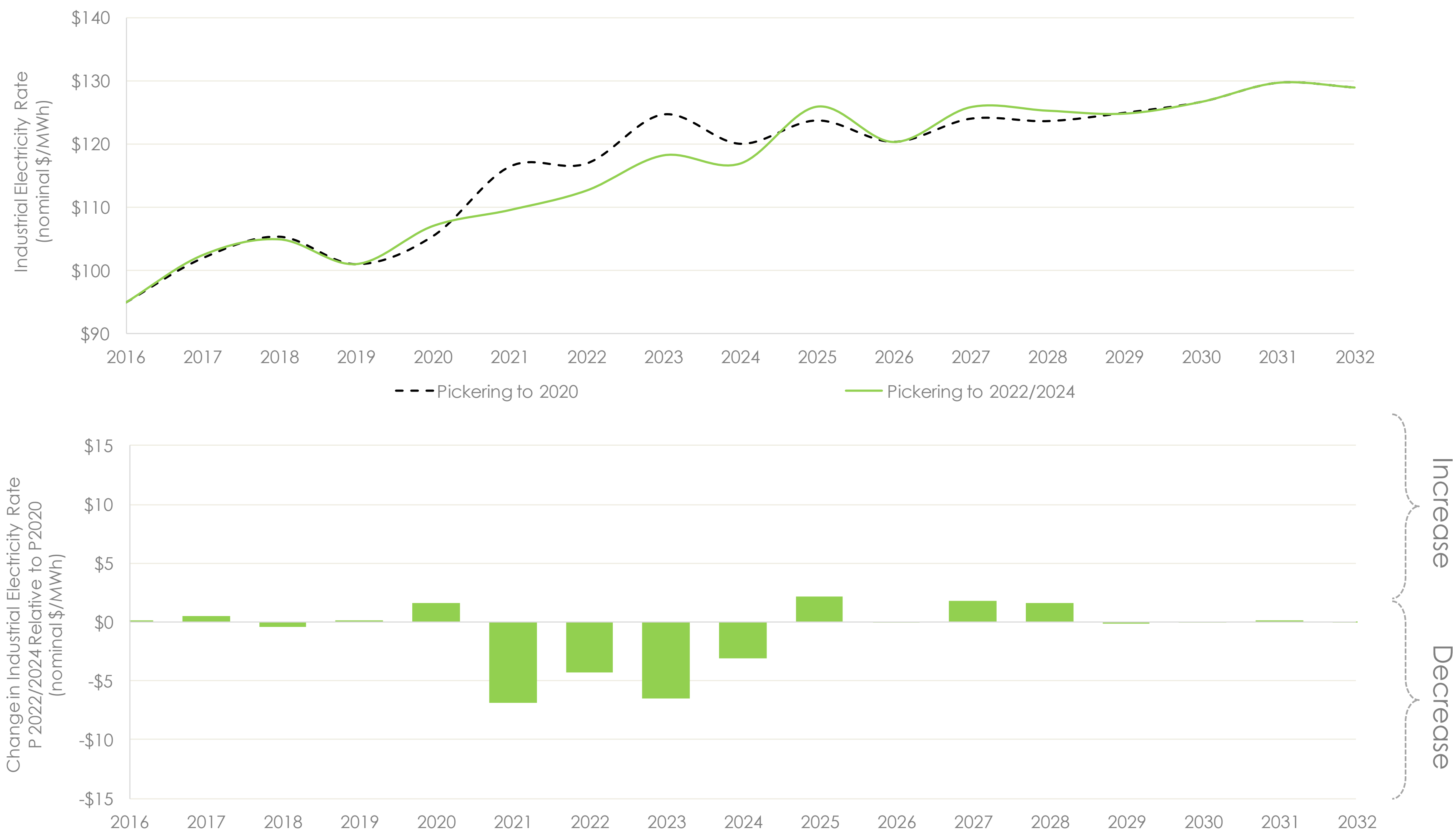
Similarly, extending Pickering operation to 2022/2024 generally leads to a reduction in industrial electricity rates between 2016 and 2024 compared to Pickering operating to 2020. Industrial electricity rates increase for a few years thereafter.



Industrial electricity rates illustrated assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor.

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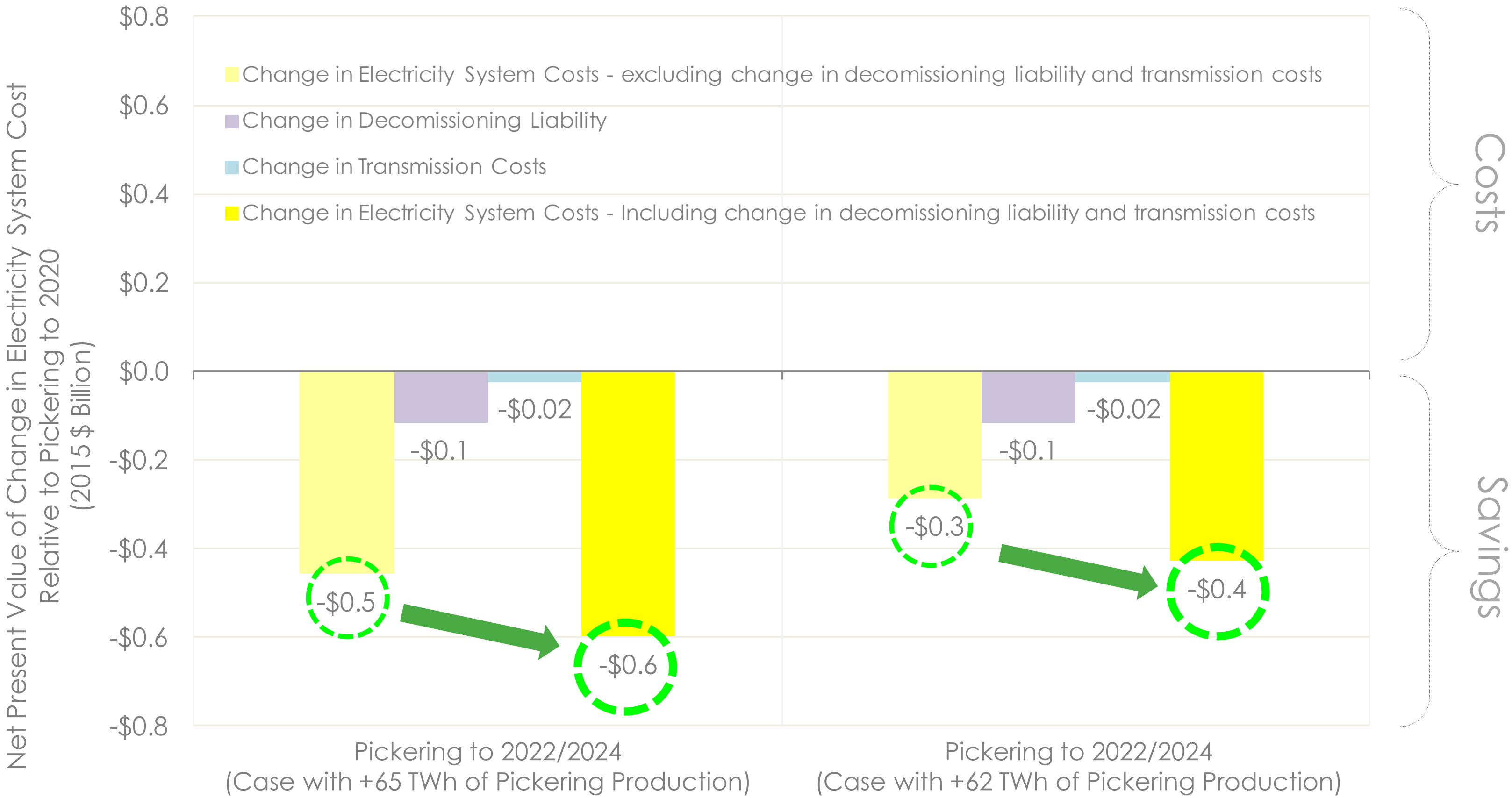
There are other benefits resulting from Pickering life extension. As Pickering life is extended, decommissioning expenditures are deferred. Extended Pickering operations could also defer the need for transmission reinforcements in the GTA region. Deferral of related expenditures results in a time value savings. After factoring in the time value effects of deferring decommissioning and transmission expenditures, the benefit of extending Pickering operations marginally increases.



NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral value.

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APPENDIX 2:

IESO's Assessment of Pickering Life Extension Options, Delivered to Ministry of Energy in March 2015

Assessment of Pickering Life Extension Options: Executive Summary

Presentation to Ministry of Energy

March 9, 2015

Note: The appendix accompanying this presentation, which contains the detailed assessment, is excluded for brevity.

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Purpose

- IESO to present the assessment of Pickering life extension options to the Ministry of Energy

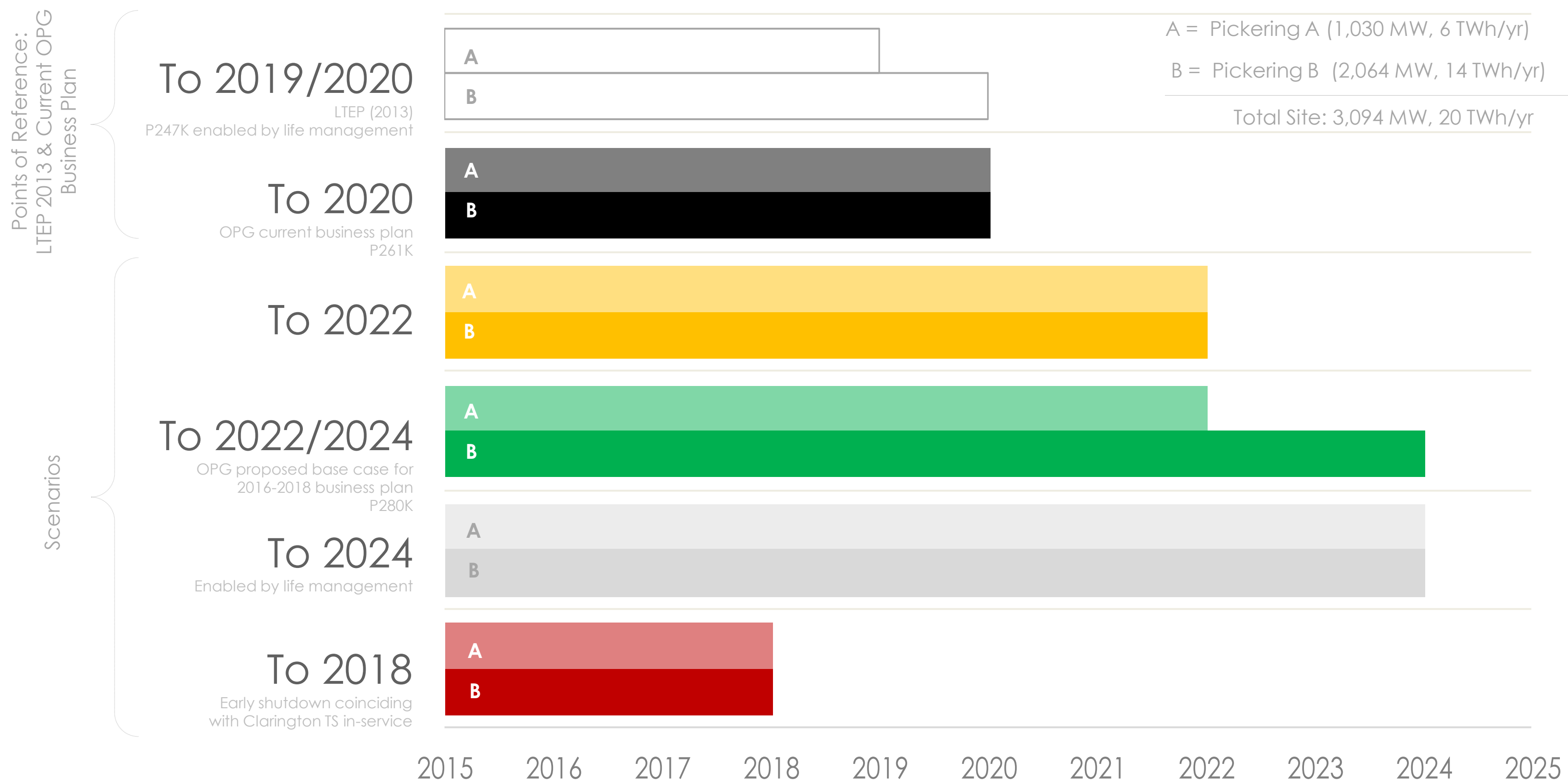
Overview

- The IESO has conducted an independent assessment of the long-term integrated power system impacts of various Pickering life extension scenarios between 2018 and 2024
- Pickering extension scenarios are considered against three Darlington refurbishment sequences
  - Analysis updates and builds on previous Pickering life extension studies conducted by the IESO
  - Technical and economic information concerning the Pickering and Darlington stations was provided by OPG between December 2014 and January 2015 for each scenario assessed
  - The scenarios have not been discussed publicly nor have they received necessary CNSC approvals
- Implications of the Pickering scenarios are assessed from a variety of perspectives, including:
  - Capacity needs and timing
  - Energy production from existing and contemplated resources
  - Greenhouse gas emissions
  - Surplus energy
  - Total cost of electricity service
  - Ratepayer costs
- A summary of this assessment is provided in the following slides. The IESO's full assessment is provided in the Appendix.

Summary of findings

- On balance, the option of extended Pickering operations merits further exploration:
  - Pickering operation to 2022/2024 appears to be the most promising candidate among extension options assessed, as it provides the most savings and is among options with the lowest emissions
  - Extended operation to 2022 or shutdown in 2018 also holds potential for benefit, but less so than operation to 2022/2024
- In light of the impact that Pickering capital and operating costs have on the value proposition of extended Pickering operations, it may be worth exploring options for cost control
  - If OPG's actual capital and operating costs exceed estimates, then the cost savings resulting from Pickering life extension could be reduced or eliminated
- Unlapping of Darlington refurbishment outages generally reduces the value of Pickering extension
- It is worth exploring Pickering extension options involving fewer Pickering units (e.g. four to five units rather than six) to reduce its contribution to surplus baseload generation
- The IESO should be routinely updated by OPG on the status and substance of Pickering extension exploration efforts and related regulatory developments given the implications on need for additional supply and transmission investment

Pickering scenarios assessed



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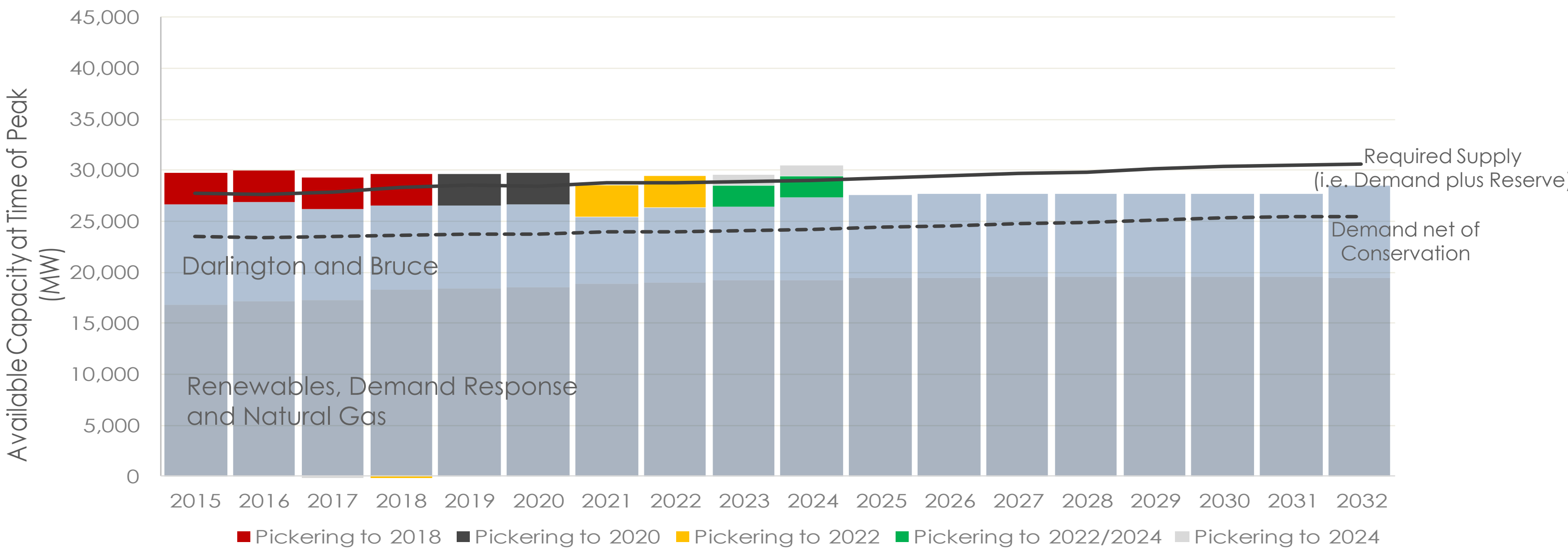
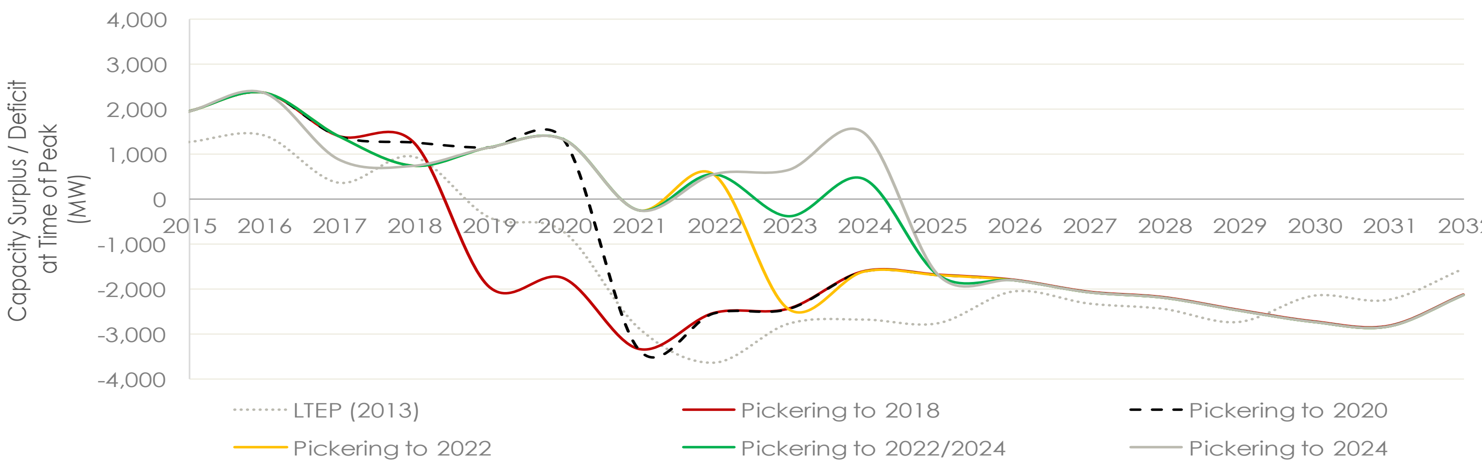
Resource requirements under Pickering scenarios





Summary of changes in costs

Pickering Scenarios	Darlington Scenarios: Lapped	Darlington Scenarios: Unlapped Yes Idle Time	Darlington Scenarios: Unlapped No Idle Time
2018	-$0.1	+$0.3	-$0.2
2020	BASE	+$0.4	-$0.1
2022	-$0.4	Not Assessed	
2022/2024	**-$0.6**	+$0.1	-$0.3
2024	+$0.1	Not Assessed	

= Net Cost
= Net Benefit

Table shows NPV from 2015-2032 in billions of 2014 dollars compared to the base case

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Summary of changes in emissions

Pickering Scenarios	Darlington Scenarios: Lapped	Darlington Scenarios: Unlapped Yes Idle Time	Darlington Scenarios: Unlapped No Idle Time
2018	+4.8MT	+6.6MT	+4.5MT
2020	BASE	+1.7MT	-0.3MT
2022	-5.8MT	Not Assessed	
2022/2024	**-9.3MT**	-7.2MT	-8.9MT
2024	**-9.9MT**	Not Assessed	

= Net Cost
= Net Benefit

Table shows total change in CO_2 emissions between 2015-2032 in megatonnes (MT) compared to the base case

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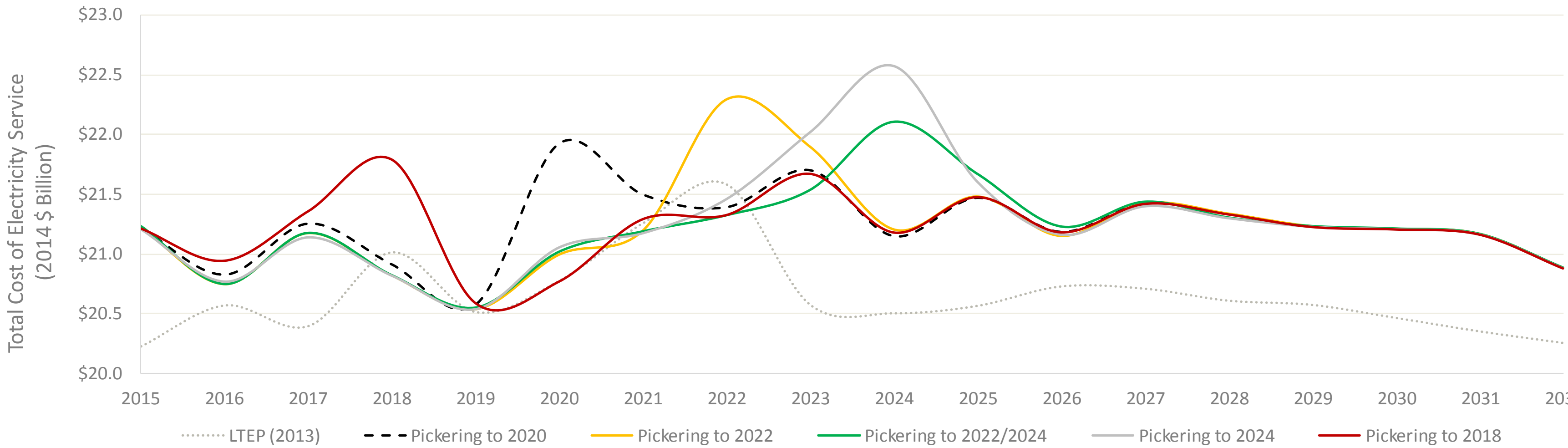
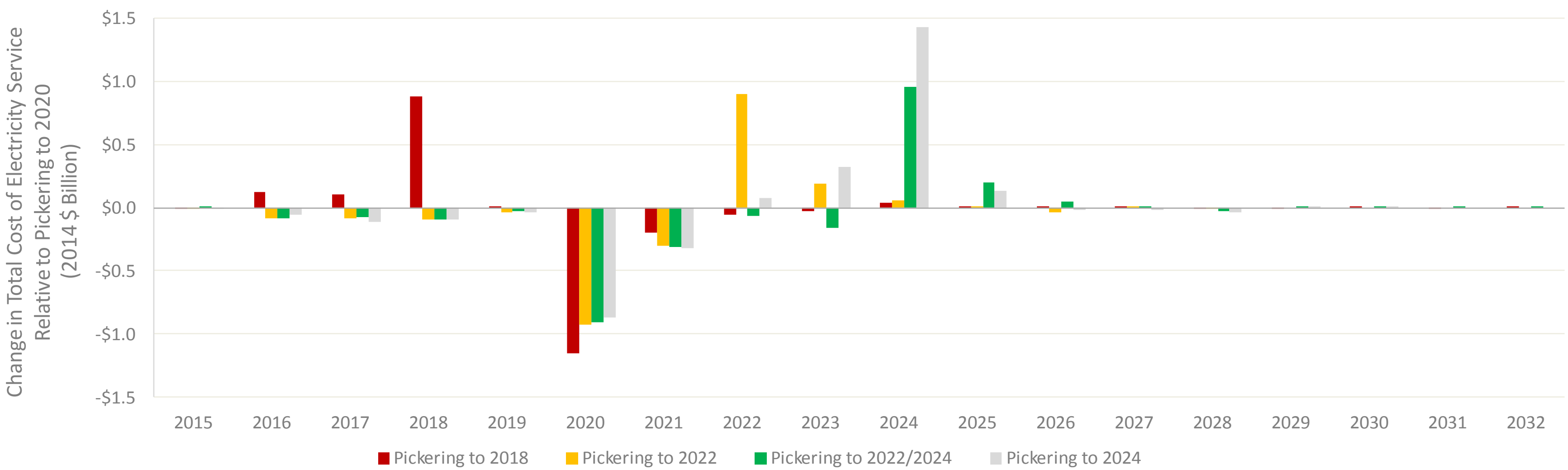
Total cost of electricity service





Excludes transmission and decommissioning advancement/deferral costs.

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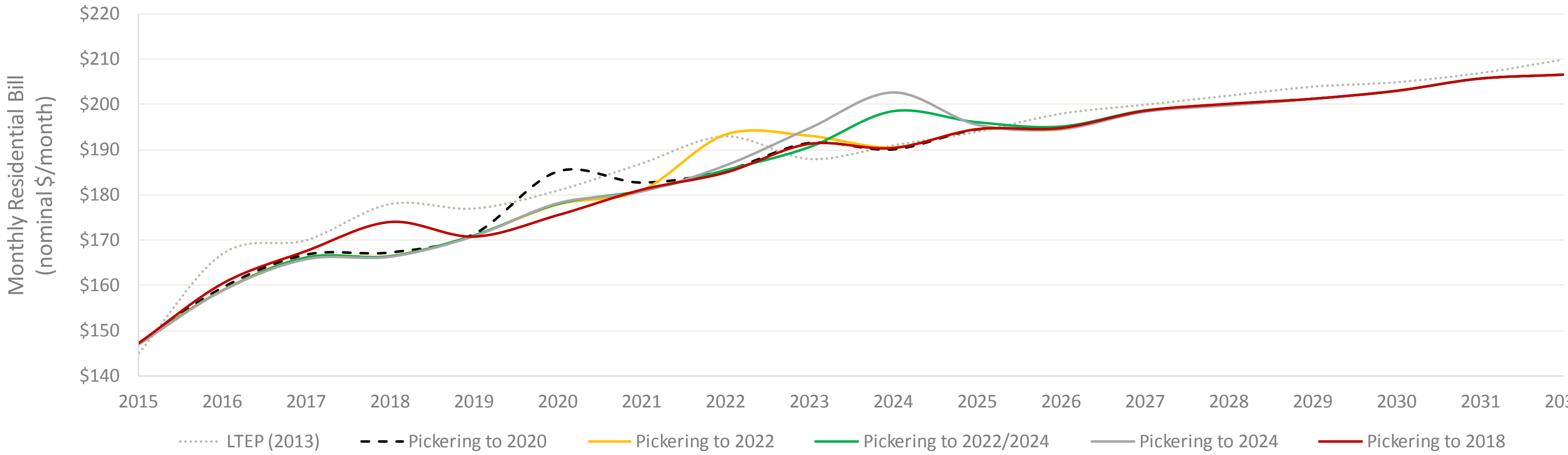
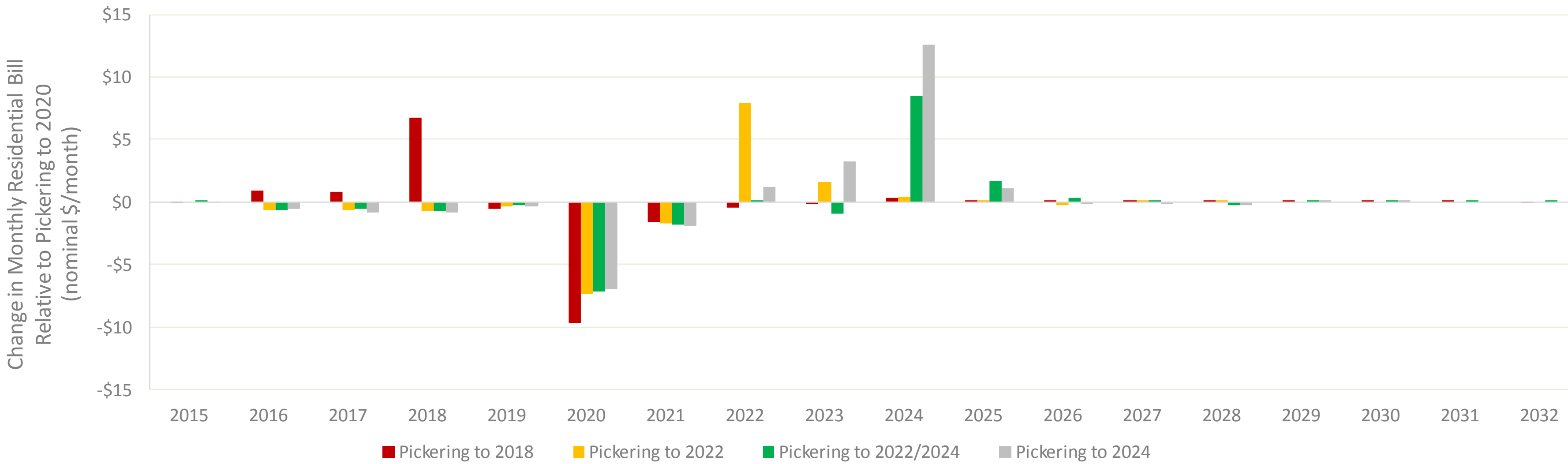
Residential electricity bills





Assumes a typical residential consumption of 800 kWh/month. Excludes transmission and decommissioning advancement/deferral costs.

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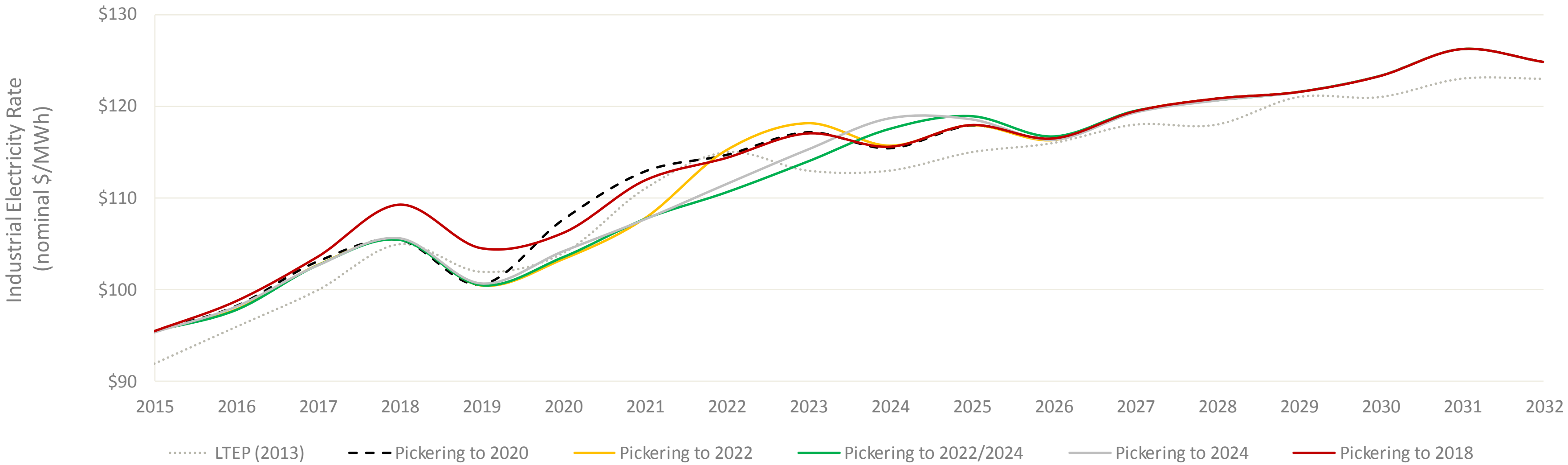
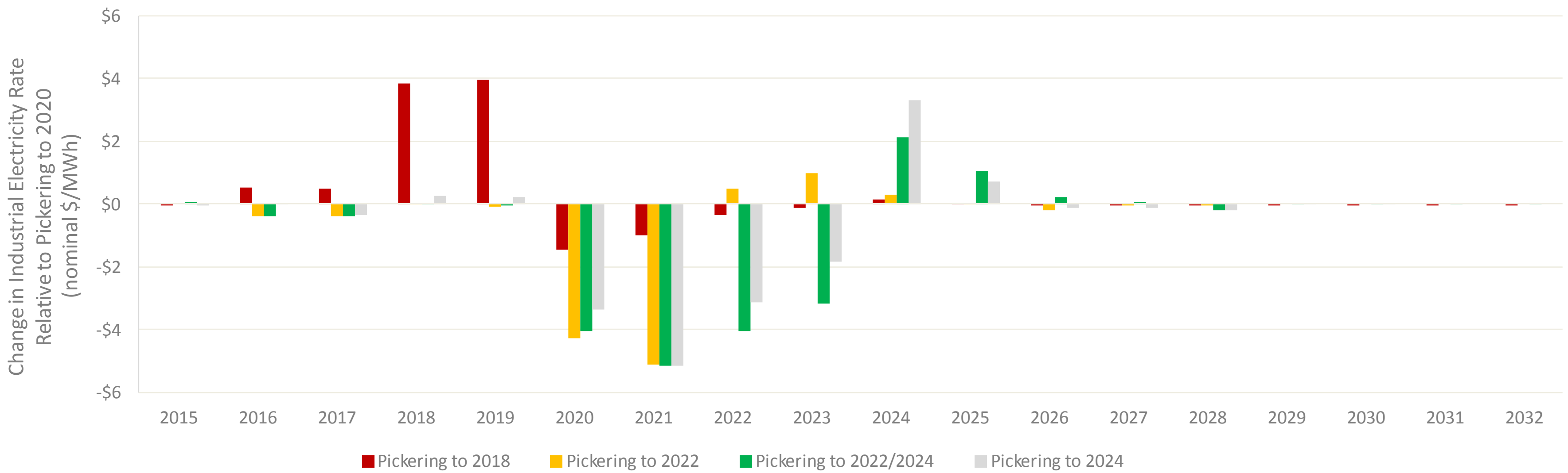
Industrial electricity rates





Assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor. Excludes transmission and decommissioning advancement/deferral costs.

Extending Pickering operations beyond 2020

- There is value in Pickering life extension. Extending operation beyond 2020:
  - Defers timing of need and the supply/transmission investments that would otherwise be required
  - Defers procurement decisions with respect to new resources, providing more time in exercising options while reducing risk of over investment during a period of supply/demand uncertainty
  - Defers decommissioning and severance costs
  - Offsets production from natural gas-fired resources and imports
  - Increases export revenues and reduces carbon emissions
  - But also increases potential surplus energy
- Extension of Pickering A units to 2022 and B units to 2024:
  - Shows the greatest net benefit among Pickering scenarios assessed
  - Minimizes increases to OPG nuclear rates to 2024
  - Defers the increase in the total cost of electricity service that eventually takes place under each of the scenarios considered and minimizes the magnitude of the total cost increase
- The value of extending Pickering operation to 2022/2024 is tied to the price of natural gas and carbon prices and to Pickering capital and operating costs
  - Value seen when natural gas or combined natural gas and carbon prices are above $4/MMBtu
- However, extension beyond 2022/2024 shows decreasing utility and results in a cumulative disbenefit
- Removing overlap among Darlington refurbishment outages (a.k.a. “unlapping”) generally reduces the value of extended Pickering operations

Early Pickering shutdown

- Early Pickering shutdown could lead to cost savings, but less savings than extended operations under the reference conditions assessed
  - Also results in less potential surplus energy and more carbon emissions
- The cost savings of early Pickering shutdown are less vulnerable to natural gas price/carbon risk than observed in Pickering extension scenarios
- All else being equal, cost savings from early Pickering shutdown would be negated if:
  - Pickering capital and operating costs declined by 10% from current projections; or,
  - If natural gas/carbon prices exceeded approximately $6/MMBtu
- Early shutdown would present practical challenges related to securing replacement supplies within the span of three years and within a context of significant transition in the Ontario electricity system
- Early shutdown would also present practical challenges related to labour and community impacts
- Early shutdown would advance increases to OPG nuclear rates as well as increases in the total cost of electricity service that eventually takes place under each of the scenarios considered

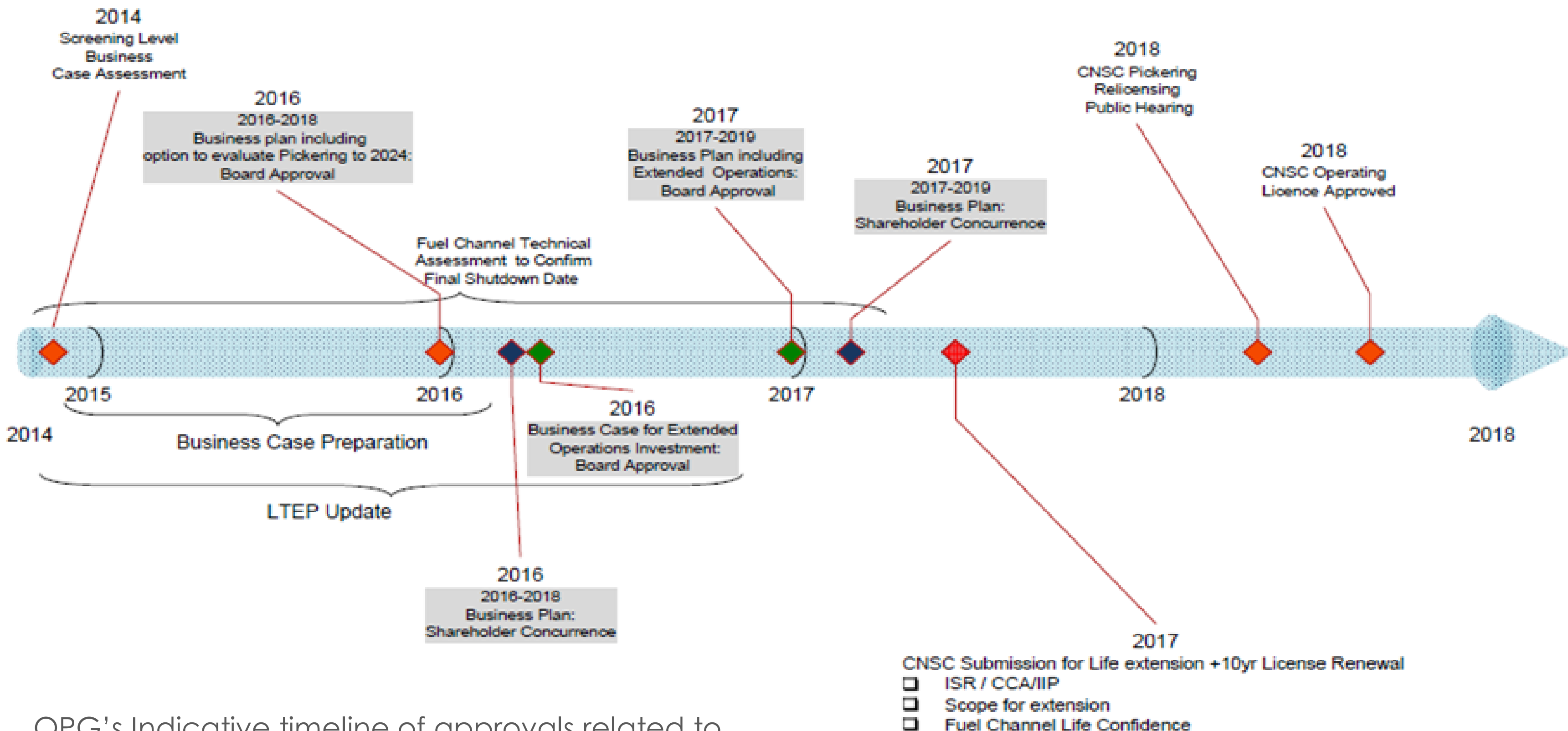
Next Steps

- Explore extension options involving fewer Pickering units to reduce contribution to surplus baseload generation
- Consider cost control mechanisms to ensure Pickering life extension continues to provide value
- IESO should be routinely updated on the status and substance of Pickering extension exploration efforts and related regulatory developments given the implications on need for additional supply and transmission investment

APPENDIX 3:

Additional Detail on Elements of a “Work Plan” in progress developed by Ministry of Energy, OPG, and IESO

Over the next few years, OPG will seek to demonstrate the technical feasibility of extended Pickering operation, develop the business case and pursue regulatory approvals at the OEB and CNSC. OPG's filing to the CNSC would take place in 2017 and a CNSC decision would be received by late 2018.



