GEC INTERROGATORIES (FIRST SET)

Preamble:

The Board's Decision and Order on the Issues List issued on June 4, 2014 indicates that generation planning is not within the scope of the EB-2013-0321 proceeding. In providing answers to the questions below, the OPA is not acknowledging that the questions and answers are within the scope of the proceeding. The OPA will leave it to the Board to decide the extent to which these questions and answers are within the scope of the matters that the Board will address in EB-2013-0321.

1. Confirm that OPA's opinion was and is based on Pickering costs provided by OPG and that OPA has not sought to verify them

A: The OPA's assessment of OPG's proposal for expenditures in 2013 and 2014 to maintain the option of continued operation at Pickering relied on information provided to the OPA by OPG on the cost of continued operation, length of the continued operation period and capability of Pickering units during the continued operation period. This information was accepted by the OPA as given and is summarized in Appendix 1 of EB-2013-0321, Ex. F2-2-3, Attachment 2.

In its assessment, the OPA also considered a range of sensitivity scenarios, including scenarios in which the Pickering nuclear generating station was assumed to have worse operating performance, a shorter than planned continued operation period and higher capital and fixed operating costs. The OPA's overall conclusions on the merits of the Pickering continued operation option are outlined in its August 15, 2012 letter, which includes cost considerations across a range of potential outcomes as well as other considerations which were not quantitatively assessed. It was on the basis of all of these considerations that the OPA indicated in August 2012 its support for OPG to incur approximately $85 million at Pickering from 2013 to 2014 to preserve the option of continued operation.

2. Confirm that the April 16th draft report is the only report and that it underlies the August 15th letter (though the softening of the point estimate reflects the fact that it was an evolving situation).

A: The OPA's letter dated August 15, 2012 (EB-2013-0321, Exhibit F2-2-3, Attachment 2) was informed by analysis described in the draft report prepared by the OPA entitled "Report on the Integrated Power System Planning Impacts of Pickering NGS Continued Operation" and dated April 16, 2012. Since 2012, the OPA has continued to assess the option of Pickering Continued Operations in light of evolving circumstances and has developed two analyses on the subject for OPA-internal purposes. These analyses, prepared in 2013 and 2014, incorporate updates to the OPA's outlook for electricity supply and demand and ongoing refinements to OPA modelling as of the time of preparation. The conclusions of the analyses are consistent with those expressed in the OPA's letter of August 15, 2012. The analyses were not documented as formal written reports.

3. Explain why Bashir's April 24th memo was in error (F.O.I. p. 137)

A: The email from Bashir Bhana dated April 24, 2012 references an Ontario electricity demand forecast prepared by the OPA sometime in the early spring of 2012 and considers the implications of that forecast on OPA's assessment of continued operations at Pickering. In his email, Mr. Bhana observes that the demand forecast in question is generally lower than the medium growth forecast previously assessed by the OPA. Mr. Bhana goes on to anticipate that he would expect the lower forecast to see a reduced net economic benefit from Pickering continued operations relative to the net economic benefit previously estimated against a higher medium growth electricity demand forecast.

The forecast referenced by Mr. Bhana was soon superseded by another electricity demand forecast, which was formally made available to OPA planners for use on June 08, 2012. While still lower than the medium growth forecast described in the OPA's April 16, 2012 report, the June 08, 2012 forecast was generally higher than the forecast referenced by Mr. Bhana by approximately 10 TWh per year. The June 08, 2012 forecast corrected some double counting of "natural" and "program-driven" conservation that was apparent in the forecast referenced by Mr. Bhana in his email.

In time, the June 08, 2012 electricity demand forecast was further refined and updated sometime in the summer of 2012. This summer 2012 forecast informed, along with other supply and modelling updates, a refreshed assessment of Pickering continued operations prepared by the OPA in the spring of 2013.

The OPA prepared another refreshed assessment of Pickering continued operations in the first quarter of 2014, which reflected further supply and demand-related updates. The updates reflected in the OPA's 2014 analysis are consistent with the supply and demand assumptions expressed in the Ontario government's 2013 Long-Term Energy Plan.

4. Confirm that there is not a more recent formal analysis of the costs and benefits of Pickering operations.

A: As indicated above, the OPA has continued to assess Pickering continued operations in light of evolving circumstances, including updated demand forecasts, supply outlooks and modelling refinements. Beyond the report prepared in April 2012, the OPA developed a refreshed analysis in 2013 and another in 2014. The 2013 and 2014 analyses yielded conclusions that are consistent with the OPA's 2012 analysis. The 2013 and 2014 analyses were not written as formal reports.

5. For each of the sensitivity analyses in the April 16th study, indicate OPA's current information and the likely impact of that. Including for example:

   a. the newest load forecast lowers average energy demand by X which (all else being equal) would lower NPV by Y,

   b. Henry Hub futures prices for the 2014-20 period are currently in the $4.2 - $4.8 range? so compared to the study assumption of prices rising to $5.5 by 2015 and holding there through 2020 that would result in NPV shift of X

   c. Indicate whether OPA has new info on capacity factor or operating or capital costs… and what that info is, that would significantly change conclusions and quantify

A: Due to time limitations, the OPA is unable to assess each sensitivity scenario as requested in the above question in detail. In case it is helpful, however, the OPA's 2013 and 2014 assessments of continued operations at Pickering reflected ongoing changes to the OPA's outlook for Ontario supply and demand and produced results that were consistent with those of the OPA's 2012 assessment.

Broadly, the OPA's 2013 and 2014 assessments of the economic costs/benefits of Pickering continued operation tended to yield results that were consistent with its 2012 assessment and supportive of the conclusions and recommendations made.

If taken on its own, a reduced outlook for Ontario electricity demand would tend to diminish the economic benefits of Pickering continued operation. The effect of a lower demand would be to reduce opportunities for electricity produced by Pickering under continued operation to offset production from other, more expensive sources. Conversely, a higher electricity demand would increase opportunities in this regard.

Similarly, a lower natural gas price would, on its own, improve the cost competitiveness of production from natural gas-fired sources relative to production from Pickering during the continued operation period. It follows that higher natural gas prices would decrease the cost competitiveness of production from natural gas-fired resources compared to continued operation at Pickering. The range of natural gas prices referenced in the question falls within the range of natural gas prices considered in the OPA's assessments of continued operations at Pickering.

The operational performance of Pickering continued operations would also have bearing on its economic performance. For example, a lower capacity factor would reduce the amount of electricity produced from Pickering and therefore diminish opportunities for electricity from Pickering to displace electricity from more expensive sources. While the average forced loss rate, capability factor and planned outage assumptions that the OPA relied upon for reference scenario purposes are outlined in its April 2012 report, the OPA also considered both better and worse possibilities for sensitivity purposes in its 2012 analysis. For example, the OPA considered a sensitivity in which Pickering was assumed to have an average annual capacity factor of approximately 64% during the continued operation period – this was based on the worst five-year average in the plant's history and, within the OPA's analysis, had the effect of lowering output from Pickering by a total of 34 TWh over the period assessed. Conversely, the OPA also considered a sensitivity in which Pickering was assumed to have an annual capacity factor of approximately 85% during the continued operation period – this was based on the best five-year average in the plant's history.

6. Confirm that OPA assumed all Pickering units operating into 2020

A: Not all Pickering units were assumed to operate to 2020 in the OPA's analysis. Based on the information received from OPG, the OPA assumed in its analysis that five units at Pickering would operate into 2020, whereas one Pickering unit would operate into 2019 but not into 2020.

7. Indicate what cost if any was assumed for FCLE to enable 2020

A: Assumptions related to the costs of Pickering continued operations were provided to the OPA by OPG and are summarized in Appendix 1 of EB-2013-0321, Ex. F2-2-3, Attachment 2. Costs provided by OPG broadly relate to Capital and OM&A for plant operation, fuel and fuel-related costs as well as costs to enable continued operation in 2013-2014. These aggregated groups of costs were expressed as incremental costs attributable to continued operation between 2013 and 2020 (i.e. incremental to if Pickering did not continue to operate).

8. Confirm that OPA did not consider and is not in a position to evaluate the cost implications of new CNSC requirements post-Fukishima or those expected as a result of its May 7th decision conditions.

A: Confirmed.

9. Confirm that gas generation (or imports at the same price) was the assumed alternative to incremental Pickering generation and that enhanced DR or CDM was not considered as a partial response.

A: The OPA's 2012 analysis of Pickering continued operations incorporated conservation amounts consistent with those prescribed in the government of Ontario's 2010 Long-Term Energy Plan (i.e. 4,550 MW and 13 TWh by the end of 2015; 5,840 MW and 21TWh by the end of 2020).

The evaluation of Pickering continued operation was performed using a reference scenario and a number of sensitivity scenarios that considered potential benefits of continued operation against factors that could either support or erode those benefits. The economic performance of continued operation against these conditions helped inform the OPA's conclusions on the economic merits of Pickering continued operation.

Each scenario studied included the evaluation of two cases: (1) a resource portfolio "without" Pickering continued operation and (2) a resource portfolio "with" Pickering continued operation. Each portfolio was derived and assessed using the following steps:

1. Identify the amount and timing of existing, committed, or directed resources
2. Determine the contribution of resources during peak periods
3. Determine the amount of resources needed for adequacy
4. Determine the extent to which existing, committed, and directed resources meet the resource requirement and identify the capacity gap
5. Determine the transmission enhancements that are required to connect committed and directed resources
6. Identify resource options to fill any remaining capacity gap, and
7. Perform simulations to give insight into the operation of the proposed resource mix using the OPA's energy production simulation software. Simulations consider intra- and inter-jurisdictional electricity transactions for each hour of each year between 2013 and 2020.

Each case was based on reference scenario conditions and modified as required for each sensitivity scenario. Economic advantages or disadvantages of continued operation of Pickering were identified by comparing the net present value of costs of the "with continued operation" case for the period 2013 to 2020 to the net present value of costs of the "without continued operation" case for the same period. The net present value of costs consisted of the following cost components:

1. Generation operating costs
2. Capital investments in electricity resources, and
3. Import costs and export revenues.

In practice, there could be opportunity for deferring or avoiding other supply investments that would otherwise have been made in absence of continued operation. It was assumed the capacity and energy supplied by Pickering NGS during the continued operation period would be replaced by alternative sources of supply *as needed to meet system requirements.*

A number of options were considered to meet additional short-term capacity and energy needs that may arise in the absence of Pickering NGS continued operation:

4. Gas-fired Generation – May consist of new simple-cycle gas turbines or equivalent coal units converted to gas for capacity and existing combined-cycle gas turbines for energy. The lead time required is shorter than other alternatives

and capital costs are lower. Operating costs are higher and CO_2 emissions are increased as compared to a case with continued operations.

5. Additional Conservation and Demand Response – This alternative would require a large amount of energy savings to offset the reduction in energy production from Pickering NGS. The additional effort to achieve this, beyond the current aggressive conservation targets, was considered to be an unrealistic planning assumption.

6. Firm Imports – An option that would require a significant amount of firm inter-tie capacity to be purchased and is expected to be priced similar to gas-fired generation capacity.

Based on the above considerations, gas-fired generation ("unspecified gas-fired generation") was considered an appropriate representation of the various options for meeting additional short-term capacity and energy needs.

10. Confirm OPG's indication that SBG was not evaluated by OPA. Confirm that new load forecast would increase expected SBG

A: Potential surplus energy ("PSE") is a condition that occurs when electricity production from facilities that are self-scheduling or have limited dispatch capability is greater than the Ontario demand. Generation resources that are self-scheduling or have limited dispatch capability include facilities such as wind, non-utility generation, and nuclear. In practice, surplus energy does not exist in real time operation of the power system as electricity production matches demand for electricity. The mechanisms the system has to mitigate potential surplus energy include exporting the surplus energy, strategically scheduling outages, spilling hydro, nuclear maneuvering and curtailing generation including wind and solar in order to balance the system. In real time, the amount of potential surplus energy that could be experienced may be quite different from the planned or expected amounts due to even minor changes in actual production by specific generators like hydroelectric or nuclear facilities or due to changes in demand (due to, for example, weather).

In EB-2013-0321 Exhibit L Tab 6.6 Schedule 8 GEC-007, the OPA advised OPG that it did not directly assess the costs or benefits of PSE in the context of its assessment of Pickering continued operations. The OPA did, however, consider PSE in a more general sense. For example, the OPA did estimate the potential impacts of Pickering continued operation on projected PSE amounts (TWh per year). Further, when assessing the Pickering continued operation against an alternative, the OPA's analysis effectively credited the alternative for providing only the amount of capacity and energy required to meet resource requirements (i.e. rather than replacing one-for-one the capacity and energy that would have been provided by Pickering continued operations). The effect of this was to reduce the economic value of those portions of Pickering continued operation that would have contributed to potential capacity and/or energy surpluses and therefore increase, all else being equal, the competitiveness of the "no Pickering continued operation" alternative.

11. Confirm that PSE will rise due to new forecast and estimate it

A: The OPA's outlook for annual PSE in the period to 2020 has generally decreased since 2012. Much of this revised outlook relates to modelling improvements implemented by the OPA since 2012, which tend to correct what the OPA views as previously overstated long-term projections of scheduled production from Ontario's hydroelectric and nuclear generators, including during potential surplus conditions. The rest of the revised outlook reflects changing implementation timelines of new renewable additions in Ontario, updated views of the likely mix of those renewable sources and evolving outlooks on the timing and duration of nuclear planned outages and refurbishment outages.

The OPA's reduced projections of PSE are mostly for the period up to approximately 2017, after which projected PSE amounts are consistent with those projected in the OPA's 2012 report. Prior to 2017, the OPA's PSE projections are between one third and one-half lower than projected in the OPA's 2012 analysis. All else being equal, a lower demand would tend to increase the potential for surpluses. In consideration of the interplay of a variety of relevant factors, however, the OPA's outlook for PSE has, on net, diminished.

12. Confirm that 9TWh of renewables would be curtailed – and give a ballpark update of this with the new load forecast (p. 718)

A: In its 2012 assessment, the OPA's reference scenario with Pickering continued operation saw a total displacement of approximately 9 TWh of energy production from renewable and CHP resources between 2013 and 2020 compared to a reference scenario without Pickering continued operation.

In the OPA's 2014 analysis, which reflects the demand forecast described in the government's 2013 Long-Term Energy Plan as well as other ongoing updates to the OPA's supply/demand outlook, the total amount of displaced renewable and CHP energy production between 2014 and 2020 was estimated to be approximately 5 TWh.

13. Confirm that PCO will have the effect of lowering export revenues (p.772)

A: In its 2012 assessment, the OPA estimated the difference in generation operating costs, capital investments in electricity resources and import costs and export revenues between scenarios which included continued operations at Pickering and scenarios which included an illustrative alternative to continued operations at Pickering.

Under reference conditions, the scenario which included Pickering continued operation saw higher total capital and fixed operating costs, but lower total dispatch or variable costs. Total dispatch costs include import costs and export revenues. While export volumes were seen to increase in the scenario which included continued operation at

Pickering, export revenues within the same scenario were somewhat lower as the average marginal cost (a proxy for the Hourly Ontario Energy Price) decreased as a result of lower marginal cost energy from Pickering continued operation. At the same time, however, total import costs diminished more significantly in the scenario which included Pickering continued operation.

14. Indicate what other changes have occurred that OPA considers significant to the analysis.

A: As indicated above, the OPA's outlook for Ontario's supply/demand picture has continued to evolve since 2012 and the OPA has continued to assess Pickering continued operations accordingly.

Significant changes between 2012 and the present time include a generally reduced outlook for Ontario annual electricity demand, changes in the implementation timing of planned and directed renewable amounts, changes in the anticipated composition of these renewable amounts and changes in the timing and duration of nuclear planned outages and refurbishment outages. In addition, the OPA has implemented various refinements to its modelling of the Ontario electricity system.

The OPA developed assessments of continued operations at Pickering in 2013 and 2014 in light of the evolving circumstances outlined above. The results of each of these assessments have been consistent with the results of the OPA's 2012 assessment. Supply demand assumptions in the OPA's 2014 assessment are consistent with those of the government of Ontario's 2013 Long-Term Energy Plan.

Aside from changes in the OPA's outlooks over time, today the OPA continues to view the next decade or so as a period of significant transition in the Ontario electricity system involving numerous moving pieces, uncertainties and some degree of risk. Several of these moving pieces are described in the OPA's August 2012 letter and continue to be relevant to the OPA's consideration of the merits of the Pickering continued operations option.

15. Confirm that the government's indication that it will consider earlier shutdown of Pickering once Clarington is on line was not available and therefore not considered at the time of the study or letter

A: The government of Ontario's 2013 Long-Term Energy Plan indicates that "Ontario plans to refurbish units at the Darlington and Bruce Generating Stations" and elsewhere, that "the continued operation of Pickering facilitates the refurbishment of the first units at Darlington and Bruce by providing replacement capacity and energy without greenhouse gas emissions while managing prices". The 2013 Long-term Energy Plan then continues: "however, an earlier shutdown of the Pickering units may be possible depending on projected demand the progress of the fleet refurbishment program and the timely completion of the Clarington Transformer Station".

The OPA did assess a sensitivity scenario in its 2012 report which assumed a reduced continued operation period (by 50% of the otherwise planned duration). Results of this sensitivity scenario suggested that, under the conditions assessed, a longer continued operation period would be more advantageous than a shorter continuation period in that the capacity and energy value of Pickering continued operation was estimated to be greatest in the period beyond 2017, during which Ontario's supply/demand balance is generally expected to be tighter than in the period prior to 2017.

GEC INTERROGATORIES (SECOND SET)

1. Can you release the power points that you indicate summarize the 2013 and 2014 updated analyses (and if there is one, for any update that was done after the April 16th, 2012 draft that informed the final point estimate in the August 12th letter)?

A: Please see Attachments 1 to 3 for power point slides that summarize the 2013 and 2014 analyses prepared for OPA internal discussion purposes. They have been redacted to remove confidential information about Bruce Power and a gas-fired generator in Ontario.

2. Can we get the summary inputs and assumptions sheets for the more recent updates and for the study done in 2012 (I assume that in each case you would have the equivalent of Appendix 1 to the August 15th letter and page 865 of the F.O.I. pdf that is called 'Pickering Continued Operation Study for OPG 2013/2014 Rate Application - Reference Case and Assumptions Summary' – though it is not clear whether that particular page is the actual inputs etc. that were used for the April 16th run or whatever update was done for the August 12th letter)

A: Assumptions used in the 2013 and 2014 analyses around the costs and performance of Pickering are the same as those used in the 2012 analysis (listed in Appendix 1 to the August 15th letter). Differences in the 2013 and 2014 analyses from the 2012 analysis relate mostly to evolving supply and demand outlooks. Key differences in these areas are highlighted in the 2013 and 2014 decks. The 2014 analysis reflects the supply and demand assumptions described in the 2013 LTEP.

GEC INTERROGATORIES (THIRD SET)

1. You were not able to provide a sensitivity analysis for the lower gas prices I mentioned. Can you indicate whether the gas futures prices filed at Exhibit K5.2, pages 46-51, conform to OPA's current estimates of Henry Hub prices (if not please explain)? Can you confirm that the 2013 and 14 analyses do not reflect these latest values? What gas price is assumed?

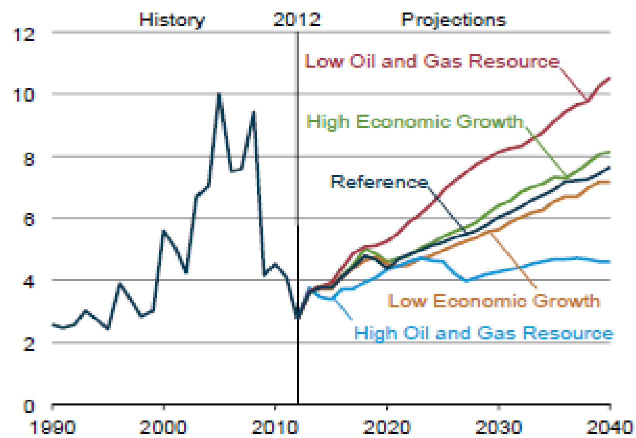
A: The OPA considered a range of natural gas prices in its analysis: \$4.00/MMBTu, \$5.50/MMBTu and \$8.00/MMBTu. A range was considered in recognition of the uncertainties involved in fuel price projections. This range was considered in the OPA's

2012, 2013 and 2014 analyses. The 2014 analysis also examined a natural gas price of $4.75/MMBTu. The futures contained in the referenced attachment fall within the range of $4.00/MMBTu and $5.50/MMBTu.

Consideration of ranges is a common practice in a variety of fields. As one example, the U.S. Energy Information Administration considers a range of future natural gas prices in its 2014 Annual Energy Outlook. The range, illustrated in the figure below, depicts a variety of possibilities related to economic growth, resource recovery rates as well as other factors such as coal and nuclear availability.

Natural gas prices depend on economic growth and resource recovery rates among other factors

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2012 dollars per million Btu)



Source: U.S. Energy Information Administration,
2014 Annual Energy Outlook. April, 2014.
http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf

As an aside, the Futures prices in the referenced attachment under the column heading "Prior Settle" appear to be based on relatively low volumes for the period beginning in April 2016 and ending in December 2020. For example, of the 57 months illustrated in the referenced attachment during that time, 52 months show a volume of zero, four show a volume of 1 and one shows a volume of 21.

2. Can you confirm that the 2013 LTEP load forecast is used in the latest analysis or provide what was used?

   A: It is assumed that the "latest analysis" referenced in the question relates to the OPA's 2014 analysis (i.e. rather than the 2012 analysis) described in the OPA's responses to GEC on June 17, 2014 and summarized in the form of a power point presentation which was shared with GEC via e-mail on June 25, 2014. As indicated in the OPA's June 17, 2014 and June 25, 2014 response, the OPA's 2014 analysis reflects the demand forecast contained in the 2013 Long-Term Energy Plan (LTEP).

3. Is there a more recent load forecast and if so, can it be provided?

   A: The most recent load forecast is the forecast contained in the 2013 LTEP. The OPA developed a series of modules that provide a detailed breakdown of the facts and figures underpinning the 2013 LTEP. The module entitled "Module 1" contains information on the 2013 LTEP electricity demand forecast. All of the modules are available on the OPA web site at the following address: http://www.powerauthority.on.ca/power-planning/long-term-energy-plan-2013.

4. We understand that Quebec has lots of surplus capacity at this time (see the HQ report that includes an English translation, filed at Exhibit K6.3. pages 10-32). Does the HQ report conform to OPA's understanding?

   A: OPA understands that HQ has power available above their needs that they offer to sell, from time to time, to their neighboring utilities.

5. The 2013 LTEP (Achieving Balance - Ontario's Long-Term Energy Plan – page 41) notes that Ontario summer peak import capability from Quebec is 2775 MW and winter is 2795. Can you provide any available forecasts and analyses of the $/MWh cost for utilizing Hydro Quebec energy via this transmission capacity from Quebec during the 2014-2020 period? In other words, given that Quebec is selling power at very low rates and appears to have lots of extra capacity, and is winter rather than summer peaking, what price would OPA expect Quebec to charge for energy in the 2014-2020 period?

   A: The OPA does not forecast the price Hydro Quebec offers power into the Ontario market. The total cost of power from Quebec to Ontario would be a function of a number of factors including Quebec's offer price as well as any costs to deliver that power to the load center all of which depends on the specifics of any proposed arrangement.

6. If imports from Quebec would be at Ontario's avoided cost (which appears to have been the assumption in 2012), if a price was negotiated now as an alternative to Pickering continued operation, would the price not be equal to your estimate of Pickering Continued Operations cost as opposed to the price of gas capacity and fuel?

   A: The OPA has assessed that the least cost option that can be acquired with a reasonable level of certainty as an alternative to PCO would be equivalent to supplying almost all the energy from the balance of the other existing supply sources and the capacity from new simple cycle peaking units.

7. If imports were obtained as required as 'economy sales' wouldn't they be at the average of sellers cost and buyers avoided cost wouldn't the cost be lower than gas generation costs?

A: In Ontario "economy sales" are required to flow through the IESO administered market and would be set at the Hourly Ontario Electricity Price (HOEP).

8. Please indicate whether OPA has analysed the option of closing Pickering A (which has far worse value for money performance) rather than all 6 reactors and provide any such analysis.

A: The OPA has not analyzed the option of closing Pickering A.

ED INTERROGATORIES (ALL)

1. According to Tab 4 (p. 8) in the Document Book (Exhibit K6.3), the costs of the OPA's energy conservation programs between 2015 and 2020 will be 3.5 to 4 cents per kWh. Can you confirm those estimates?

A: The Tab referenced is a slide contained in a 2013 LTEP module developed by the OPA ("2013 LTEP Module 4: Cost of Electricity Service"). The slide summarizes OPA estimates of levelized energy efficiency program costs and demand response costs and includes those costs that are recovered from electricity ratepayers (i.e. excludes the equipment investments made by the customer implementing the conservation initiative). For the period 2015 – 2020, the OPA's estimate of levelized energy efficiency program costs ranges between 3.5 to 4 cents per kWh.

2. Can the OPA confirm that the fuel and operating costs of a natural gas-fired combined-cycle power plant are approximately 3.8 cents per kWh assuming a gas price of $5/MMBTu? (Our calculation is based on Tab 5 (p. 9) of the Document Book (Exhibit K6.3), which contains an OPA interrogatory response. The response shows the fuel and operating cost of a natural gas-fired combined-cycle power plant assuming a gas price of $8/MMBTu. Adding up the circled numbers, the total operating costs would be approximately 5.9 kWh. If we assume a price of $5/MMBTu, the fuel cost would decrease by 5/8ths from 5.6 to 3.5 cents per kWh, which would result in an operating cost of 3.8 cents per kWh.)

A: The information in the referenced interrogatory was developed by the OPA in 2007/2008. The OPA's current estimate of VOMA for a combined cycle plant in 2014$ is $5.50. In addition, the OPA's current estimate is that the heat rate for a new combined cycle plant is closer to 7,150. Based on these assumptions, the fuel cost of a new natural gas-fired combined cycle generator at a natural gas price of $5/MMBTu would be approximately $36/MWh. Adding VOMA costs of $5.50/MWh to this fuel cost would result in a total fuel and VOMA cost of $41.50/MWh. This estimated fuel and VOMA cost does not include capital.

Please note the question seems to contain a written typo/error: the question indicates that a reduction of natural gas price from $8/MMBTu to $5/MMBTu would represent a decrease of 5/8ths (five eights).

3. Tab 6-A of the Document Book (Exhibit K6.3) includes Chapter 16 from a February 2014 report of the Quebec Energy Commission. According to page 183 (page 30 of the Document Book), Table 16.2, Hydro Quebec will be exporting 20.1 TWh of electricity at 3 cents per kWh in 2014 and 25.4 TWh of electricity at 3 cents per kWh in 2016. Do you have any reason to doubt the accuracy of these figures?