OPG's Indicative timeline of approvals related to the operation of Pickering NGS beyond 2020

Elements of a work plan in progress
(source: Ministry of Energy, April 28 2015)

Organization	Activity to Increase the Economic, Technical and Regulatory Confidence	Completion Date
IESO	Update supply/demand outlook, ongoing assessment of Pickering extended operations and alternatives, ongoing contingency planning in case Pickering extended operations does not proceed	Ongoing
OPG	Economic evaluation of incremental investment and benefits of operation of Pickering units past 2020 • Ministry briefing	Q2 2015
OPG	2016-2018 Business Plan submission with operation to 2020 and evaluation of option for Pickering extension to 2024	Q4 2015
ENERGY	Cabinet submission on Pickering extension	Q4 2015
OPG	Technical assessment of fuel channels: • measurements to confirm rate of aging mechanisms • completion of research program on fuel channel aging and related safety analysis	Q2 2016
OPG Board	Approved business case for life management measures and their costs	Q2/3 2016
ENERGY	Consultations for 2017 LTEP	Q3 2016

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Elements of a work plan in progress (continued)

(source: Ministry of Energy, April 28 2015)

Organization	Activity to Increase the Economic, Technical and Regulatory Confidence	Completion Date
OPG ENERGY	OPG Board approved business plan for extended operations of the Pickering units submitted to Energy	Q4 2016
ENERGY IESO	Decision to make Pickering extension preferred supply option	Q4 2016

ENERGY	Release 2017 LTEP including Pickering extension	Q1 2017
OPG	OPG's determination of end of life dates for Pickering and regulatory submission requesting approval of extended operations of Pickering units	Q2 2017
CNSC	Approval of Pickering extended operations operating license	Q3 2018

ENERGY	Release 2017 LTEP including alternative supply options	Q1 2017
IESO	Implement alternatives as required	By 2020

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Assessment of Pickering Life Extension Options

Prepared for discussion with Ministry of Energy

Power System Planning

March 9, 2015

Independent Electricity System Operator

Overview

- Upon Ministry of Energy request, the IESO has conducted an independent assessment of the long-term integrated power system impacts of various Pickering life extension scenarios. Pickering extension scenarios are considered against three Darlington refurbishment sequences.
  - This report updates and builds upon previous Pickering life extension studies conducted by the former OPA
  - Technical and economic information concerning the Pickering and Darlington stations was provided to the IESO by OPG between December 2014 and January 2015 for each scenario assessed
  - The scenarios have not been discussed publicly nor have they received necessary CNSC approvals

- Implications of the Pickering scenarios are assessed from a variety of perspectives, including:
  - Capacity needs and timing
  - Energy production from existing and contemplated resources
  - Greenhouse gas emissions
  - Surplus energy
  - Total cost of electricity service
  - Ratepayer costs

- Results of the IESO's assessment are presented in the following slides, additional details are available in the Appendix

Summary of results

- Extending Pickering operation beyond 2020 defers some supply and transmission investments that would otherwise be required, defers decommissioning and severance costs, offsets production from natural gas-fired resources and imports, increases export revenues and reduces carbon emissions
- Extending Pickering operations beyond 2020 also increases potential surplus energy
- Extension of Pickering A units to 2022 and B units to 2024 shows the greatest net benefit among Pickering scenarios assessed, minimizes increases to OPG nuclear rates to 2024, defers the increase in the total cost of electricity service that eventually takes place under each of the scenarios considered and minimizes the magnitude of the total cost increase
- The value of extending Pickering operation to 2022/2024 is sensitive to natural gas and carbon prices: it shows value when natural gas or combined natural gas and carbon prices are above $4/MMBtu
- The value of extending Pickering operation to 2022/2024 is also sensitive to Pickering capital operating costs, but less sensitive than to natural gas/carbon price
- Extension beyond 2022/2024 shows decreasing utility and results in a cumulative disbenefit
- Removing overlap among Darlington refurbishment outages (a.k.a. “unlapping”) generally reduces the value of extended Pickering operations

Summary of results (continued)

- Early Pickering shutdown could lead to cost savings, but less savings than extended operations under the reference conditions assessed
- Early Pickering shutdown results in less potential surplus energy and more carbon emissions
- The cost savings of early Pickering shutdown are less vulnerable to natural gas price/carbon risk than observed in Pickering extension scenarios. All else being equal, cost savings from early Pickering shutdown would be negated if Pickering capital and operating costs declined by 10% from current projections or if natural gas/carbon prices exceeded approximately $6/MMBtu
- Early shutdown would present practical challenges related to securing replacement supplies within the span of three years and within a context of significant transition in the Ontario electricity system
- Early shutdown would also present practical challenges related to labour and community impacts
- Early shutdown would advance increases to OPG nuclear rates as well as increases in the total cost of electricity service that eventually takes place under each of the scenarios considered

Looking ahead

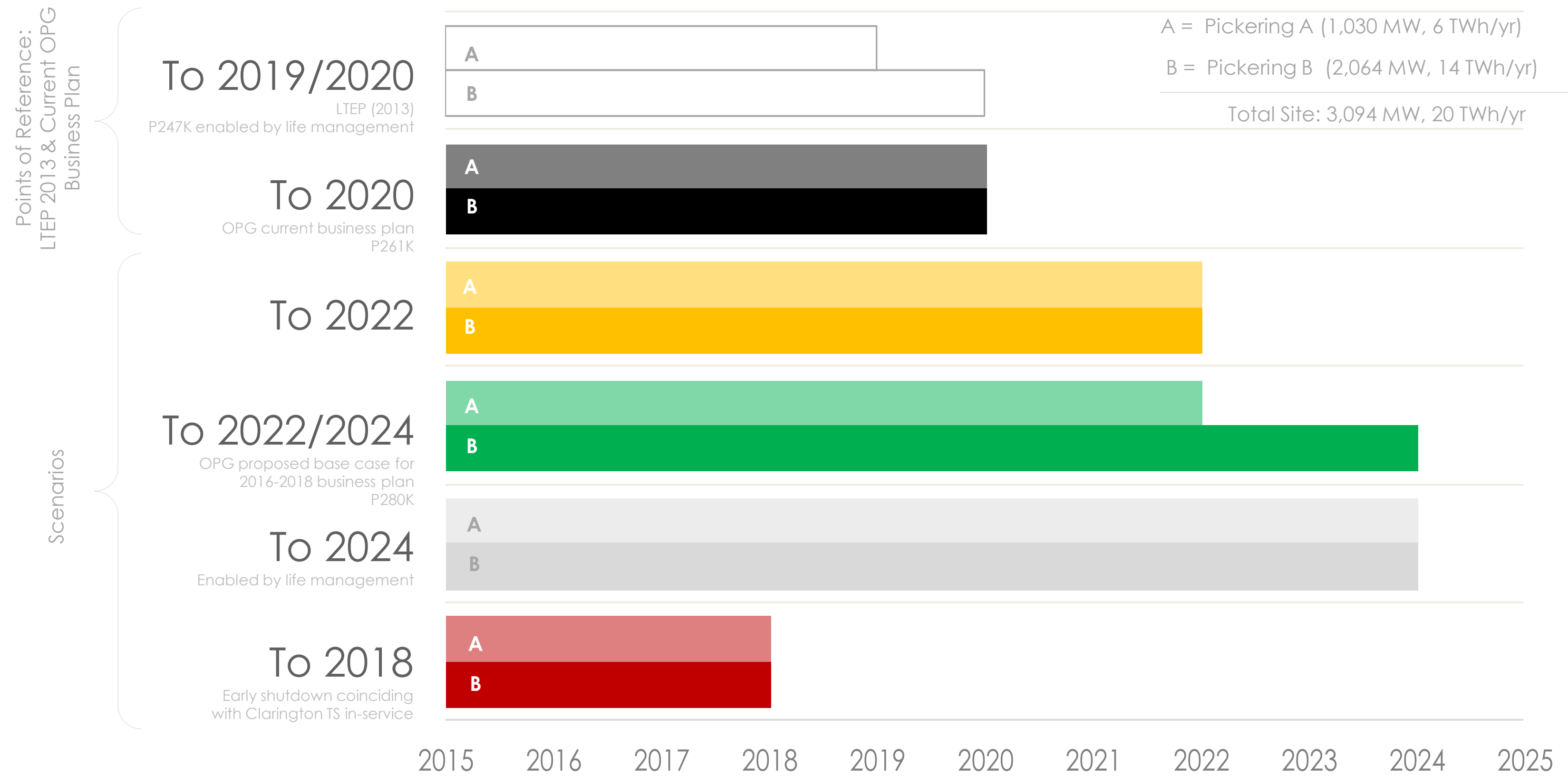
- On balance, the option of extended Pickering operations merits further exploration. The scenario of Pickering operation to 2022/2024 appears to be the most promising candidate among extension options assessed. Extended operation to 2022 also holds potential for benefit, but less so than operation to 2022/2024.

- In light of the impact of Pickering extended operations on potential surplus energy, it may be worth exploring Pickering extension options involving fewer Pickering units (e.g. four to five units rather than six)

- In light of the impact of Pickering capital and operating costs on the value proposition of extended Pickering operations, it may be worth exploring options for cost control

- In light of implications of Pickering shutdown timing on the need for additional supply and transmission investment, IESO should be routinely updated by OPG on the status and substance of Pickering extension exploration efforts and related regulatory developments

Four Pickering scenarios are assessed: three feature longer Pickering operation than in LTEP 2013 or in OPG's more recent business plan, one features earlier shutdown



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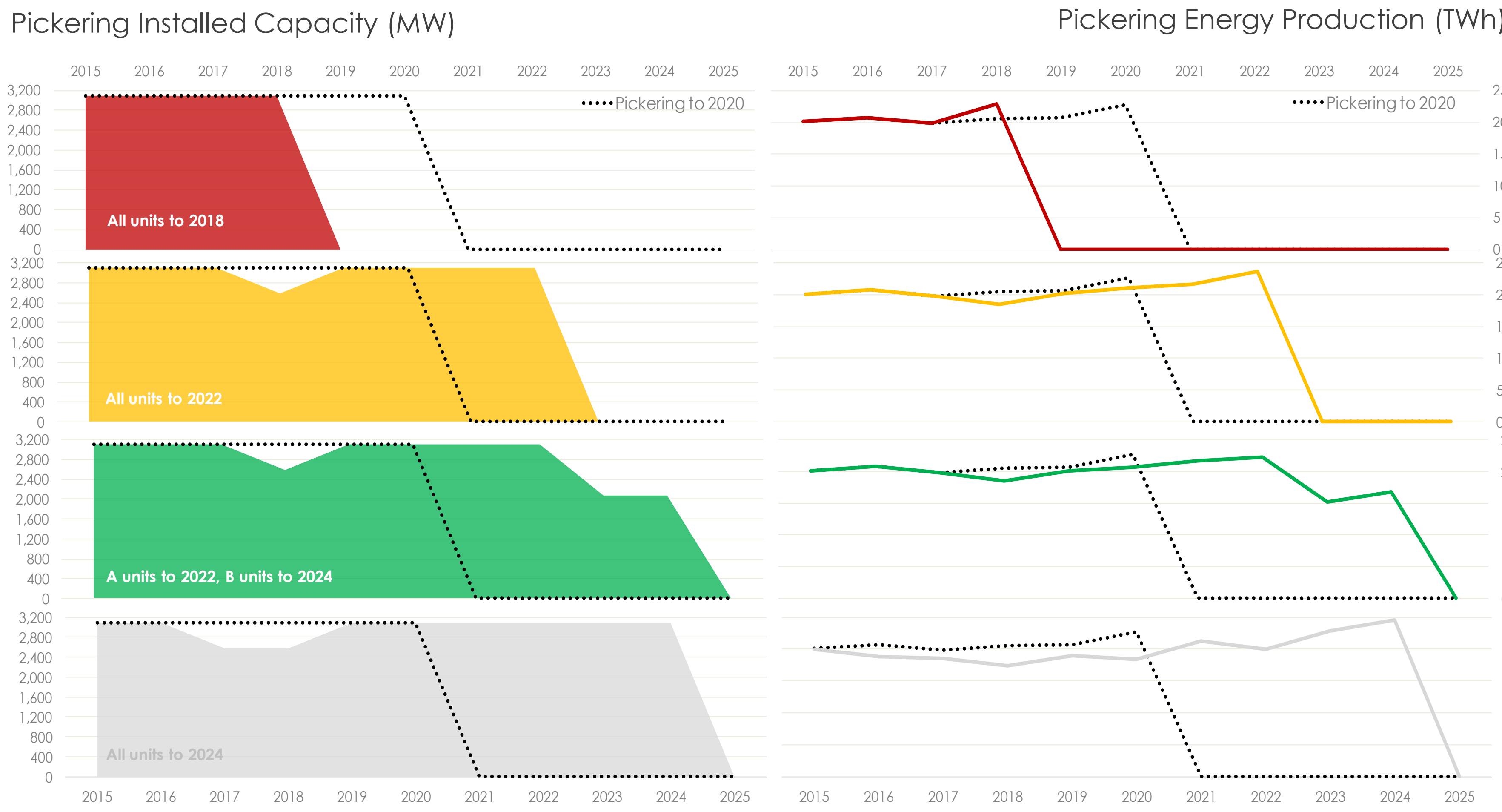
Approximately 3,100 MW and 20 TWh is provided by Pickering for each year of operation. Operation beyond 2020 is enabled by additional outages prior to 2020. These outages result in lower availability and output in some years prior to 2020.



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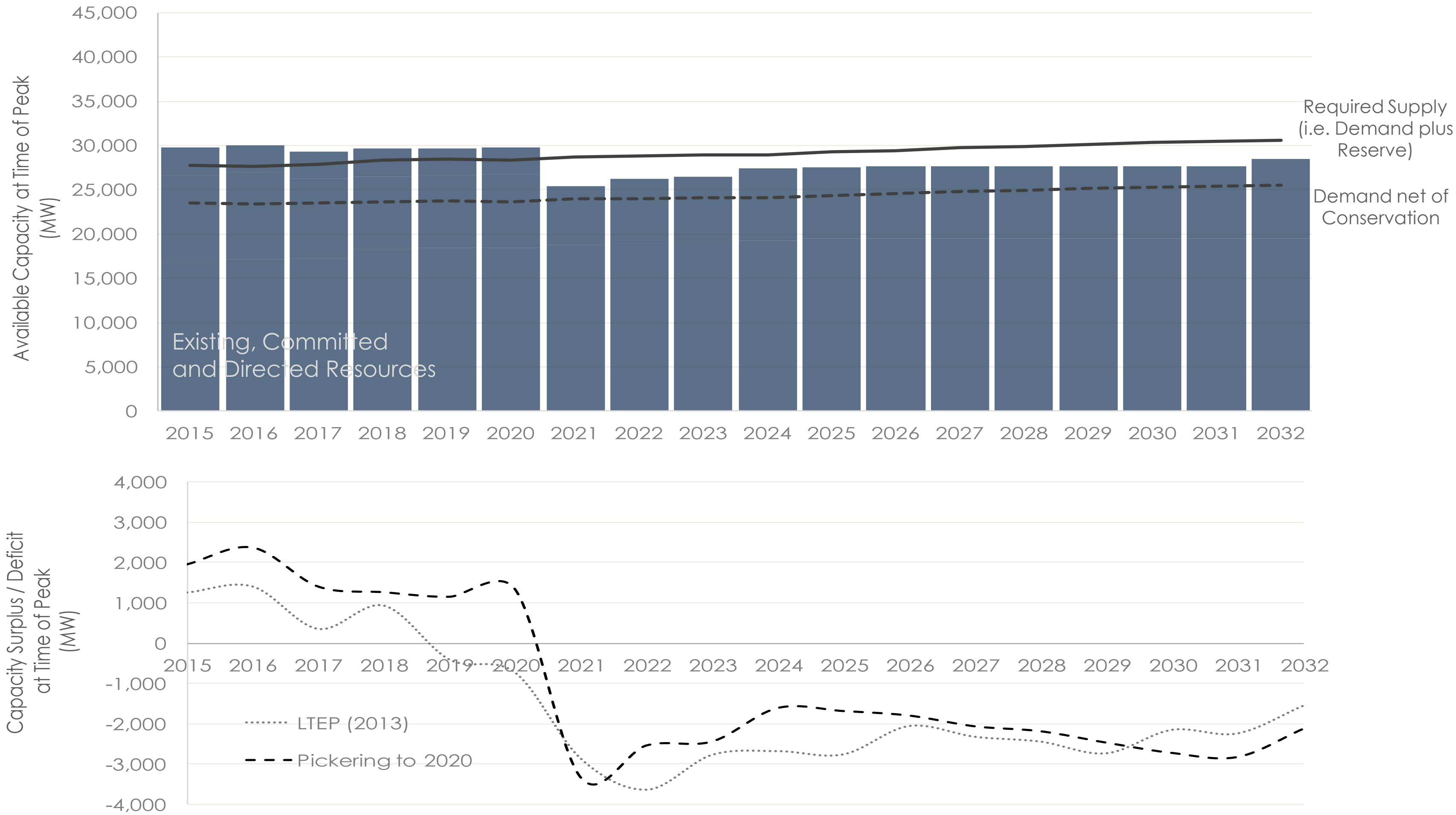
Existing, committed and directed resources will provide adequate supply for the next few years, after which time additional resources will be required. LTEP 2013 saw needs emerge in 2018/2019. Needs arise by 2020 in the current outlook.



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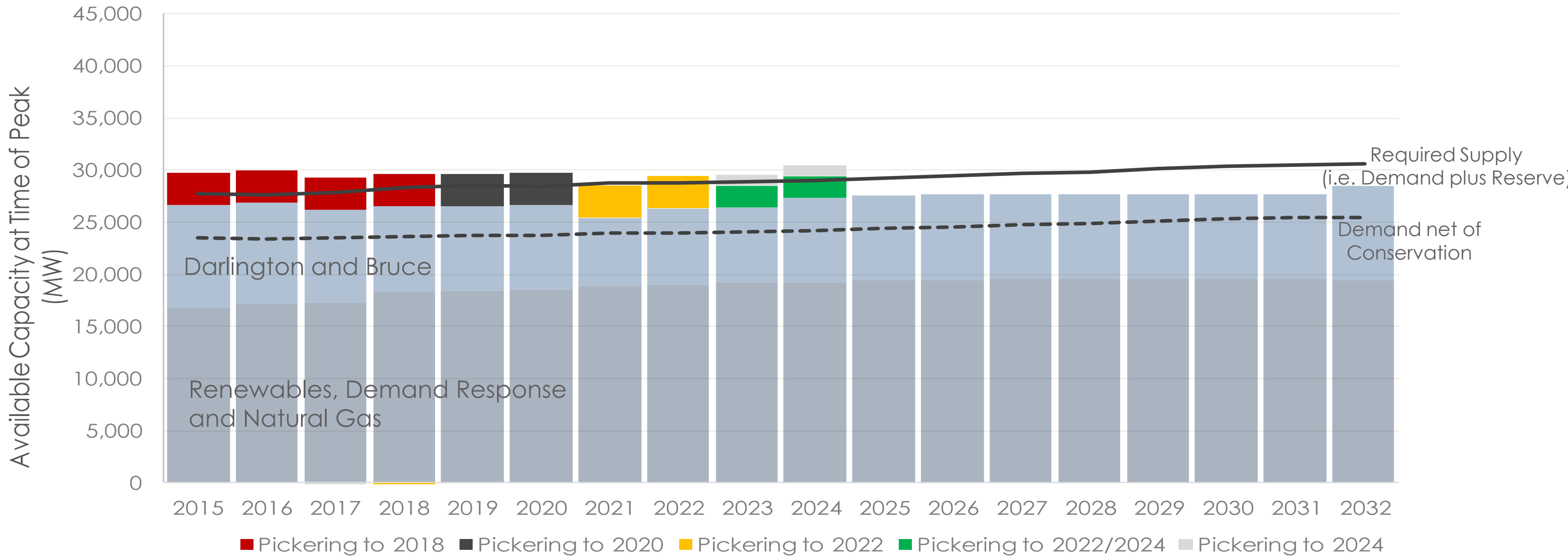
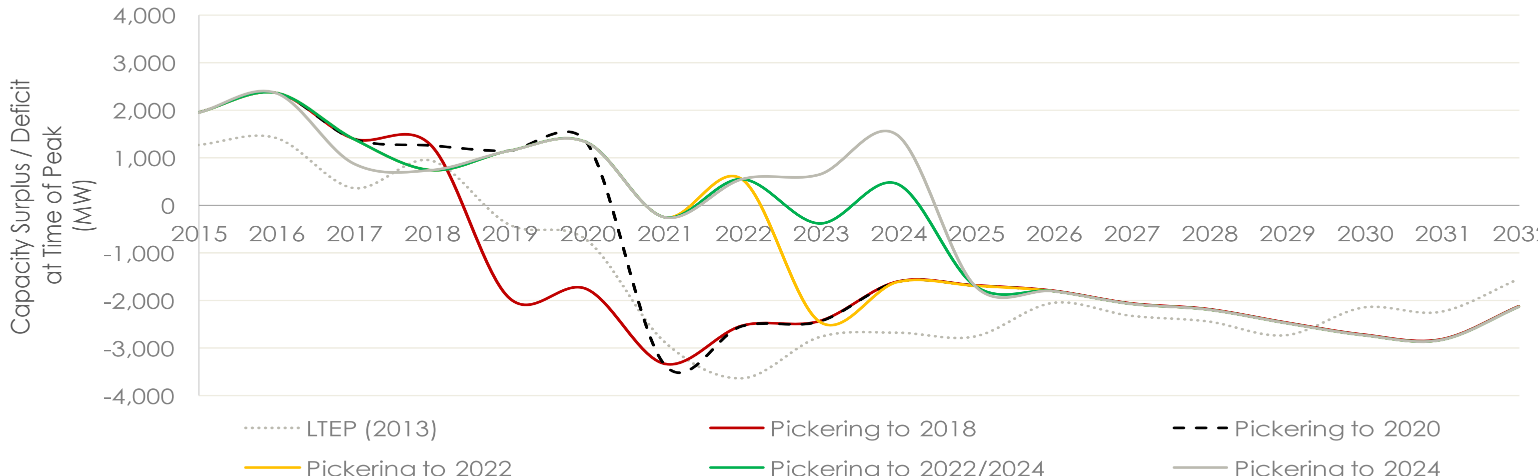
Extended operation at Pickering beyond 2020 would defer the need for additional supply, earlier shutdown would advance the need





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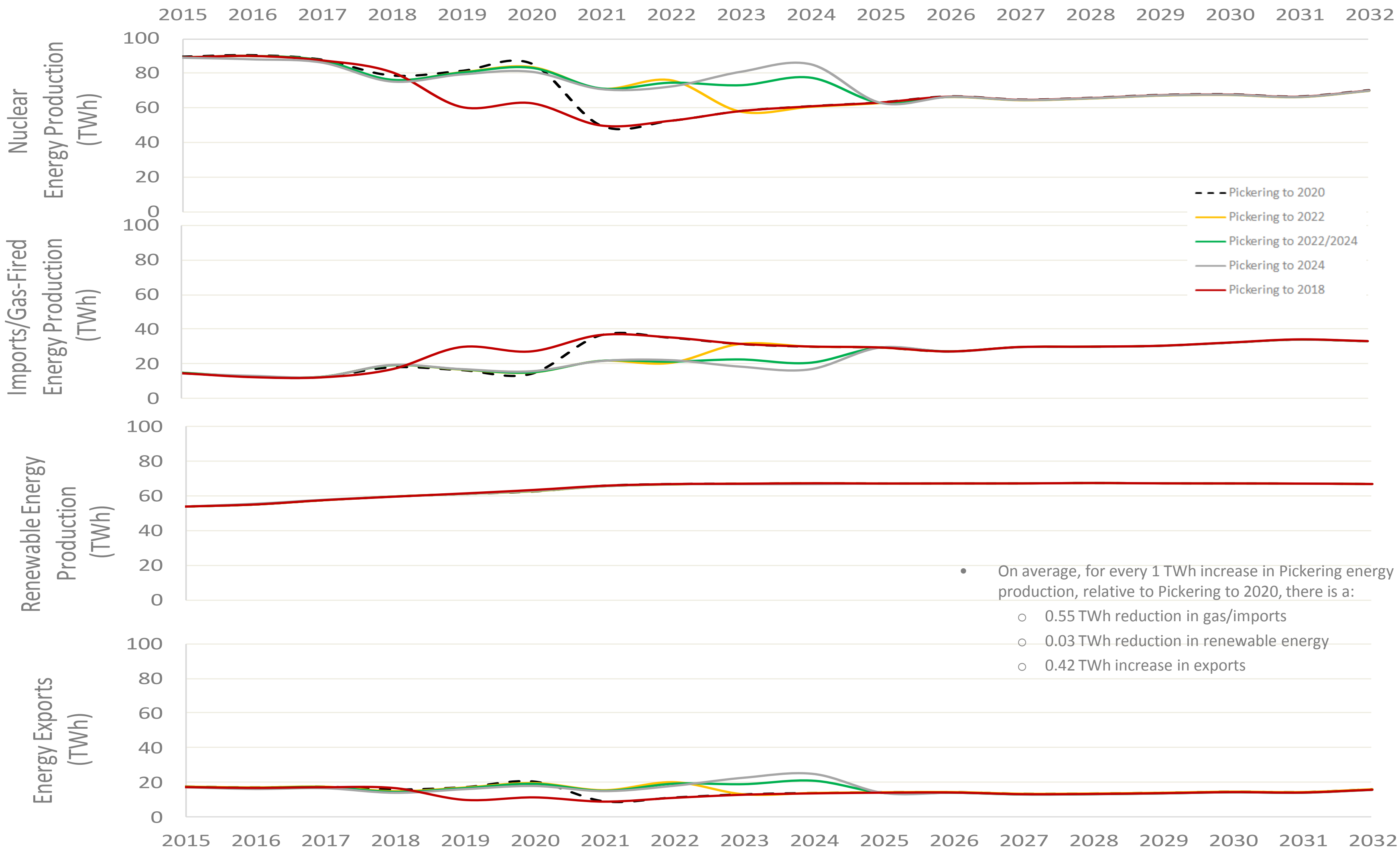
Energy production from Pickering displaces production from gas-fired resources, reduces energy imports and increases energy exports



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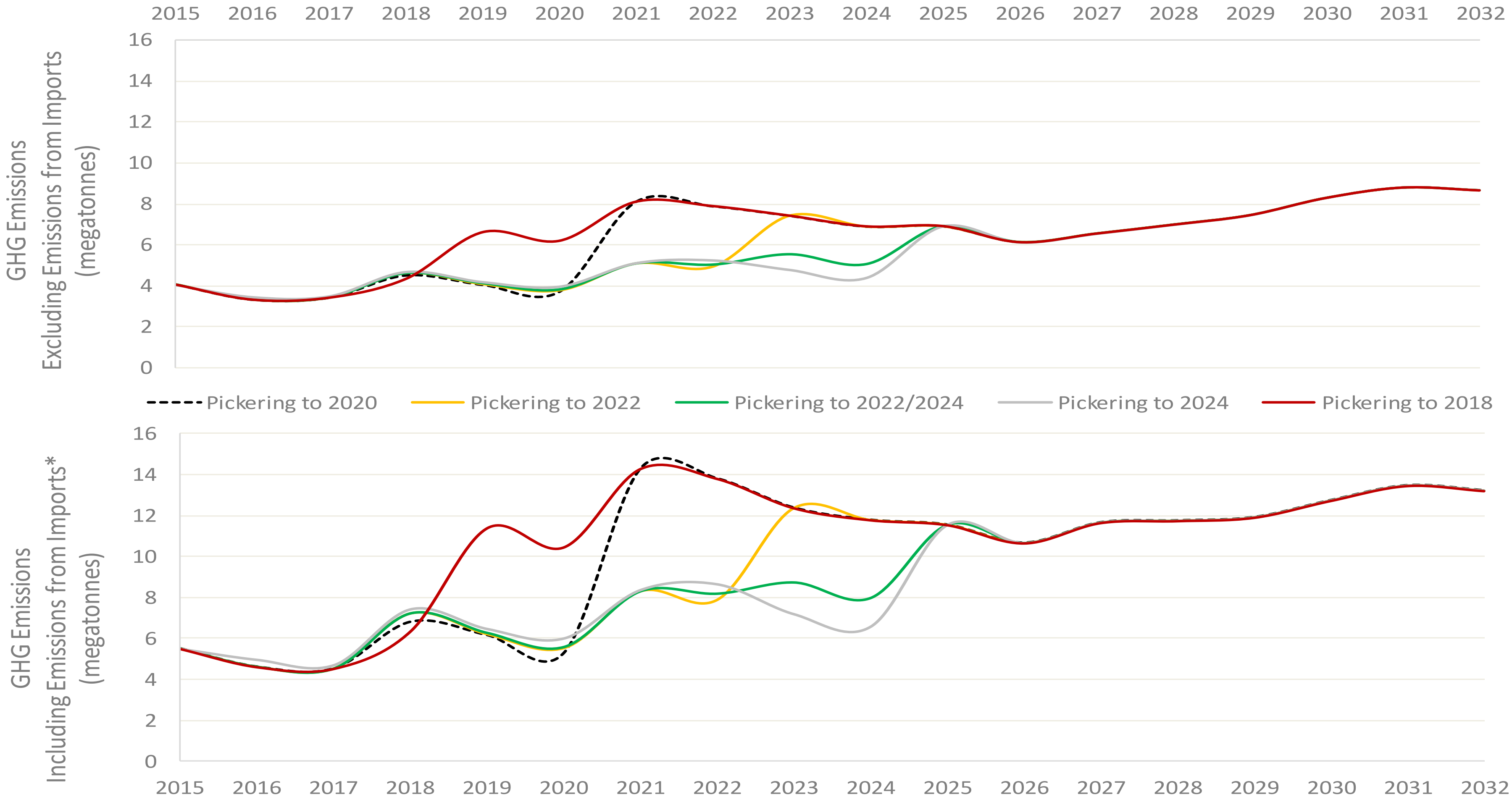
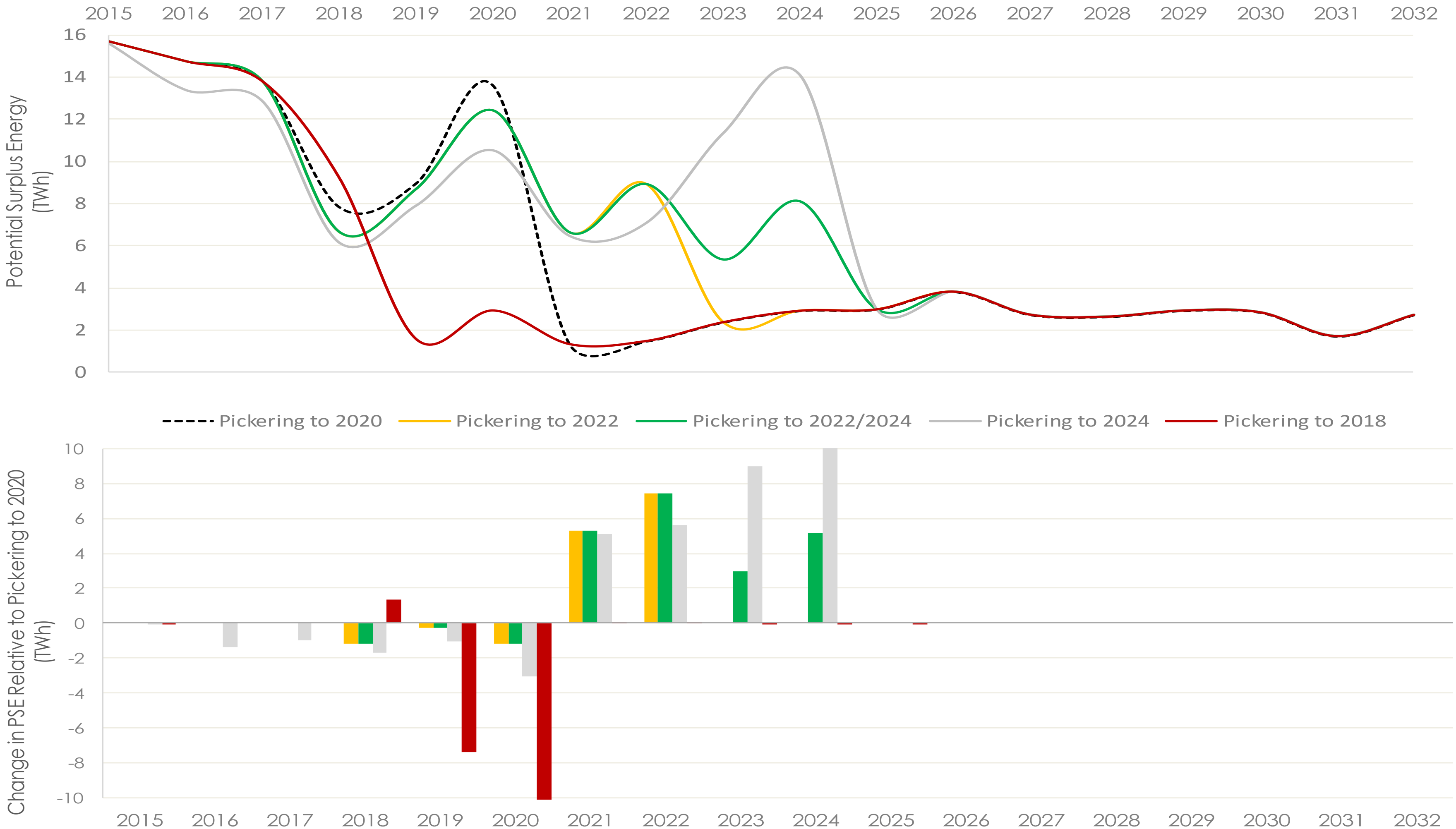
Energy production from Pickering reduces greenhouse gas emissions



*CCGT emission rates used for import emissions rates as a proxy

Energy production from Pickering increases potential surplus energy



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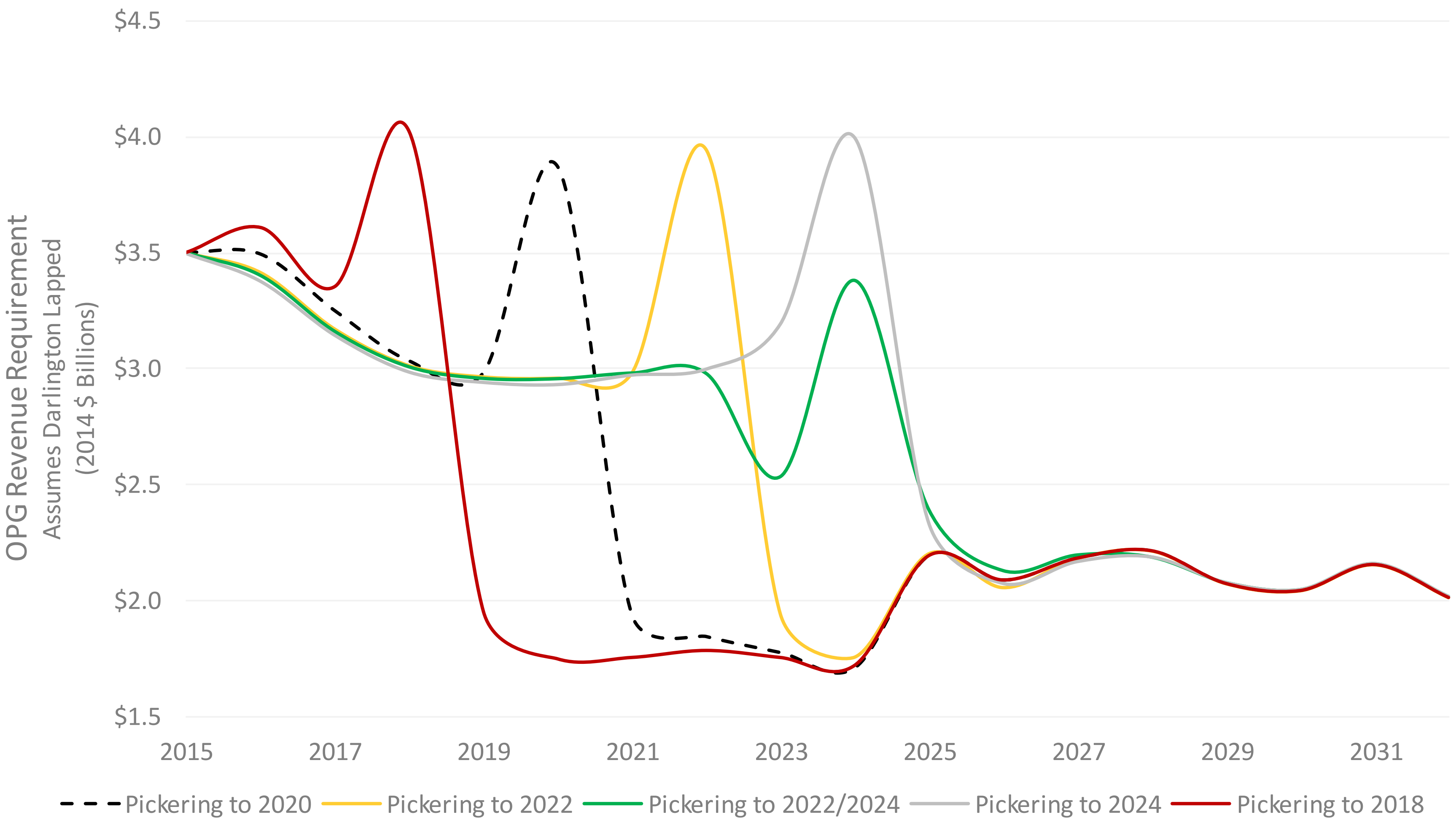
OPG's nuclear program will cost between $1.7 billion and $4.0 billion per year between now and 2032, depending on the Pickering extension and Darlington refurbishment sequence scenario



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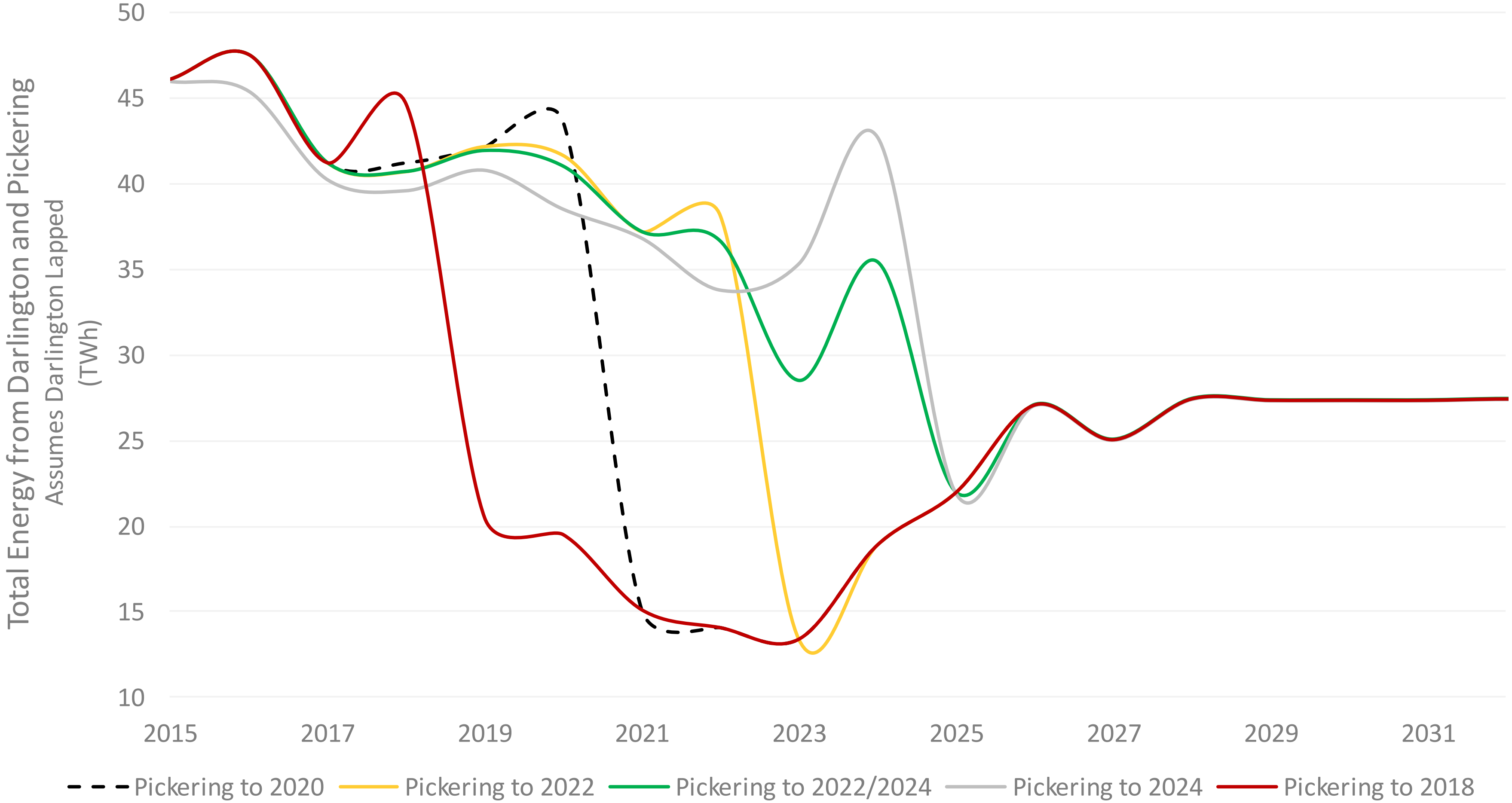
The costs of OPG's nuclear program will be recovered against the energy quantities generated by OPG nuclear stations. Annual quantities will vary depending on the scenario. Energy quantities decline as Pickering units are shut down and as Darlington units undergo refurbishment.