A: The OPA understands table 16.2 to indicate that the Commission sur les enjeux énergétiques du Québec estimates that Quebecers will lose between $817M and $1434M if Quebec power is sold at 3 cents per kWh in the period from 2014 to 2022.

4. How much of OPG's potential water power generation will be foregone (spilt) in 2014 and 2015 due to the surplus base-load generation resulting from Pickering GS?

A: As indicated in its June 17, 2014 response to GEC, in its 2012 assessment, the OPA's reference scenario with Pickering continued operation saw a total displacement of approximately 9 TWh of energy production from renewable and CHP resources between 2013 and 2020 compared to a reference scenario without Pickering continued operation. In the OPA's 2014 analysis, which reflects the demand forecast described in the government's 2013 Long-Term Energy Plan as well as other ongoing updates to the OPA's supply/demand outlook, the total amount of displaced renewable and CHP energy production between 2014 and 2020 was estimated to be approximately 5 TWh.

Out of the nearly 5TWh of displaced renewable and CHP production between 2014 and 2020 that was estimated in the OPA's 2014 analysis, 1.2TWh of that total would be displaced in 2014 and 2015. OPA further estimates that waterpower would represent 52% of the total of 1.2TWh displaced in 2014 and 2015 while wind would represent 34%. Displaced CHP production would account for 9% of the total, while biomass and solar displacement would account for 3% and 2%, respectively.

In conducting its analysis, the OPA did not specifically monitor the ownership/operatorship of the generating resources that might be displaced and therefore cannot at this time advise as to how much of the estimated waterpower displacement could specifically be attributed to OPG waterpower resources.

5. How much solar and wind generation will be curtailed in 2014 and 2015 due to the surplus base generation resulting from Pickering GS?

A: Please see the response to the question above.

6. Can the OPA confirm that the LUEC for a representative natural gas-fired combined heat and power plant would be approximately 4.7 cents per kWh assuming a gas price of $5/MMBTu and an average annual capacity factor of 90%? (Our calculations are as follows: The OPA interrogatory response referred to in Exhibit K6.3, indicates a LUEC of 6 ¢/kWh assuming a commodity cost of $8/MMBTU and an average annual capacity factor of 90%. Reducing the fuel cost by 5/8 (from 3.4 ¢/kWh to 2.1 ¢/kWh) brings the cost down by 1.3 ¢/kWh to 4.7 ¢/kWh.

A: The OPA's current estimate of LUEC for a representative natural gas fired CHP is $102.50/MWh, if assuming $5/mmBTu gas, and is based on a 50% acf, typical of Ontario facilities under OPA contract.

If 90% acf is assumed the LUEC would be $74.5/MWh.

This information is based on the latest actual procurement and operational experience in Ontario with the factors outlined below.

Assumptions

Inflation (%)	2%
Real Social Discount Rate (%)	4%
Nominal Social Discount Rate (%)	6%
Natural Gas Price ($/MMBtu)	$5.0

LUEC Component Breakdown

Components	50% ACF	90% ACF
Capital and Fixed ($/MWh)	$63.0	$35.0
Fuel ($/MWh)	$33.0	$33.0
VOMA ($/MWh)	$6.5	$6.5
Total ($/MWh)	$102.5	$74.5

Merits of Pickering Continued Operations

Evaluation Update

April 10, 2013

DRAFT

Overview

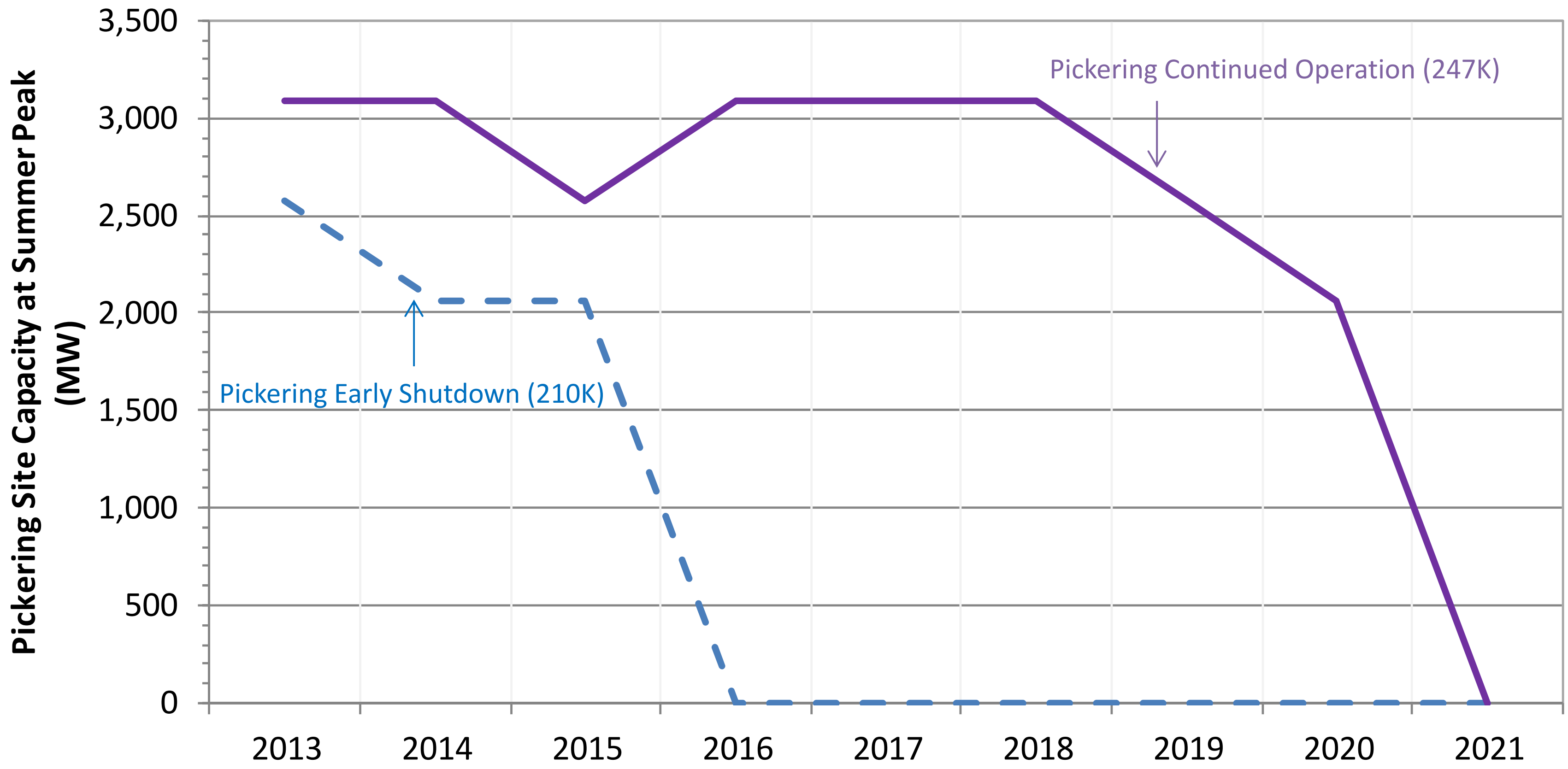
- In April 2012, OPA completed its study of the merits of Pickering Continued Operation in support of OPG's OEB rate application
  - At the time, a similar study was also completed on the merits of Darlington refurbishment
  - The filing of the rate application has since been delayed (likely to 2016)
  - Since then there has also been increased technical confidence continued operation could be achieved (Pickering license renewal in the next few months is a signpost to watch)

- Recently, the analysis has been updated to reflect recent updates to the supply outlook, specifically
  - Early coal closure, gas plant relocation delays, reduced DR, no conversion of Thunder Bay, and slower uptake of renewables to meet 2018 targets
  - [redacted]
  - UPLAN refinements (hydro modeling)

- The updated analysis yields observations consistent with the April 2012 study
  - Pickering Continued Operations has a net system benefit of $270M over the gas alternative (NPV 2012 dollars)
  - Compared to the April 2012 study, this represents an increase in the net benefit from $172M
  - The increase in net benefit is due to an increase in capacity value and reduction in other baseload generation and PSE during the Pickering Continued Operation period
    - Capacity value incre[redacted]resources
    - Baseload reduction [redacted] lower than projected nuclear and baseload hydro production (which increases the value of additional baseload production from Pickering Continued Operations)

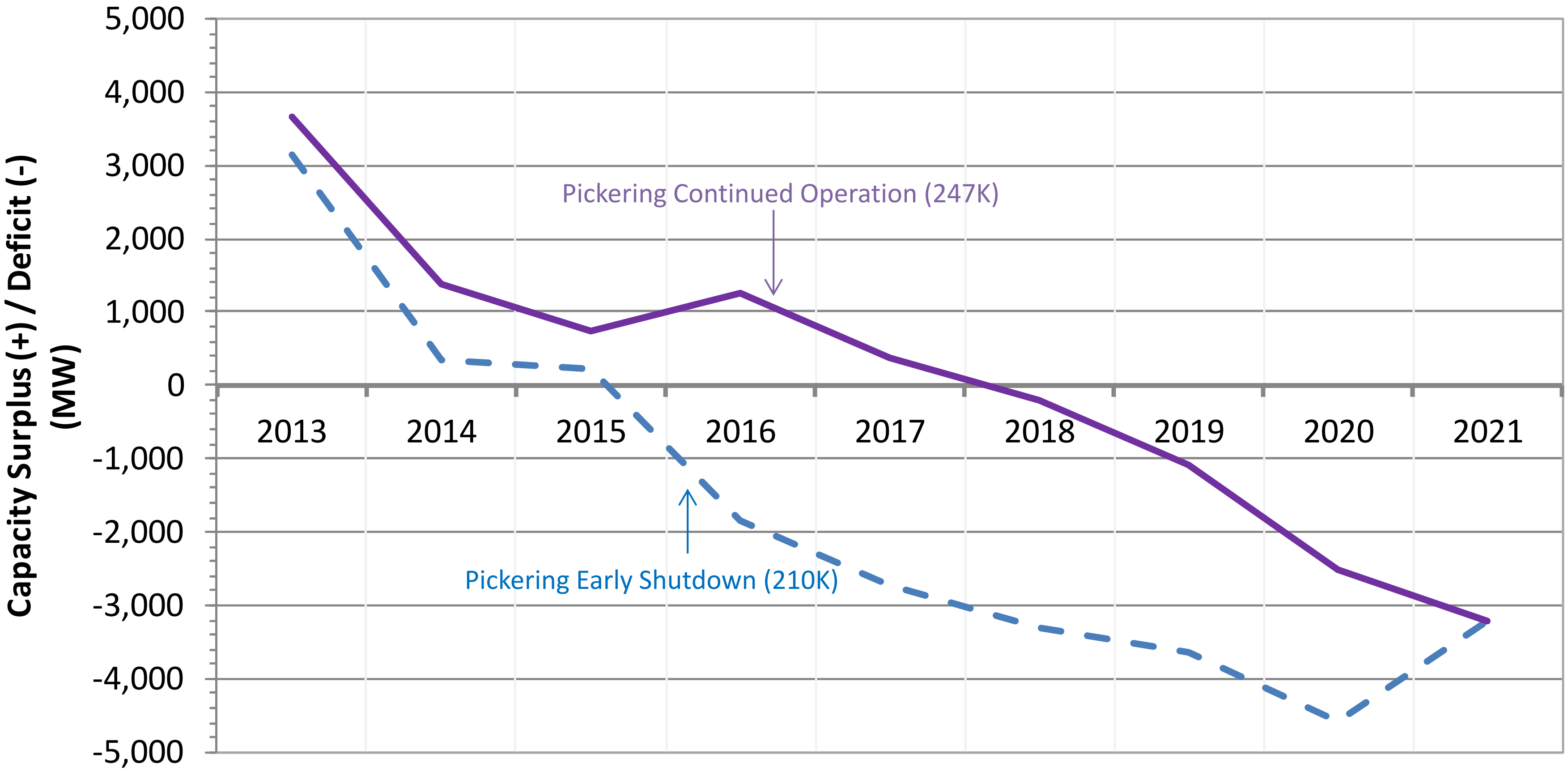
Pickering Site Capacity Profile

- Early shutdown by 2016 compared to shut down in 2018-2020 after continued operations



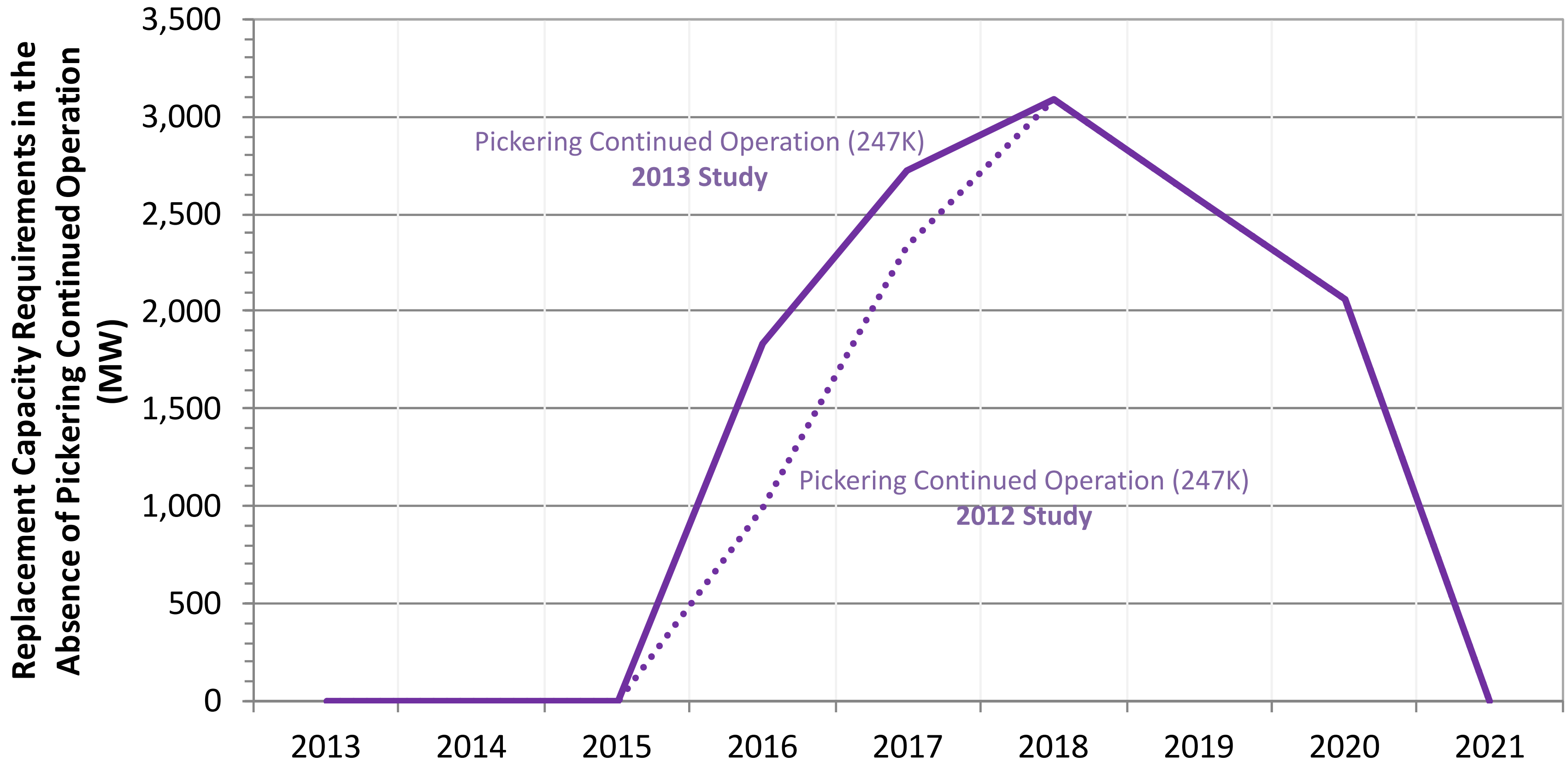
Capacity Surplus/Deficit

- Pickering Continued Operation defers provides capacity benefit in the near to mid-term, delaying onset of capacity shortfalls by 3 years



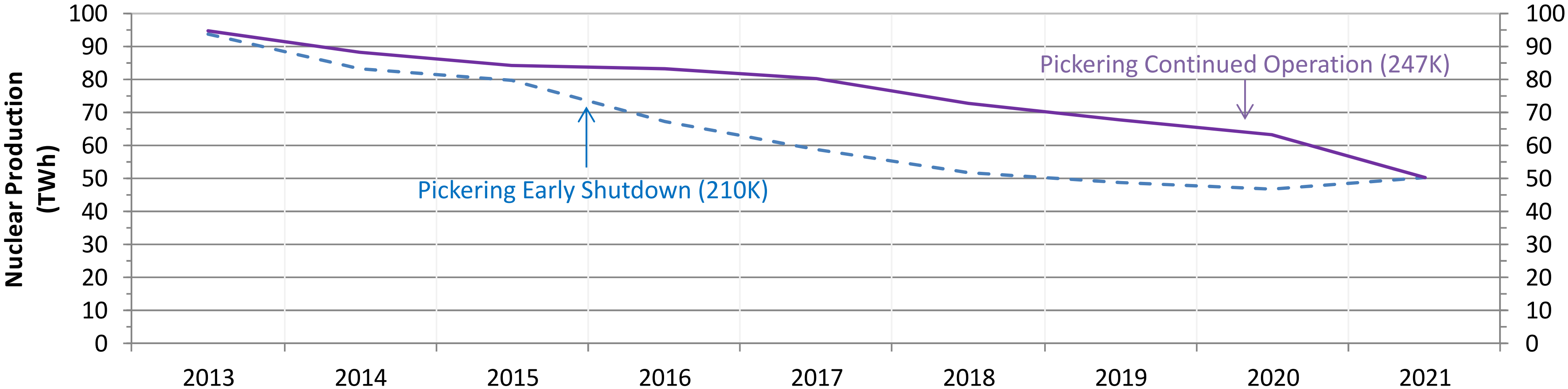
Replacement Capacity Requirements

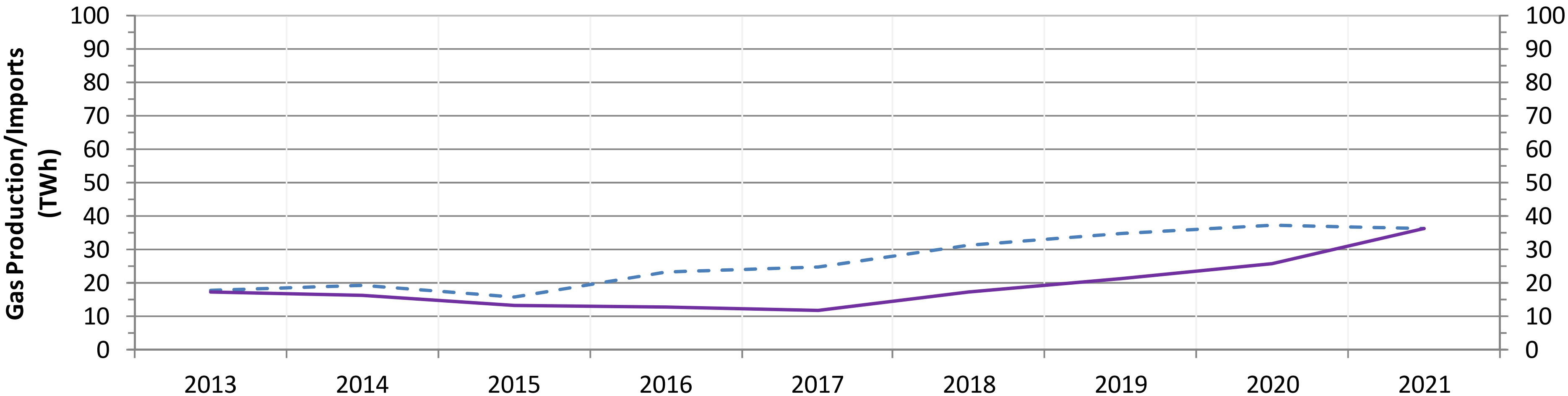
- Compared to the 2012 study, there is an increase in the amount of replacement capacity required in the absence of Pickering Continued Operation, between 2016 and 2017
  - This is largely due to the delay in the gas plant relocations, reduction in DR, no conversion of Thunder Bay, and slower uptake of renewables



Energy Production

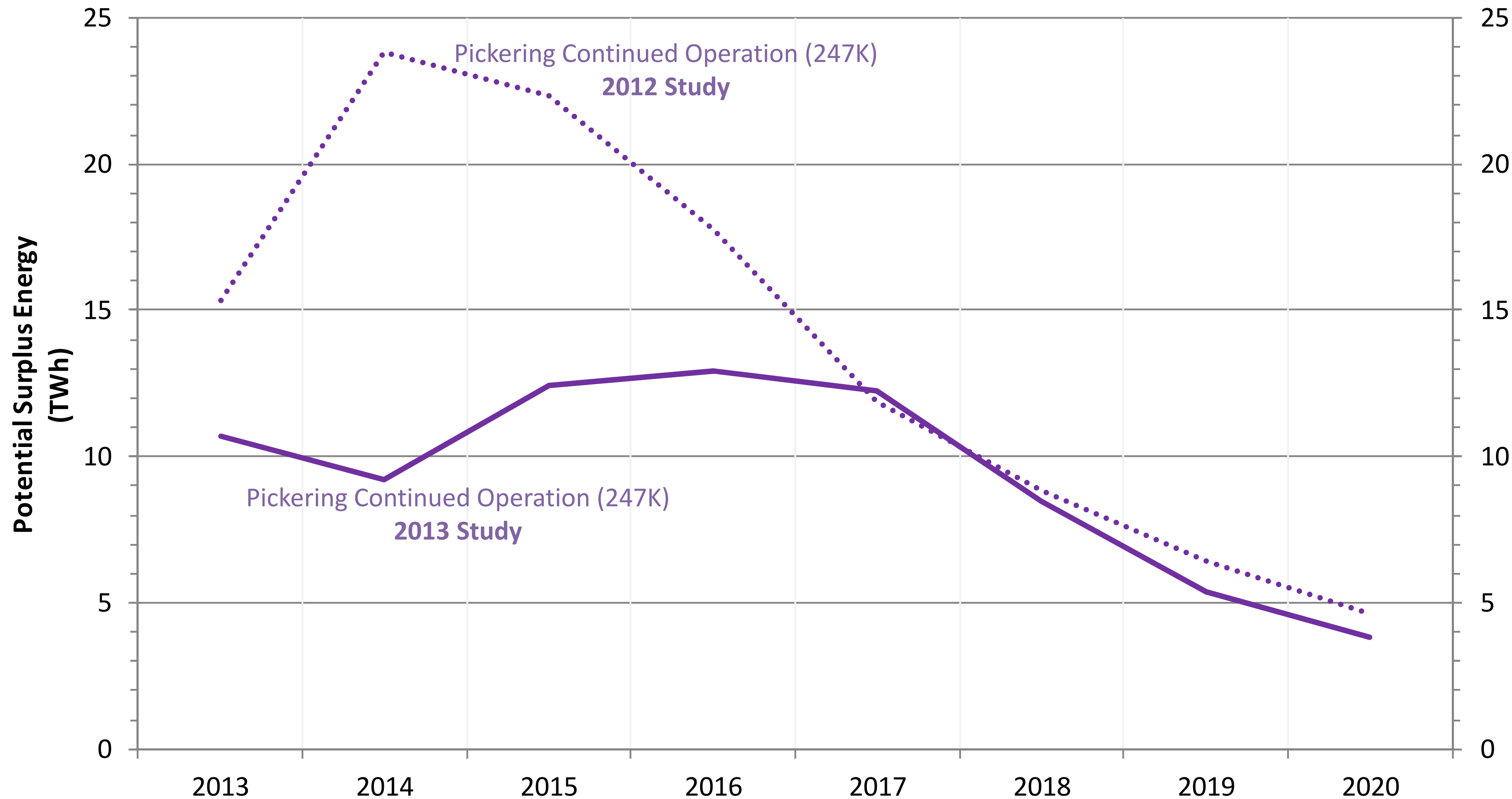
- Between 2013-2020, Pickering Continued Operations provides an additional 104 TWh of energy production between, displacing about 69 TWh of gas/imports and 4 TWh of renewables. Exports increase by 32 TWh.