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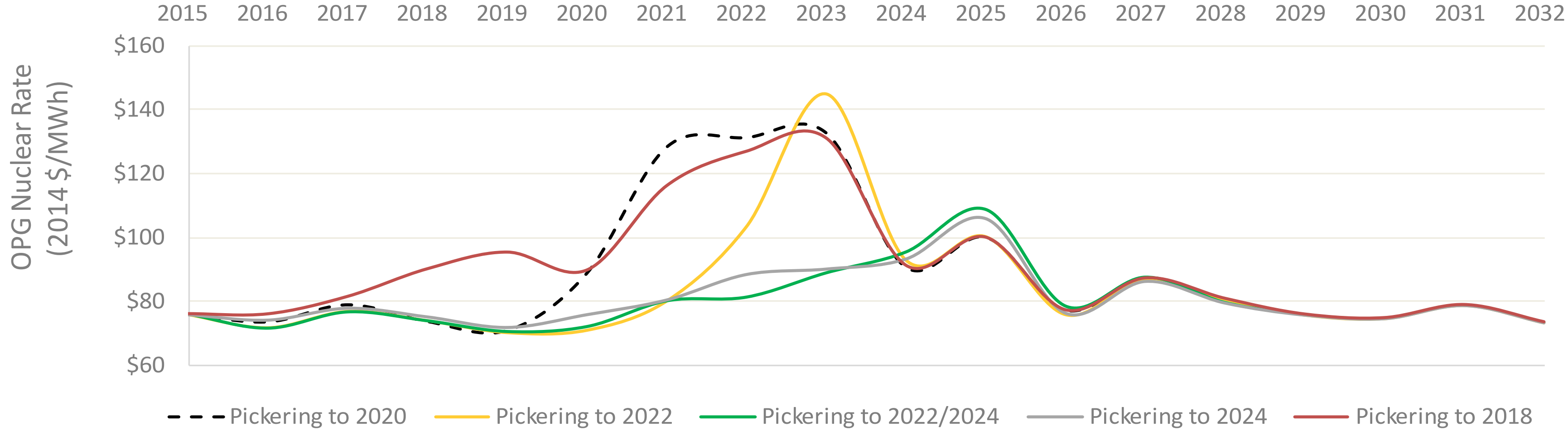
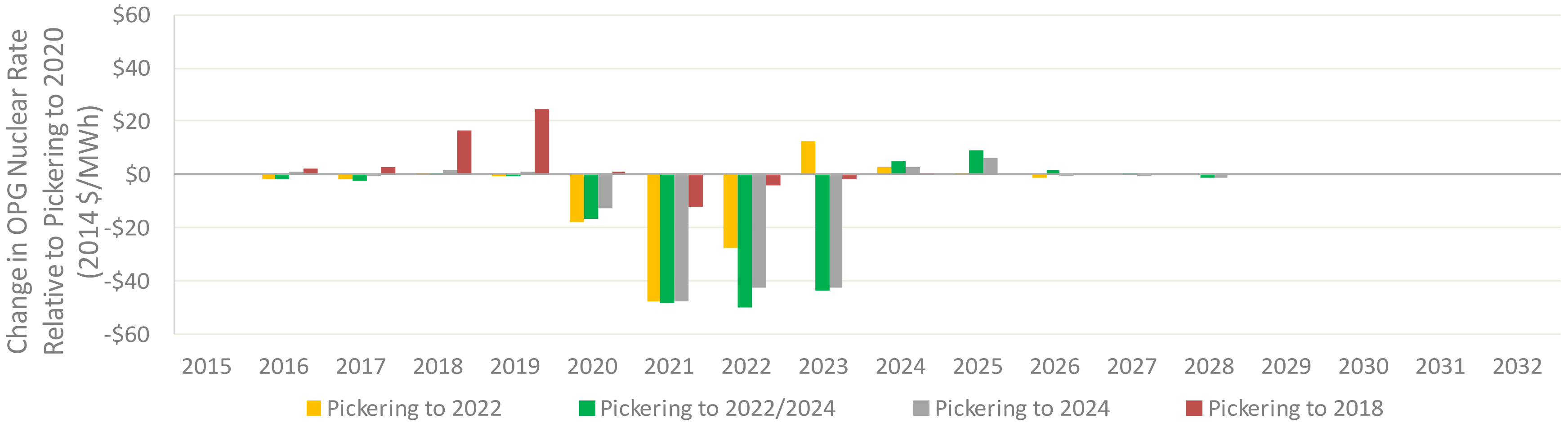
OPG's total nuclear rate will increase as OPG nuclear production decreases. Life extension at Pickering increases OPG's annual nuclear production and tends to reduce OPG nuclear rates to 2024.





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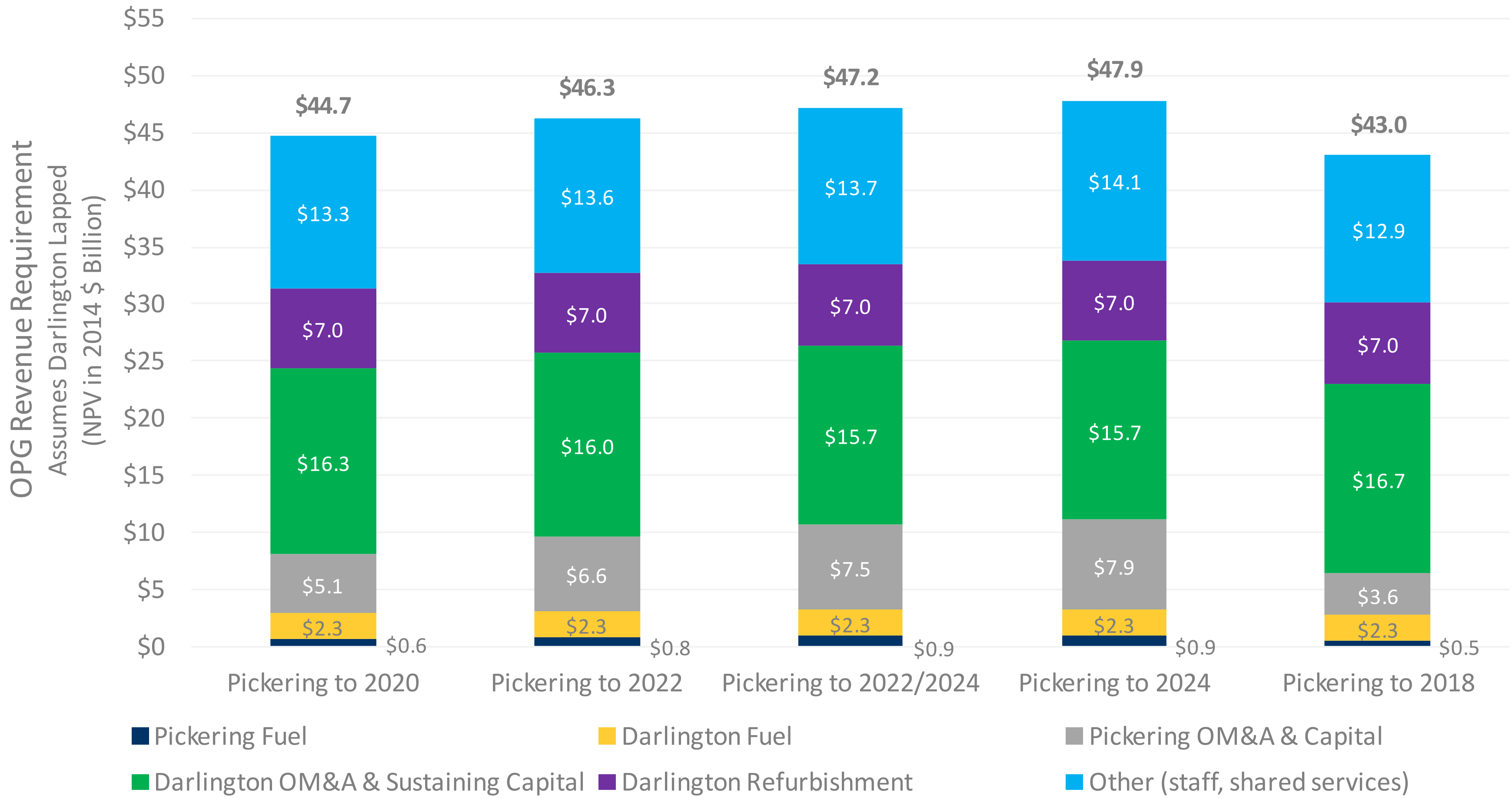
Rates reflect Pickering scenario stated and Darlington lapped (per LTEP (2013))

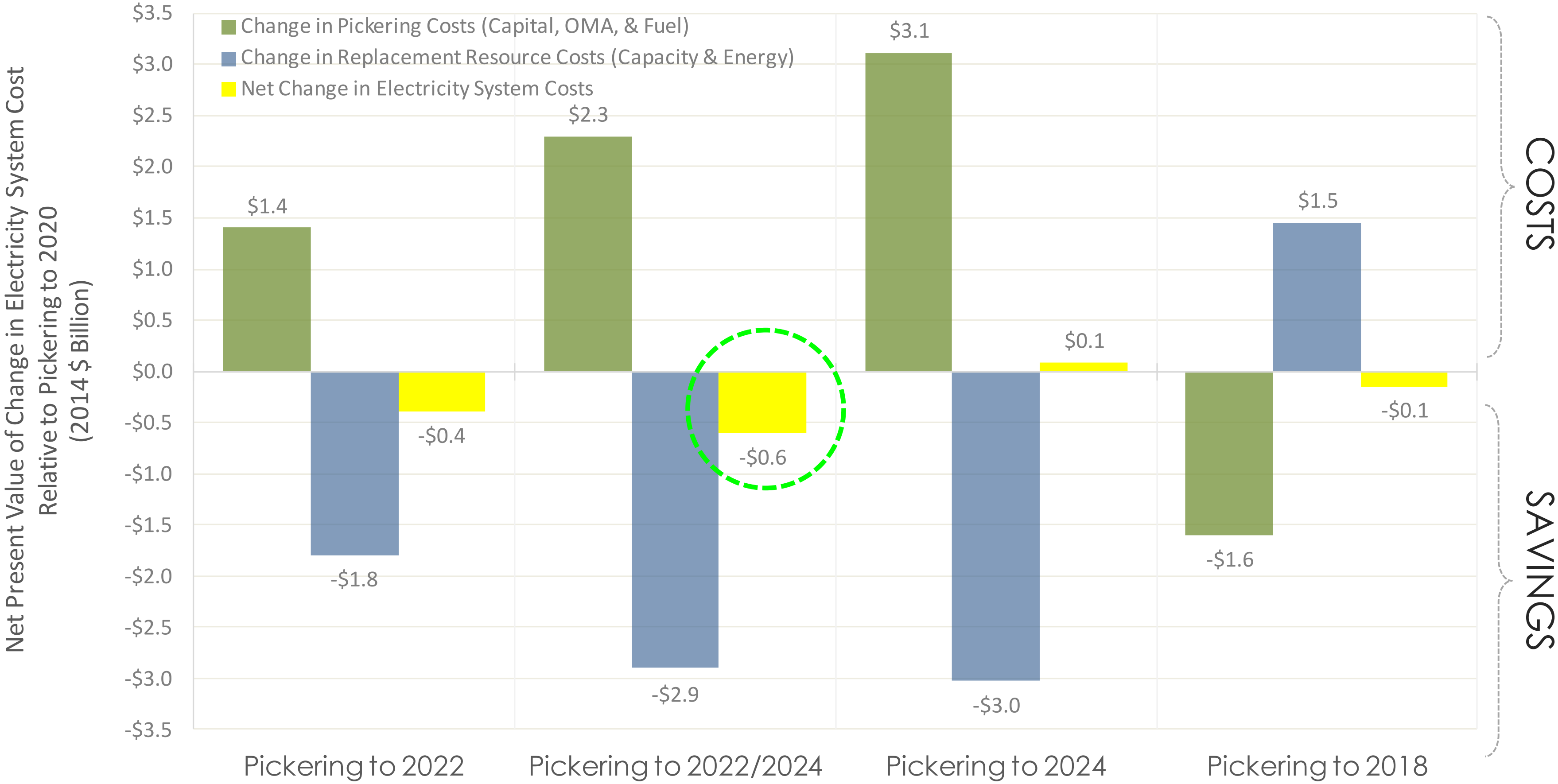
The present value of OPG nuclear costs will range between $43 billion and $48 billion, depending on the scenario. Pickering will account for between $4 billion and $9 billion of this total. Capital and non-fuel OM&A will comprise approximately 90% of Pickering costs.



Economic evaluation: overview of approach

- The cost of extending Pickering life is compared to the savings resulting from reduced electricity system replacement energy and capacity costs, all relative to Pickering to 2020 (the current base case)
  - If the cost of Pickering life extension is less than the cost of replacement energy and capacity, there is a net benefit and overall electricity system costs decrease
  - Conversely, if the cost of Pickering life extension is greater than the cost of replacement energy and capacity, there is a net cost and overall electricity system costs increase.
- The current base case, Pickering to 2020, reflects recent updates to the supply mix and various policy initiatives since LTEP (2013) (see Appendix for list of updates)
  - Changes in Pickering life are compared to this base case
- In the absence of Pickering life extension:
  - Capacity needs are assumed to be met by an unspecified capacity resource with performance and cost characteristics equivalent to a simple-cycle gas turbine
  - Replacement energy is provided by existing generation resources
- Scenarios are evaluated under reference gas price assumptions of $5.25/MMBtu at Henry Hub
  - This is equivalent to gas at $4/MMBtu plus carbon priced at $23/tonne
- Sensitivity analysis is performed to evaluate the impact changes in Pickering capital cost and gas price have on system costs
- System costs analysis is performed in 2014 dollars. The change in net present value (NPV) of system cost of each Pickering life extension scenario relative to Pickering to 2020 is presented, 4% real discount rate is assumed
- Impacts on the annual cost of electricity service, residential bills, and industrial rates are also presented
  - Analysis reflects OPG nuclear rates developed by OPG for each individual scenario assessed
- Impacts on the cost of transmission are treated separately

Pickering extension to 2022/2024 yields the greatest net present value among the scenarios considered under the conditions assessed (i.e. results in the greatest cost savings)



Ontario electricity system costs decrease by extending Pickering to 2022 or 2022/2024 or shutting down early in 2018, relative to the Pickering to 2020 case. Costs marginally increase by extending to 2024.

NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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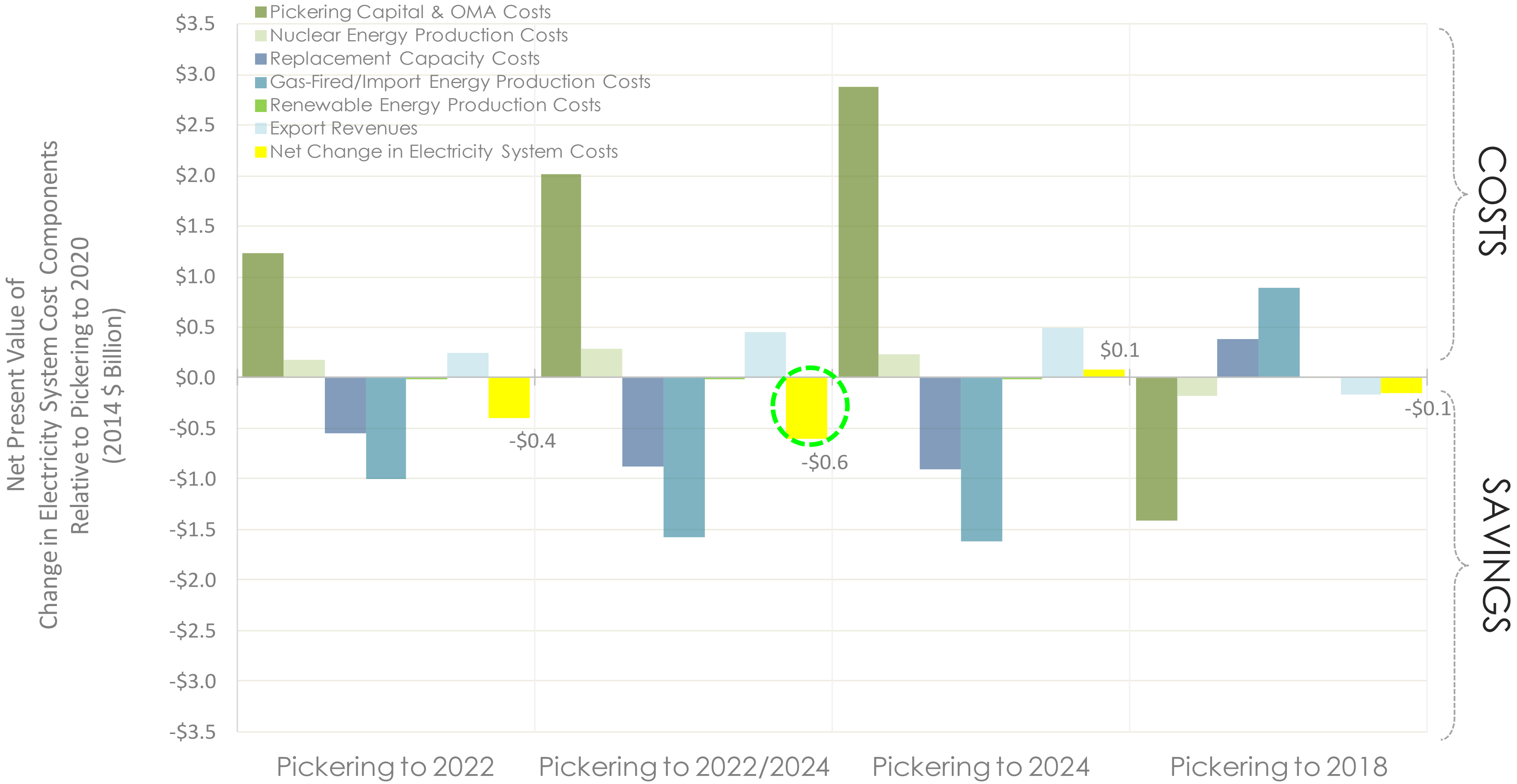
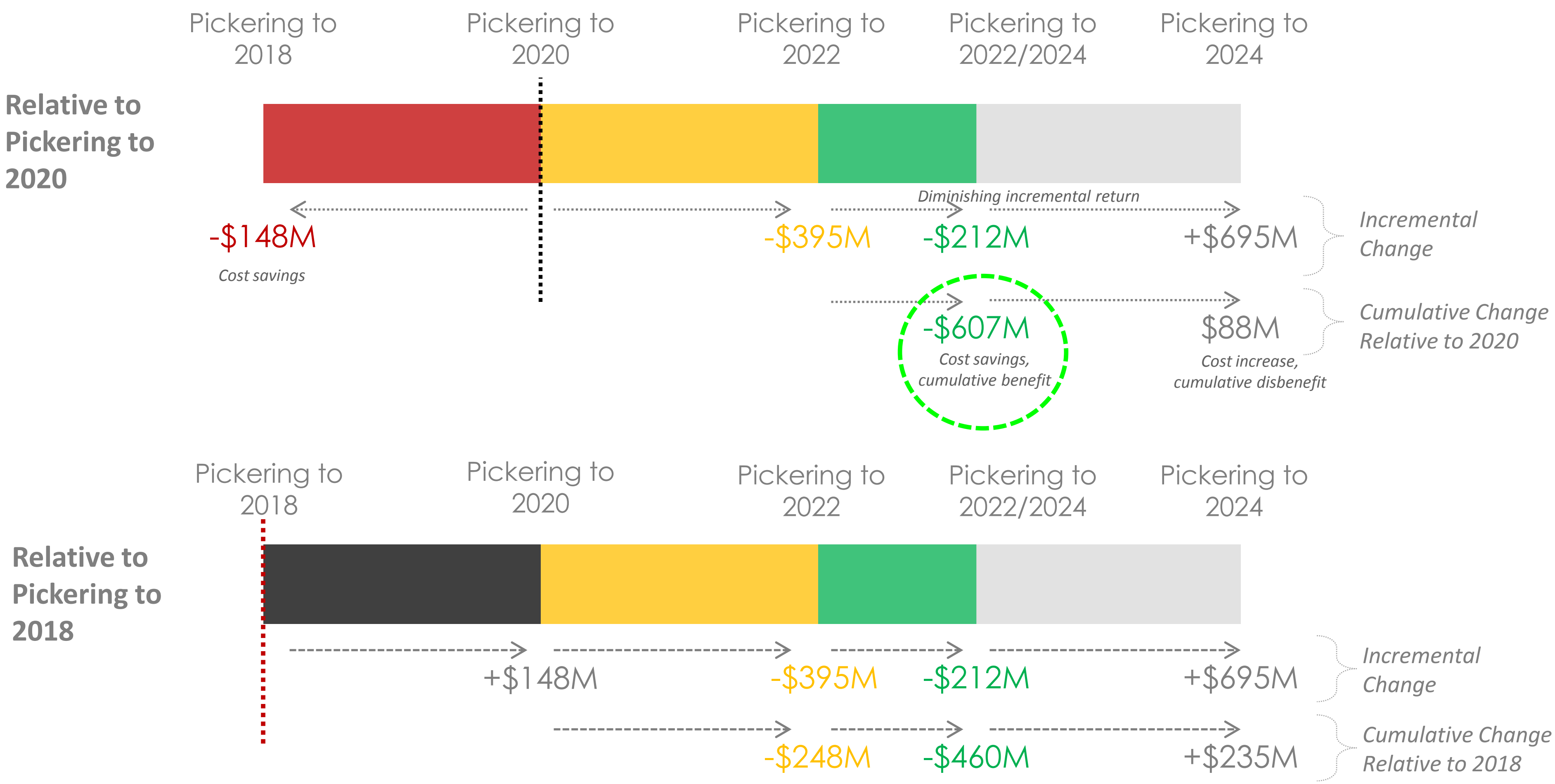
Cost savings from extending Pickering operations derive from reductions in replacement capacity costs and reductions in replacement energy costs from gas-fired resources and energy imports. These savings offset Pickering capital and operating costs, which comprise the largest cost components of Pickering extension.



NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

Pickering extension beyond 2020 results in cost savings, but at a diminishing incremental return beyond 2022. Beyond 2022/2024, diminishing returns result in a cumulative disbenefit.



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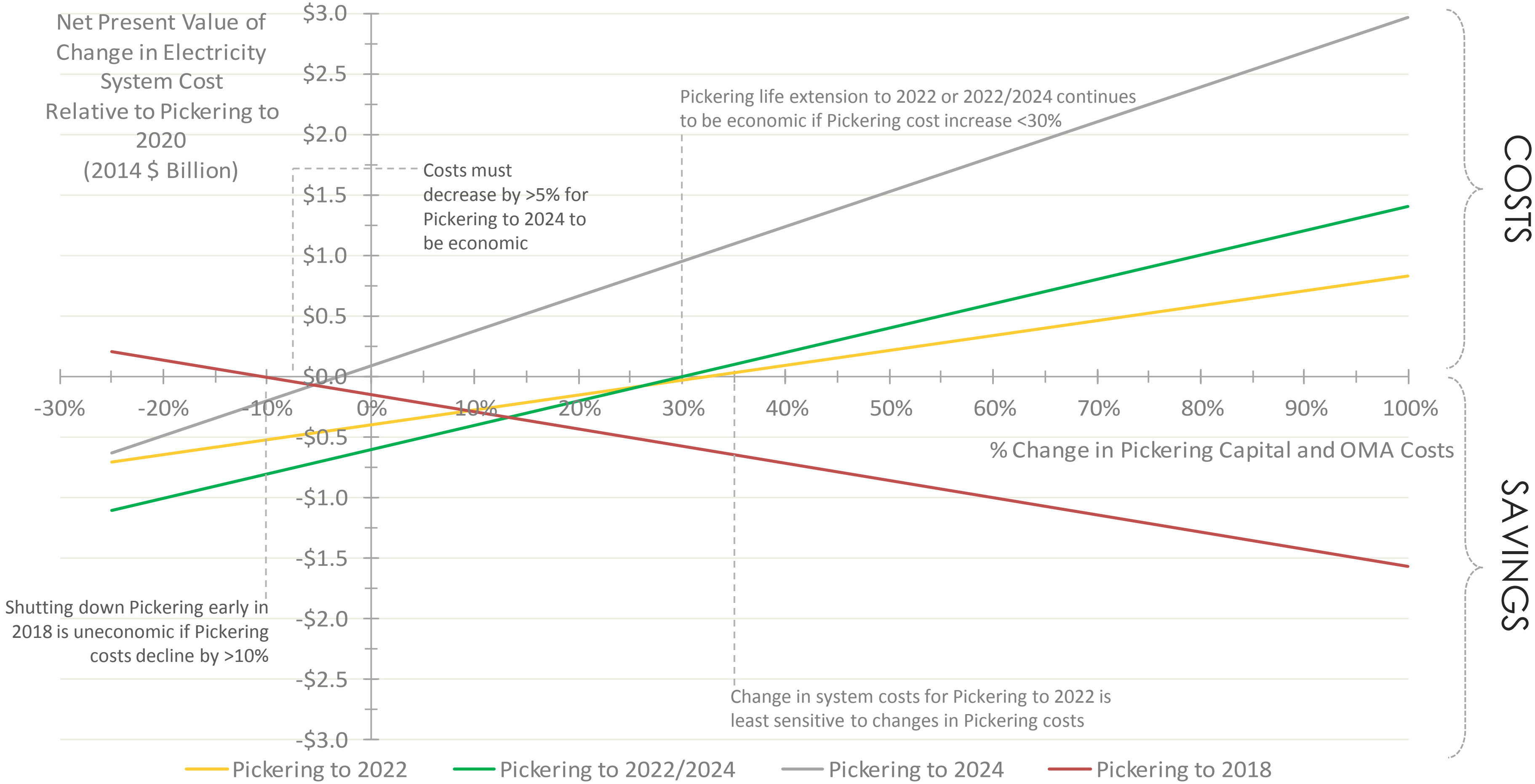
Positive sign (+) indicates system cost increase , negative sign (-) indicates cost decrease. NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral costs.

The economic proposition of extended Pickering operations is sensitive to Pickering capital and operating costs. As these costs increase, the value of extending Pickering beyond 2020 decreases, while the value of earlier shut down increases



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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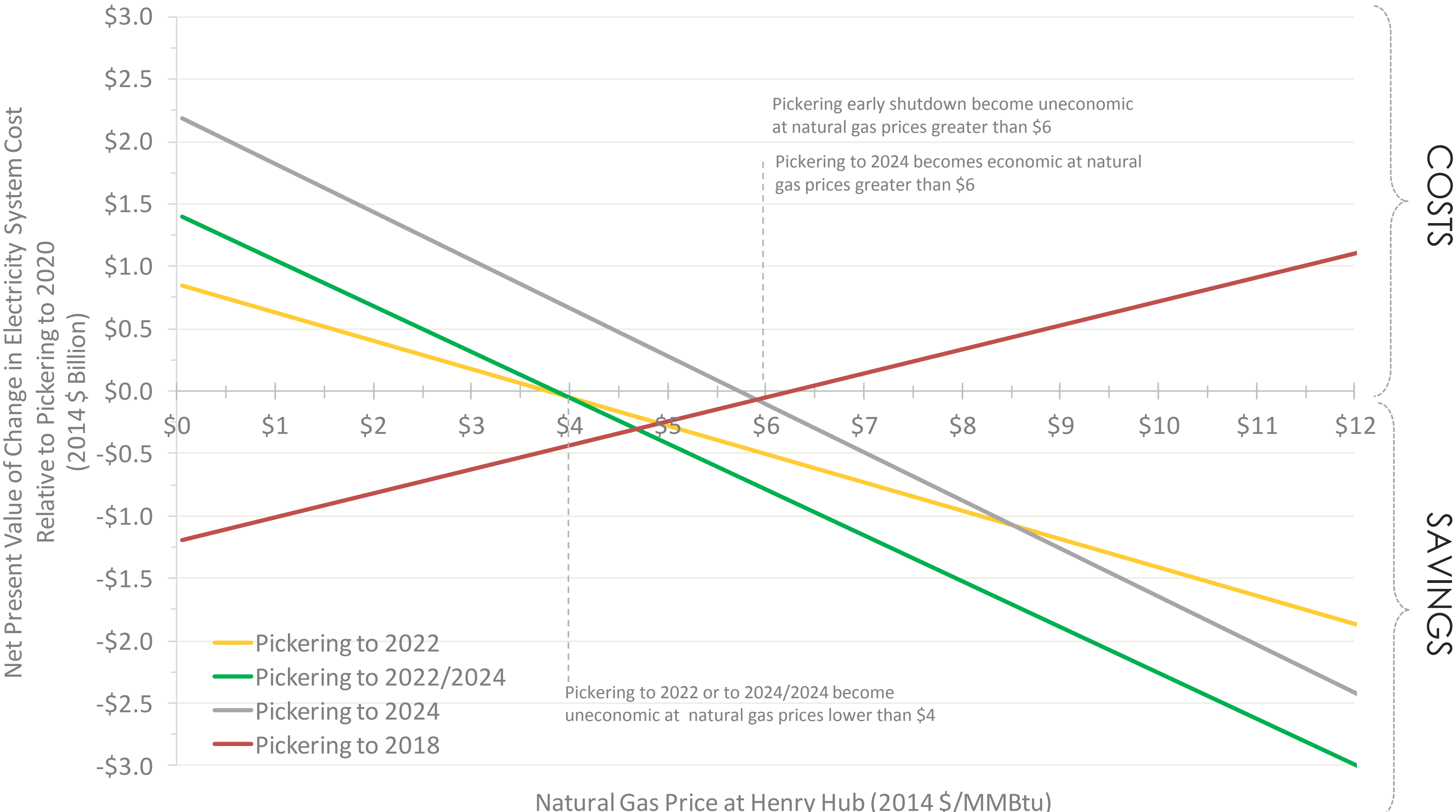
Benefits of extended Pickering operations are also sensitive to natural gas prices. Higher natural gas prices result in greater value from extended operations. Lower prices result in lower value.



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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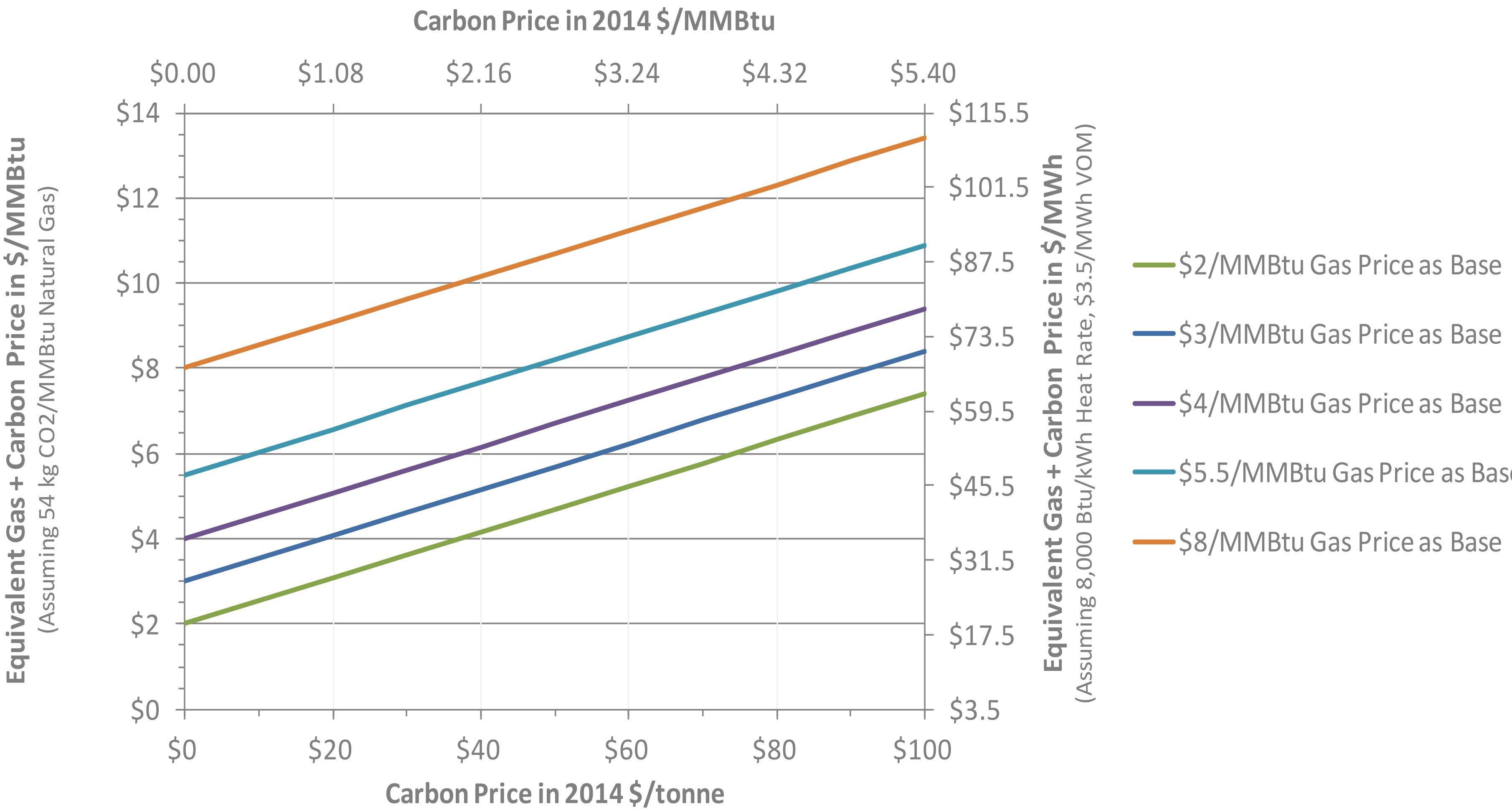
Carbon costs increase the effective cost of natural gas and can therefore impact the economic value of Pickering extended operations



- Example A: Gas at $5.25/MMBtu is equivalent to:
  - Gas at $3/MMBtu plus $42/tonne carbon
  - Gas at $4/MMBtu plus $23/tonne carbon
- Example B: Gas at $4.00/MMBtu is equivalent to:
  - Gas at $3/MMBtu plus ~$20/tonne carbon
  - Gas at $2/MMBtu plus ~$40/tonne carbon

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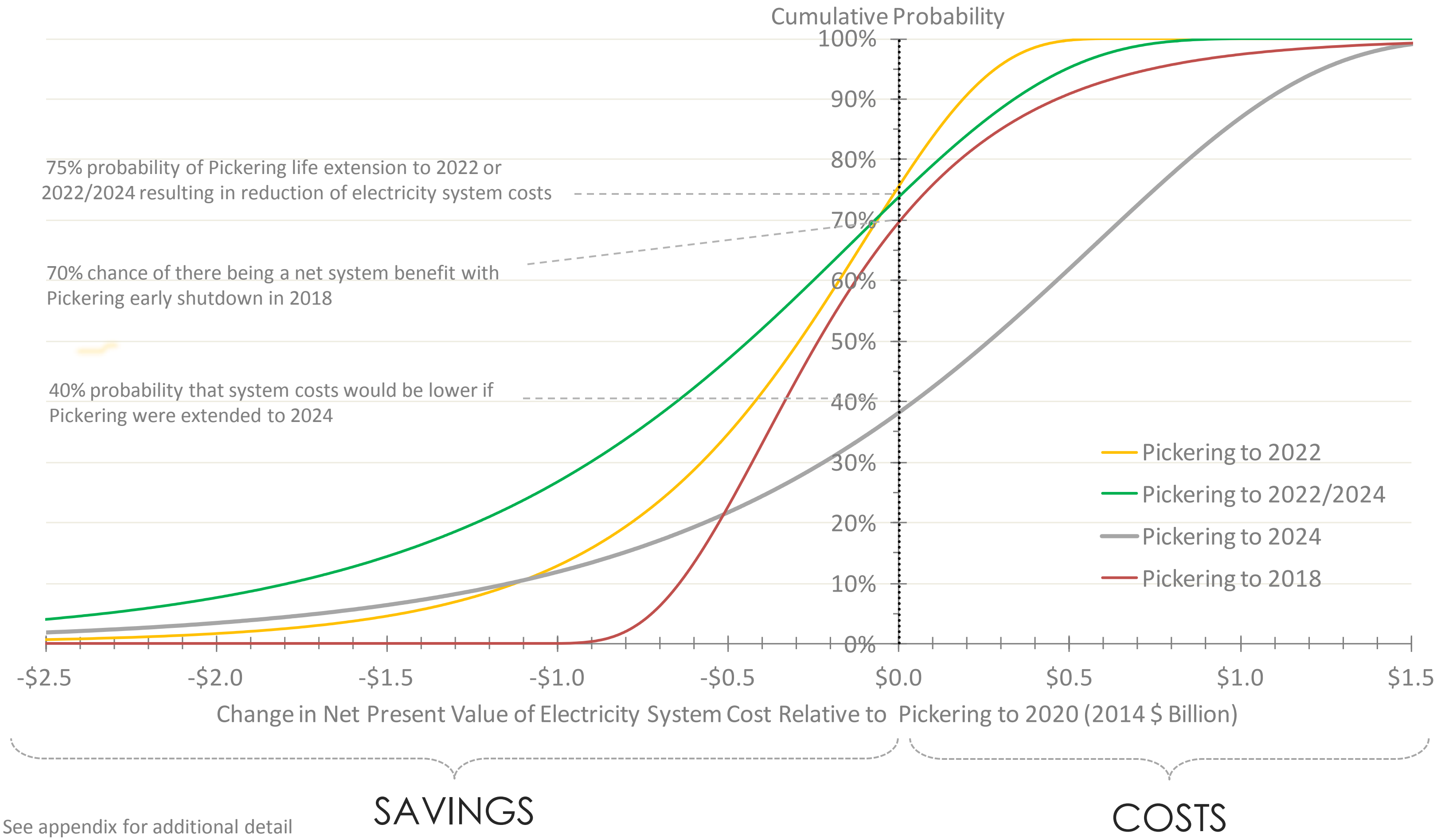
Consideration of the historical gas price distribution between 1997 and 2014 adds insight into the cumulative probability of change in electricity system cost as a function of natural gas price under various Pickering extension scenarios



See appendix for additional detail

System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.