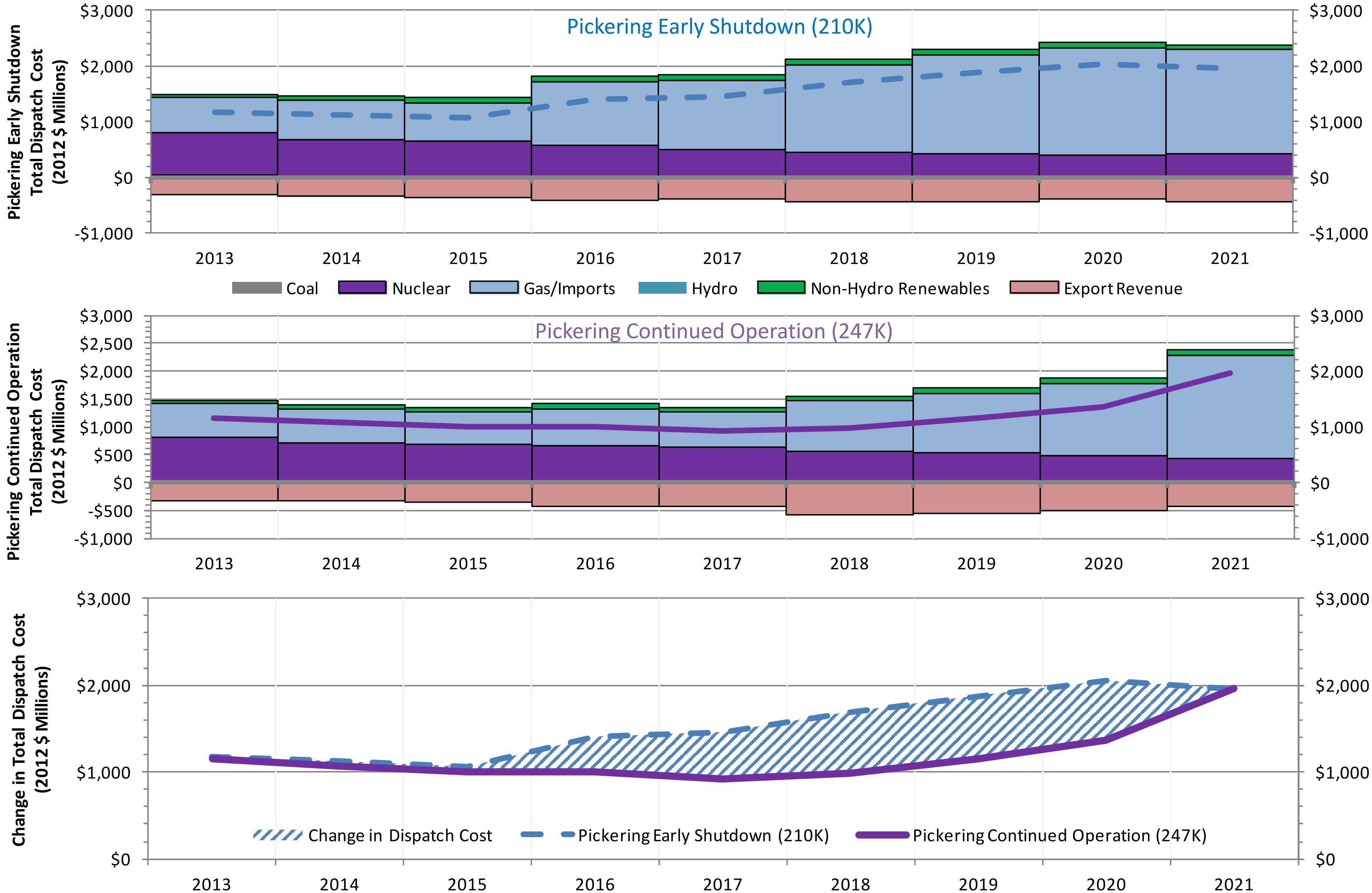


Potential Surplus Energy

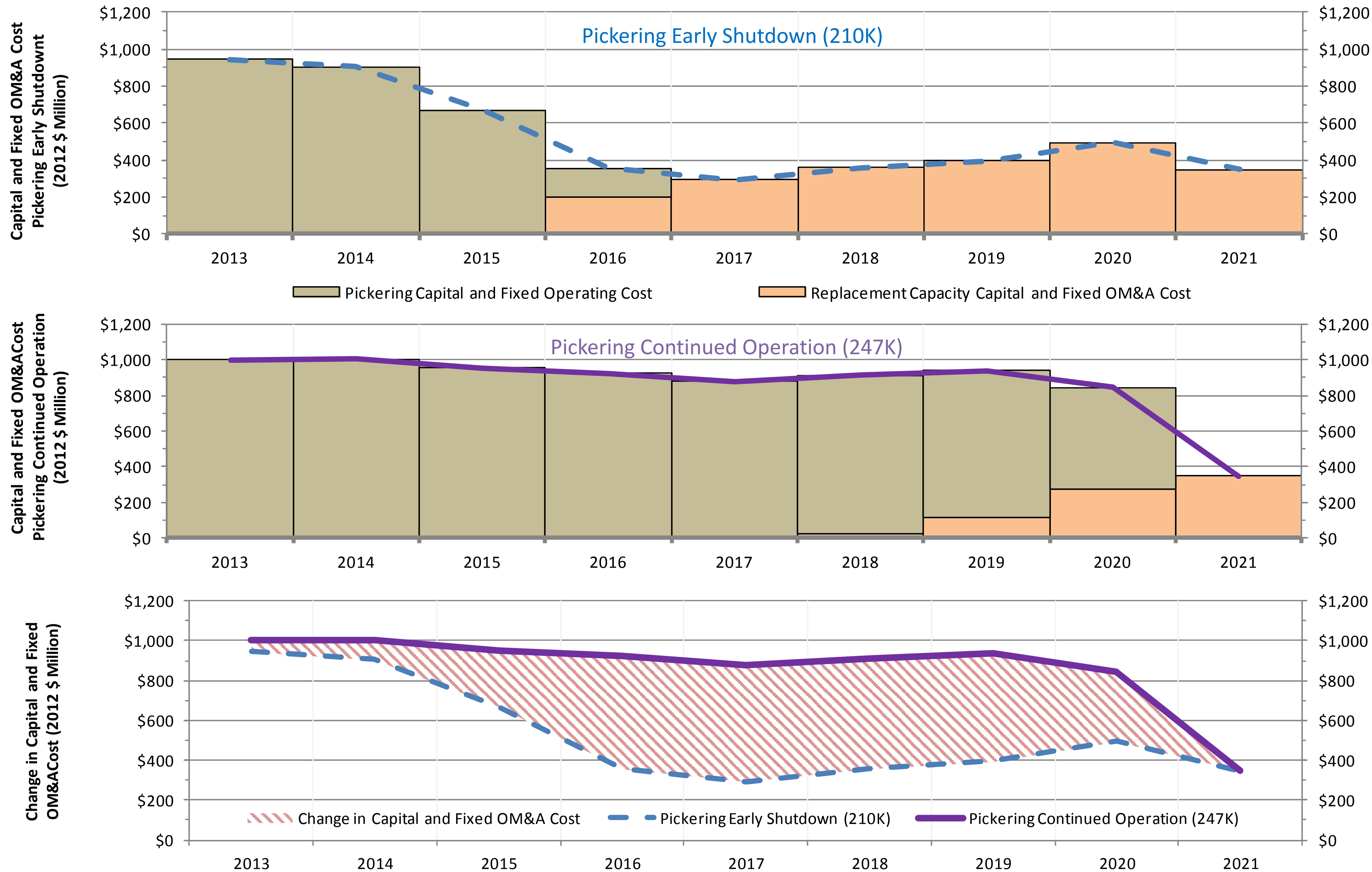
- Compared to the 2012 study, the 2013 study has a considerable reduction in other baseload generation and PSE during the Pickering Continued Operation period [redacted] and lower than projected nuclear and baseload hydro production
- About 17 TWh less PSE in the current study between 2015-2020



Change in Dispatch Costs

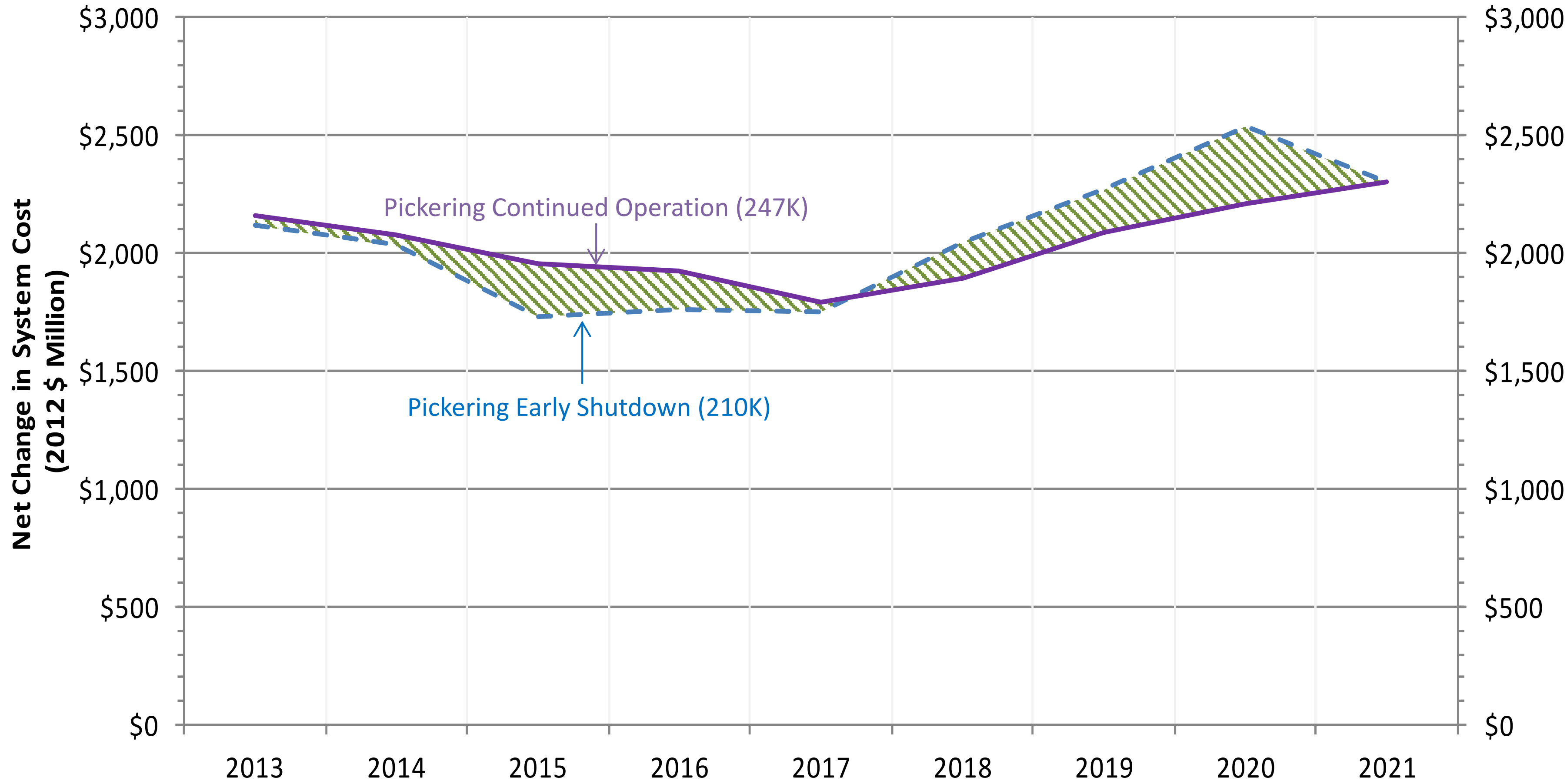


Change in Capital and Fixed Costs



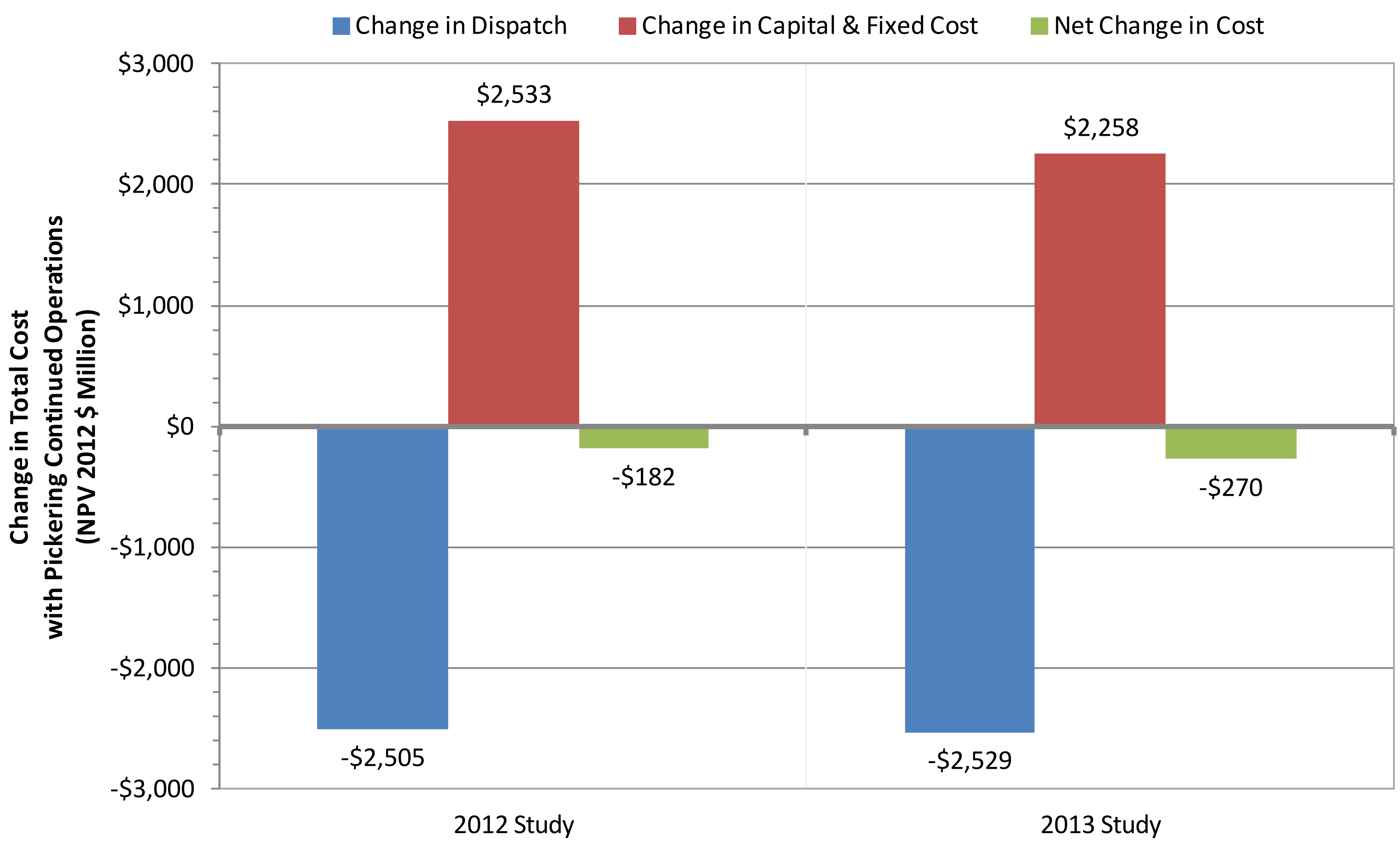
Annual Net Change in Total Costs

- Net costs increase in the first few years relative to the gas alternative but decrease during the period of continued operation



Total Cost Impact – Dispatch Cost, Capital & Fixed Cost, and Net Change in Cost

- Overall, Pickering Continued Operations provides a net benefit of $270M as compared to $182M in the 2012 study