Excludes transmission and decommissioning advancement/deferral costs.

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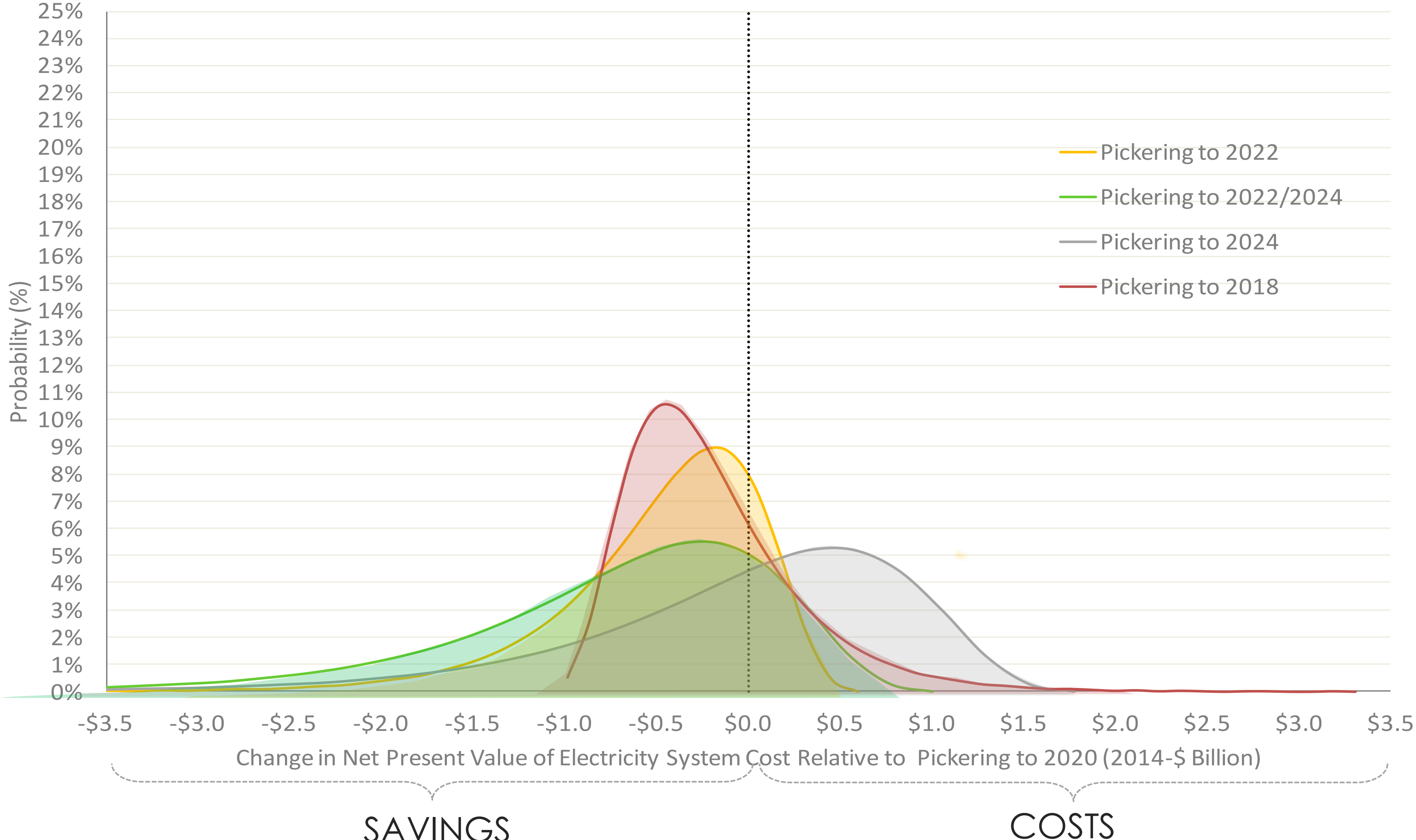
Viewing the same results as a set of NPV distributions illustrates the considerable overlap of possibilities among the scenarios as well as the variability within each distribution



System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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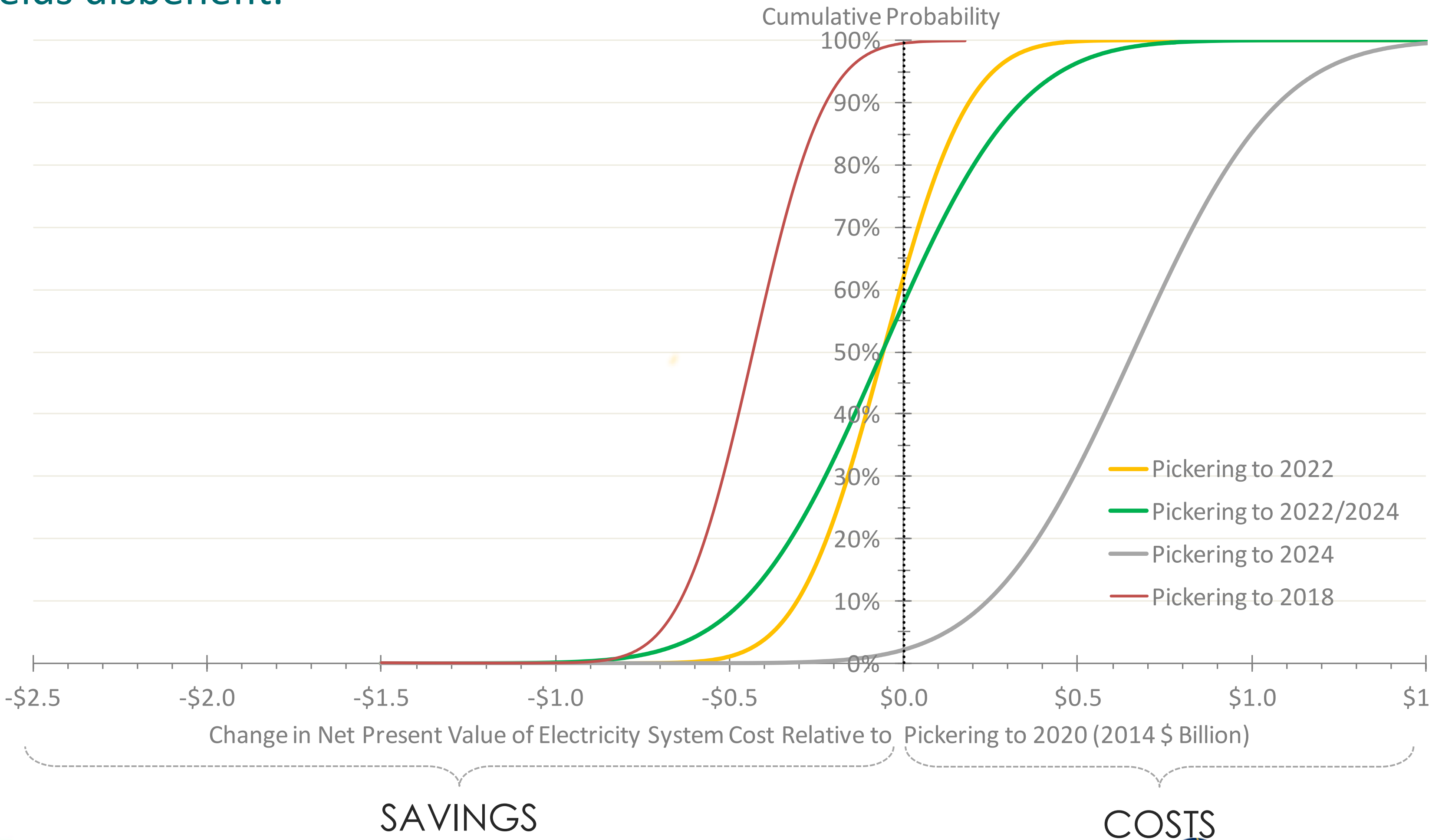
When only the distribution of natural gas prices in more recent years is considered (between 2010 and 2014), early shutdown poses the greatest probability for net cost reduction. Among the other scenarios, Pickering to 2022 and 2022/2024 continue to offer moderate probabilities for savings, while Pickering to 2024 largely yields disbenefit.



System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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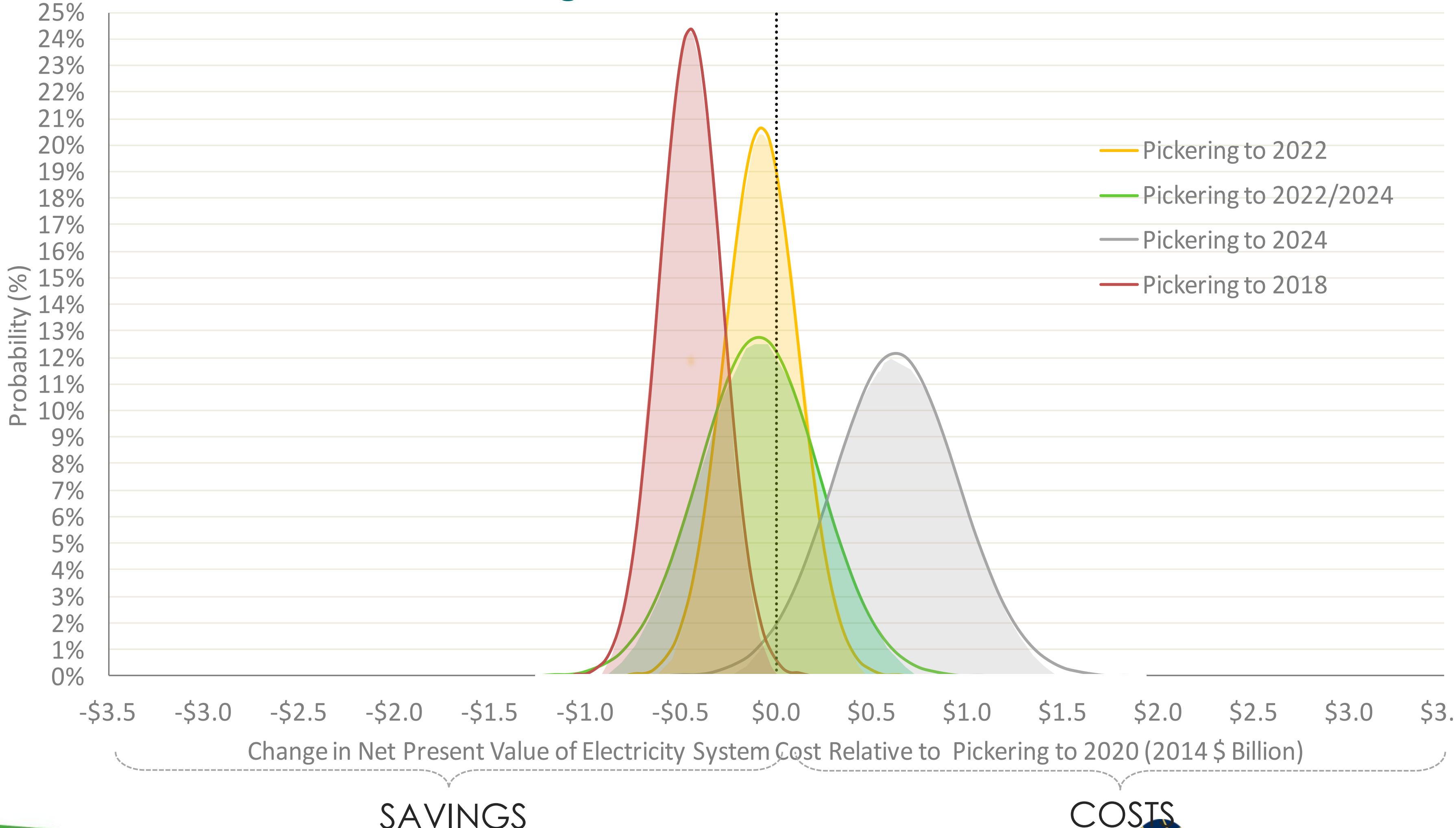
The mean natural gas price between 2010-2014 was lower than the mean between 1997 and 2014 and its distribution was more narrow. Considering this recent trend within the current analysis results in less overlap among scenario outcomes and a narrower range of likelihoods within each scenario.



System Cost Increase (+) / Decrease (-).
NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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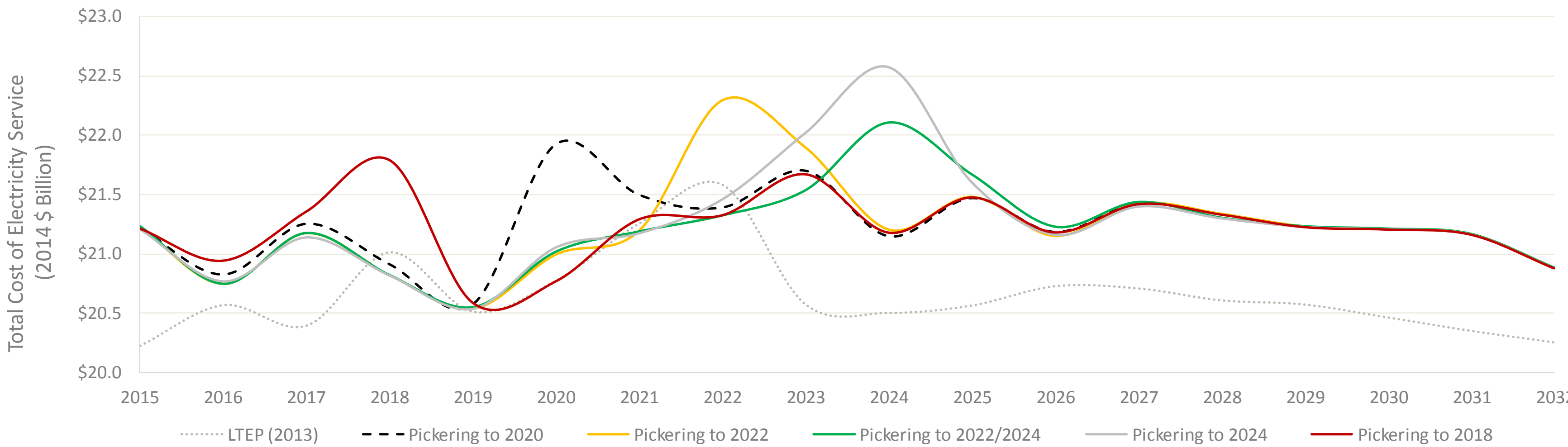
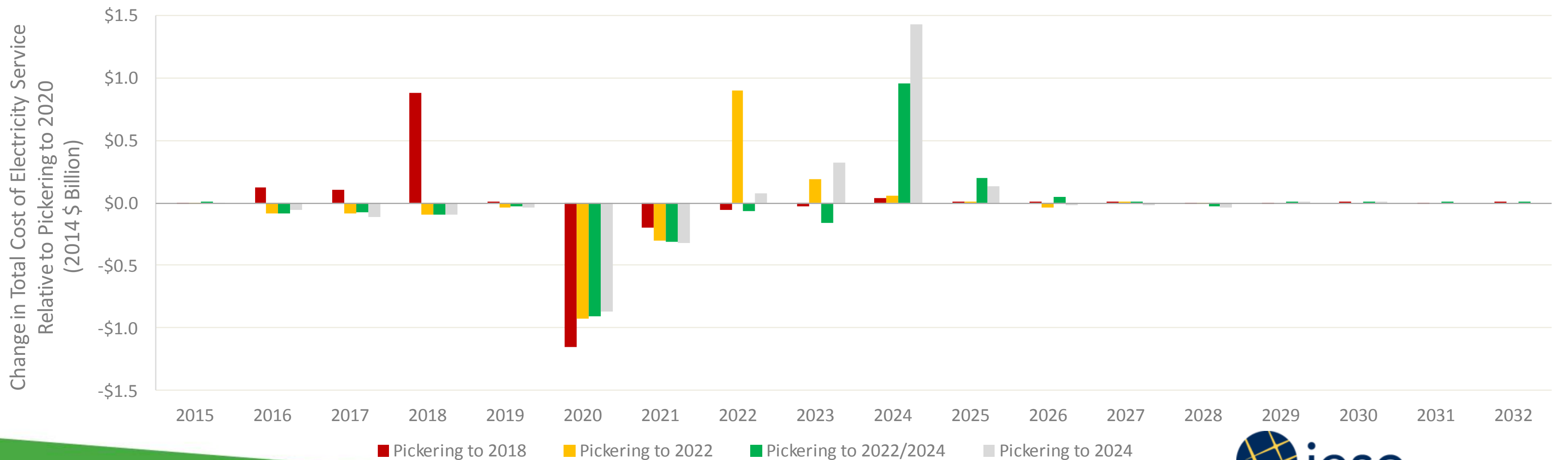
Extending Pickering operations beyond 2020 defers the increase in the total cost of electricity service that eventually takes place under each of the scenarios considered. Extending Pickering to 2022/2024 also minimizes the magnitude of the total cost increase.





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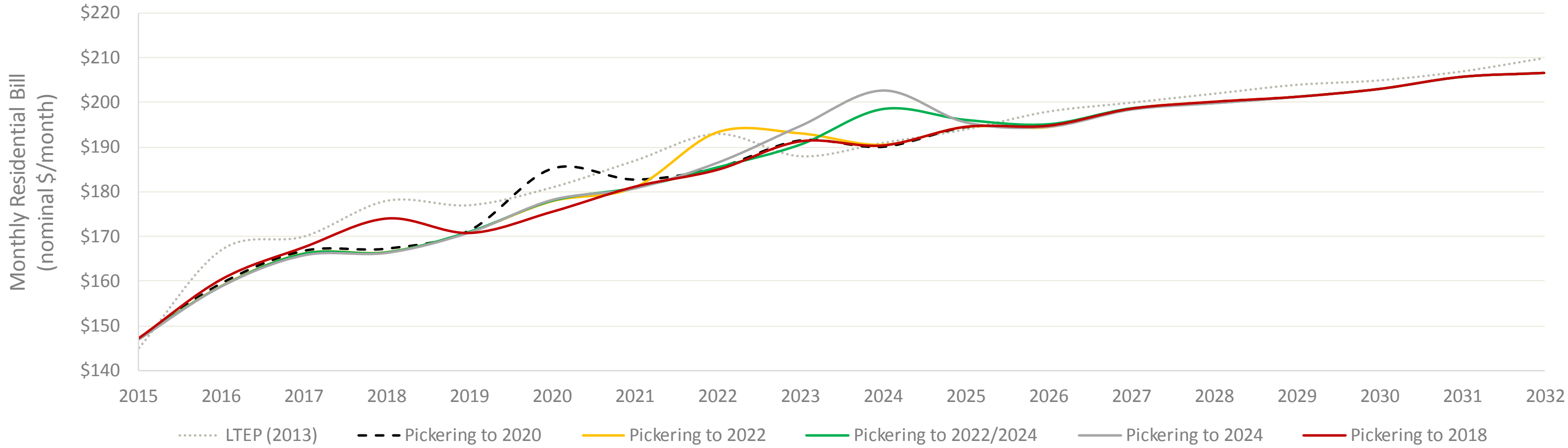
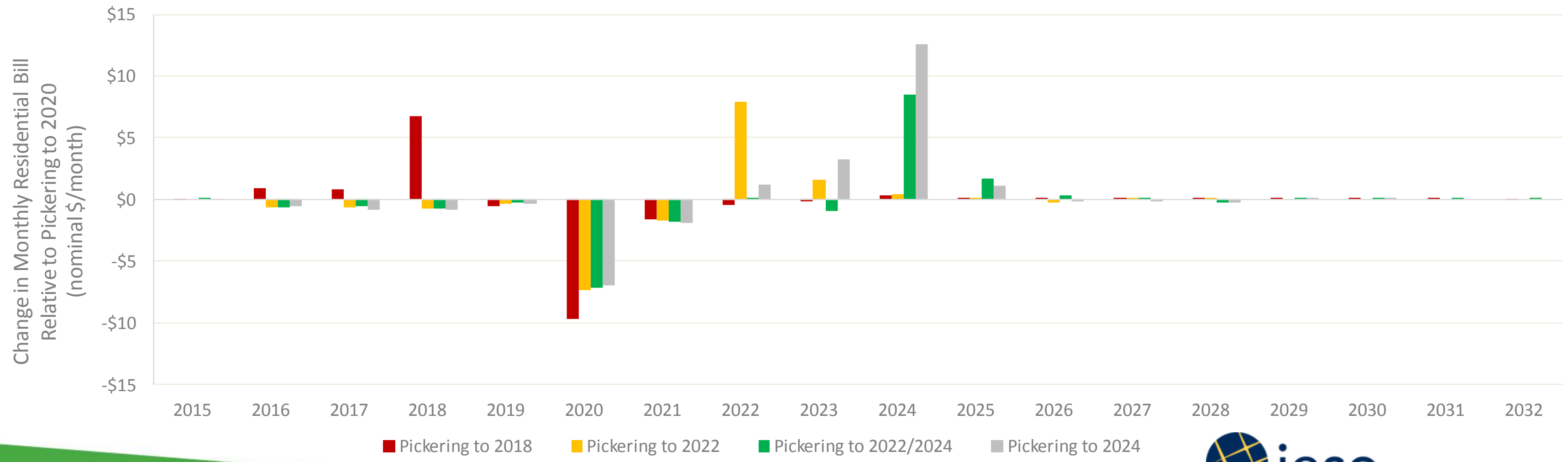
Excludes transmission and decommissioning advancement/deferral costs.

Extending Pickering operation beyond 2020 results in a reduction in residential electricity bills between 2016 and 2021 compared to the base case. Bills increase thereafter, the extent and timing of which varies with Pickering shut down timing. Early Pickering shutdown results in an increase in residential bills prior to 2020.





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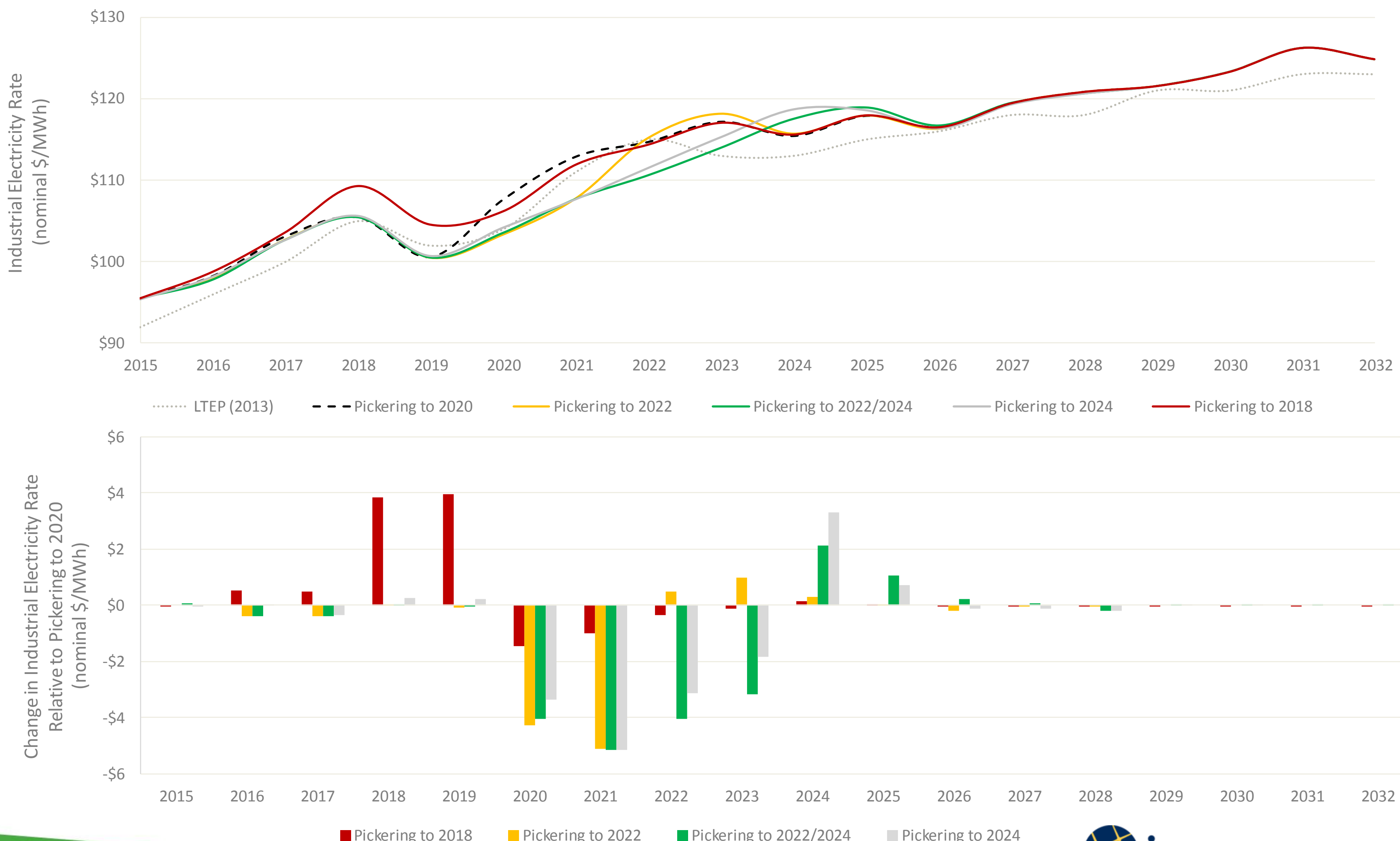
Assumes a typical residential consumption of 800 kWh/month. Excludes transmission and decommissioning advancement/deferral costs.

Similarly, extending Pickering life beyond 2020 results in a reduction in industrial electricity rates between 2016-2023. Early shutdown increases industrial rates prior to 2020, but decreases rates thereafter.



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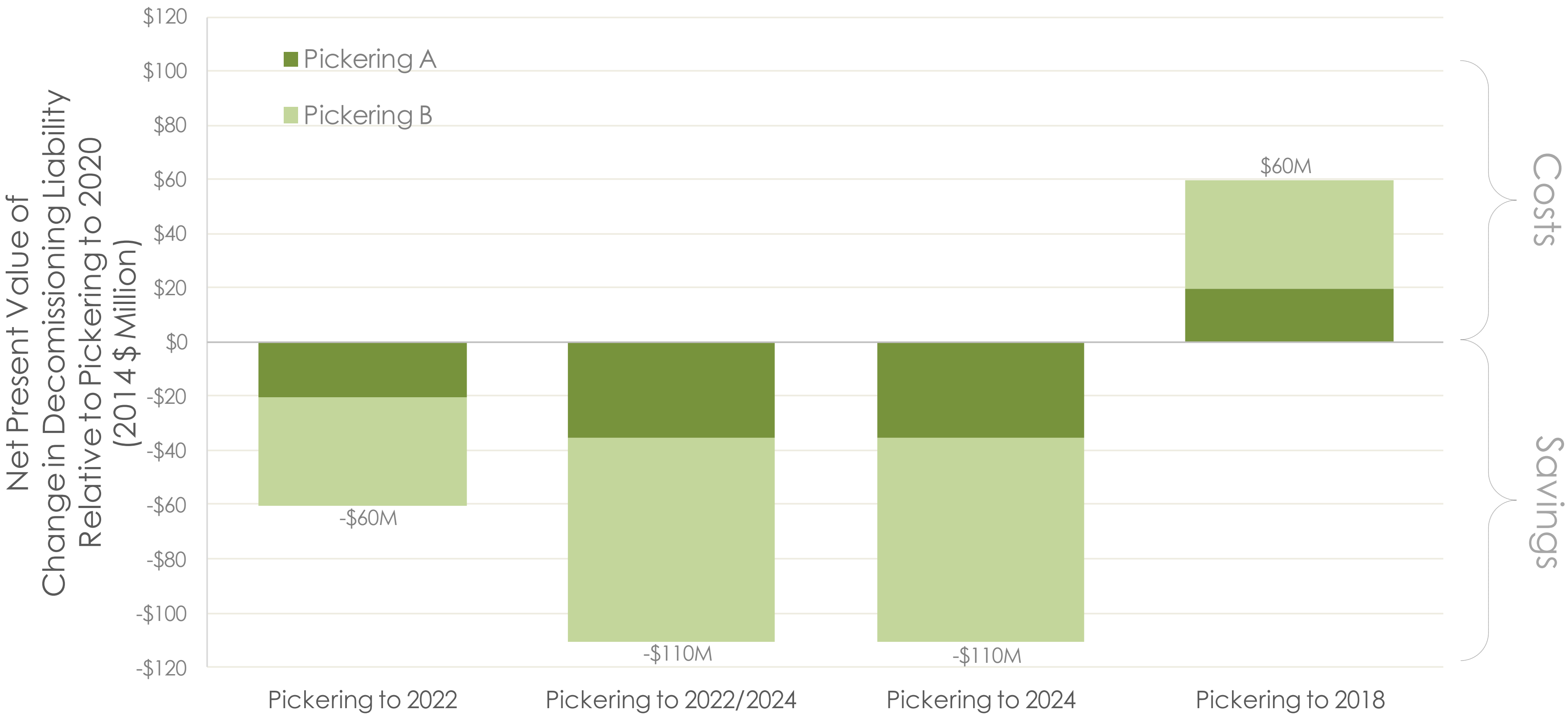
Assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor. Excludes transmission and decommissioning advancement/deferral costs.

Other cost considerations: Pickering decommissioning liability is affected by shutdown timing. As Pickering life is extended, decommissioning expenditures are deferred. Deferral results in a time value savings in decommissioning liability.



NPV evaluated at a 4% real discount rate.

Transmission considerations: extended Pickering operations could defer the timing of transmission needs and lead to deferral-related cost savings

- The availability of Pickering has an impact on transmission flows into and out of the GTA
- The transmission plan for East GTA includes the construction of a new 500/230 kV transformer station in Clarington to maintain supply reliability to Durham Region following Pickering shutdown and to provide a secure electricity supply in this high growth area
  - Hydro One is currently constructing the new transformer station ("Clarington TS") and remains on schedule for an in-service of 2018
  - The IESO (former OPA) identified the need for the project in 2005 and requested the transmitter to initiate the project in 2011, with required approvals support
- In evaluating the various Pickering scenarios, it is assumed the in-service of Clarington TS remains unchanged and that the station would be in-service under the scenario of early Pickering shutdown (Pickering to end of 2018)
- The IESO has also identified a need for additional bulk transmission reinforcement in West GTA, following the shutdown of Pickering
  - The project includes construction of a new 500/230 kV autotransformer in the Milton area. The transmitter has provided a planning level capital cost estimate of $200M for the facility. The project would be sited within an existing switchyard. The IESO is currently targeting an in-service of 2020, coinciding with the current plan for Pickering shutdown in 2020
  - Advancing the in-service of this station to coincide with a Pickering shutdown at the end of 2018 could cost an additional $13M. However, deferring the in-service to 2022 through 2024 could result in $12-$23M in time value savings (cost expressed as NPV in 2014 $)
  - In addition, given the 3-year lead time required for in-service of the new station, there is both regulatory and construction risk that could potentially delay the in-service of the new TS (by an order of 1-2 years) thus requiring the inclusion of some interim solutions, such as forced operation of peaking gas generation, for a short period of time preceding station in-service

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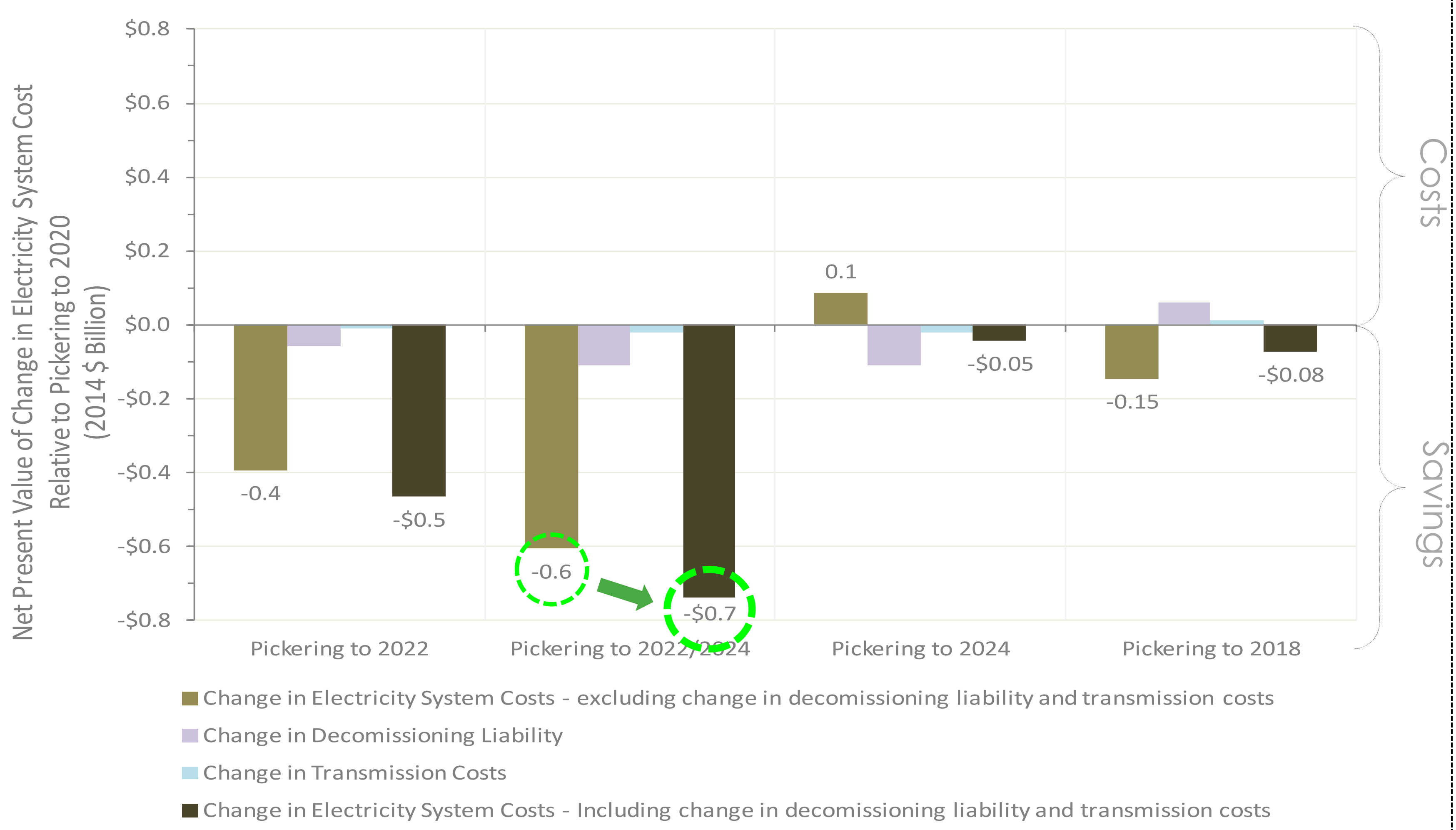
After factoring in time value effects of deferring or advancing decommissioning and transmission, the benefit of extending Pickering operations marginally increases



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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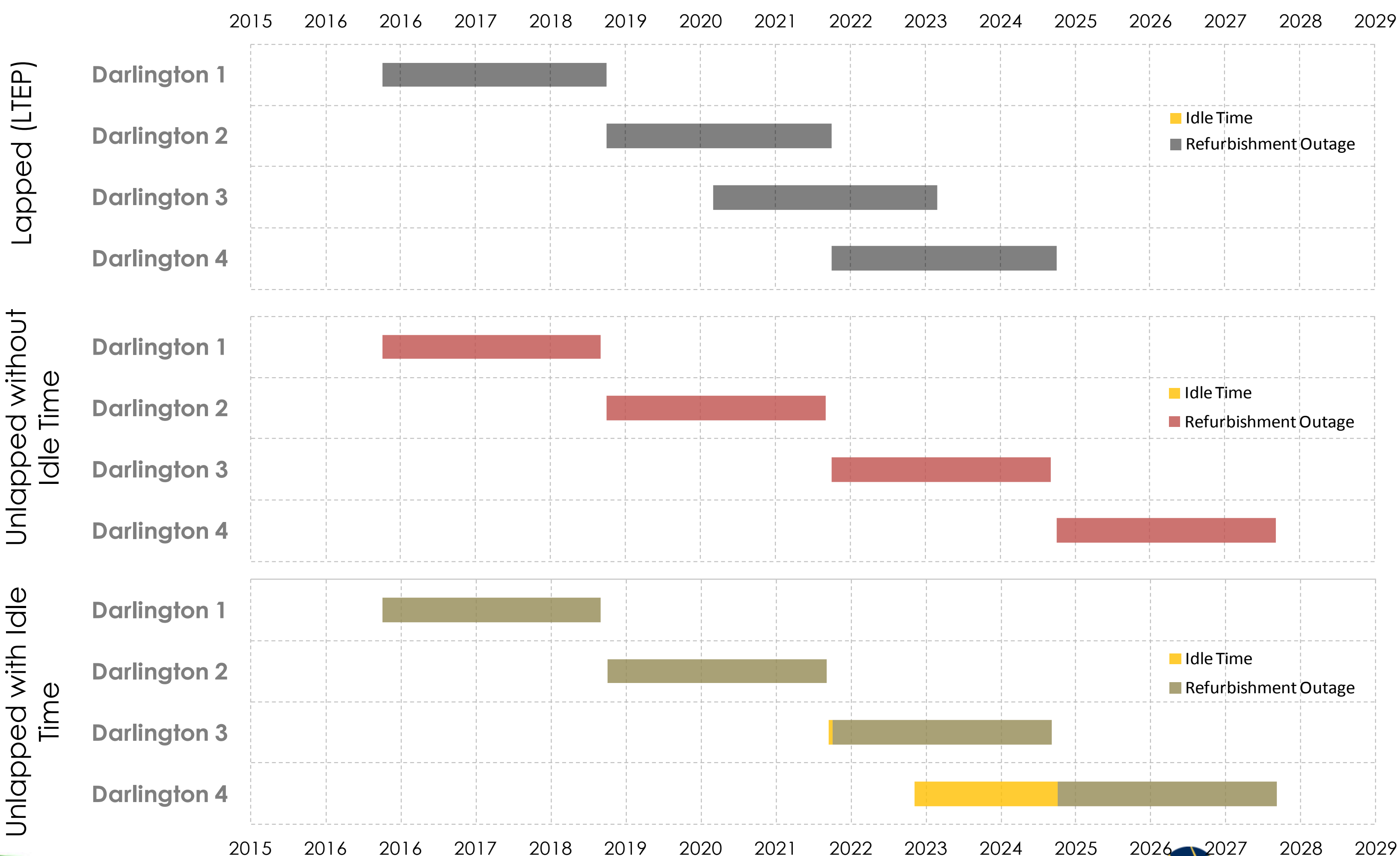
Impact of Alternative Darlington Refurbishment Schedules on the Value of Pickering Life Extension

Pickering extension options were assessed against three Darlington refurbishment sequences. One sequence features some overlap among Darlington refurbishments. Two sequences feature no overlap - in sequences without overlap, one relies on idle time at Darlington units 3 and 4 to attain the required service life.



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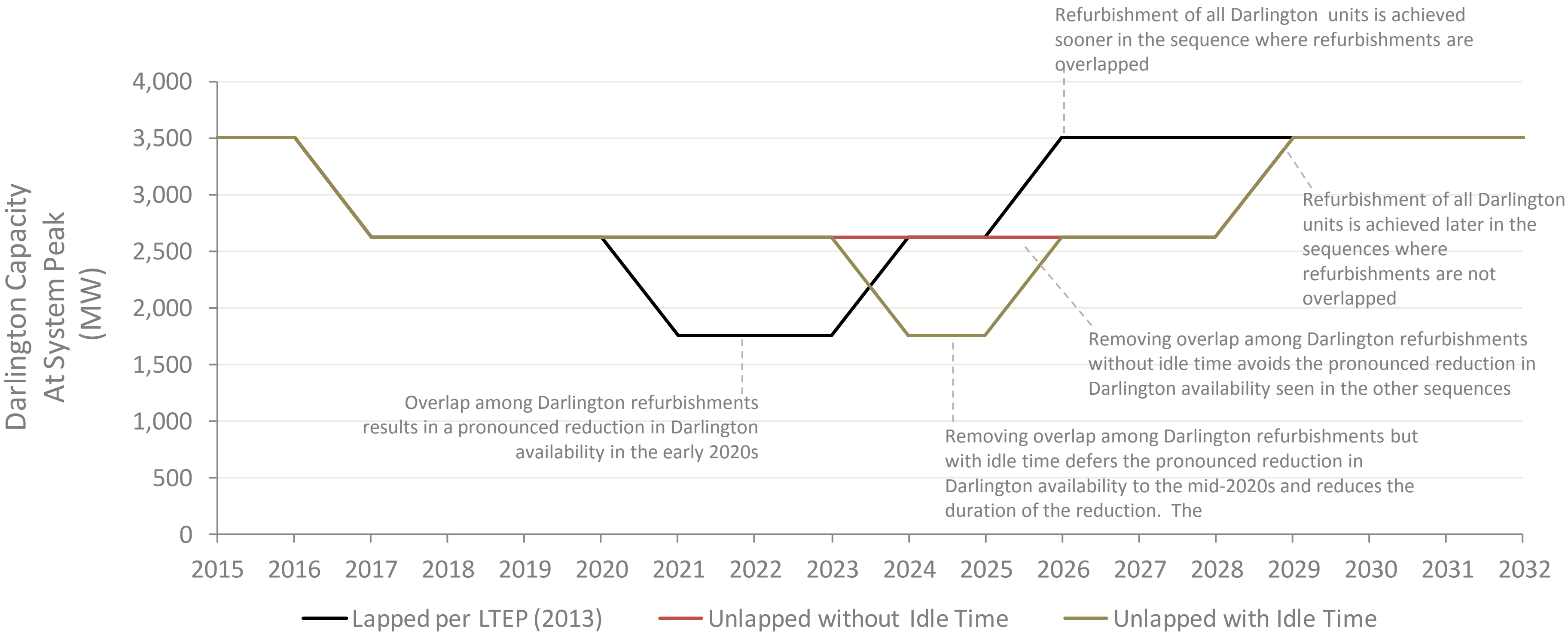
Removing overlap (a.k.a. “unlapping”) among Darlington refurbishment outages increases available supply from Darlington to 2023, but defers the completion of the full Darlington refurbishment to the late 2020s



- OPG’s current refurbishment schedule for Darlington sees refurbishments commencing in 2016 with an overlapping of refurbishment outages between units D2 and D3 as well as between units D3 and D4 . This schedule is per OPG’s current business plan and is consistent with that assumed in LTEP (2013)
- The alternative refurbishment schedules explored eliminate overlapping refurbishment outages across Darlington units
  - In the case “without idle time”, it is assumed all units are operable up to their scheduled refurbishment dates
  - In the case “with idle time”, where unit end of life is prior to refurbishment start, units are shutdown early and are unavailable until after refurbishment is complete

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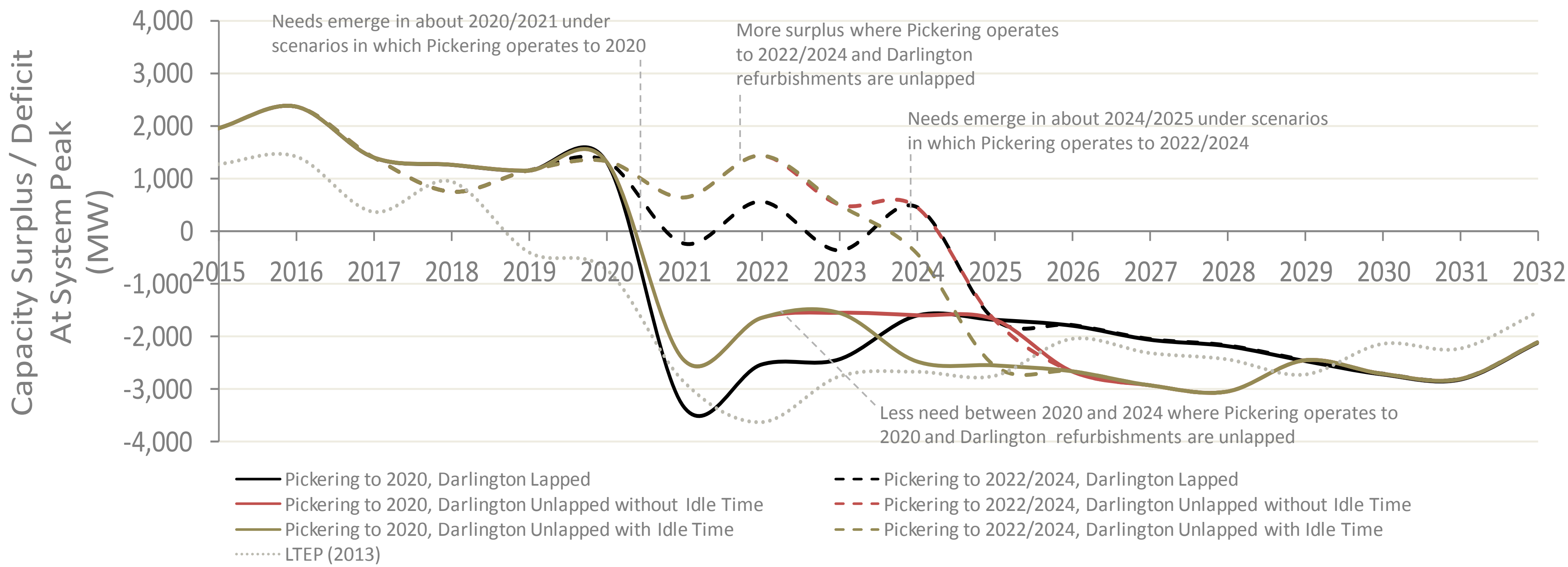
Removing overlap among Darlington refurbishments would not significantly change the timing of projected capacity needs under reference Pickering and Pickering extended operations scenarios. Where Pickering is shut down in 2020, however, unlapping Darlington would reduce the amount of additional resources needed between 2020 and 2024. Where Pickering operates to 2022/2024, unlapping Darlington would increases surpluses.



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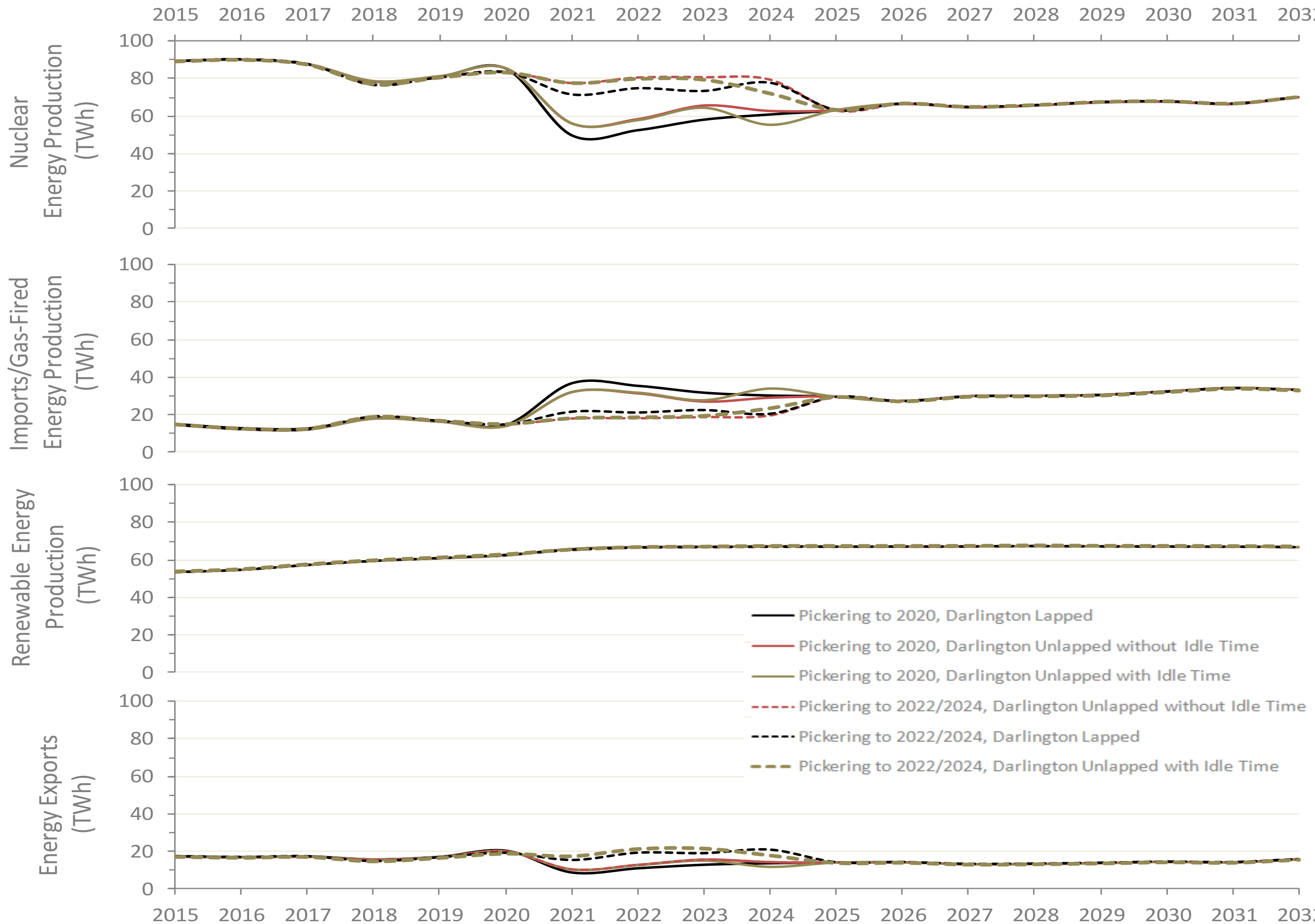
Unlapped Darlington refurbishments result in greater Darlington availability between 2020 and 2024 and therefore result in greater energy production from Darlington within the same period. All of this, in turn, leads to less gas-fired production and imports and more exports.



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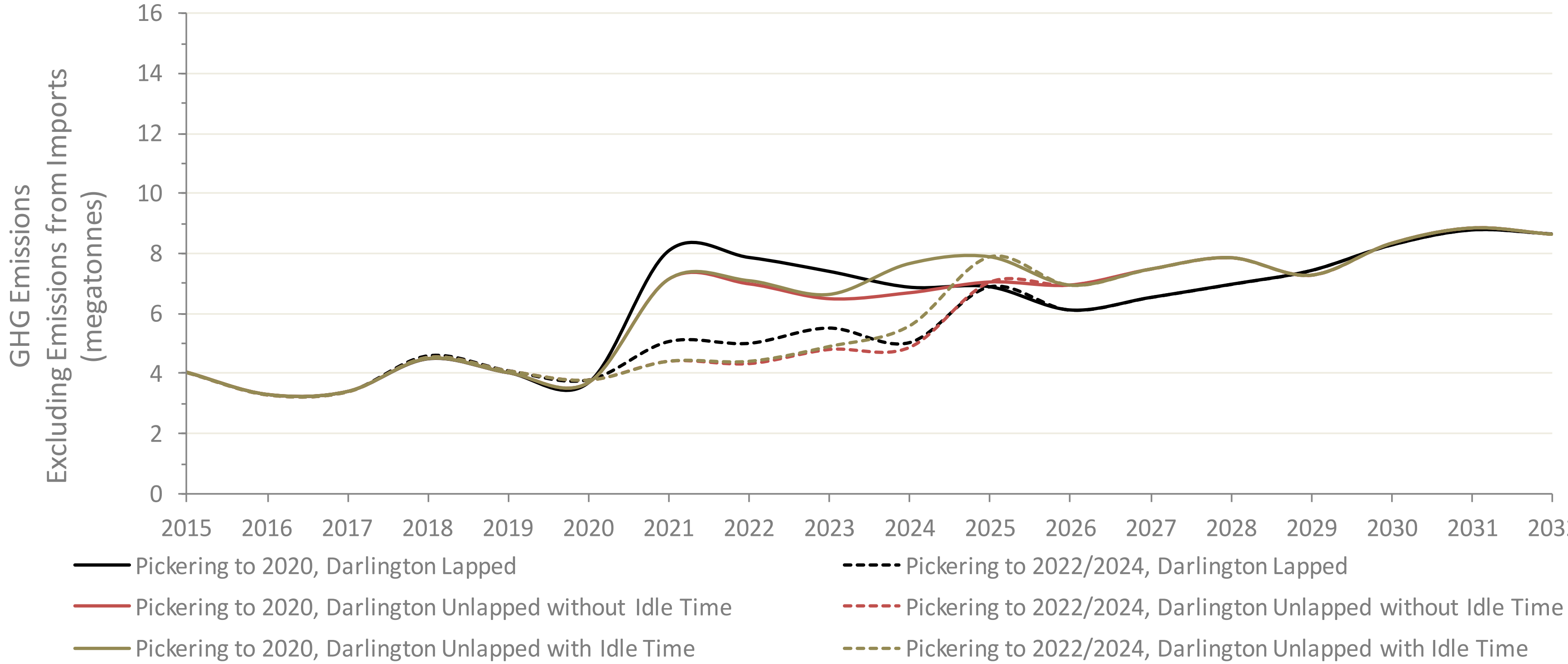
Unlapping Darlington refurbishments leads to lower greenhouse gas emissions in the early 2020s and higher greenhouse gas emissions in the late 2020s



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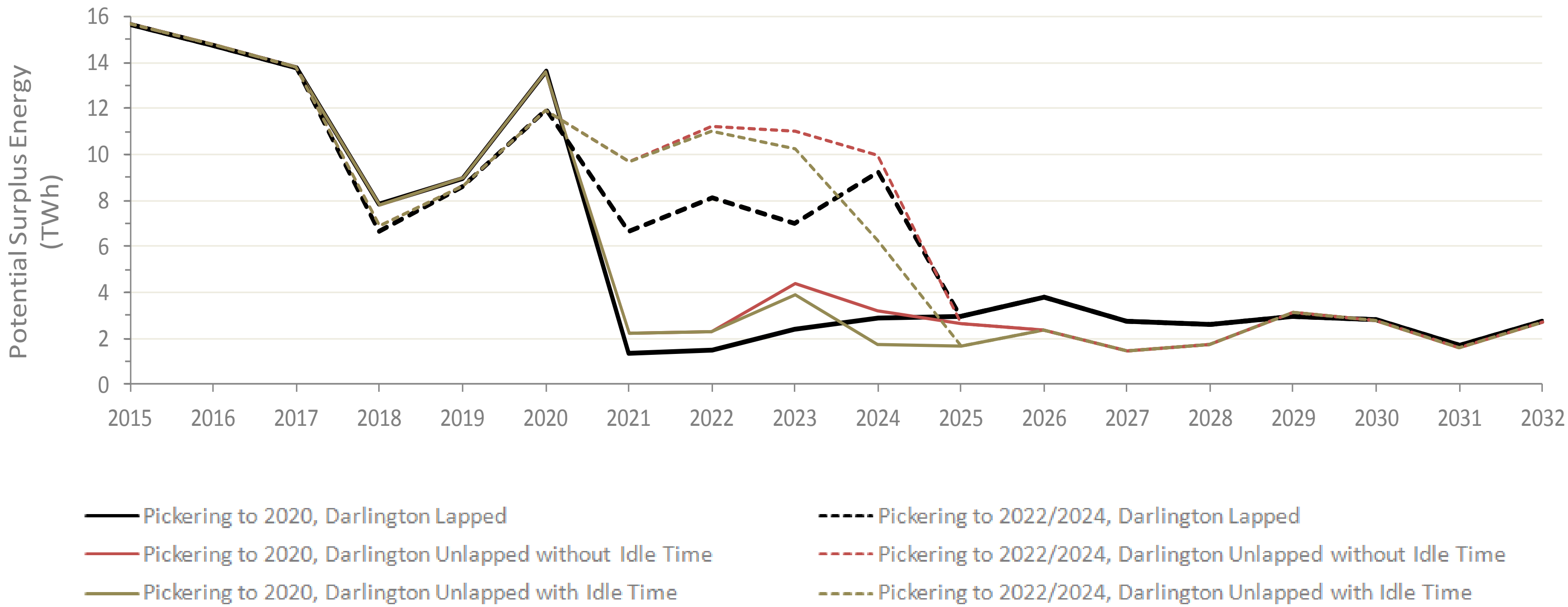
Unlapping Darlington refurbishments tends to increase potential surplus energy in the early-to-mid 2020s, but reduces potential surplus energy in the late 2020s



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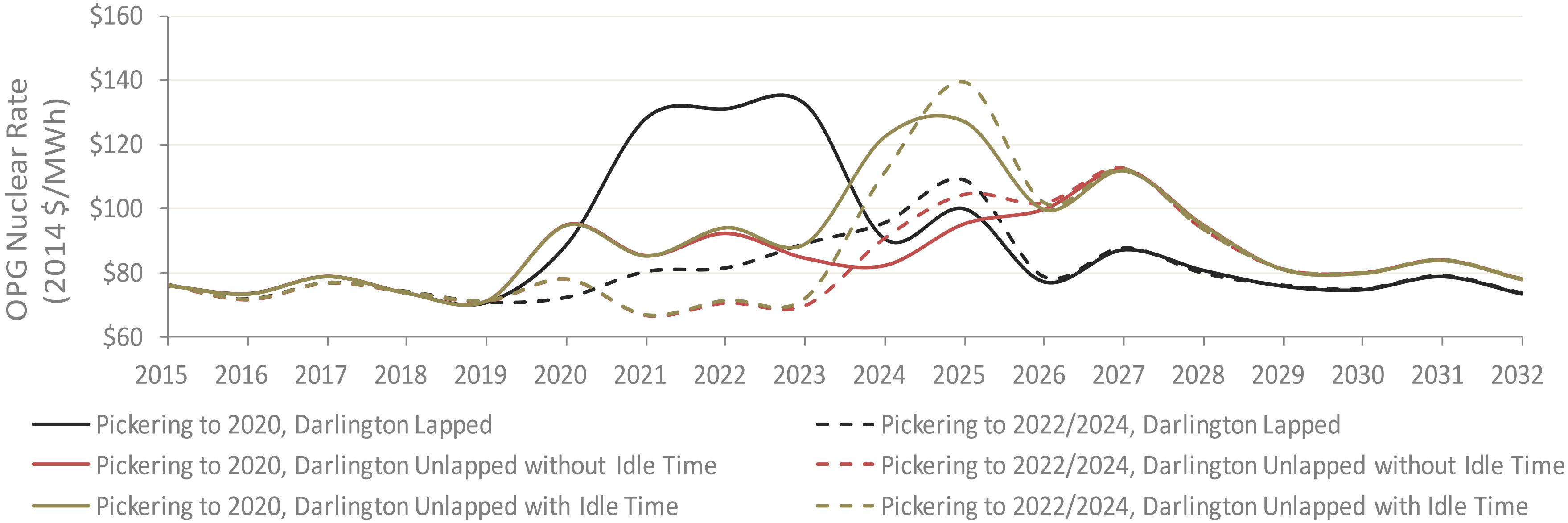
Unlapping Darlington reduces OPG's nuclear rates between 2020 and 2024 as a result of higher annual Darlington production. Rates are further reduced by extending Pickering operation.



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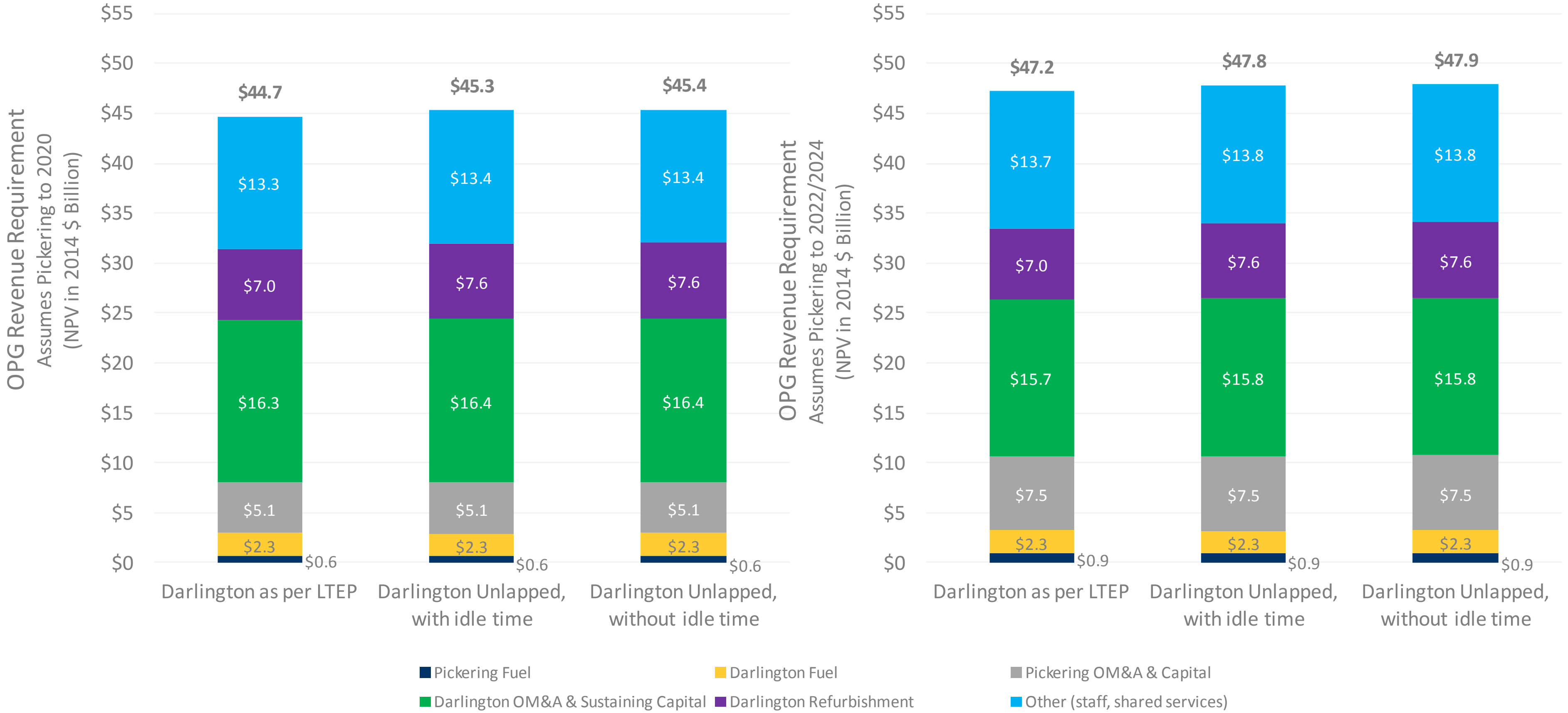
Unlapping Darlington increases OPG's nuclear costs by $0.6 (with idle time) to $0.7B (without idle time) (NPV 2014 $). This is driven by increase in refurbishment capital cost due to longer project schedule (extension of support costs, potential inefficiencies in crew transitions, etc). OPG has indicated that changes to Darlington's current "lapped" refurbishment schedule may also introduce additional project risks.



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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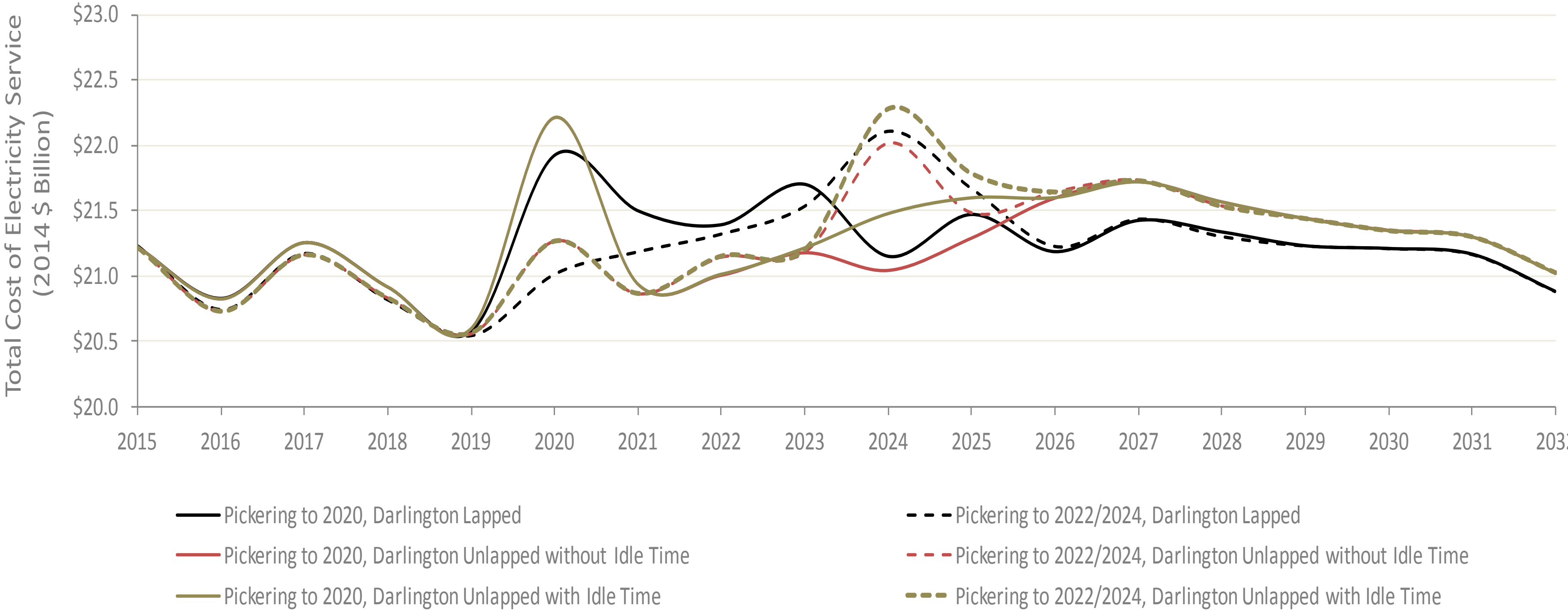
The effect on the total annual cost of electricity service of unlapping refurbishment outages at Darlington varies over time



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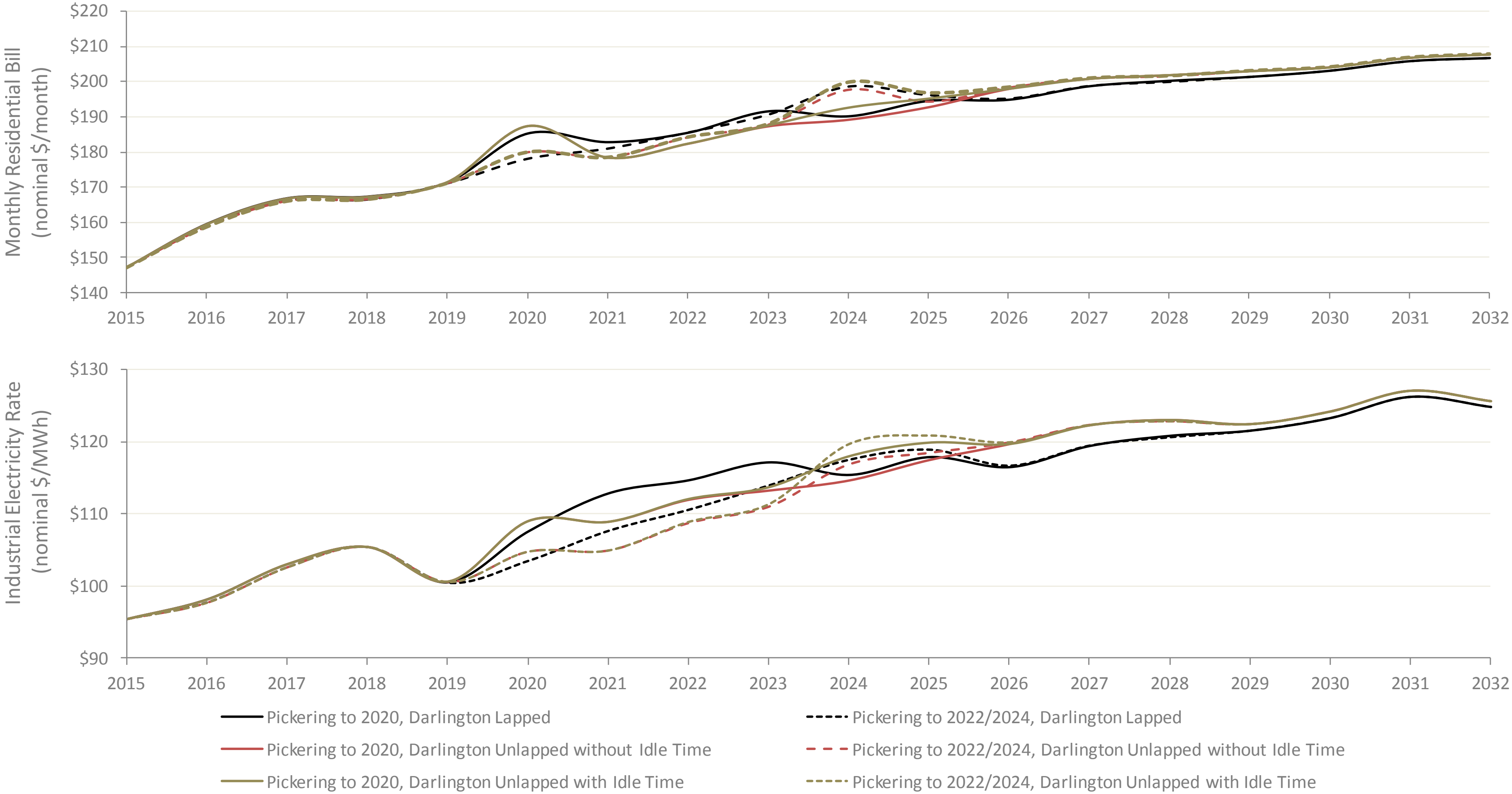
Similar trends are evident when it comes to the impact of unlapped Darlington refurbishment on residential bills and industrial rates



Residential bill assumes a typical residential consumption of 800 kWh/month. Industrial rate assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor . Excludes transmission and decommissioning advancement/deferral costs.

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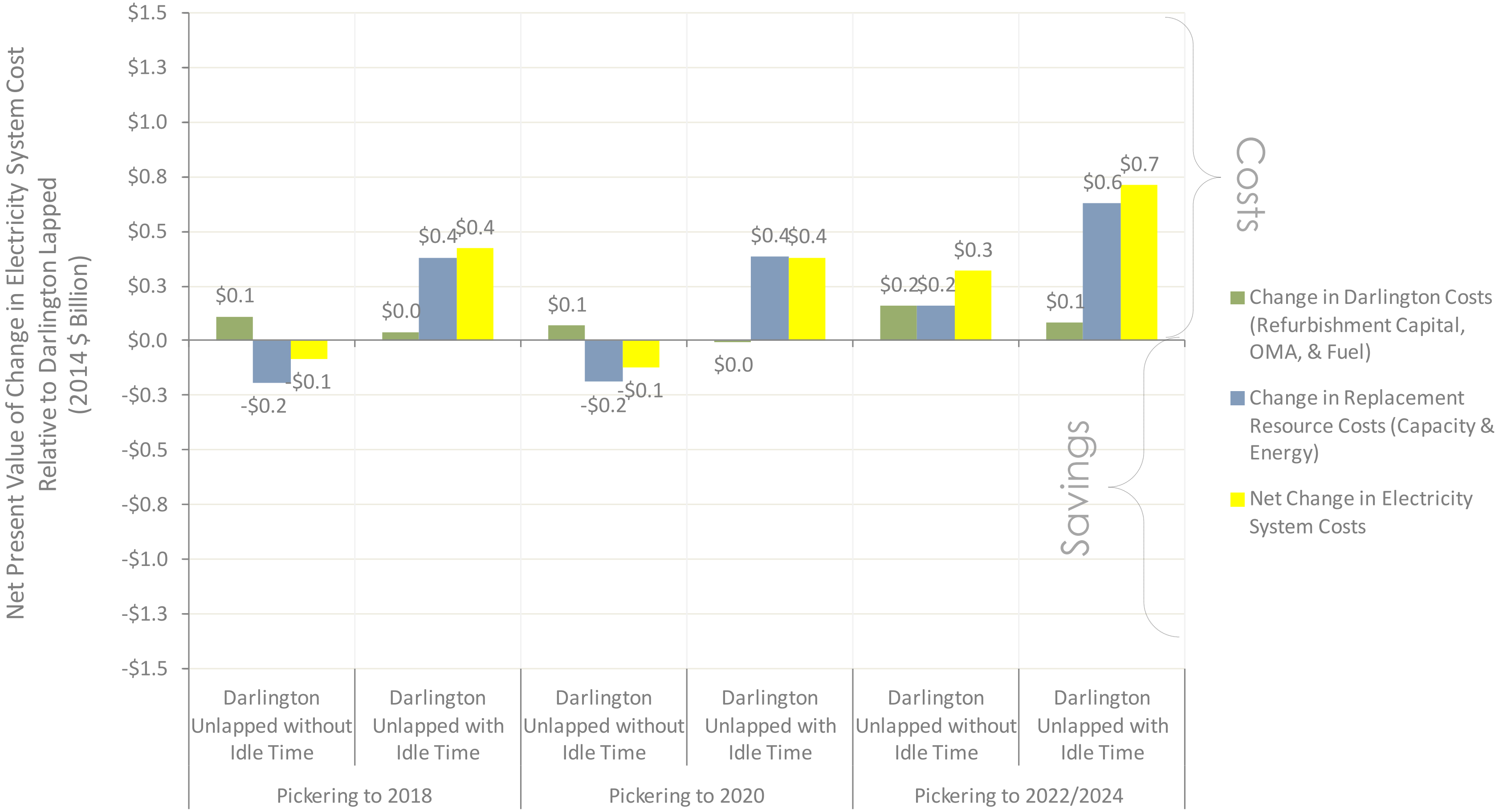
The value of unlapping Darlington refurbishments varies by Pickering extension scenario. Unlapping Darlington increases net costs under most Pickering scenarios assessed, unlapping with idle time increases costs more. Where benefits of unlapping Darlington are seen, they are marginal and are premised on achieving the unlapped sequence without idle time.



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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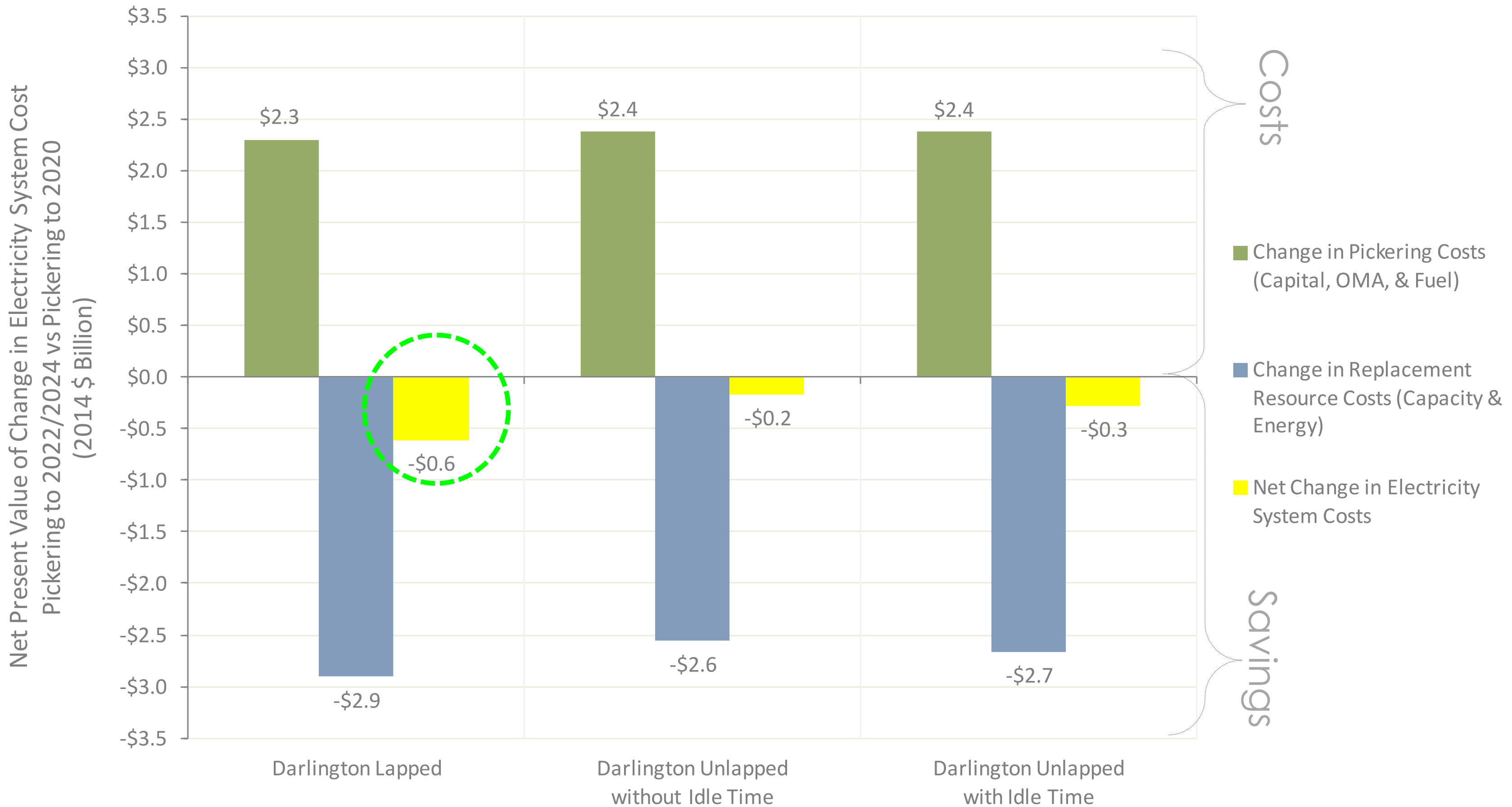
Reciprocally, the value of extended Pickering operations varies by Darlington scenario. Broadly, unlapping Darlington reduces the value of extended Pickering operations: the two compete for the same bandwidth. The example below shows the effects of unlapping Darlington on the net benefits of extended Pickering operation to 2022/2024: net benefits diminish as Darlington units are unlapped.



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate. Excludes transmission and decommissioning advancement/deferral costs.