- APPENDIX -

Key Assumptions in Brief

- January 2013 demand/supply outlook with:
  - Nuclear: Darlington refurbishment in 2016 [redacted]
  - Renewables: 19,700 MW solar/wind/bio/hydro by 2018 per LTEP
  - Coal: Phased out by 2014
  - Gas: 10,000 MW from existing and committed, no coal to gas conversions and no NUG contract renewals assumed. Additional capacity requirements assumed to be met by SCGT.
  - Demand: Moderate growth forecast net of conservation per LTEP targets

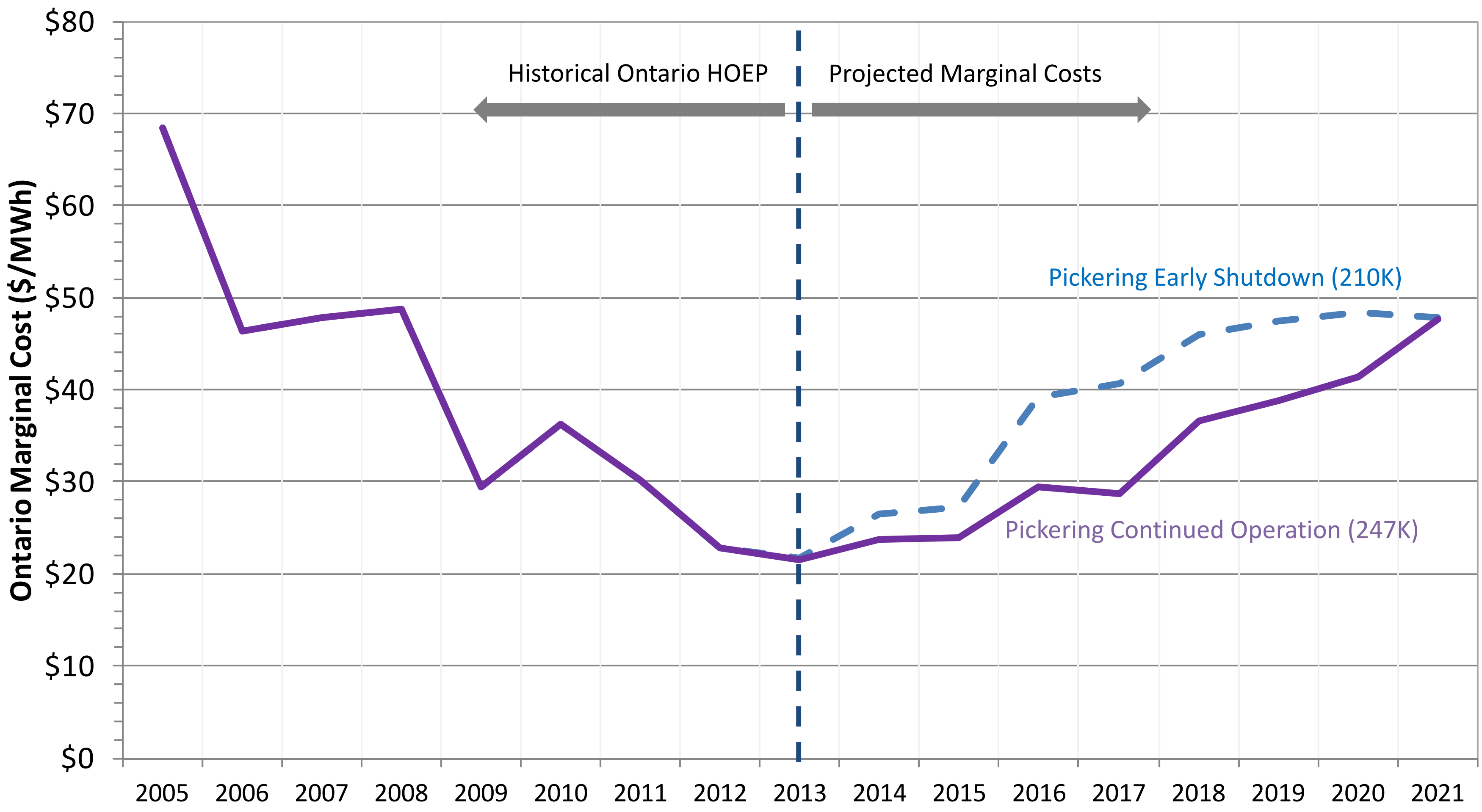
- Cost assumptions:
  - Pickering (from OPG Feb 2012):
    - Incremental capital and fixed operating cost during continued operation period: $3.5B
    - Incremental fuel and fuel handling cost: $490M
    - NPV cost of advancing severance and decommissioning liabilities: $210M
  - Gas:
    - Replacement capacity cost [redacted]
    - Gas/carbon price of $5.5/MMBtu at Henry Hub

- Energy analysis completed using the UPLAN energy dispatch simulation model taking into consideration inter-jurisdictional electricity trade

- All costs expressed in 2012 dollars unless specified otherwise

Marginal Cost (HOEP)

- Frequency at which gas is on the margin increases in the absence of Pickering continued operation
- Average marginal cost (HOEP) increase of $10/MWh without Pickering Continued Operation
- As a result, customers exposed to the market price (large industrials) would see a cost increase whereas other customers would see a reduced allocation of global adjustment



Pickering Continued Operation: Total System Cost Impact Supplemental Information
Gas price of $5.5/MMBtu Henry Hub

NPV (2013 to 2021), 2012 $ Million	Pickering Early Shutdown (210K)	Pickering Continued Operation (247K)	Net Change in Cost Relative to Pickering Early Shutdown	2012 Study
Total Dispatch Cost				
Coal Dispatch Cost	$41	$36	-$4	-$4
Nuclear Dispatch Cost	$12,330	$12,821	$492	$490
Gas Dispatch Cost	$22,973	$21,727	-$1,247	-$1,410
Hydro Dispatch Cost	$0	$0	$0	$0
Non-Hydro Renewables Dispatch Cost	$1,984	$1,984	-$1	-$7
Imports Cost	$14,420	$12,993	-$1,428	-$1,627
Export Revenue	$12,078	$12,418	$341	-$53
Total Dispatch Cost	**$39,670**	**$37,142**	**-$2,529**	**-$2,505**
Capital and Fixed Cost				
Pickering	$2,475	$5,993	$3,518	$3,518
Decomissioning and Severance	$210	$0	-$210	-$210
Replacement Capacity - Capital and Fixed Cost	$8,047	$6,997	-$1,050	-$937
Clarington TS Deferral	$0	$0	$0	-$48
Total Capital and Fixed Cost	$10,733	$12,991	$2,258	$2,323
Total Cost	**$50,403**	**$50,132**	**-$270**	**-$182**

Note: Clarington TS deferral value of $48M included in 2012 study but assumed to be nil in 2013 study page intentionally blank

Merits of Pickering Continued Operations: Summary of Economic Assessment

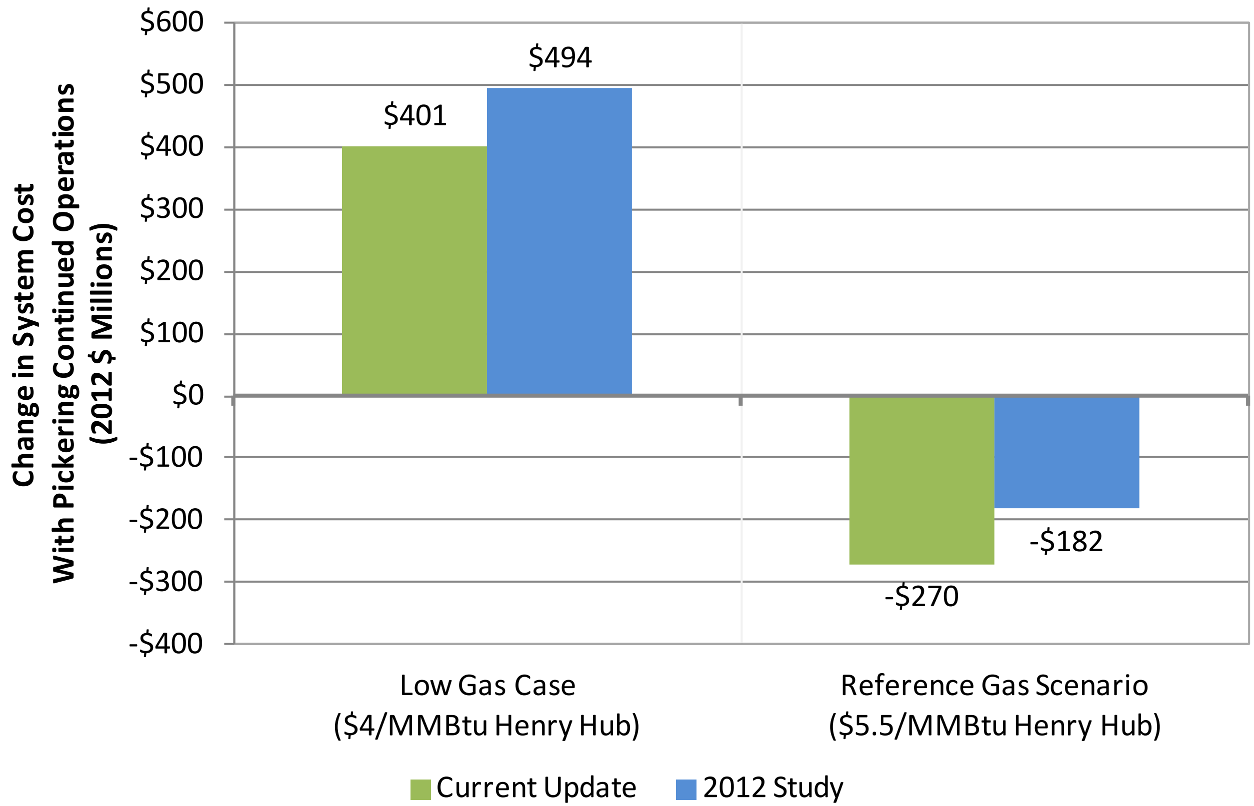
Evaluation Update

April 26, 2013

DRAFT

Observation Summary

- Early Pickering shutdown by 2016 compared to shut down in 2018-2020 after continued operations
- At $5.5/MMBtu natural gas, Pickering Continued Operation reduces system costs by $270M. At $4/MMBtu, system costs would increase by about $400M. Break-even at about $4.8/MMBtu.
- The observations are consistent with the 2012 study. Further detail provided in the following slides.



Summary of System Cost Impacts
Low Gas Price Case: $4/MMBtu

Low Gas Case ($4/MMBtu Henry Hub)

NPV (2013 to 2021), 2012 $ Million	Pickering Early Shutdown (210K)	Pickering Continued Operation (247K)	Net Change in Cost Relative to Pickering Early Shutdown	2012 Study
Total Dispatch Cost				
Coal Dispatch Cost	$41	$36	-$4	-$6
Nuclear Dispatch Cost	$12,330	$12,821	$492	$490
Gas Dispatch Cost	$19,629	$18,597	-$1,031	-$1,080
Hydro Dispatch Cost	$3	$0	-$3	$0
Non-Hydro Renewables Dispatch Cost	$1,984	$1,984	-$1	-$7
Imports Cost	$11,065	$10,008	-$1,057	-$1,185
Export Revenue	$10,045	$10,298	$253	$41
Total Dispatch Cost	**$35,006**	**$33,148**	**-$1,857**	**-$1,829**
Capital and Fixed Cost				
Pickering	$2,475	$5,993	$3,518	$3,518
Decomissioning and Severance	$210	$0	-$210	-$210
Replacement Capacity - Capital and Fixed Cost	$8,047	$6,997	-$1,050	-$937
Clarington TS Deferral	$0	$0	$0	-$48
Total Capital and Fixed Cost	$10,733	$12,991	$2,258	$2,323
Total Cost	**$45,738**	**$46,139**	**$401**	**$494**

Summary of System Cost Impacts

Reference Gas Price Case: $5.5/MMBtu

Reference Gas Scenario ($5.5/MMBtu Henry Hub)