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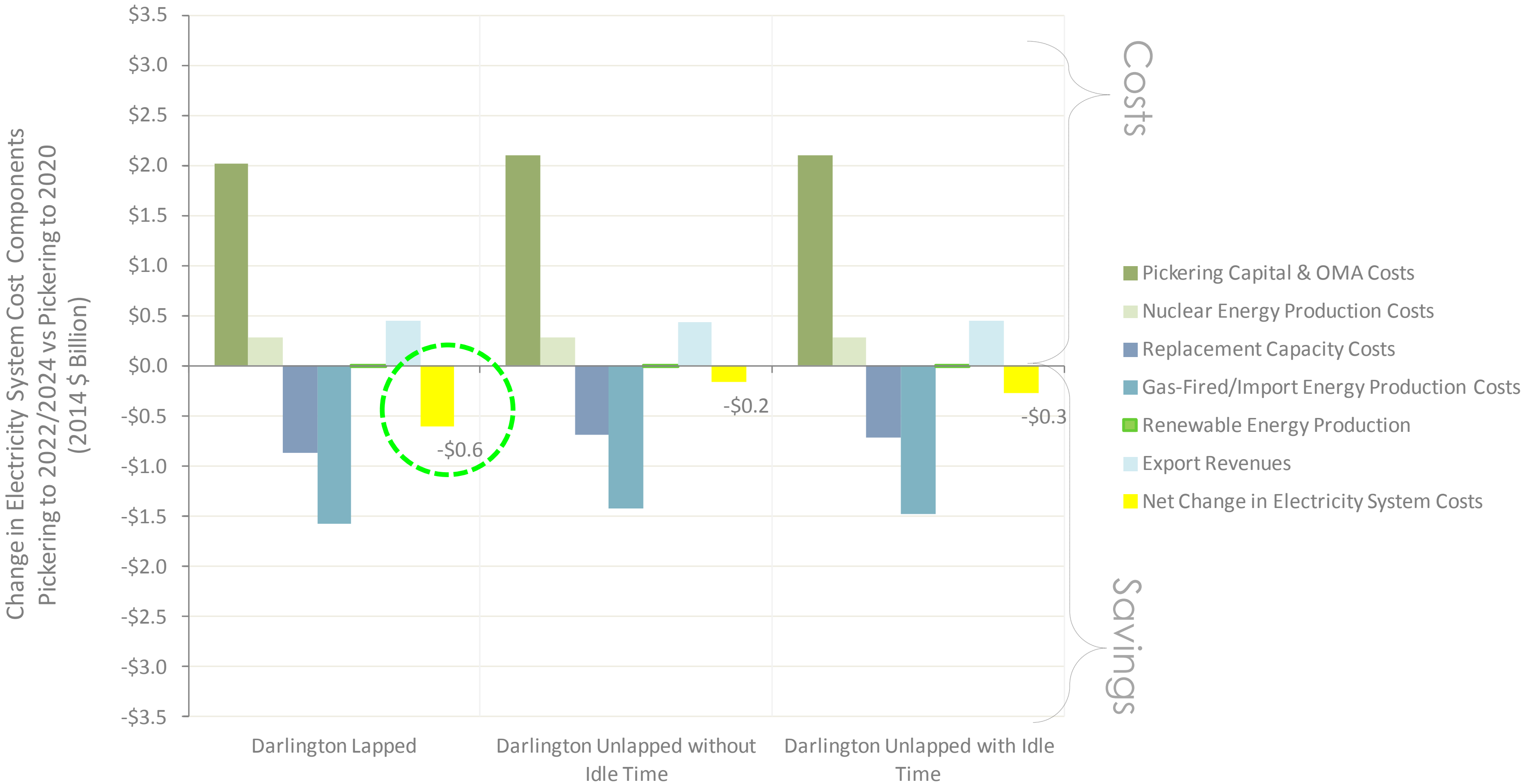
Expanding on the previous illustration: although Pickering costs remain relatively unchanged across Darlington scenarios, unlapping Darlington in conjunction with extended Pickering operation reduces the amount of cost savings that extended Pickering operation achieves from avoided replacement capacity and avoided energy production from gas-fired resources and imports



System Cost Increase (+) / Decrease (-). NPV evaluated at a 4% real discount rate.
Excludes transmission and decommissioning advancement/deferral costs.

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Cost summary: extended Pickering operations to 2022/2024 has the most value among options considered. Unlapping Darlington reduces the value of extended Pickering operations.

Pickering Scenarios	Darlington Scenarios: Lapped	Darlington Scenarios: Unlapped Yes Idle Time	Darlington Scenarios: Unlapped No Idle Time
2018	-$0.1	+$0.3	-$0.2
2020	BASE	+$0.4	-$0.1
2022	-$0.4	Not Assessed	
2022/2024	**-$0.6**	+$0.1	-$0.3
2024	+$0.1	Not Assessed	

= Net Cost
= Net Benefit

Table shows NPV from 2015-2032 in billions of 2014 dollars compared to the base case

Emissions summary: extending Pickering operations to 2022/2024 or 2024 results in the lowest cumulative emissions between 2015 and 2032 among options considered.

Darlington Scenarios

Pickering Scenarios	Lapped	Unlapped Yes Idle Time	Unlapped No Idle Time
2018	+4.8MT	+6.6MT	+4.5MT
2020	BASE	+1.7MT	-0.3MT
2022	-5.8MT	Not Assessed	
2022/2024	**-9.3MT**	-7.2MT	-8.9MT
2024	**-9.9MT**	Not Assessed	

= Net Cost

= Net Benefit

Table shows total change in CO_2 emissions between 2015-2032 in megatonnes (MT) compared to the base case

APPENDIX

- Overview of methodology
- Assumptions
- Data tables

Overview of approach and of reference supply mix assumptions

- Between December 2014 and January 2015, OPG provided the IESO with technical and economic information on various Pickering life extension scenarios and Darlington refurbishment sequences
- The IESO has evaluated the impact Pickering extension scenarios from a number of perspectives, including capacity needs and timing, energy production, emissions, surplus energy, total cost of electricity service and ratepayer costs
- Each Pickering life extension scenario is compared to a "reference case". This reference case is an updated version of the LTEP (2013), reflecting the following recent changes:
  - Pickering units operate to the end of 2020 per OPG's current business plan
  - Bruce refurbishment per July/August 2014 schedule from Bruce Power (note Darlington unchanged)
  - Expanded ICI (includes customer 3-5 MW are part of high 5)
  - Ontario Electricity Support Program (effective 2016 – an additional $170M/y $2012) which will only be paid out to low income residential customers after Ontario Clean Energy Benefit expires)
  - IEI Stream 3 (expansion – also assumed to allow Stream 2 customers to carry on with is program until 2024)
  - Early Removal of DRC for residential customers (no DRC for residential bills after 2015)
  - Update of Thunder Bay
  - Included cost impact of Storage (2017 to 2019)
  - Updated CHPSOP 2.0
  - Updated NUGs recontracted
  - Updated OPG rates as per December 3, 2014
- The reference case demand, supply, and cost assumptions are consistent with the Ministry Scenario 2A (per Ministry 2014 LTEP scenario request)

Cost assumptions

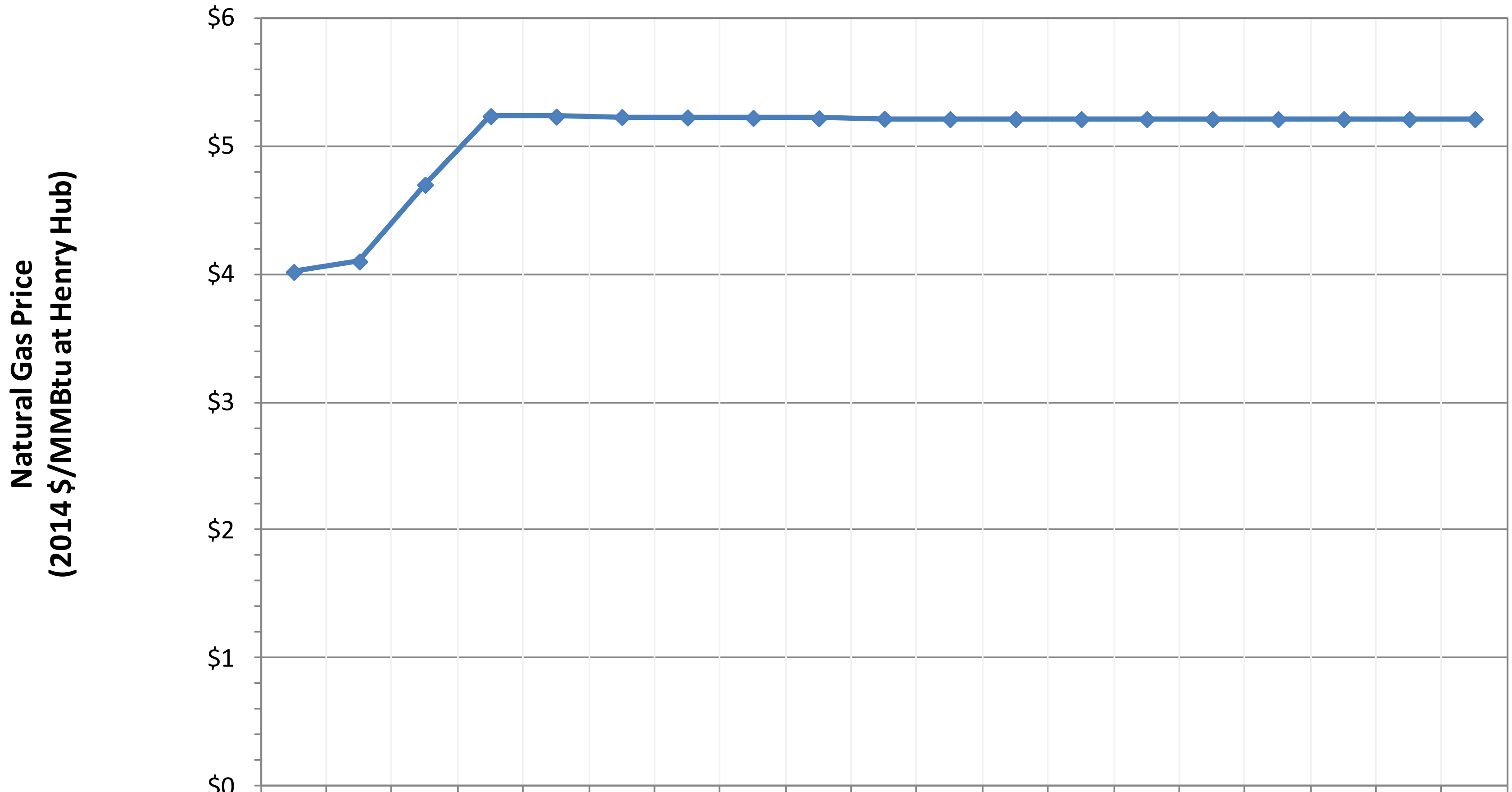
- Additional peaking requirements are assumed to be met by new unspecified capacity based resources priced at a SCGT (represents the least-cost supply resource)
  - $130/kW-yr from a ratepayer perspective based on York Region SCGT
  - DR, NUG contract renewals, coal conversions, or firm imports can also provide capacity if similarly prices

- Additional energy requirements met by existing, committed, and directed resources
  - Current gas-fired fleet relatively underutilized so limited need to build additional supply for energy. As gas-fired production increases, opportunities for lower cost resources to displace this production

- Long-run average gas price assumed to be $5.25/MMBtu at Henry Hub for Reference Case and no explicit cost for carbon
  - Based on Sproule
  - Alternatively, this can be looked at as a combined gas and carbon price
    - For example, gas at $5.25/MMBtu is equivalent to gas at $4/MMBtu plus carbon priced at $23/tonne (for context, BC carbon tax is currently $30/tonne, AB ~$15/tonne, RGGI ~$3/tonne)

- NPV evaluated with a 4% real social discount rate and all costs expressed in 2014 dollars

Reference natural gas price



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Reference Natural Gas Price	$4.0	$4.1	$4.7	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2	$5.2

Cost Tables:
Pickering to 2022, Darlington Lapped vs Pickering to 2020, Darlington Lapped

(A) Pickering to 2022, Darlington Lapped vs (B) Pickering to 2020, Darlington Lapped																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	-2	0	-2	22	24	0	0	0	0	0	0	0	0	0	0	*41*
Fossil/Gas	0	0	0	0	0	0	-7	-7	0	0	0	0	0	0	0	0	0	0	*-14*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	0	0	1	0	0	-8	-8	0	0	0	0	0	0	0	0	0	0	*-14*
Economic Exports	0	0	0	-1	0	-1	6	9	0	0	0	0	0	0	0	0	0	0	*13*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	-$3	$0	-$10	$117	$128	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$171*
Fossil/Gas	$0	$0	$0	$12	$4	$7	-$339	-$335	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*-$484*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$1	$0	$2	-$4	-$3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*-$3*
Imports	$0	$0	$0	$27	$2	$13	-$372	-$374	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*-$520*
Exports	$0	$0	$0	-$4	$0	-$4	$140	$198	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$243*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$41**	**$7**	**$16**	**-$739**	**-$782**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$77	-$77	-$134	-$46	-$895	$860	$1,952	$185	$51	$9	-$34	$0	$0	$0	$0	$0	$0	*$1,230*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$402	-$329	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*-$546*
Net Change in Capital & Fixed Cost	**$0**	**-$77**	**-$77**	**-$134**	**-$46**	**-$895**	**$458**	**$1,623**	**$185**	**$51**	**$9**	**-$34**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$77**	**-$76**	**-$93**	**-$39**	**-$879**	**-$281**	**$841**	**$185**	**$51**	**$9**	**-$34**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***-$395***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

ieso
Independent Electricity System Operator

Cost Tables:

Pickering to 2022/2024, Darlington Lapped
Pickering to 2020, Darlington Lapped

(A) Pickering to 2022/2024, Darlington Lapped vs (B) Pickering to 2020, Darlington Lapped																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	-2	-1	-2	22	22	15	17	0	0	0	0	0	0	0	0	*71*
Fossil/Gas	0	0	0	0	0	0	-7	-7	-5	-4	0	0	0	0	0	0	0	0	*-23*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*-1*
Economic Imports	0	0	0	1	0	0	-8	-7	-5	-5	0	0	0	0	0	0	0	0	*-23*
Economic Exports	0	0	0	-1	0	-1	6	8	6	7	0	0	0	0	0	0	0	0	*25*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	-$3	-$1	-$14	$117	$120	$83	$92	$0	$0	$0	$0	$0	$0	$0	$0	*$282*
Fossil/Gas	$0	$0	$0	$12	$8	$12	-$339	-$323	-$212	-$210	$0	$0	$0	$0	$0	$0	$0	$0	*-$758*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$1	$0	$3	-$4	-$3	-$2	-$3	$0	$0	$0	$0	$0	$0	$0	$0	*-$6*
Imports	$0	$0	$0	$27	$4	$13	-$372	-$353	-$220	-$237	$0	$0	$0	$0	$0	$0	$0	$0	*-$818*
Exports	$0	$0	$0	-$4	-$2	-$2	$140	$191	$152	$149	$0	-$1	$0	$0	$0	$0	$0	$0	*$446*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$41**	**$13**	**$17**	**-$739**	**-$749**	**-$503**	**-$508**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$91	-$88	-$141	-$53	-$885	$857	$1,008	$612	$1,611	$188	$38	$10	-$31	$0	$0	$0	$0	*$2,014*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$402	-$329	-$268	-$208	$0	$0	$0	$0	$0	$0	$0	$0	*-$875*
Net Change in Capital & Fixed Cost	**$0**	**-$91**	**-$88**	**-$141**	**-$53**	**-$885**	**$455**	**$679**	**$343**	**$1,403**	**$188**	**$38**	**$10**	**-$31**	**$0**	**$0**	**$0**	**$0**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$91**	**-$88**	**-$100**	**-$40**	**-$869**	**-$284**	**-$71**	**-$160**	**$895**	**$188**	**$38**	**$10**	**-$31**	**$0**	**$0**	**$0**	**$0**	***-$607***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

ieso Independent Electricity System Operator

Cost Tables:
Pickering to 2024, Darlington Lapped vs Pickering to 2020, Darlington Lapped

(A) Pickering to 2024, Darlington Lapped vs (B) Pickering to 2020, Darlington Lapped																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	-2	-1	-3	-2	-4	21	20	23	25	0	0	0	0	0	0	0	0	*77*
Fossil/Gas	0	0	0	0	0	1	-7	-6	-6	-6	0	0	0	0	0	0	0	0	*-24*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	1	0	1	0	1	-8	-6	-7	-7	0	0	0	0	0	0	0	0	*-24*
Economic Exports	0	-1	0	-1	-1	-2	6	7	10	11	0	0	0	0	0	0	0	0	*29*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	-$1	-$12	-$5	-$9	-$7	-$26	$115	$105	$83	$92	$0	$0	$0	$0	$0	$0	$0	$0	*$234*
Fossil/Gas	$0	$19	$10	$23	$19	$34	-$335	-$296	-$297	-$286	$0	$0	$0	$0	$0	$0	$0	$0	*-$785*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$4	$2	$1	$1	$5	-$4	-$2	-$4	-$7	$0	$0	$0	$0	$0	$0	$0	$0	*-$1*
Imports	$0	$21	$6	$40	$15	$39	-$368	-$326	-$303	-$312	$0	$0	$0	$0	$0	$0	$0	$0	*-$840*
Exports	$0	-$1	-$2	-$15	-$2	-$9	$136	$166	$218	$207	$0	-$1	$0	$0	$0	$0	$0	$0	*$493*
Net Change in Dispatch Cost	**$0**	**$34**	**$15**	**$69**	**$29**	**$61**	**-$729**	**-$685**	**-$738**	**-$721**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	-$8	-$94	-$125	-$157	-$62	-$877	$848	$1,089	$1,356	$2,264	$130	-$20	-$20	-$31	$0	$0	$0	$0	*$2,880*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$402	-$329	-$316	-$208	$0	$0	$0	$0	$0	$0	$0	$0	*-$909*
Net Change in Capital & Fixed Cost	**-$8**	**-$94**	**-$125**	**-$157**	**-$62**	**-$877**	**$446**	**$760**	**$1,040**	**$2,056**	**$130**	**-$20**	**-$20**	**-$31**	**$0**	**$0**	**$0**	**$0**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**-$8**	**-$60**	**-$110**	**-$89**	**-$34**	**-$816**	**-$283**	**$75**	**$301**	**$1,336**	**$130**	**-$20**	**-$20**	**-$31**	**$0**	**$0**	**$0**	**$0**	***$88***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

ieso
Independent Electricity System Operator

Cost Tables:
Pickering to 2018, Darlington Lapped vs Pickering to 2020, Darlington Lapped

(A) Pickering to 2018, Darlington Lapped vs (B) Pickering to 2020, Darlington Lapped																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	2	-21	-23	0	0	0	0	0	0	0	0	0	0	0	0	*-41*
Fossil/Gas	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	0	0	*12*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	*1*
Economic Imports	0	0	0	-1	7	7	0	0	0	0	0	0	0	0	0	0	0	0	*13*
Economic Exports	0	0	0	1	-7	-9	0	0	0	0	0	0	0	0	0	0	0	0	*-15*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	$20	-$124	-$127	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*-$185*
Fossil/Gas	-$1	-$1	-$1	-$21	$296	$288	$0	$1	$0	$1	$1	-$1	-$1	-$1	-$1	-$1	-$1	-$2	*$448*
Non-Hydro Renewables	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$1*
Hydro	$0	$0	$0	-$1	$4	$11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$11*
Imports	$0	$0	$0	-$21	$301	$272	$1	-$1	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$1	*$444*
Exports	-$1	-$1	-$1	$11	-$104	-$102	$0	$0	-$1	-$1	$0	-$2	-$1	-$1	-$1	-$2	-$1	-$1	*-$164*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**-$35**	**$582**	**$547**	**$1**	**$0**	**$0**	**$1**	**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	$114	$103	$868	-$829	-$1,870	-$192	-$58	-$24	$12	$0	$0	$0	$0	$0	$0	$0	$0	*-$1,419*
Replacement Capacity (Gas)	$0	$0	$0	$0	$252	$228	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$387*
Net Change in Capital & Fixed Cost	**$0**	**$114**	**$103**	**$868**	**-$578**	**-$1,642**	**-$192**	**-$58**	**-$24**	**$12**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**$114**	**$104**	**$833**	**$4**	**-$1,095**	**-$191**	**-$58**	**-$23**	**$12**	**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***-$147***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

Cost Tables:

Pickering to 2022/2024, Darlington Unlapped with Idle Time vs Pickering to 2020, Darlington Unlapped with Idle Time

(A) Pickering to 2022/2024, Darlington Unlapped with Idle Time vs (B) Pickering to 2020, Darlington Unlapped with Idle Time

Change in Energy Production (TWh)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	*Total*
Nuclear	0	0	0	-2	-1	-2	22	22	15	17	0	0	0	0	0	0	0	0	*72*
Fossil/Gas	0	0	0	0	0	0	-7	-7	-4	-5	0	0	0	0	0	0	0	0	*-22*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*-1*
Economic Imports	0	0	0	1	0	0	-7	-7	-4	-5	0	0	0	0	0	0	0	0	*-22*
Economic Exports	0	0	0	-1	0	-1	7	9	7	6	0	0	0	0	0	0	0	0	*27*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***

Change in Dispatch Cost (2014 $M)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	*NPV*
Nuclear	$0	$0	$0	-$3	-$1	-$14	$117	$120	$83	$92	$0	$0	$0	$0	$0	$0	$0	$0	*$282*
Fossil/Gas	$0	$0	$0	$6	$8	$12	-$308	-$306	-$195	-$233	$0	$0	$0	$0	$0	$0	$0	$0	*-$730*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$3	-$7	-$4	-$3	-$2	$0	$0	$0	$0	$0	$0	$0	$0	*-$9*
Imports	$0	$0	$0	$18	$4	$13	-$317	-$317	-$191	-$259	$0	$0	$0	$0	$0	$0	$0	$0	*-$753*
Exports	$0	$0	$0	$1	-$2	-$2	$129	$182	$147	$168	$0	$0	$0	$0	$0	$0	$0	$0	*$445*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$21**	**$13**	**$17**	**-$644**	**-$689**	**-$453**	**-$572**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***

Change in Capital & Fixed Cost (2014 $M)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	*NPV*
OPG Nuclear	$0	-$91	-$88	-$101	-$49	-$913	$911	$1,029	$641	$1,608	$178	$42	$10	-$32	$0	$0	$0	$0	*$2,100*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$319	-$215	-$202	-$268	$0	$0	$0	$0	$0	$0	$0	$0	*-$722*
Net Change in Capital & Fixed Cost	**$0**	**-$91**	**-$88**	**-$101**	**-$49**	**-$913**	**$592**	**$814**	**$439**	**$1,339**	**$178**	**$42**	**$10**	**-$32**	**$0**	**$0**	**$0**	**$0**	***$0***

Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$91**	**-$88**	**-$80**	**-$36**	**-$896**	**-$51**	**$126**	**-$14**	**$768**	**$178**	**$42**	**$10**	**-$32**	**$0**	**$0**	**$0**	**$0**	***-$278***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

ieso
Independent Electricity System Operator

Cost Tables:
Pickering to 2022/2024, Darlington Unlapped without Idle Time vs Pickering to 2020, Darlington Unlapped without Idle Time

(A) Pickering to 2022/2024, Darlington Unlapped without Idle Time vs (B) Pickering to 2020, Darlington Unlapped without Idle Time																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	-2	-1	-2	22	22	15	17	0	0	0	0	0	0	0	0	*72*
Fossil/Gas	0	0	0	0	0	0	-7	-6	-4	-4	0	0	0	0	0	0	0	0	*-21*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*-1*
Economic Imports	0	0	0	1	0	0	-7	-7	-4	-5	0	0	0	0	0	0	0	0	*-21*
Economic Exports	0	0	0	-1	0	-1	7	9	7	7	0	0	0	0	0	0	0	0	*28*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	-$3	-$1	-$14	$117	$120	$83	$92	$0	$0	$0	$0	$0	$0	$0	$0	*$282*
Fossil/Gas	$0	$0	$0	$6	$8	$12	-$308	-$303	-$190	-$206	$0	$0	$0	$0	$0	$0	$0	$0	*-$706*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$3	-$7	-$4	-$3	-$4	$0	$0	$0	$0	$0	$0	$0	$0	*-$10*
Imports	$0	$0	$0	$18	$4	$13	-$317	-$315	-$182	-$225	$0	$0	$0	$0	$0	$0	$0	$0	*-$722*
Exports	$0	$0	$0	$1	-$2	-$2	$129	$182	$146	$154	$0	$0	$0	$0	$0	$0	$0	$0	*$434*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$21**	**$13**	**$17**	**-$644**	**-$683**	**-$439**	**-$496**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$91	-$88	-$101	-$49	-$913	$911	$1,023	$641	$1,619	$182	$42	$10	-$32	$0	$0	$0	$0	*$2,105*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$319	-$215	-$202	-$208	$0	$0	$0	$0	$0	$0	$0	$0	*-$682*
Net Change in Capital & Fixed Cost	**$0**	**-$91**	**-$88**	**-$101**	**-$49**	**-$913**	**$592**	**$808**	**$439**	**$1,411**	**$182**	**$42**	**$10**	**-$32**	**$0**	**$0**	**$0**	**$0**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$91**	**-$88**	**-$80**	**-$36**	**-$896**	**-$51**	**$125**	**$0**	**$914**	**$182**	**$42**	**$10**	**-$32**	**$0**	**$0**	**$0**	**$0**	***-$168***

Independent Electricity System Operator

Cost Tables:
Pickering to 2020, Darlington Unlapped with Idle Time vs Pickering to 2020, Darlington Lapped

(A) Pickering to 2020, Darlington Unlapped with Idle Time vs (B) Pickering to 2020, Darlington Lapped																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	0	0	0	6	5	6	-6	-7	-6	-7	-6	1	0	0	0	*-13*
Fossil/Gas	0	0	0	0	0	0	-2	-2	-2	2	2	2	2	2	0	0	0	0	*4*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	0	0	0	0	0	-2	-2	-2	2	2	2	2	2	0	0	0	0	*4*
Economic Exports	0	0	0	0	0	0	1	2	2	-2	-2	-2	-2	-2	0	0	0	0	*-5*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	$0	$0	$0	$33	$28	$33	-$30	-$36	-$33	-$35	-$29	$6	-$2	-$2	$1	*-$31*
Fossil/Gas	$0	$0	$0	$0	$0	$0	-$107	-$86	-$87	$87	$111	$91	$104	$96	-$18	$5	$5	-$3	*$94*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$1	$1	$0	$0	$0	$0	$0	$0	*$0*
Imports	$0	$0	$0	$0	$0	$0	-$128	-$88	-$98	$91	$121	$106	$119	$92	-$20	$9	$3	-$1	*$94*
Exports	$0	$0	$0	$0	$0	$0	$35	$52	$60	-$54	-$64	-$69	-$73	-$59	$10	-$3	-$3	$1	*-$90*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$237**	**-$199**	**-$212**	**$202**	**$259**	**$235**	**$260**	**$218**	**-$42**	**$14**	**$9**	**-$5**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$5	$0	$0	$20	$275	-$180	-$43	-$132	-$5	-$250	$42	-$95	-$117	$242	$115	$116	$138	*$27*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$114	-$114	-$114	$114	$114	$114	$114	$114	$0	$0	$0	$0	*$107*
Net Change in Capital & Fixed Cost	**$0**	**-$5**	**$0**	**$0**	**$20**	**$275**	**-$294**	**-$157**	**-$246**	**$109**	**-$136**	**$156**	**$19**	**-$3**	**$242**	**$115**	**$116**	**$138**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$4**	**$0**	**$0**	**$20**	**$275**	**-$531**	**-$356**	**-$459**	**$311**	**$123**	**$391**	**$279**	**$216**	**$199**	**$130**	**$125**	**$133**	***$381***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

Cost Tables:
Pickering to 2020, Darlington Unlapped without Idle Time vs Pickering to 2020, Darlington Lapped

(A) Pickering to 2020, Darlington Unlapped without Idle Time vs (B) Pickering to 2020, Darlington Lapped																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	0	0	0	6	6	7	2	-1	-6	-7	-6	1	0	0	0	*2*
Fossil/Gas	0	0	0	0	0	0	-2	-2	-2	-1	0	2	2	2	0	0	0	0	*-1*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	0	0	0	0	0	-2	-2	-2	-1	0	2	2	2	0	0	0	0	*-1*
Economic Exports	0	0	0	0	0	0	1	2	3	1	0	-2	-2	-2	0	0	0	0	*0*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	$0	$0	$0	$33	$31	$40	$10	-$7	-$33	-$35	-$29	$6	-$2	-$2	$1	*$22*
Fossil/Gas	$0	$0	$0	$0	$0	$0	-$107	-$98	-$104	-$22	$19	$91	$104	$96	-$18	$5	$5	-$3	*-$60*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$1	$0	$0	$0	$0	$0	$0	*-$1*
Imports	$0	$0	$0	$0	$0	$0	-$128	-$99	-$118	-$35	$33	$106	$119	$92	-$20	$9	$3	-$1	*-$70*
Exports	$0	$0	$0	$0	$0	$0	$35	$59	$72	$22	-$4	-$69	-$73	-$59	$10	-$3	-$3	$1	*$14*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$237**	**-$225**	**-$254**	**-$69**	**$49**	**$235**	**$260**	**$218**	**-$42**	**$14**	**$9**	**-$5**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$5	$0	$0	$20	$275	-$180	-$23	-$128	-$33	-$218	$38	-$95	-$117	$242	$117	$116	$138	*$45*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$114	-$114	-$114	$0	$0	$114	$114	$114	$0	$0	$0	$0	*-$45*
Net Change in Capital & Fixed Cost	**$0**	**-$5**	**$0**	**$0**	**$20**	**$275**	**-$294**	**-$138**	**-$242**	**-$33**	**-$218**	**$153**	**$19**	**-$3**	**$242**	**$117**	**$116**	**$138**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$4**	**$0**	**$0**	**$20**	**$275**	**-$531**	**-$363**	**-$496**	**-$103**	**-$169**	**$387**	**$279**	**$216**	**$199**	**$132**	**$125**	**$133**	***-$121***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

ieso
Independent Electricity System Operator

Cost Tables:

Pickering to 2022/24, Darlington Unlapped with Idle Time vs Pickering to 2022/24, Darlington Lapped

(A) Pickering to 2022/24, Darlington Unlapped with Idle Time vs (B) Pickering to 2022/24, Darlington Lapped																		
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	1	0	0	6	5	6	-6	-7	-6	-7	-6	1	0	0	0	*-13*
Fossil/Gas	0	0	0	0	0	0	-2	-1	-2	1	2	2	2	2	0	0	0	0	*5*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	0	0	0	0	0	-2	-1	-2	2	2	2	2	2	0	0	0	0	*5*
Economic Exports	0	0	0	0	0	0	2	2	3	-3	-2	-2	-2	-2	0	0	0	0	*-3*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	$0	$0	$0	$33	$28	$33	-$30	-$36	-$33	-$35	-$29	$6	-$2	-$2	$1	*-$31*
Fossil/Gas	$0	$0	$0	-$6	$0	$0	-$75	-$69	-$70	$64	$111	$91	$104	$96	-$18	$5	$5	-$3	*$122*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$0	-$3	-$2	-$1	$1	$1	$1	$0	$0	$0	$0	$0	$0	*-$3*
Imports	$0	$0	$0	-$9	$0	$0	-$74	-$53	-$69	$68	$121	$106	$119	$92	-$20	$9	$3	-$1	*$160*
Exports	$0	$0	$0	$5	$0	$0	$23	$43	$55	-$35	-$64	-$69	-$73	-$59	$10	-$3	-$3	$1	*-$91*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**-$20**	**$0**	**$0**	**-$142**	**-$138**	**-$162**	**$138**	**$259**	**$234**	**$260**	**$218**	**-$42**	**$14**	**$9**	**-$5**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$5	$0	$40	$23	$247	-$126	-$22	-$103	-$8	-$261	$46	-$95	-$117	$242	$115	$116	$138	*$114*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$31	$0	-$48	$54	$114	$114	$114	$114	$0	$0	$0	$0	*$259*
Net Change in Capital & Fixed Cost	**$0**	**-$5**	**$0**	**$40**	**$23**	**$247**	**-$156**	**-$22**	**-$150**	**$46**	**-$146**	**$160**	**$19**	**-$3**	**$242**	**$115**	**$116**	**$138**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$4**	**$0**	**$20**	**$23**	**$247**	**-$298**	**-$159**	**-$313**	**$184**	**$113**	**$394**	**$279**	**$215**	**$199**	**$130**	**$125**	**$133**	***$711***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

Independent Electricity System Operator

Cost Tables:

Pickering to 2022/24, Darlington Unlapped without Idle Time vs Pickering to 2022/24, Darlington Lapped

(A) Pickering to 2022/24, Darlington Unlapped without Idle Time vs (B) Pickering to 2022/24, Darlington Lapped																			
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	1	0	0	6	6	7	2	-1	-6	-7	-6	1	0	0	0	*2*
Fossil/Gas	0	0	0	0	0	0	-2	-2	-2	0	0	2	2	2	0	0	0	0	*1*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	0	0	0	0	0	-2	-1	-2	0	0	2	2	2	0	0	0	0	*0*
Economic Exports	0	0	0	0	0	0	2	3	4	1	0	-2	-2	-2	0	0	0	0	*3*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	$0	$0	$0	$33	$31	$40	$10	-$7	-$33	-$35	-$29	$6	-$2	-$2	$1	*$22*
Fossil/Gas	$0	$0	$0	-$6	$0	$0	-$75	-$77	-$82	-$18	$19	$91	$104	$96	-$18	$5	$5	-$3	*-$8*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$0	-$3	-$2	-$2	-$1	$0	$1	$0	$0	$0	$0	$0	$0	*-$5*
Imports	$0	$0	$0	-$9	$0	$0	-$74	-$61	-$81	-$23	$33	$106	$119	$92	-$20	$9	$3	-$1	*$27*
Exports	$0	$0	$0	$5	$0	$0	$23	$50	$66	$26	-$4	-$69	-$73	-$59	$10	-$3	-$3	$1	*$3*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**-$20**	**$0**	**$0**	**-$142**	**-$159**	**-$190**	**-$58**	**$49**	**$234**	**$260**	**$218**	**-$42**	**$14**	**$9**	**-$5**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$5	$0	$40	$23	$247	-$126	-$8	-$99	-$25	-$225	$42	-$95	-$117	$242	$117	$116	$138	*$137*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$31	$0	-$48	$0	$0	$114	$114	$114	$0	$0	$0	$0	*$149*
Net Change in Capital & Fixed Cost	**$0**	**-$5**	**$0**	**$40**	**$23**	**$247**	**-$156**	**-$8**	**-$147**	**-$25**	**-$225**	**$156**	**$19**	**-$3**	**$242**	**$117**	**$116**	**$138**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$4**	**$0**	**$20**	**$23**	**$247**	**-$298**	**-$167**	**-$337**	**-$83**	**-$176**	**$391**	**$279**	**$215**	**$199**	**$132**	**$125**	**$133**	***$318***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

Cost Tables:
Pickering to 2018, Darlington Unlapped with Idle Time vs Pickering to 2018, Darlington Lapped

(A) Pickering to 2018, Darlington Unlapped with Idle Time vs (B) Pickering to 2018, Darlington Lapped																		
Change in Energy Production (TWh)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***Total***
Nuclear	0	0	0	0	0	0	6	5	6	-6	-7	-6	-7	-6	1	0	0	0	*-13*
Fossil/Gas	0	0	0	0	0	0	-2	-2	-2	2	2	2	2	2	0	0	0	0	*4*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	0	0	0	0	0	-2	-2	-2	2	2	2	2	2	0	0	0	0	*4*
Economic Exports	0	0	0	0	0	0	1	2	2	-2	-2	-2	-2	-2	0	0	0	0	*-5*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	$0	$0	$0	$33	$28	$33	-$30	-$36	-$33	-$35	-$29	$6	-$2	-$2	$1	*-$31*
Fossil/Gas	$0	$0	$0	$0	$0	$0	-$106	-$87	-$87	$87	$110	$93	$105	$97	-$17	$6	$6	-$1	*$97*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$0	$0	$0	$0	$0	$0	*$0*
Imports	$0	$0	$0	$0	$0	$0	-$130	-$88	-$98	$92	$121	$106	$119	$92	-$20	$9	$3	-$2	*$95*
Exports	$0	$0	$0	$0	$0	$0	$35	$52	$61	-$53	-$63	-$68	-$71	-$58	$11	-$1	-$2	$2	*-$83*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$238**	**-$199**	**-$212**	**$202**	**$259**	**$234**	**$260**	**$218**	**-$42**	**$14**	**$9**	**-$5**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$5	$0	$0	$23	$315	-$169	-$43	-$133	-$3	-$250	$42	-$95	-$117	$242	$115	$116	$138	*$70*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$114	-$114	-$114	$114	$114	$114	$114	$114	$0	$0	$0	$0	*$107*
Net Change in Capital & Fixed Cost	**$0**	**-$5**	**$0**	**$0**	**$23**	**$315**	**-$283**	**-$157**	**-$247**	**$111**	**-$136**	**$156**	**$19**	**-$3**	**$242**	**$115**	**$116**	**$138**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$5**	**$0**	**$0**	**$23**	**$315**	**-$521**	**-$356**	**-$460**	**$312**	**$123**	**$390**	**$279**	**$216**	**$199**	**$130**	**$125**	**$133**	***$421***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

Cost Tables:
Pickering to 2018, Darlington Unlapped without Idle Time vs Pickering to 2018, Darlington Lapped

(A) Pickering to 2018, Darlington Unlapped without Idle Time vs (B) Pickering to 2018, Darlington Lapped

Change in Energy Production (TWh)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	*Total*
Nuclear	0	0	0	0	0	0	6	6	7	2	-1	-6	-7	-6	1	0	0	0	*2*
Fossil/Gas	0	0	0	0	0	0	-2	-2	-2	-1	0	2	2	2	0	0	0	0	*-1*
Non-Hydro Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Economic Imports	0	0	0	0	0	0	-2	-2	-2	-1	0	2	2	2	0	0	0	0	*-1*
Economic Exports	0	0	0	0	0	0	1	2	3	1	0	-2	-2	-2	0	0	0	0	*0*
Net Change in Energy Production	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***0***
Change in Dispatch Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
Nuclear	$0	$0	$0	$0	$0	$0	$33	$31	$40	$10	-$7	-$33	-$35	-$29	$6	-$2	-$2	$1	*$22*
Fossil/Gas	$0	$0	$0	$0	$0	$0	-$106	-$98	-$104	-$23	$18	$93	$105	$97	-$17	$6	$6	-$1	*-$57*
Non-Hydro Renewables	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Hydro	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$1	$0	$0	$0	$0	$0	$0	*-$1*
Imports	$0	$0	$0	$0	$0	$0	-$130	-$98	-$118	-$34	$33	$106	$119	$92	-$20	$9	$3	-$2	*-$69*
Exports	$0	$0	$0	$0	$0	$0	$35	$60	$72	$22	-$4	-$68	-$71	-$58	$11	-$1	-$2	$2	*$20*
Net Change in Dispatch Cost	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**-$238**	**-$225**	**-$255**	**-$70**	**$48**	**$234**	**$260**	**$218**	**-$42**	**$14**	**$9**	**-$5**	***$0***
Change in Capital & Fixed Cost (2014 $M)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	***NPV***
OPG Nuclear	$0	-$5	$0	$0	$23	$315	-$169	-$23	-$128	-$32	-$218	$38	-$95	-$117	$242	$117	$116	$138	*$88*
Replacement Capacity (Gas)	$0	$0	$0	$0	$0	$0	-$114	-$114	-$114	$0	$0	$114	$114	$114	$0	$0	$0	$0	*-$45*
Net Change in Capital & Fixed Cost	**$0**	**-$5**	**$0**	**$0**	**$23**	**$315**	**-$283**	**-$138**	**-$242**	**-$32**	**-$218**	**$153**	**$19**	**-$3**	**$242**	**$117**	**$116**	**$138**	***$0***
Total Net Change in Electricity Costs (2014 $M)	**$0**	**-$5**	**$0**	**$0**	**$23**	**$315**	**-$521**	**-$363**	**-$497**	**-$102**	**-$170**	**$387**	**$279**	**$216**	**$199**	**$132**	**$125**	**$133**	***-$82***

System cost increase (+) / decrease (-). NPV evaluated at a 4% real discount rate.

Independent Electricity System Operator

Total Annual Cost of Electricity Service (2014 $ Billion)

Across Pickering Life Extension Scenarios, with Darlington Lapped

Total Annual Cost of Electricity Service Across Pickering Life Extension Scenarios, with Darlington Lapped (2014 $ Billion)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$20.22	$20.57	$20.39	$21.01	$20.51	$20.77	$21.26	$21.59	$20.57	$20.50	$20.56	$20.73	$20.71	$20.61	$20.57	$20.46	$20.35	$20.25
Pickering to 2020	$21.22	$20.83	$21.25	$20.91	$20.58	$21.92	$21.50	$21.39	$21.70	$21.15	$21.47	$21.18	$21.42	$21.34	$21.23	$21.21	$21.17	$20.88
Pickering to 2022	$21.22	$20.75	$21.17	$20.82	$20.54	$20.99	$21.19	$22.29	$21.89	$21.20	$21.48	$21.15	$21.42	$21.33	$21.23	$21.21	$21.17	$20.88
Pickering to 2022/2024	$21.23	$20.75	$21.17	$20.82	$20.55	$21.02	$21.19	$21.32	$21.54	$22.11	$21.67	$21.23	$21.44	$21.30	$21.23	$21.21	$21.17	$20.88
Pickering to 2024	$21.21	$20.77	$21.14	$20.82	$20.54	$21.06	$21.18	$21.46	$22.02	$22.58	$21.61	$21.16	$21.40	$21.30	$21.23	$21.21	$21.17	$20.88
Pickering to 2018	$21.22	$20.95	$21.36	$21.79	$20.59	$20.77	$21.30	$21.33	$21.67	$21.18	$21.48	$21.19	$21.42	$21.34	$21.23	$21.21	$21.17	$20.88

Change in Costs: Relative to Pickering to 2020, with Darlington Lapped (2014 $ Billion)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Pickering to 2020	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Pickering to 2022	$0.00	-$0.08	-$0.08	-$0.10	-$0.04	-$0.93	-$0.30	$0.90	$0.19	$0.05	$0.01	-$0.04	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Pickering to 2022/2024	$0.01	-$0.08	-$0.08	-$0.09	-$0.03	-$0.91	-$0.31	-$0.07	-$0.16	$0.96	$0.20	$0.04	$0.01	-$0.03	$0.00	$0.00	$0.00	$0.00
Pickering to 2024	-$0.01	-$0.06	-$0.11	-$0.09	-$0.04	-$0.86	-$0.32	$0.07	$0.32	$1.43	$0.14	-$0.02	-$0.02	-$0.03	$0.00	$0.00	$0.00	$0.00
Pickering to 2018	$0.00	$0.12	$0.11	$0.88	$0.01	-$1.15	-$0.20	-$0.06	-$0.02	$0.03	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Cost increase (+). Cost decrease (-).

Change in Costs: Relative to LTEP (2013) (2014 $ Billion)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Pickering to 2020	$1.00	$0.26	$0.86	-$0.10	$0.07	$1.15	$0.24	-$0.19	$1.13	$0.65	$0.91	$0.46	$0.72	$0.73	$0.66	$0.75	$0.82	$0.63
Pickering to 2022	$1.00	$0.18	$0.78	-$0.20	$0.03	$0.22	-$0.06	$0.70	$1.32	$0.70	$0.92	$0.42	$0.72	$0.73	$0.66	$0.75	$0.82	$0.63
Pickering to 2022/2024	$1.01	$0.18	$0.78	-$0.19	$0.04	$0.24	-$0.07	-$0.26	$0.96	$1.61	$1.11	$0.50	$0.73	$0.70	$0.66	$0.75	$0.82	$0.63
Pickering to 2024	$0.99	$0.20	$0.75	-$0.19	$0.03	$0.28	-$0.08	-$0.12	$1.45	$2.08	$1.04	$0.44	$0.69	$0.70	$0.66	$0.75	$0.82	$0.63
Pickering to 2018	$1.00	$0.38	$0.97	$0.78	$0.08	$0.00	$0.04	-$0.26	$1.10	$0.68	$0.92	$0.46	$0.72	$0.73	$0.66	$0.75	$0.82	$0.63

Cost increase (+). Cost decrease (-).

Total Annual Cost of Electricity Service (2014 $ Billion)

Across Darlington Scenarios

Total Annual Cost of Electricity Service Across Darlington Scenarios (2014 $ Billion)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$20.22	$20.57	$20.39	$21.01	$20.51	$20.77	$21.26	$21.59	$20.57	$20.50	$20.56	$20.73	$20.71	$20.61	$20.57	$20.46	$20.35	$20.25
Pickering to 2020, Darlington Lapped	$21.22	$20.83	$21.25	$20.91	$20.58	$21.92	$21.50	$21.39	$21.70	$21.15	$21.47	$21.18	$21.42	$21.34	$21.23	$21.21	$21.17	$20.88
Pickering to 2020, Darlington Unlapped without Idle Time	$21.22	$20.82	$21.25	$20.91	$20.60	$22.21	$20.93	$21.00	$21.18	$21.04	$21.29	$21.60	$21.72	$21.57	$21.44	$21.35	$21.30	$21.02
Pickering to 2020, Darlington Unlapped with Idle Time	$21.22	$20.82	$21.25	$20.91	$20.60	$22.21	$20.93	$21.01	$21.21	$21.48	$21.60	$21.60	$21.72	$21.57	$21.44	$21.35	$21.30	$21.02
Pickering to 2022/2024, Darlington Lapped	$21.23	$20.75	$21.17	$20.82	$20.55	$21.02	$21.19	$21.32	$21.54	$22.11	$21.67	$21.23	$21.44	$21.30	$21.23	$21.21	$21.17	$20.88
Pickering to 2022/2024, Darlington Unlapped without Idle Time	$21.22	$20.73	$21.16	$20.83	$20.56	$21.27	$20.86	$21.14	$21.18	$22.01	$21.48	$21.64	$21.73	$21.53	$21.44	$21.35	$21.30	$21.02
Pickering to 2022/2024, Darlington Unlapped with Idle Time	$21.22	$20.73	$21.16	$20.83	$20.56	$21.27	$20.86	$21.15	$21.20	$22.28	$21.78	$21.64	$21.73	$21.53	$21.44	$21.35	$21.30	$21.02

Change in Costs: Pickering to 2022/2024 versus Pickering to 2020 under assumed Darlington schedule (2014 $ Billion)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Darlington Lapped	$0.01	-$0.08	-$0.08	-$0.09	-$0.03	-$0.91	-$0.31	-$0.07	-$0.16	$0.96	$0.20	$0.04	$0.01	-$0.03	$0.00	$0.00	$0.00	$0.00
Darlington Unlapped without Idle Time	$0.00	-$0.10	-$0.09	-$0.08	-$0.04	-$0.95	-$0.07	$0.14	$0.00	$0.97	$0.19	$0.04	$0.01	-$0.03	$0.00	$0.00	$0.00	$0.00
Darlington Unlapped with Idle Time	$0.00	-$0.10	-$0.09	-$0.08	-$0.04	-$0.95	-$0.07	$0.14	-$0.01	$0.81	$0.19	$0.04	$0.01	-$0.03	$0.00	$0.00	$0.00	$0.00

Cost increase (+). Cost decrease (-).

Change in Costs: Relative to LTEP (2013) (2014 $ Billion)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Pickering to 2020, Darlington Lapped	$1.00	$0.26	$0.86	-$0.10	$0.07	$1.15	$0.24	-$0.19	$1.13	$0.65	$0.91	$0.46	$0.72	$0.73	$0.66	$0.75	$0.82	$0.63
Pickering to 2020, Darlington Unlapped without Idle Time	$0.99	$0.26	$0.86	-$0.10	$0.09	$1.44	-$0.32	-$0.58	$0.60	$0.54	$0.73	$0.87	$1.01	$0.96	$0.87	$0.89	$0.95	$0.77
Pickering to 2020, Darlington Unlapped with Idle Time	$0.99	$0.26	$0.86	-$0.10	$0.09	$1.44	-$0.32	-$0.57	$0.64	$0.98	$1.03	$0.87	$1.01	$0.96	$0.87	$0.88	$0.95	$0.77
Pickering to 2022/2024, Darlington Lapped	$1.01	$0.18	$0.78	-$0.19	$0.04	$0.24	-$0.07	-$0.26	$0.96	$1.61	$1.11	$0.50	$0.73	$0.70	$0.66	$0.75	$0.82	$0.63
Pickering to 2022/2024, Darlington Unlapped without Idle Time	$0.99	$0.16	$0.77	-$0.18	$0.05	$0.49	-$0.39	-$0.44	$0.61	$1.51	$0.92	$0.91	$1.02	$0.93	$0.87	$0.89	$0.95	$0.77
Pickering to 2022/2024, Darlington Unlapped with Idle Time	$0.99	$0.16	$0.77	-$0.18	$0.05	$0.49	-$0.39	-$0.43	$0.63	$1.78	$1.22	$0.92	$1.02	$0.93	$0.87	$0.88	$0.95	$0.77

Cost increase (+). Cost decrease (-).

Residential Electricity Bill (nominal $/month)

Across Pickering Life Extension Scenarios, with Darlington Lapped

Residential Electricity Bill Across Pickering Life Extension Scenarios, with Darlington Lapped (nominal $/month)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$145	$167	$170	$178	$177	$181	$187	$193	$188	$191	$194	$198	$200	$202	$204	$205	$207	$210
Pickering to 2020	$147	$159	$167	$167	$171	$185	$183	$185	$191	$190	$194	$195	$199	$200	$201	$203	$206	$207
Pickering to 2022	$147	$159	$166	$166	$171	$178	$181	$193	$193	$190	$194	$194	$199	$200	$201	$203	$206	$207
Pickering to 2022/2024	$147	$159	$166	$166	$171	$178	$181	$185	$190	$198	$196	$195	$199	$200	$201	$203	$206	$207
Pickering to 2024	$147	$159	$166	$166	$171	$178	$181	$186	$195	$203	$196	$195	$198	$200	$201	$203	$206	$207
Pickering to 2018	$147	$160	$168	$174	$171	$175	$181	$185	$191	$190	$194	$195	$199	$200	$201	$203	$206	$207

Change in Costs: Relative to Pickering to 2020, with Darlington Lapped (nominal $/month)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Pickering to 2020	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2022	$0.0	-$0.6	-$0.6	-$0.8	-$0.3	-$7.3	-$1.7	$7.9	$1.6	$0.4	$0.1	-$0.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2022/2024	$0.1	-$0.6	-$0.6	-$0.8	-$0.2	-$7.1	-$1.8	$0.1	-$0.9	$8.5	$1.7	$0.4	$0.1	-$0.3	$0.0	$0.0	$0.0	$0.0
Pickering to 2024	-$0.1	-$0.5	-$0.9	-$0.8	-$0.3	-$6.9	-$1.9	$1.2	$3.3	$12.6	$1.1	-$0.2	-$0.2	-$0.3	$0.0	$0.0	$0.0	$0.0
Pickering to 2018	$0.0	$0.9	$0.8	$6.7	-$0.6	-$9.7	-$1.6	-$0.5	-$0.2	$0.3	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Cost increase (+). Cost decrease (-).

Change in Costs: Relative to LTEP (2013) (nominal $/month)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2020	$2.1	-$7.6	-$3.3	-$10.8	-$5.7	$4.1	-$4.4	-$7.7	$3.4	-$1.0	$0.4	-$3.3	-$1.5	-$2.0	-$2.8	-$2.1	-$1.4	-$3.5
Pickering to 2022	$2.1	-$8.2	-$3.9	-$11.6	-$6.1	-$3.2	-$6.1	$0.3	$5.0	-$0.6	$0.4	-$3.6	-$1.5	-$2.0	-$2.8	-$2.1	-$1.4	-$3.5
Pickering to 2022/2024	$2.2	-$8.2	-$3.9	-$11.6	-$6.0	-$3.0	-$6.1	-$7.6	$2.5	$7.5	$2.0	-$2.9	-$1.4	-$2.2	-$2.8	-$2.1	-$1.4	-$3.5
Pickering to 2024	$2.1	-$8.1	-$4.2	-$11.6	-$6.1	-$2.8	-$6.2	-$6.5	$6.7	$11.6	$1.5	-$3.5	-$1.7	-$2.2	-$2.8	-$2.1	-$1.4	-$3.5
Pickering to 2018	$2.1	-$6.7	-$2.5	-$4.1	-$6.3	-$5.6	-$6.0	-$8.2	$3.2	-$0.7	$0.4	-$3.3	-$1.5	-$1.9	-$2.8	-$2.1	-$1.4	-$3.5

Cost increase (+). Cost decrease (-).

Assumes a typical residential consumption of 800 kWh/month.

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Independent Electricity System Operator

Residential Electricity Bill (nominal $/month)
Across Darlington Scenarios

Residential Electricity Bill Across Darlington Scenarios (nominal $/month)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$145	$167	$170	$178	$177	$181	$187	$193	$188	$191	$194	$198	$200	$202	$204	$205	$207	$210
Pickering to 2020, Darlington Lapped	$147	$159	$167	$167	$171	$185	$183	$185	$191	$190	$194	$195	$199	$200	$201	$203	$206	$207
Pickering to 2020, Darlington Unlapped without Idle Time	$147	$159	$167	$167	$171	$187	$178	$182	$187	$189	$193	$198	$201	$202	$203	$204	$207	$208
Pickering to 2020, Darlington Unlapped with Idle Time	$147	$159	$167	$167	$171	$187	$178	$182	$188	$193	$195	$198	$201	$202	$203	$204	$207	$208
Pickering to 2022/2024, Darlington Lapped	$147	$159	$166	$166	$171	$178	$181	$185	$190	$198	$196	$195	$199	$200	$201	$203	$206	$207
Pickering to 2022/2024, Darlington Unlapped without Idle Time	$147	$159	$166	$167	$171	$180	$178	$184	$188	$198	$194	$198	$201	$202	$203	$204	$207	$208
Pickering to 2022/2024, Darlington Unlapped with Idle Time	$147	$159	$166	$167	$171	$180	$178	$184	$188	$200	$197	$198	$201	$202	$203	$204	$207	$208

Change in Costs: Pickering to 2022/2024 versus Pickering to 2020 under assumed Darlington schedule (nominal $/month)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Darlington Lapped	$0.1	-$0.6	-$0.6	-$0.8	-$0.2	-$7.1	-$1.8	$0.1	-$0.9	$8.5	$1.7	$0.4	$0.1	-$0.3	$0.0	$0.0	$0.0	$0.0
Darlington Unlapped without Idle Time	$0.0	-$0.7	-$0.7	-$0.7	-$0.3	-$7.5	$0.1	$1.8	$0.5	$8.6	$1.6	$0.4	$0.1	-$0.3	$0.0	$0.0	$0.0	$0.0
Darlington Unlapped with Idle Time	$0.0	-$0.7	-$0.7	-$0.7	-$0.3	-$7.5	$0.1	$1.8	$0.4	$7.1	$1.6	$0.4	$0.1	-$0.3	$0.0	$0.0	$0.0	$0.0

Cost increase (+). Cost decrease (-).

Change in Costs: Relative to LTEP (2013) (nominal $/month)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2020, Darlington Lapped	$2.1	-$7.6	-$3.3	-$10.8	-$5.7	$4.1	-$4.4	-$7.7	$3.4	-$1.0	$0.4	-$3.3	-$1.5	-$2.0	-$2.8	-$2.1	-$1.4	-$3.5
Pickering to 2020, Darlington Unlapped without Idle Time	$2.1	-$7.6	-$3.3	-$10.8	-$5.6	$6.4	-$8.6	-$10.7	-$0.7	-$1.8	-$1.3	$0.0	$0.8	-$0.1	-$1.0	-$0.9	-$0.2	-$2.2
Pickering to 2020, Darlington Unlapped with Idle Time	$2.1	-$7.6	-$3.3	-$10.8	-$5.6	$6.4	-$8.6	-$10.6	-$0.4	$1.6	$1.2	$0.0	$0.8	-$0.1	-$1.0	-$0.9	-$0.2	-$2.2
Pickering to 2022/2024, Darlington Lapped	$2.2	-$8.2	-$3.9	-$11.6	-$6.0	-$3.0	-$6.1	-$7.6	$2.5	$7.5	$2.0	-$2.9	-$1.4	-$2.2	-$2.8	-$2.1	-$1.4	-$3.5
Pickering to 2022/2024, Darlington Unlapped without Idle Time	$2.1	-$8.3	-$4.0	-$11.5	-$5.9	-$1.1	-$8.5	-$8.8	-$0.2	$6.7	$0.3	$0.3	$0.9	-$0.4	-$1.0	-$0.9	-$0.2	-$2.2
Pickering to 2022/2024, Darlington Unlapped with Idle Time	$2.1	-$8.3	-$4.0	-$11.5	-$5.9	-$1.1	-$8.5	-$8.8	-$0.1	$8.8	$2.8	$0.4	$0.9	-$0.4	-$1.0	-$0.9	-$0.2	-$2.2

Cost increase (+). Cost decrease (-).

Assumes a typical residential consumption of 800 kWh/month.

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Industrial Electricity Rate (nominal $/MWh)

Across Pickering Life Extension Scenarios, with Darlington Lapped

Industrial Electricity Rate Across Pickering Life Extension Scenarios, with Darlington Lapped (nominal $/MWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$92	$96	$100	$105	$102	$104	$111	$115	$113	$113	$115	$116	$118	$118	$121	$121	$123	$123
Pickering to 2020	$95	$98	$103	$105	$101	$108	$113	$115	$117	$115	$118	$117	$119	$121	$122	$123	$126	$125
Pickering to 2022	$95	$98	$103	$105	$100	$103	$108	$115	$118	$116	$118	$116	$119	$121	$122	$123	$126	$125
Pickering to 2022/2024	$96	$98	$103	$105	$101	$104	$108	$111	$114	$118	$119	$117	$120	$121	$122	$123	$126	$125
Pickering to 2024	$95	$98	$103	$106	$101	$104	$108	$112	$115	$119	$119	$116	$119	$121	$122	$123	$126	$125
Pickering to 2018	$95	$99	$104	$109	$105	$106	$112	$114	$117	$116	$118	$116	$119	$121	$122	$123	$126	$125

Change in Costs: Relative to Pickering to 2020, with Darlington Lapped (nominal $/MWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Pickering to 2020	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2022	$0.0	-$0.4	-$0.4	$0.0	-$0.1	-$4.3	-$5.1	$0.5	$1.0	$0.3	$0.0	-$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2022/2024	$0.1	-$0.4	-$0.4	$0.0	$0.0	-$4.0	-$5.2	-$4.1	-$3.2	$2.1	$1.0	$0.2	$0.1	-$0.2	$0.0	$0.0	$0.0	$0.0
Pickering to 2024	$0.0	$0.0	-$0.3	$0.3	$0.2	-$3.4	-$5.2	-$3.1	-$1.8	$3.3	$0.7	-$0.1	-$0.1	-$0.2	$0.0	$0.0	$0.0	$0.0
Pickering to 2018	$0.0	$0.5	$0.5	$3.8	$4.0	-$1.4	-$1.0	-$0.3	-$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0

Cost increase (+). Cost decrease (-).

Change in Costs: Relative to LTEP (2013) (nominal $/MWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2020	$3.4	$2.2	$3.1	$0.4	-$1.5	$3.6	$1.9	-$0.3	$4.2	$2.4	$2.9	$0.5	$1.4	$2.9	$0.6	$2.3	$3.3	$1.9
Pickering to 2022	$3.4	$1.8	$2.7	$0.5	-$1.6	-$0.7	-$3.3	$0.2	$5.2	$2.7	$2.9	$0.3	$1.4	$2.8	$0.6	$2.3	$3.3	$1.9
Pickering to 2022/2024	$3.5	$1.8	$2.7	$0.5	-$1.5	-$0.4	-$3.3	-$4.4	$1.0	$4.6	$3.9	$0.7	$1.5	$2.7	$0.6	$2.3	$3.3	$1.9
Pickering to 2024	$3.4	$2.2	$2.7	$0.7	-$1.2	$0.2	-$3.3	-$3.4	$2.3	$5.7	$3.6	$0.4	$1.3	$2.7	$0.6	$2.3	$3.3	$1.9
Pickering to 2018	$3.4	$2.7	$3.6	$4.3	$2.5	$2.1	$0.9	-$0.6	$4.0	$2.6	$2.9	$0.5	$1.4	$2.8	$0.6	$2.3	$3.2	$1.9

Cost increase (+). Cost decrease (-).

Assumes a typical large industrial customer with a demand of 5MW and a 75% capacity factor.

Industrial Electricity Rate (nominal $/MWh)

Across Darlington Scenarios

Industrial Electricity Rate Across Darlington Scenarios (nominal $/MWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$92	$96	$100	$105	$102	$104	$111	$115	$113	$113	$115	$116	$118	$118	$121	$121	$123	$123
Pickering to 2020, Darlington Lapped	$95	$98	$103	$105	$101	$108	$113	$115	$117	$115	$118	$117	$119	$121	$122	$123	$126	$125
Pickering to 2020, Darlington Unlapped without Idle Time	$95	$98	$103	$105	$101	$109	$109	$112	$113	$115	$117	$120	$122	$123	$122	$124	$127	$126
Pickering to 2020, Darlington Unlapped with Idle Time	$95	$98	$103	$105	$101	$109	$109	$112	$114	$118	$120	$120	$122	$123	$122	$124	$127	$126
Pickering to 2022/2024, Darlington Lapped	$96	$98	$103	$105	$101	$104	$108	$111	$114	$118	$119	$117	$120	$121	$122	$123	$126	$125
Pickering to 2022/2024, Darlington Unlapped without Idle Time	$95	$98	$103	$105	$101	$105	$105	$109	$111	$117	$118	$120	$122	$123	$122	$124	$127	$126
Pickering to 2022/2024, Darlington Unlapped with Idle Time	$95	$98	$103	$105	$101	$105	$105	$109	$111	$120	$121	$120	$122	$123	$122	$124	$127	$126

Change in Costs: Pickering to 2022/2024 versus Pickering to 2020 under assumed Darlington schedule (nominal $/MWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Darlington Lapped	$0.1	-$0.4	-$0.4	$0.0	$0.0	-$4.0	-$5.2	-$4.1	-$3.2	$2.1	$1.0	$0.2	$0.1	-$0.2	$0.0	$0.0	$0.0	$0.0
Darlington Unlapped without Idle Time	$0.0	-$0.4	-$0.4	$0.0	-$0.1	-$4.2	-$4.0	-$3.2	-$2.2	$2.2	$1.0	$0.2	$0.1	-$0.2	$0.0	$0.0	$0.0	$0.0
Darlington Unlapped with Idle Time	$0.0	-$0.4	-$0.4	$0.0	-$0.1	-$4.2	-$4.0	-$3.2	-$2.3	$1.7	$1.0	$0.2	$0.1	-$0.2	$0.0	$0.0	$0.0	$0.0

Cost increase (+). Cost decrease (-).

Change in Costs: Relative to LTEP (2013) (nominal $/MWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LTEP (2013)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Pickering to 2020, Darlington Lapped	$3.4	$2.2	$3.1	$0.4	-$1.5	$3.6	$1.9	-$0.3	$4.2	$2.4	$2.9	$0.5	$1.4	$2.9	$0.6	$2.3	$3.3	$1.9
Pickering to 2020, Darlington Unlapped without Idle Time	$3.4	$2.2	$3.1	$0.4	-$1.4	$5.0	-$2.1	-$3.0	$0.2	$1.6	$2.5	$3.7	$4.3	$5.0	$1.5	$3.2	$4.1	$2.6
Pickering to 2020, Darlington Unlapped with Idle Time	$3.4	$2.2	$3.1	$0.4	-$1.4	$5.0	-$2.1	-$2.9	$0.7	$5.0	$4.9	$3.7	$4.3	$5.0	$1.5	$3.2	$4.1	$2.6
Pickering to 2022/2024, Darlington Lapped	$3.5	$1.8	$2.7	$0.5	-$1.5	-$0.4	-$3.3	-$4.4	$1.0	$4.6	$3.9	$0.7	$1.5	$2.7	$0.6	$2.3	$3.3	$1.9
Pickering to 2022/2024, Darlington Unlapped without Idle Time	$3.4	$1.7	$2.6	$0.4	-$1.4	$0.8	-$6.1	-$6.2	-$2.0	$3.9	$3.5	$3.9	$4.4	$4.8	$1.5	$3.2	$4.1	$2.6
Pickering to 2022/2024, Darlington Unlapped with Idle Time	$3.4	$1.7	$2.6	$0.4	-$1.4	$0.8	-$6.1	-$6.1	-$1.6	$6.7	$5.9	$3.9	$4.4	$4.8	$1.5	$3.2	$4.1	$2.6

Cost increase (+). Cost decrease (-).

Gas price volatility analysis

- A probabilistic evaluation is completed to assess the change in net present value (NPV) of electricity system cost as a function of natural gas price

- Gas price distributions are derived using historical gas prices. Two sets of distributions are derived from historical natural gas prices (from US EIA) and modeled:

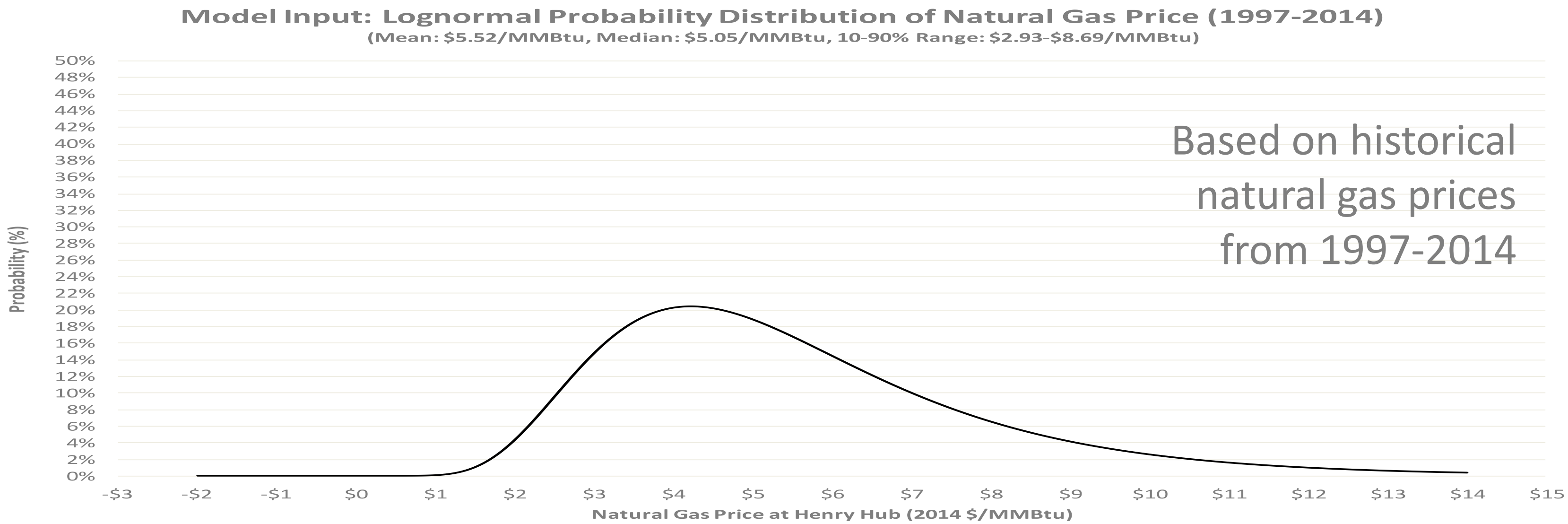
  1) Using long-run historical gas prices: historical gas prices from 1997 through 2014 are fit to a log-normal distribution. This distribution has a positive skew yielding a greater likelihood of higher gas prices then the mean (more upside risk than downside).

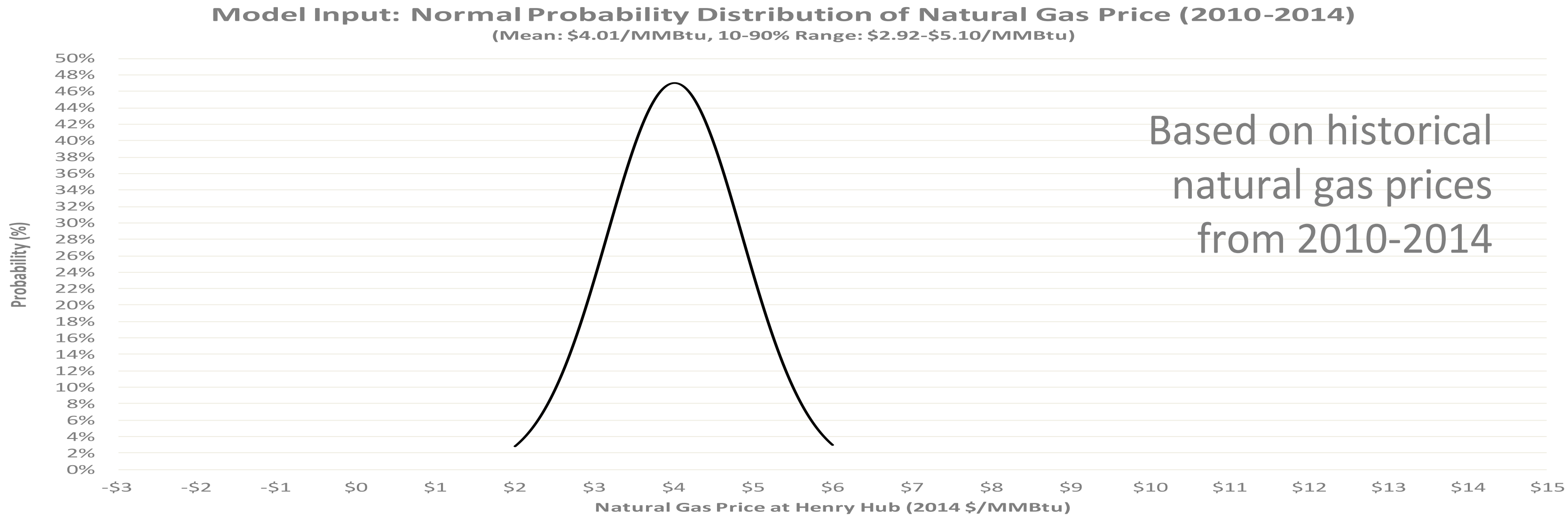
  2) Using recent historical gas prices: historical gas prices from 2010 through 2014 are fit to a log-normal distribution. This distribution is relatively normally distributed yielding an equal likelihood of gas prices being higher or lower than the mean.

- The analysis is completed using Monte Carlo simulations based on user specified probability distributions. 5,000 iterations are completed although results tend to converge at about 500 iterations.

- Results of the analysis are presented for both sets of gas price distributions

Natural gas price probability distributions





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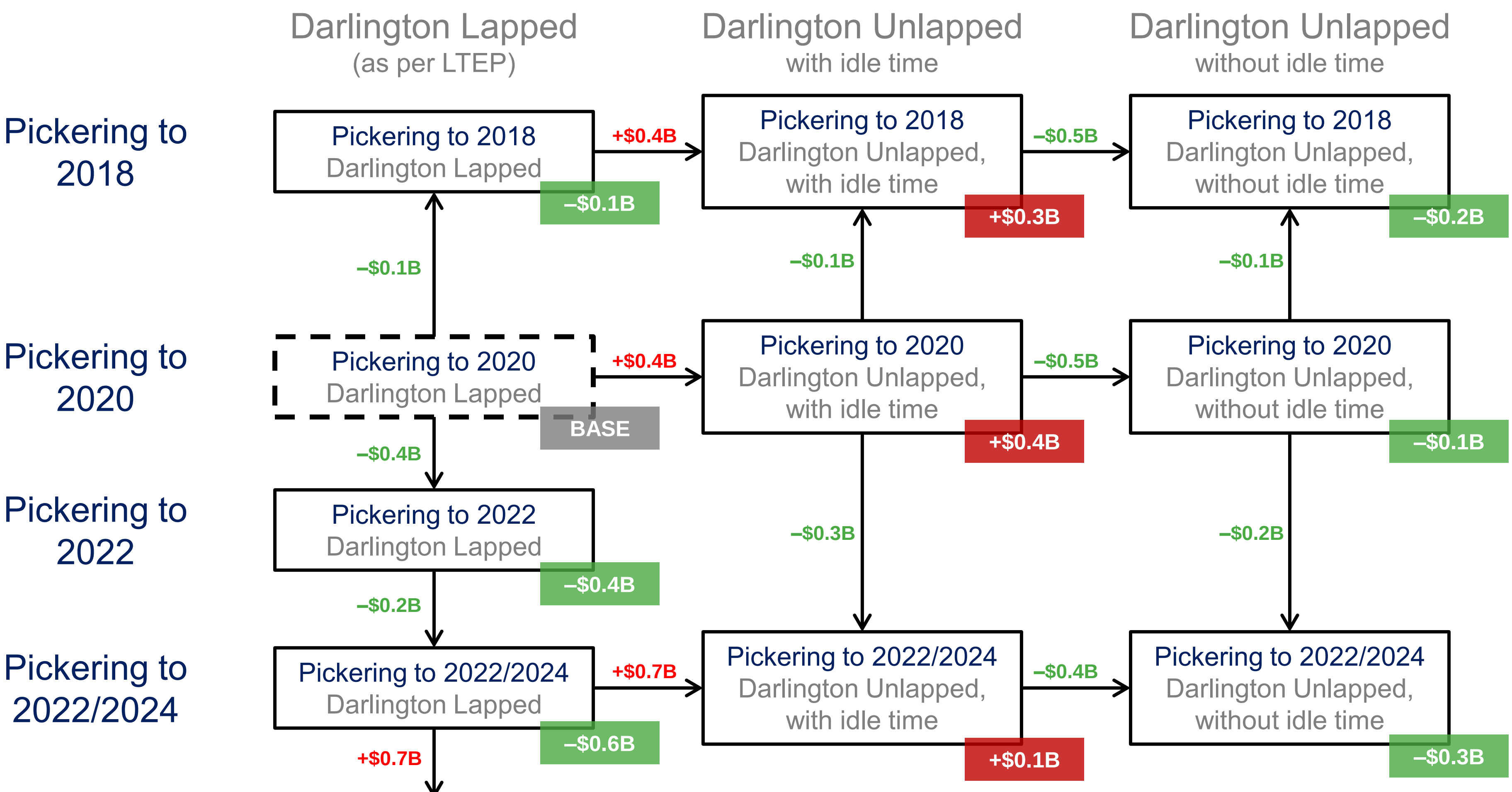
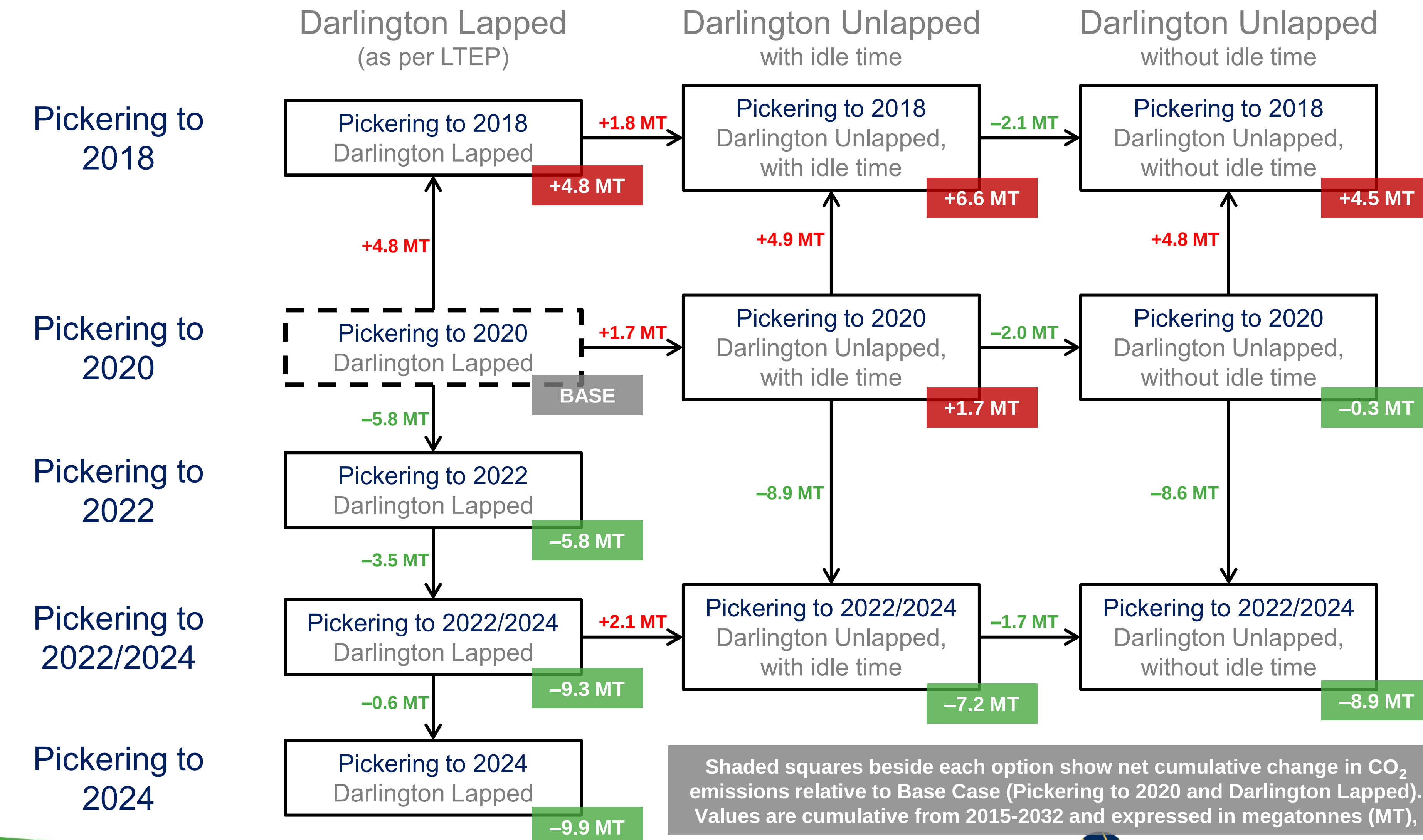
Summary of change in net present value of electricity costs across Pickering/Darlington options



Shaded squares beside each option show cumulative net cost (+) or benefit (-) relative to Base Case (Pickering to 2020 and Darlington Lapped). Net Present Value from 2015-2032 in 2014 $ Billion at 4% real discount rate.