NPV (2013 to 2021), 2012 $ Million	Pickering Early Shutdown (210K)	Pickering Continued Operation (247K)	Net Change in Cost Relative to Pickering Early Shutdown	2012 Study
Total Dispatch Cost				
Coal Dispatch Cost	$41	$36	-$4	-$4
Nuclear Dispatch Cost	$12,330	$12,821	$492	$490
Gas Dispatch Cost	$22,973	$21,727	-$1,247	-$1,410
Hydro Dispatch Cost	$0	$0	$0	$0
Non-Hydro Renewables Dispatch Cost	$1,984	$1,984	-$1	-$7
Imports Cost	$14,420	$12,993	-$1,428	-$1,627
Export Revenue	$12,078	$12,418	$341	-$53
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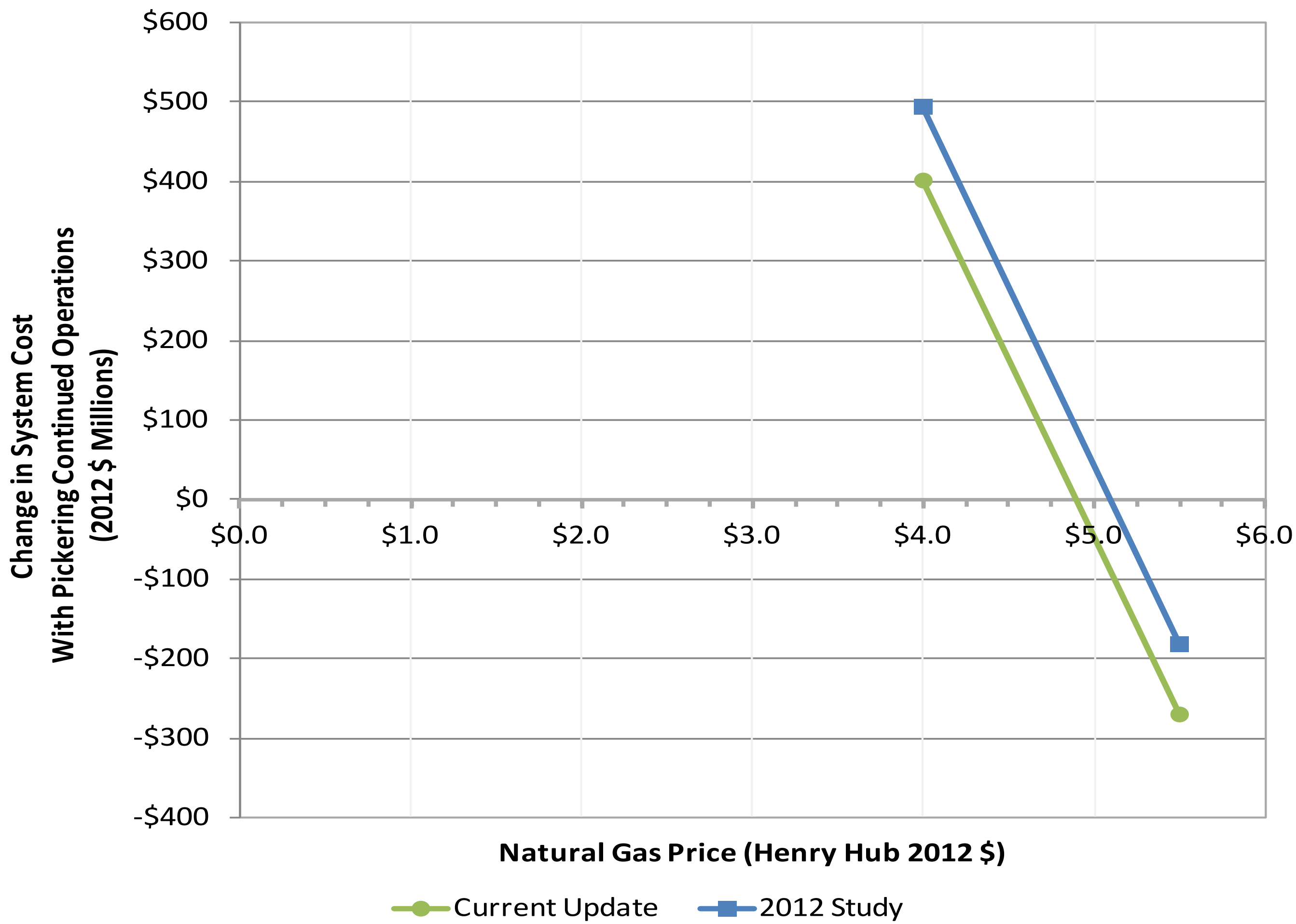
Total Capital and Fixed Cost	$10,733	$12,991	$2,258	$2,323
Total Cost	**$50,403**	**$50,132**	**-$270**	**-$182**

Break-Even Summary

- Pickering Continued Operation is break-even at a gas price of $4.8/MMBtu as compared to $5.1 in the 2012 study. Note the break-even gas price is consistent [redacted] Darlington refurbishment



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Feb 13th 2014

PICKERING CONTINUED OPERATIONS ANALYSIS

Overview

- Pickering Continued Operations (PCO) has net system benefits of $ 220 M over the gas alternative (NPV $2012 for 2014 to 2020 period)
- Compared to the Feb 2012 study, this represent a $5 M decrease in the net benefit from $ 225 M over the same study period*.
  - The increase in benefits of savings from dispatch cost is offset by the increase in capital & fixed cost as the deferral of Clarington TS is not credited as a benefit in this update.
- Preliminary results from low gas price ($4/MM btu)shows that PCO has net system dis-benefit (cost) of $270 M. Compared to the Feb 2012 study this is a $402 M decrease in the net cost from $690 M.
- Preliminary results from high gas price ($8/Mmbtu) shows that PCO has net system benefit of $1.7 B. Compared to the Feb 2012 study this is a $550 M increase in the net benefit from $1.2 B.

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Key changes in supply mix – compared to 2012 study

- Net peak demand is lower compared to that in the 2012 study in the order of 300 MW in the near term
- Available resource in the summer is lower in the near term in the order of 1000 MW
  - Less coal (~1000 MW)
  - Less DR (~700 MW)
  - More nuclear from 2017 to 2020 (2000 MW)
    - Due to changes in Bruce & Darlington refurbishment schedule
  - Less “options” in 2020 (~1500 MW)
- The system starts to see a deficit in supply by 2019 (compared to by 2018 in the 2012 study)
  - In the near term resource above requirement is less
  - Deficit is smaller as well

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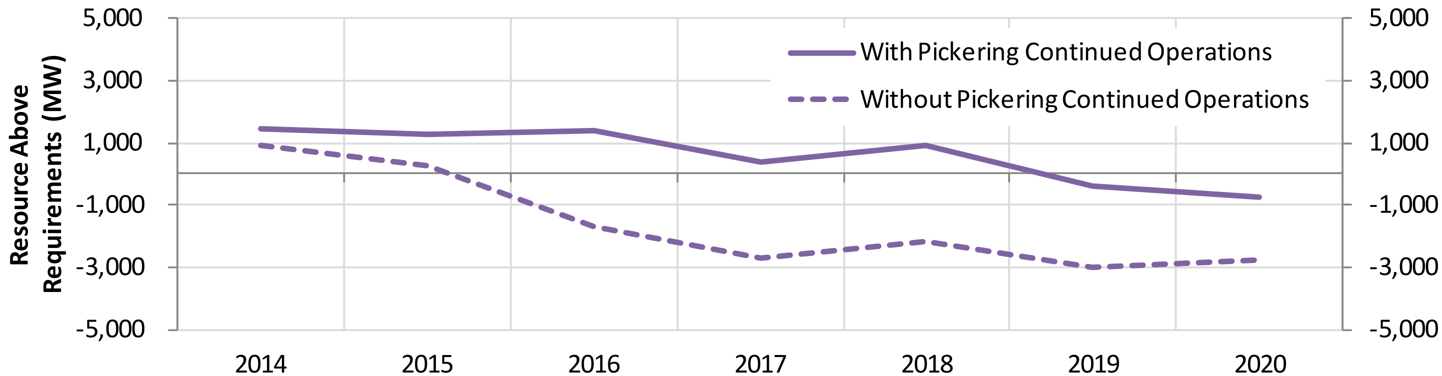
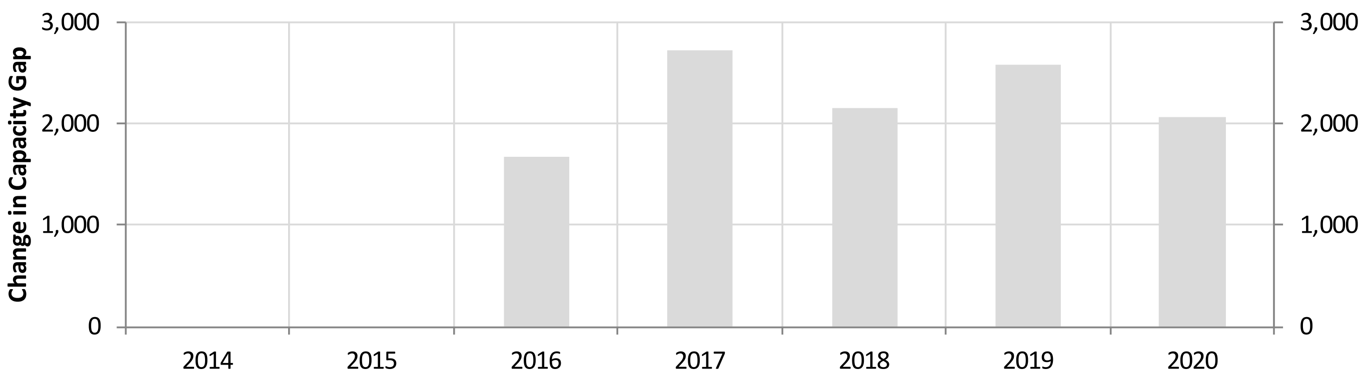
Resource Above Requirements

- Without Pickering Continued Operations, capacity deficit starts in 2016





Resource Above Requirement	2014	2015	2016	2017	2018	2019	2020
Without Pickering CO	924	233	-1,680	-2,735	-2,156	-2,984	-2,791
With Pickering CO	1,440	1,265	1,414	359	938	- 406	- 729
Need for Additional Capacity Without Pickering			1,680	2,735	2,156	2,578	2,062

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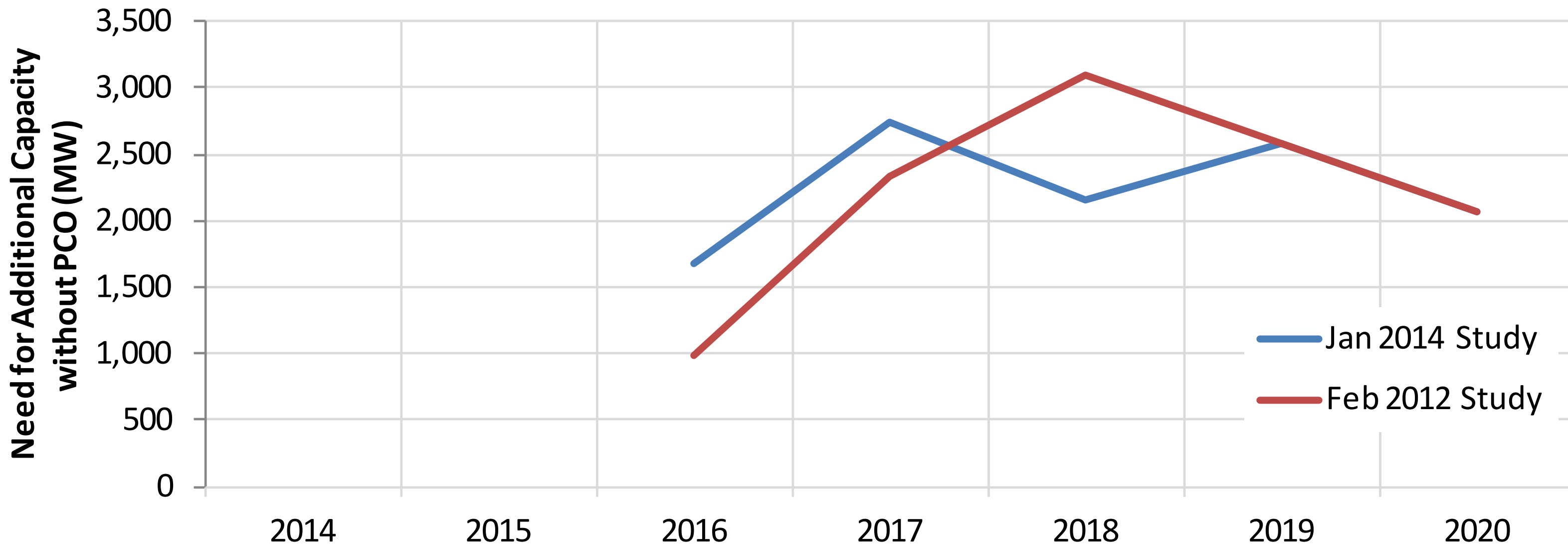
Replacement Capacity Requirements

- Compared to the 2012 study, there is an increase in the amount of replacement capacity required in the absence of PCO in 2016 and 2017
- But the need for replacement capacity is less in 2018



Replacement Capacity, MW	2014	2015	2016	2017	2018	2019	2020
Jan 2014 Study			1,680	2,735	2,156	2,578	2,062
Feb 2012 Study			985	2,341	3,094	2,578	2,062