Summary of change in CO_2 emissions across Pickering/Darlington options



Shaded squares beside each option show net cumulative change in CO_2 emissions relative to Base Case (Pickering to 2020 and Darlington Lapped). Values are cumulative from 2015-2032 and expressed in megatonnes (MT),

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ONTARIO POWER GENERATION

November 2015

File: P-BCS-00970-0001 REV: 000

Reviews and Approvals

Name	Title	Action	Signature	Date
B. McGee	Senior Vice President - Pickering	Review		
L. Swami	Senior Vice President – Decommissioning & Nuclear Waste Management	Review		
P. Pasquet	Senior Vice President	Review		
S. Woods	SVP and Chief Nuclear Engineer	Technical Concurrence		
C. Carmichael	Vice President – Nuclear Finance	Financial Review	[signature]	Nov 10/15
A. Barrett	Vice President – Regulatory Affairs	Regulatory Review		
G. Jager	President, OPG Nuclear and Chief Nuclear Officer	Recommend BCS	Please sign on Executive Summary	
B. Summers	Chief Financial Officer	Finance Approval	Please sign on Executive Summary [signature]	Nov 11, 2015
J. Lyash	President & CEO	Approval	Please sign on Executive Summary [signature]	Nov 12, 2015

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ONTARIO POWER GENERATION

November 2015

File: P-BCS-00970-0001 REV: 000

Technical and Economic Assessment of Pickering Extended Operations beyond 2020

October 2015

Contents

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EXECUTIVE SUMMARY:

RECOMMENDATIONS:

1. Extended Operations of all six Pickering Units beyond the end of 2020 shows economic value and qualitative benefits to OPG and the Ontario electricity system. Based on this assessment, operation of two units to nominally 2022 and the remaining 4 units to nominally 2024 is recommended.
2. OPG should continue working to provide improved certainty associated with implementation of the Preferred Extended Operations Alternative by refining the extended operations targeted ends-of-life for each unit as greater certainty becomes available regarding the technical fitness-for service of the fuel channels in each of the units.
3. The incremental costs to enable Extended Operations are estimated at approximately $310M. It is recommended that $52M (including $5M contingency) be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

OPG's planning assumption for the 2015-2017 Business Plan had all six of the Pickering units shutting down at the end of 2020. OPG has been working with the IESO and the Ministry of Energy to explore options to extend operations beyond 2020. Preliminary technical and economic assessments have been undertaken that demonstrate that extending operations would be safe, is technically feasible and would have economic and qualitative benefits. Extending the life of Pickering would also optimize the value of OPG's existing assets, improve OPG's financial position and mitigate Ontario electricity system capacity uncertainties during Darlington and Bruce Refurbishment outages in the early 2020s. This business case summarizes the status of the technical and economic feasibility assessment of continuing to operate the Pickering Units for 2-4 years after 2020.

In the fall of 2014 and early 2015, OPG assessed a number of alternatives for extending the operation of Pickering beyond the end of 2020. Data was provided to the IESO in December 2014 and again in October 2015 to facilitate the completion of an independent system economic value analysis. The Ministry of Energy was periodically briefed on the status of the assessments.

Based on the assessments completed by OPG and independently by the IESO, the preferred alternative of operating six units to 2022 and four units to 2024 was selected in the spring of 2015. This alternative, herein called the **Preferred Alternative** is summarized in Table E1 below:

Table E1: Preferred Alternative Selected

Preferred Alternative			
P1 & 4 (End of)	P5-8 (End of)	Assumed VBO (*)	Comments
2022	2024	2021	High Confidence in Fuel Channel life assumed to be achieved to the end of 2024 for P5-8. Preferred alternative from a system value perspective.

OPG has assessed the incremental generation associated with the Preferred Alternative. Incremental generation is the amount of generation over and above that which would have been achieved in the Base Case of operation to 2020. OPG's economic assessment shows that the value to the Ontario electricity system ranges from $0.5 Billion to $0.6 Billion.

In addition, OPG has assessed numerous benefits including reduced OPG nuclear rates, financial benefits, deferral of severance and related costs, and deferral / reduction of nuclear rate spikes associated with the shutting down of Pickering and placing the refurbished Darlington units in service. Extending Pickering operations would improve OPG's cash flow by $4 Billion from 2021 to 2024 compared to the alternative of shutting down in 2020 and assumes that OPG implements a rate smoothing deferral account. Extending Pickering operations also provides incremental net income to OPG. Extension of the Pickering plant to 2022/2024 would allow OPG to execute the job reductions associated with the shutdown at or near the end of the Darlington Refurbishment Project, thereby reducing the amount of disruption such a large downsizing could potentially have on that project.

The incremental costs to enable the Preferred Alternative have been estimated at approximately $310M. Incremental costs incurred from 2016-2020 to enable extended operations are required to execute work programs that will allow Pickering to operate beyond 2020. These costs would not have been required in the base case if Pickering was shutting down in 2020. There are also incremental costs required to restore on-going operating programs to normal levels of spending prior to and including 2020. For example, planned outages eliminated in 2020 as part of the base case would now need to be restored as part of normal operating practice. Finally, costs from 2021-2024 reflect normal operating costs for that period of time. Costs are summarized in Table E2.

Table E2: Estimated Incremental Costs to Enable Extended Operations

Work Program	2016 - 2020 ($M)	Post 2020 ($M)	Totals ($M)	Comments
Normal Extension of Base & Outage OM&A, Projects, Nuclear and Corporate Support Costs	240	4,220	4,460	Restoring resources to normal levels pre-2020 and costs to operate post-2020
Total Costs to Enable Extended Operations Alternative	310	0	310	Incremental work program costs required to enable extended operations
Grand Total	**550**	**4,220**	**4,770**	

A partial release of $52M (including $5M contingency) would cover the costs of incremental work programs required in 2016 and 2017 to extend operations including the Fuel Channel Life Assurance Project, the Periodic Safety Review and incremental inspections and maintenance work required to demonstrate fitness for service of major components during the extended operations period.

The normal costs to operate the station into the Extended Operations period are estimated at $4.5B. This includes approximately $240 Million leading up to 2020 to restore work program costs which were set to decline in the Base Case, plus $4.2B to operate and provide support services to the plant in the post-2020 period.

Table E3 summarizes the generation forecasts developed for the extended operations Preferred Alternative.

Table E3: Estimated Generation Impacts of the Preferred Alternative

Generation Plan		2016 - 2020	Post 2020	Total
OPTION 1	Additional Planned Outage Days	630	1,103	**1,734**
	Incremental TWh	-7.4	71.9	**64.5**
OPTION 2	Additional Planned Outage Days	637	1,354	**1,991**
	Incremental TWh	-7.5	68.9	**61.5**

The additional outage days in the period 2016 to 2020 are associated with incremental inspections required to enable the Preferred Alternative as well as restore normal planned outages and durations in 2020. In the Base Case (planned shutdown in 2020) certain planned outages in 2020 would not have been necessary or would have been reduced in scope.

The planned outage days in the period 2021 to 2024 are associated with operation of the units for the additional 2 and 4 calendar years (a total of 20 additional unit-years). The two options reflect the range of outcomes required to execute inspection and maintenance activities necessary to maintain fitness for service of plant equipment.

The "medium" to "high" risks associated with the Preferred Alternative are summarized below:

1. Reputational Risk (High): e.g. the risk that interest groups that are opposed to nuclear power will contest Extended Operations, particularly during the next license renewal process, and thereby cause increased community concern and potential earlier shutdown than planned. *Mitigating Actions:* Ongoing demonstration of the value and safety of Pickering through external communications, hearings and stakeholder relations.
2. Regulatory Risks (Medium): e.g. the risk that the proposed disposition for one or more known issues is not accepted by the CNSC. *Mitigating Actions:* Completion of the PSR and a pro-active approach with the CNSC to demonstrate technical fitness-for-service and maintenance of high safety standards.
3. Technical/Fitness-for-Service Risks (Medium): e.g. the risk that a major component, e.g. fuel channels, does not continue to meet fitness-for-service requirements. *Mitigating Actions:* On-going comprehensive inspection and maintenance programs are included in the work program; life cycle management program of major components adjusted based on the extended end-of-life dates.
4. System Value Assessment (Medium) – changes to Ontario system parameters such as flat or declining load growth, reduction in the cost of competing generation or changes to baseload supply (e.g. refurbishment schedules changes) could impact the overall economic system value negatively. *Mitigating Actions:* None that OPG can implement directly. Robust analysis across a range of scenarios and OPG ensuring that costs and generation forecasts are achieved.

Management assesses the risks associated with the extended operations Preferred Alternative to be manageable.

Management recommends that funding of $52M be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

SIGNATURES

Recommended by:

11 Nov 2015
Glenn Jager Date
President OPG Nuclear & Chief Nuclear Officer

Finance Approval:

Nov 11, 2015
Beth Summers Date
Chief Financial Officer

Line Approval per OAR Element 1.3:

Nov 12, 2015
Jeff Lyash Date
President & Chief Executive Officer

BACKGROUND:

OPG's planning assumption for the 2015-2017 Business Plan had all six of the Pickering units shutting down at the end of 2020. OPG has been working with the IESO and the Ministry of Energy to explore options to extend operations beyond 2020. Preliminary technical and economic assessments have been undertaken that demonstrate that extending operations would be safe, technically feasible and would have economic and qualitative benefits. Extending the life of the Pickering GS would also optimize the value of OPG's existing assets, improve OPG's financial position and mitigate Ontario electricity system capacity uncertainties during the Darlington and Bruce Refurbishment outages in the early 2020s. This business case summarizes the status of the technical and economic feasibility assessment of continuing to operate the Pickering Units for 2-4 years after 2020, and outlines the work programs, costs, generation impacts and benefits of implementing the Preferred Alternative.

ALTERNATIVES ANALYSED

As summarized in Table 1, five Extended Operations alternatives were assessed at a conceptual level in addition to the current planning reference of operating all six units to the end of 2020.

Table 1: Pickering Extended Operations Alternatives Analysed

Case	Description			
	P1 & 4 (End of)	**P5-8 (End of)**	**Assumed VBO (*)**	**Comments**
Base	2020	2020	None	Base Case for 2015 to 2017 Business Planning was 2020 Shutdown of all units.
Alt 1	2022	2022	None	Fuel Channel Life assumed sufficient to achieve the end of 2022 without life management. Not preferred from a rate impact and system value perspective.
Alt 2	2022	2024	2021	High Confidence in Fuel Channel life assumed to be achieved to the end of 2024 for P5-8. Preferred alternative from a rate impact and system value perspective.
Alt 2LM	2024	2024	2021	Fuel Channel Life constraints would require life management on two units to achieve the end of 2024. Lower value to system than preferred alternative. Rate in early period due to life management and rate spikes than in Alternative 2
Alt 3A	2024	2024	2021	Low technical confidence that all six units could operate to the end of 2024
Alt 3B**	P1 2022 P4 2024	2024	2021	Potentially high operating costs for Unit 4 without Unit 1. Future option may be enabled after further analysis.

* A Vacuum Building Outage is assumed in 2021 for all alternatives where units operate beyond 2022.

** This alternative was assessed at a high-level only. The current assumption is that the alternative will be technically viable. However, the cost of operating P4 in the absence of P1 needs to be assessed in more detail.

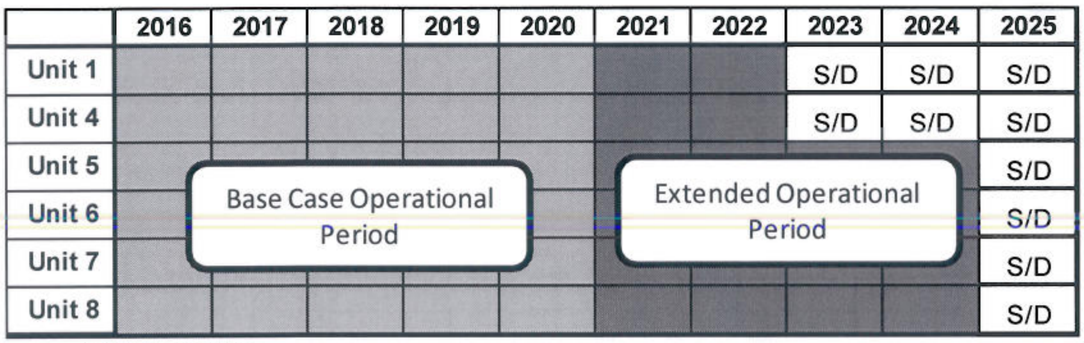
The IESO was provided with data on the above alternatives in December 2014 in order to facilitate an independent system economic value analysis. Based on the assessments completed by OPG and independently by the IESO, the preferred alternative of operating six units to 2022 and four units to 2024 was selected in the spring of 2015. This alternative is referred to as the **Preferred Alternative** in the remainder of this document.

Table 2: Preferred Alternative Selected

P1 & 4 (End of)	P5-8 (End of)	Assumed VBO (*)	Comments
2022	2024	2021	High Confidence in Fuel Channel life assumed to be achieved to the end of 2024 for P5-8. Preferred alternative from a rate impact and system value perspective.

Figure 1 shows a schematic of the remaining operational period of the Pickering units in the Base Case and the period over which the units would be operated in the Preferred Alternative.

Figure 1: Schematic showing "Base Case" and Preferred Extended Operations Alternative



S/D = shutdown

PICKERING SAFE OPERATION

To assure management that the plant is and will continue to be safe in the future, there are ongoing assessments of the condition of plant equipment. When the plant is operated beyond its original design life, the assessment of the condition of the major components such as fuel channels, feeders and steam generators is most important. This is done through an extensive inspection program during planned outages. The required inspections and maintenance of components is specified in life cycle management plans which are used to determine that the plant components are fit for their intended service.

At the end of outage inspections, fitness-for-service assessments are completed to confirm that the components are able to function as designed until the next inspection campaign. If the assessments cannot demonstrate that component condition is acceptable, the component will be replaced or repaired. If the work required is significant, management may determine that the unit is no longer able to continue to operate. The frequency of inspections and assessments is such that this determination would be made and a decision would be taken long before component failure, thereby preventing any nuclear safety event.

The fitness-for-service assessments are also independently reviewed by staff from the Canadian Nuclear Safety Commission and, if warranted, OPG would be requested to take appropriate action to address any issues.

TECHNICAL ASSESSMENT SUMMARY

An initial technical assessment of the ability of the Pickering units to continue to be fit for service to the dates set out in the Preferred Alternative has been completed. The scope of work required to develop high confidence in the fitness-for-service to these dates has been identified. As expected, the limiting major component is the life expectancy of the fuel channels.

Technical assessment work on the fuel channels' fitness-for-service will continue through the Fuel Channel Life Assurance Project with the aim of completing a high confidence prediction of fuel channel fitness-for-service on all units by the end of 2017.

The technical fitness for service of other major components such as the Steam Generators, is not considered life limiting; however, additional inspection and maintenance scope is required to assure fitness-for-service to the dates in the Preferred Alternative. This additional work has been identified; impacts on the generation plan developed and the costs are included in the forecasts.

Fuel Channels:

The technical assessment has identified that the major concern is axial elongation of the pressure tubes. A number of channels are expected to reach the limits of available bearing travel (i.e. when the leading pressure tubes will no longer be supported on their bearings), with Units 1 and 6 being of greatest concern.

Table 3 summarizes the current confidence level for operation to 2024 for all units.

Table 3: Current Level of Confidence in Operation to 2022/2024 – All Units

Unit	Current Confidence for Operation to 2022/2024	Comments
Unit 1	Low	Current projections indicate potential for channels off-bearing by 3rd Quarter 2021
Unit 4	High	Operation to 2024 is possible technically based on pressure tube degradation mechanisms
Unit 5	Medium	Current projections indicate potential for channels off-bearing by late 2022/early 2023
Unit 6	Low	Current projections indicate potential for channels off-bearing by mid-2022
Unit 7	Medium	Current projections indicate potential for channels off-bearing by late 2022/early 2023
Unit 8	High	No channels projected off bearing to end of 2024

Several mitigation measures are available for pressure tube elongation. These include physical modifications as well as more detailed technical evaluations to refine assessments of the timing and number of channels which would approach limits of bearing travel on each unit. Some of the physical modifications which are available would be costly to implement and some of the technical solutions are complex and/or would require increasing the complexity of operational procedures. Therefore, the preliminary plans to enable the Preferred Alternative include only the less costly physical modifications and less complex technical evaluations. However, the remaining mitigation options have not been ruled out and will be assessed as part of the Fuel Channel Life Assurance Project. The costs of the Fuel Channel Life Assurance Project are covered in the partial release requested in this Business Case.

Currently, pending more detailed review and development of mitigation plans, Units 1 and 6 would be challenged to meet the end dates in the Preferred Extended Operations Alternative. Two other units, Units 4 and 8, are assessed to be able to surpass the planned end of operation dates, if necessary

Unit 1 is challenged by available bearing travel in order to achieve the end of 2022 in the Preferred Alternative. However, with expected mitigation, operation of Unit 1 into mid-to-late 2022 is likely. Further mitigation would be required to enable Unit 1 to operate to the end of 2022. A final determination of the shutdown date of Unit 1 will be dependent on the results of the Fuel Channel Life Assurance Project.

Unit 6 is challenged by available bearing travel to achieve the target date of the end of 2024 in the Preferred Alternative. However, with mitigation, there is a potential to operate Unit 6 into mid-to-late 2023 and even into 2024. Confidence in operation to the end of 2024 is low at this time. Unit 6 may be replaced by Unit 4 as one of the four units operating to the end of 2024, depending on economics and the outcome of the technical analysis.

Units 5 and 7, based on current projections of available bearing travel, would have a minimal number of channels projected to be off-bearing by late 2022/early 2023 but with mitigation can be operated longer. Confidence in operation to the end of 2024 is medium to high at this time.

Unit 4 does not face the same issues with available bearing travel as Unit 1; therefore, confidence in operation until the end of 2022 is currently high. There is a potential that the Preferred Alternative may evolve to have Unit 4 replace Unit 6 as one of the four units operating to 2024.

Unit 8, having been the last unit to be placed in-service, has the lowest operational service life of Units 5-8, and is not projected to reach available bearing travel limits before the end of 2024; therefore, confidence in operation until the end of 2024 is currently high.

As mitigation plans are developed in more detail, the Preferred Alternative may be refined with more precise end-of-operation target dates for each unit.

In addition to pressure tube elongation, other fuel channel degradation mechanisms are of concern, but are not seen as limiting the operation of the units in the Preferred Alternative. Table 4 lists some of the concerns:

Table 4: Fuel Channel Risks Associated with Operation of P1&4 to 2022 and P5-8 to 2024

Mechanism	Concerns	Level of Concern	Potential Mitigation
Pressure Tube (PT) Elongation	**P1** Up to 43 channels off-bearing by end 2022 if no add'l mitigation	**High**	• **Physical**: Reconfigure and Shift fuel channels • **Analytical:** Evaluations to disposition operation with a limited number of channels off-bearing
	P6 Up to 78 channels off-bearing by end 2024 if no add'l mitigation	**High**	
Calandria Tube (CT) Sag P1/4 **CT to LISS(1) Nozzle contact P5-8**	**P1 & 4** – potential for PT to CT contact given detensioning of tight fitting spacers. CTs were not replaced during retube, and modeling is not currently possible	**Medium**	• **Inspection**: Additional measurements and sampling to demonstrate low probability of PT to CT contact and hydrogen concentration below specified levels. • **Analytical**: Disposition likelihood of channels exceeding operational limits
	P5-6: Potential for ~10 channels to contact with LISS nozzles by end 2024	**Medium**	• **Inspection:** Repeat measurements could yield increased margins • **Physical:** Potential need to replace individual fuel channels
Pressure Tube Fracture Toughness	Potential to exceed fracture toughness thresholds	**Low**	• **Analytical:** Work underway to develop updated fracture toughness curves for P1& 4 & P5-8 – small potential for station modifications

(1) LISS – Liquid Injection Shutdown System – these nozzles extend horizontally into the reactor core and could come into contact with calandria tubes late in life on certain units, resulting in concerns regarding calandria tube integrity.

Steam Generators and Feeders:

Preliminary assessments indicate that steam generators and feeders do not present a significant hurdle for proving fitness-for-service of the units. Steam generators are not expected to show any significant degradation in performance provided that maintenance (water-lancing) and inspection campaigns are extended appropriately for each of the extended life scenarios. Similarly, a limited number of feeder replacements are required on Units 5-8 in order to operate to 2024.

Balance of Plant:

Balance of plant components, including the turbine-generator sets, the condensers, heat exchangers and major motors have also been assessed based on current system health reports and previous condition assessments, and no significant issues have been found which would preclude operation to 2024. Normal maintenance activities would continue in the Extended Operations period. Condition assessments are being updated based on a 2024 end-of-life date. The cost of this work is included in the Partial Release requested in the Business Case.

REGULATORY APPROVALS

In addition to component fitness-for-service uncertainties, the Preferred Alternative of extending operations will require concurrence by the CNSC. The current power reactor operating licence for Pickering was issued in September 2013 for a 5 year term (expiring in 2018). The license included a requirement that OPG confirm, in writing, by June 30, 2017 the planned end-of-life date for Pickering. OPG expects to provide that confirmation with the licence application for the next operational period. OPG's strategy will be to secure a 10-year licence renewal which will take the units to the end of commercial operations and through the safe storage project period, i.e. until the units are in the safe stored state. CNSC concurrence with operation beyond 2020 will occur in the context of the Pickering licence renewal in 2018.

OPG has determined, based on discussions with the CNSC, that an update to the Periodic Safety Review (PSR) will be required in advance of the 2018 Re-licensing Hearings if OPG plans to extend operations beyond 2020. The PSR, which is already underway, will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. Management has scheduled completion of the PSR by the end of 2016, such that the information confirming that Pickering is safe to operate will be available prior to the decision on the permanent shutdown dates of the Pickering units and the required formal communication of that decision to the Commission by June 30, 2017.

A Periodic Safety Review evaluates an existing plant and the programmes used in its operation against the modern standards that would apply to a new nuclear plant. The evaluation may identify where, on a going forward basis, enhancements to the current design or programmes could be made. The potential safety enhancements are then assessed to identify the alternatives that can be reasonably and practicably implemented to improve safety, if any, in the context of 4 years of additional operations. There is a medium risk that the results of this updated assessment may require physical modifications to be implemented to the plant.

A key to risk mitigation for OPG will be establishing with certainty the regulatory requirements and how these interrelate to the timing of the end of extended operations, as well as maintaining openness and establishing good lines of communication with all key stakeholders.

Management is confident that a list of reasonable and practicable safety enhancements can be reached with the CNSC staff in view of the 4 years of additional operation that is sought.

STAFFING

On-going staffing risks will continue to require close management attention in order to ensure safe operation in the Preferred Alternative. For example, the sufficiency of authorized operators and control room shift supervisors has been assessed and costs have been included in the forecast to extend planned training programs for authorized staff to ensure an adequate supply. Because of the criticality of these resources to safe operations, on-going reviews will continue as part of Business and Operational Planning.

Leadership development and succession planning will be revisited with a view to ensuring that leadership will be available for the extended operation period.

COSTS AND GENERATION ASSUMPTIONS

In developing the Preferred Alternative, OPG's objective is to establish with medium to high confidence the appropriate incremental work and related costs over and above those costs included in the Base Case required to enable the extended operations. OPG's approach is summarized in the following 8 steps:

1. Resources and associated costs (Base OM&A, Outage OM&A, Projects, Nuclear and Corporate Support) are continued at normal levels during the extended operation period.
2. Additional inspections and maintenance scope for major components (fuel channels, steam generators, feeders and reactor components) are identified in detail and the impacts on outage durations and costs (primarily fuel channel inspections and maintenance) are assessed.

3. Additional "Balance of Plant" scope is identified, estimated and the impact on outages and costs (if any) are assessed.
4. Additional sustaining investments (Capital and OM&A projects) are identified, and impacts on outages and costs (if any) assessed.
5. Additional analytical scope (primarily regulatory and engineering) is identified and costs and resources estimated
6. Any other additional enabling scope (e.g. staff retention costs) is identified and estimated
7. Nuclear Support and Corporate Support costs are assessed
8. Amounts are estimated to address known uncertainties

Based on the above assessments, the costs and outage impacts have been estimated and included in the assessment of the Preferred Alternative. Also, amounts have been included to fund the Period Safety Review and any potential modifications resulting from that review.

The incremental costs to enable the Preferred Alternative have been estimated approximately $310M. Incremental costs incurred from 2016-2020 to enable extended operations are required to execute work programs that will allow Pickering to operate beyond 2020. These costs would not have been required in the base case if Pickering was shutting down in 2020. There are also incremental costs required to restore on-going operating programs to normal levels of spending prior to and including 2020. For example, planned outages eliminated in 2020 as part of the base case would now need to be restored as part of normal operating practice. Finally, costs from 2021-2024 simply reflect normal operating costs for that period of time. Costs of the Preferred Alternative are summarized in Table 5.

Table 5: Summary of Costs - Preferred Alternative

Work Program	2016 - 2020 ($M)	Post 2020 ($M)	Totals ($M)	Comments
Normal Extension of Base & Outage OM&A, Projects, Nuclear and Corporate Support Costs	240	4,220	4,460	Restoring resources to normal levels pre-2020 and costs to operate post-2020
Total Costs to Enable Extended Operations Alternative	310	0	310	Incremental work program costs required to enable extended operations
Grand Total	**550**	**4,220**	**4,770**	

Additional details associated with the costs to enable the Preferred Alternative are provided in Appendix 1.

Table 6 summarizes the generation forecasts developed for the extended operations Preferred Alternative.

Table 6: Estimated Generation Impacts of the Preferred Alternative

Generation Plan		2016 - 2020	Post 2020	Total
OPTION 1	Additional Planned Outage Days	630	1,103	**1,734**
	Incremental TWh	-7.4	71.9	**64.5**
OPTION 2	Additional Planned Outage Days	637	1,354	**1,991**
	Incremental TWh	-7.5	68.9	**61.5**

The additional outage days in the period 2016 to 2020 are associated with incremental inspections required to enable the Preferred Alternative, as well as restore normal planned outages and durations in 2020 that would have been reduced or not necessary in the Base Case (planned shutdown in 2020).

The planned outage days in the period 2021 to 2024 are associated with operation of the units for the additional 2 and 4 calendar years (a total of 20 additional unit-years). The two options reflect the range of outcomes required to execute inspection and maintenance activities necessary to maintain fitness for service of plant equipment.

ECONOMIC ASSESSMENT SUMMARY

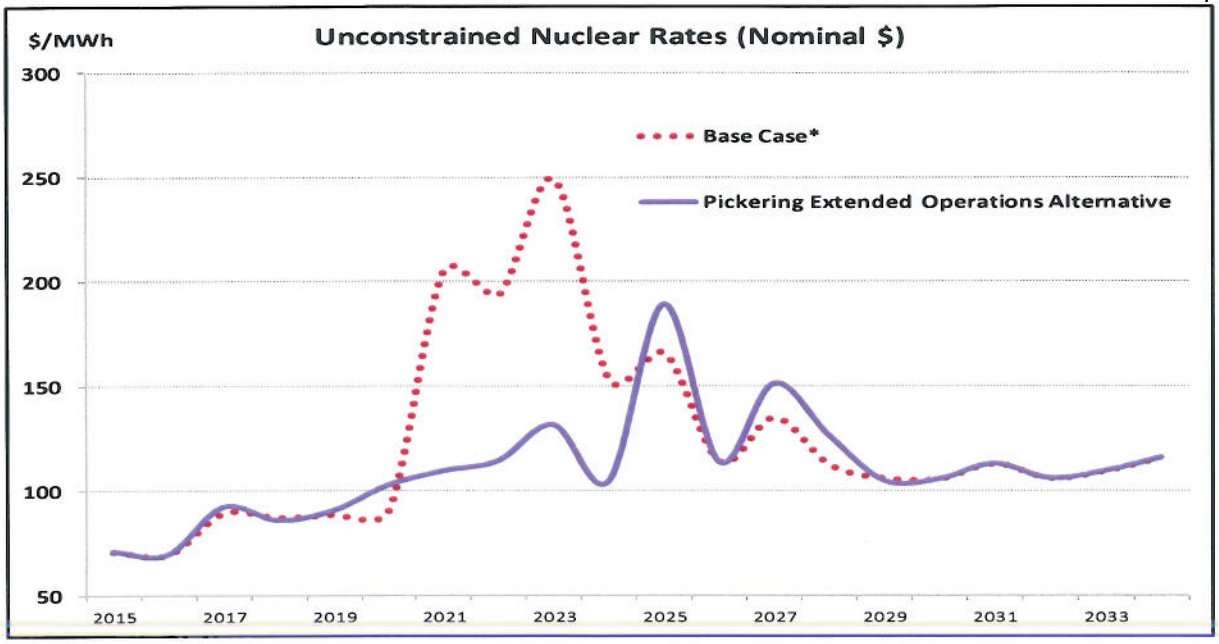
The Levelized Unit Energy Costs (LUEC) of the Preferred Alternative, i.e. the LUEC associated with the incremental costs and generation relative to the Base Case, is evaluated at 6.2 ¢/kWh to 6.5 ¢/kWh for the two options. LUEC calculations exclude the benefit of deferring severance and related costs.

The Preferred Alternative also provides a number of quantitative economic advantages for both the ratepayer and OPG. The major economic advantages are:

- **Financial Impacts:** Extending Pickering operations would improve OPG's cash flow by $4 Billion in the 2021 to 2024 period compared to the alternative of shutting down in 2020 and assuming that OPG implements a rate smoothing deferral account. Extending Pickering operations also provides incremental net income to OPG.

- **Rate Impacts:** Figure 2 shows the impact of the Preferred Alternative on OPG Nuclear rates. Extending Operations moderates the rate impacts associated with the refurbishment and return to service of the Darlington units and the earlier shutdown of Pickering which would occur in the Base Case. This occurs because extending Pickering Operations results in a larger OPG generation base over which to spread the impacts of the Darlington Refurbishment costs being placed into the rate base and because the severance and related closure costs of Pickering would be deferred.

Figure 2: OPG Nuclear Rate Impacts of Preferred Alternatives



*Note: These rate projections do not yet include finalized assumptions regarding Darlington Refurbishment Costs; however no material change is expected to these rate curves.

- **Severance and Related Costs:** Defers costs associated with closure of the station, such as severance and related costs, and pension curtailment and settlement resulting in a potential reduction in the present value of the severance and related costs. While there is significant uncertainty around these costs the deferral of these costs by 4 years, even if there is no change in the nominal value, would results in present value savings. Demographic changes by the end of Extended Operations could result in a reduction of the estimate of severance costs, potentially resulting in higher estimated Present Value savings.

- **Decommissioning Liability:** Defers expenditures associated with placing the units in the safe-stored state, and the assumed deferral of the expenditures associated with dismantling of the units. The effect is to reduce the liability associated with decommissioning of the Pickering station. This value is considered by the IESO in its assessments.

- **System Economic Value:** For the Ontario system, extended operation of Pickering would mitigate capacity availability uncertainties associated with the refurbishments of the Darlington and Bruce stations. Availability of Pickering would reduce the need to operate gas-fired capacity and would result in reduced CO_2 emissions over the 2021 to 2024 period. OPG's assessment of the median value to the Ontario electricity system of the Preferred Alternative, relative to the Base Case is summarized in Table 7.

Table 7: System Economic Value – Preferred Alternative P1& 4 S/D 2022; P5-8 S/D 2024

Generation Plan	Net Incr. Energy (TWh)	CO_2 Red'n (MT)	Med. System Economic Value (2015$M NPV)	Comments
OPTION 1	65	~18	610	System value is higher because of the assumed higher generation from 2021-2024.
OPTION 2	62	~16	530	

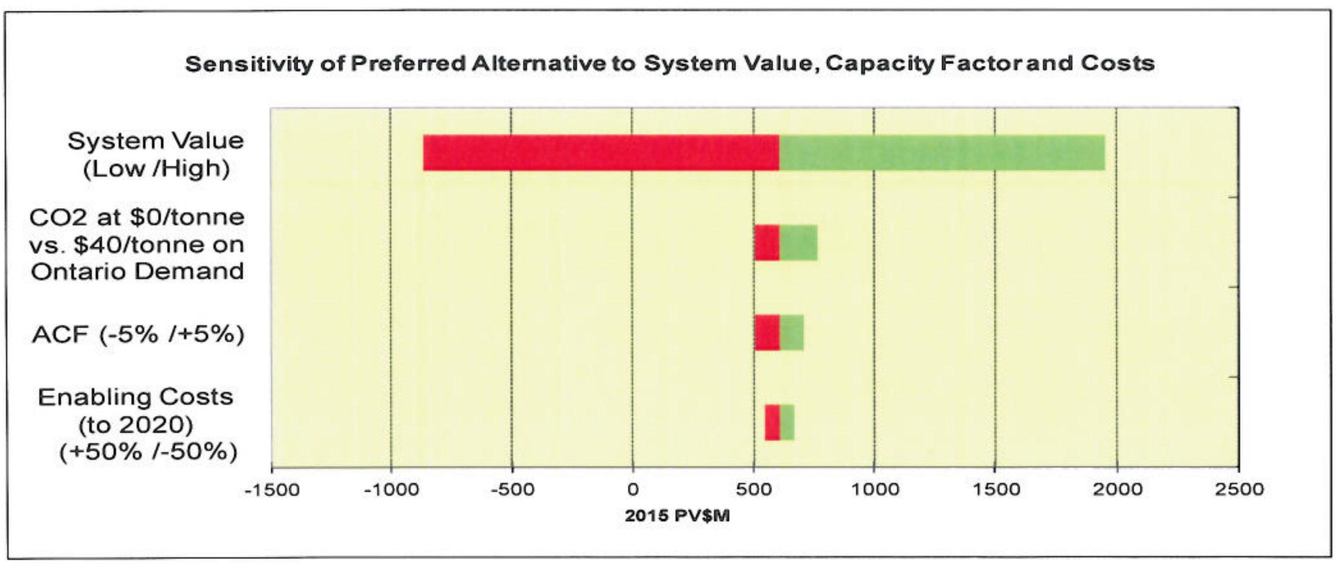
The values in Table 7 include a benefit of $245M (2015 PV$) associated with the reduced present value of severance and related costs. Also includes is a benefit of $100M representing the value of the reduction in the decommissioning liability as a result of the deferral in the decommissioning expenditures.

The IESO has completed an updated assessment using data provided by OPG in October 2015. The assessment shows a benefit ranging from ~$0.3 Billion (2015 PV$) to ~$0.5 Billion (2015 PV$). The IESO's assessment, therefore closely corresponds to OPG's internal assessment. The IESO uses a lower real discount rate (4% vs. OPG's approx. 5%) and different system assumptions (e.g. for load growth and the price of gas-fired generation).

Figure 3 shows the sensitivities of the system economic value for OPTION 1 to uncertainties in the system energy and capacity value, the performance and the incremental costs to enable the Preferred Alternative, and the value of carbon reduction.

The system economic value of the Preferred Alternative is significantly more sensitive to system assumptions than to the costs and performance of Pickering.

Figure 3: Sensitivity of System Economic Value (PLAN 1) to Changes in Assumptions



QUALITATIVE CONSIDERATIONS

The following qualitative considerations associated with Extended Operations are of significant potential value to OPG and Ontario:

- **Deferral of Job Losses:** Would defer direct job losses of approximately 4,000 in OPG, affecting the GTA and Durham Region; there would also be impacts on indirect and induced jobs and the economy, particularly in Durham Region.
- **Strategic Capacity Hedge during Nuclear Refurbishments:** Ontario's Long-Term Energy Plan has endorsed Pickering as a strategic hedge against uncertainties in the costs and schedule of refurbishment of the Bruce and Darlington units. Also, extended operation avoids the risk that unneeded gas-fired capacity would be built to address temporary capacity shortfalls during the period of intense nuclear refurbishments.
- **Emissions Reductions:** The Preferred Alternative is expected to result in a net reduction of 16 - 18 million tonnes of CO_2 relative to the operation of the electricity system with replacement energy and capacity for Pickering, which would come primarily from gas-fired generation and increased imports. Therefore, extending Pickering operations aligns with Provincial Government policies to reduce greenhouse gas emissions.
- **Increased Flexibility:** Extending some Pickering units to 2024 provides a more natural transition point for reducing OPG staff levels, as the transition would occur near the end of Darlington Refurbishment, thereby minimizing disruption for both Darlington Operations and Darlington Refurbishment.
- **Planning for Safe Store**: Would provide a longer period to plan for the safe storage of the units, allowing plans and costs to be further optimized.
- **Decommissioning and Used Fuel Funds**: A reduction of the present value of the decommissioning liability for the Pickering units (decommissioning activities can be deferred by several years) could create a larger surplus in the decommissioning fund, decreasing risks around adequacy of the funds and potentially providing future opportunities to utilize that surplus to "top-up" OPG's Used Fuel Fund.

RISK OVERVIEW

Risks associated with the Preferred Extended Operations Alternative are summarized as follows:

1. Reputational Risk (High): e.g. the risk is that interest groups that are opposed to nuclear power will contest Extended Operations, particularly during the next license renewal process, and thereby cause increased community concern. *Mitigating Actions:* Ongoing demonstration of the value and safety of Pickering through external communications, hearings and stakeholder relations.
2. Regulatory Risks (Medium): e.g. the risk that the proposed disposition for one or more known issues is not accepted by the CNSC. *Mitigating Actions:* Completion of the PSR and a pro-active approach with the CNSC to demonstrate technical fitness-for-service and maintenance of high safety standards.
3. Technical/Fitness-for-service Risks (Medium): e.g. the risk that a major component, e.g. fuel channels, does not continue to meet fitness-for-service requirements. *Mitigating Actions:* A comprehensive inspection program has been developed and included in the work program; on-going detailed life cycle management of major components.
4. System Value Assessment (Medium) – changes to Ontario system parameters such as flat or declining load growth impact, reduction in the cost of competing generation or changes to baseload supply (e.g. refurbishment schedules change) could impact the overall

economic system value negatively. *Mitigating Actions:* None that OPG can implement directly. Robust analysis across a range of scenarios and OPG ensuring that costs and generation forecasts are met or exceeded.

5. Economic Risk (Low): e.g. the risk that an unknown significant technical issue or regulatory requirement leads to prohibitively expensive repair / remediation costs. *Mitigating Actions*: On-going internal technical assessments and completion of the Periodic Safety Review.
6. Resources Risk (Low): e.g. the risk that a shortage of skilled resources in OPG results in an inability to address technical and/or operational issues and impair OPG's ability to continue to operate the plant. *Mitigating Actions:* Detailed workforce planning, training to meet demand and use of contracted resources and retention strategies and other measures, as required
7. Rate Recovery Risk (Low) – that the Ontario Energy Board (OEB) will deny the full recovery of costs through the rate setting process. *Mitigating Actions:* development of a comprehensive rate application on the merits of the business case and supporting cost/generation plan. Support from the Ministry of Energy and the IESO for the Preferred Extended Operations Alternative.

RECOMMENDATIONS:

1. Extended Operations of all six Pickering Units beyond the end of 2020 shows economic value and qualitative benefits to OPG and the Ontario electricity system. Based on this assessment, operation of two units to nominally 2022 and the remaining 4 units to nominally 2024 is recommended.
2. OPG should continue work to provide improved certainty associated with implementation of the extended operations Preferred Alternative by refining the extended operations alternative (target ends-of-life for each unit) as greater certainty becomes available regarding the technical fitness-for service of the fuel channels in each of the units.
3. The incremental costs to enable Extended Operations are estimated at approximately $310M. It is recommended that $52M (including $5M contingency) be released in order to complete the Periodic Safety Review, the Fuel Channel Life Assurance Project and to execute incremental outages and inspections in 2016 and 2017. Management will seek a full release following confirmation of the fuel channel life of the units and completion of the Periodic Safety Review.

FOR INTERNAL CONTROL

APPENDIX 1: DETAILS OF COST FORECASTS

Table A1 shows additional details, as well as the annual cost flows associated with enabling the extended operations Preferred Alternative.

The partial release of $52M is based on cost estimates for 2016 & 2017 ($47M) plus $5M of contingency.

Table A1: Preliminary Estimated Incremental Costs to Enable Extended Operations

Work Program	Total 2016 - 2020	2016	2017	2018	2019	2020	Comments
Incremental Pressure Tube, Steam Generator and Feeder Inspections & Maintenance and Outage Costs	236	4	26	34	90	82	Includes Spacer Location and Relocation work, additional Steam Generator water-lancing and feeder replacements.
Fuel Channel Life Assurance Project	9	4	5	-	-	-	Analytical and R&D work to assure high confidence in fuel channel lives
Periodic Safety Review (PSR) Update	8	7	1	-	-	-	Reduced scope PSR (Normal Cost~$20M)
Potential PSR Modifications, Balance of Plant Projects and Improved Inspection Tooling	54	-	-	17	18	19	Certainty of costs will improve after updated condition assessments and PSR is completed. Some tooling may need renewal or improvement
Total Costs to Enable Preferred Alternative	**307**	**15**	**32**	**51**	**108**	**101**	
Partial Release							
Cost to enable (2016 & 2017)	**47**	**15**	**32**				Reflects 2016 & 2017 costs to enable the Preferred Alternative
Contingency	**5**		**5**				10% contingency
Total Partial Release	**52**	**15**	**37**				