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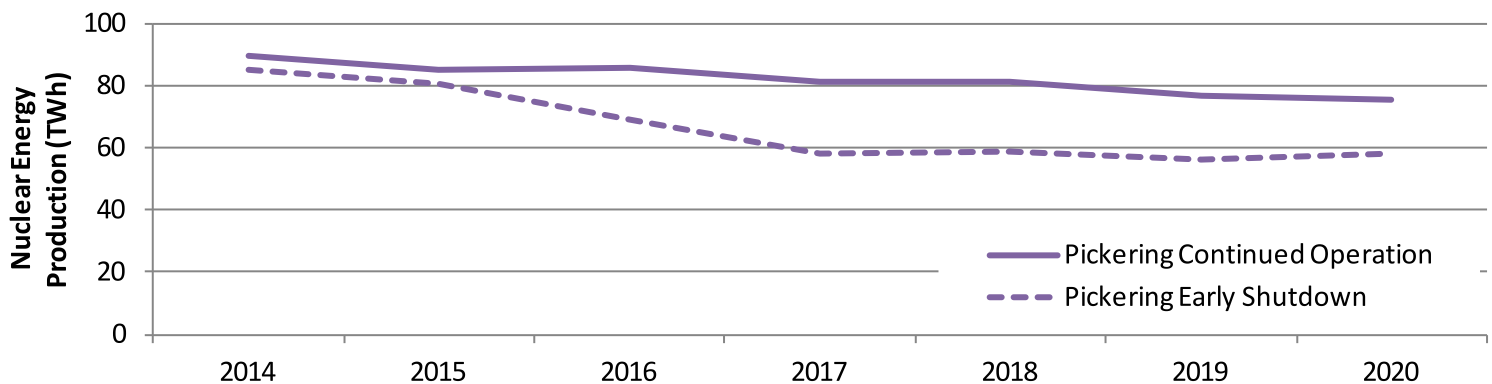
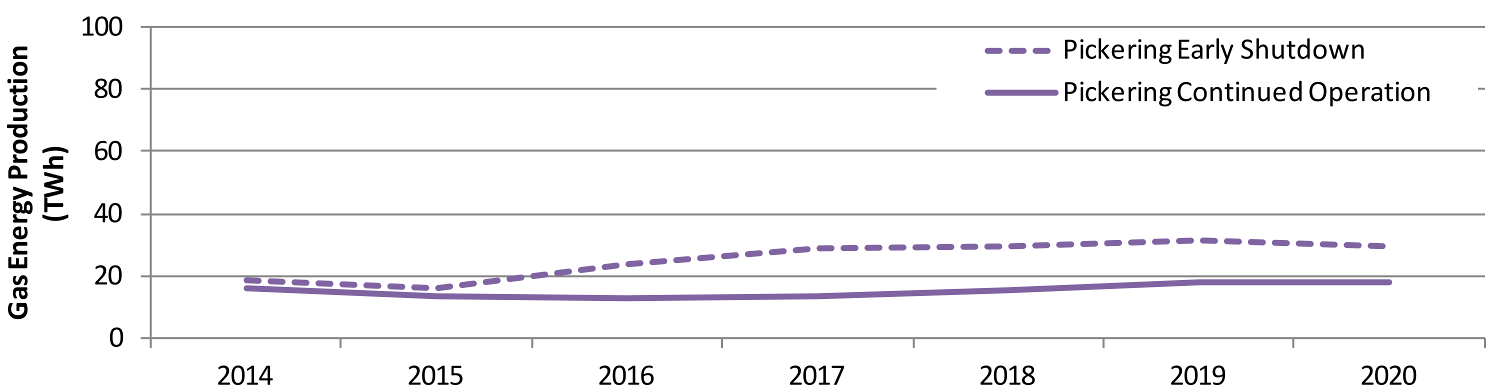
Energy Production

- Between 2014 and 2020, Pickering Continue Operations provides and additional of 109 TWh of energy production and displacing about 70 TWh of gas/imports and 4 TWh of renewables. Exports increase by about 34 TWh





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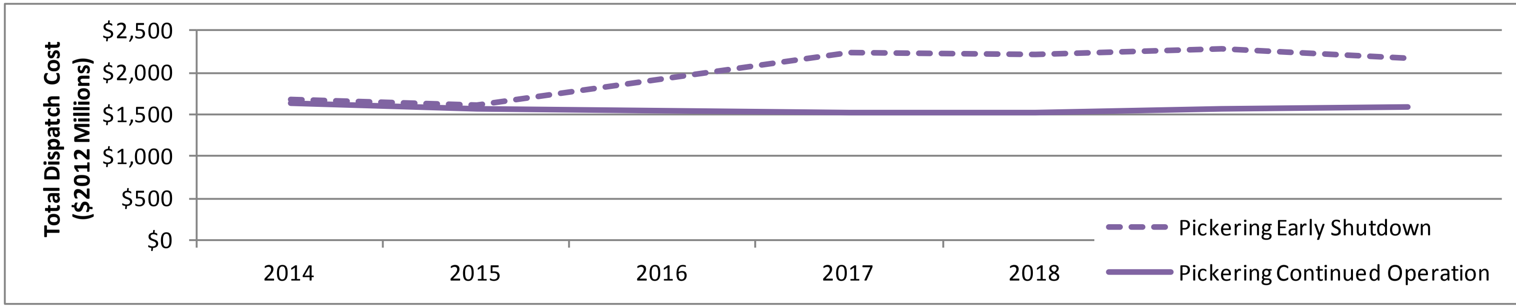
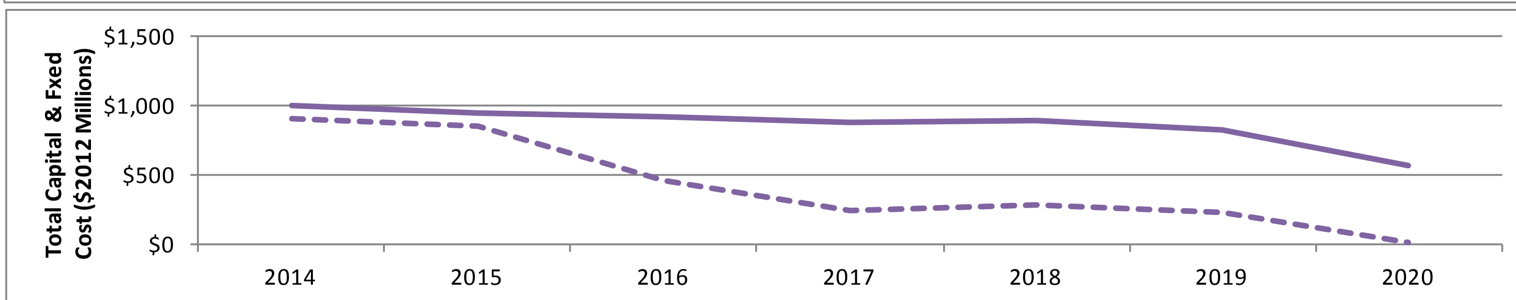
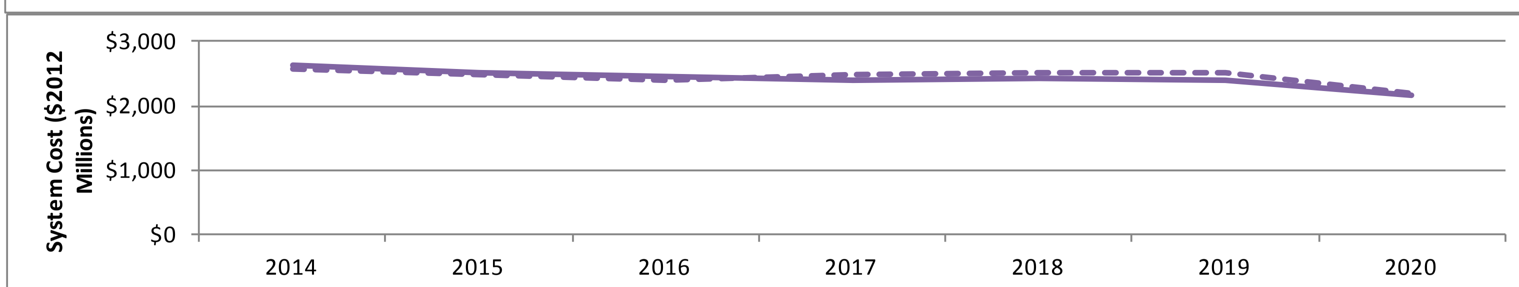
Change in Cost

- With Continued Operations, there is reduction in dispatch cost but increase in fixed & capital cost







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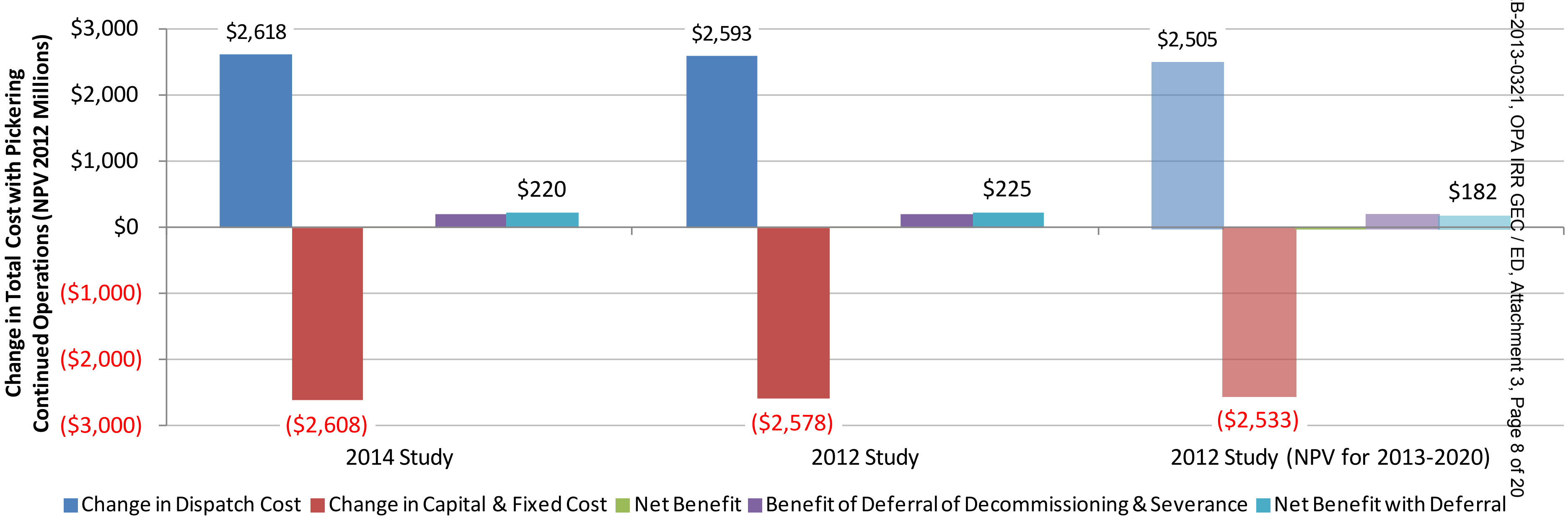
Total Cost Impact – Dispatch Cost, Capital & Fixed Cost and Net Change in Cost

- Pickering Continued Operations provides a net benefit of $220 million compared $225 in the 2012 study.
- The increase in benefits of savings from dispatch cost is offset by the increase in capital & fixed cost.



*Based on NPV of 2014 to 2020

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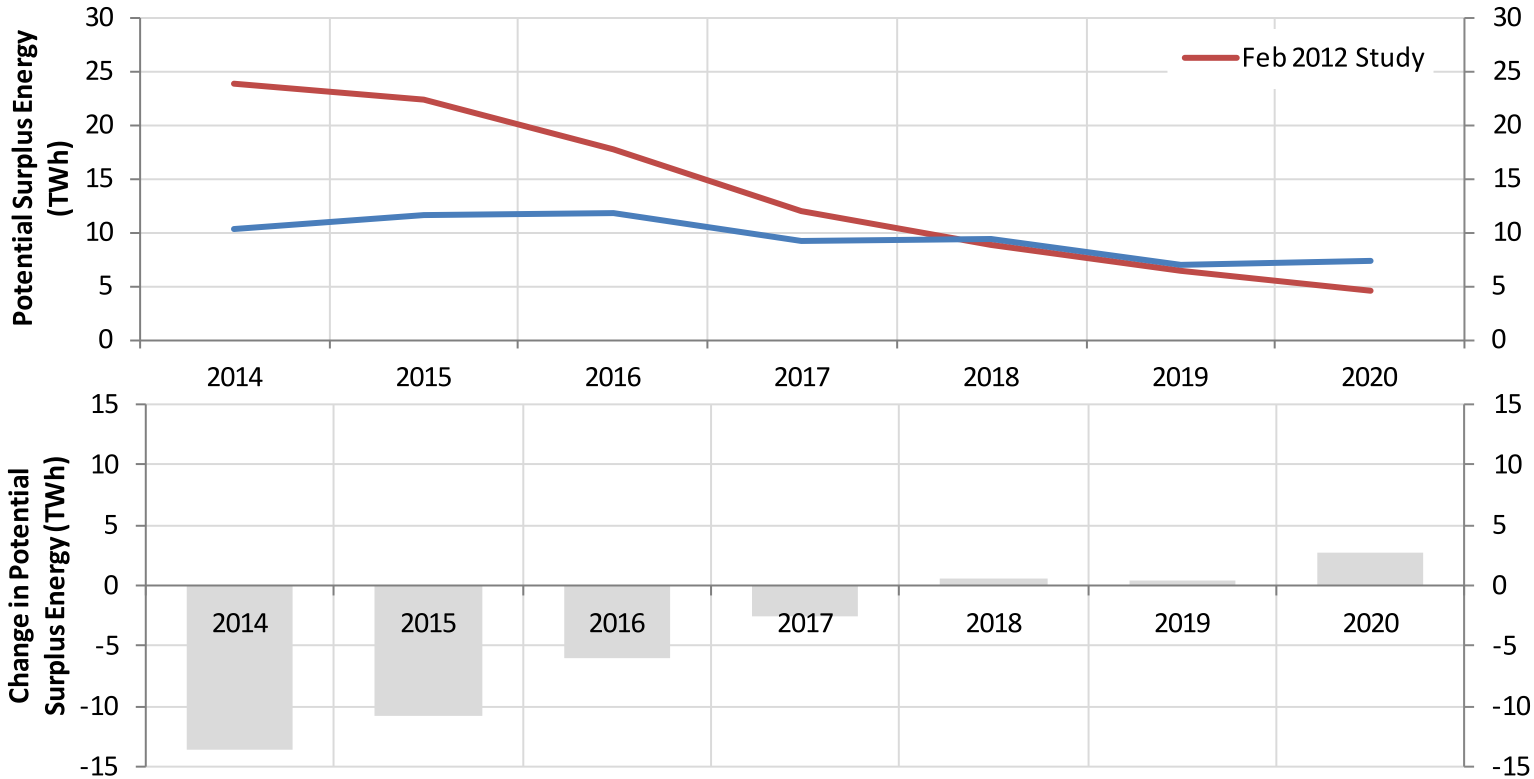
Potential Surplus Energy

- Compared to the 2012 study, the 2014 study has considerable reduction (30 TWh) in PSE during the Pickering Continued Operation.
- This is due to lower net energy demand, lower than projected nuclear and baseload hydro production [redacted]



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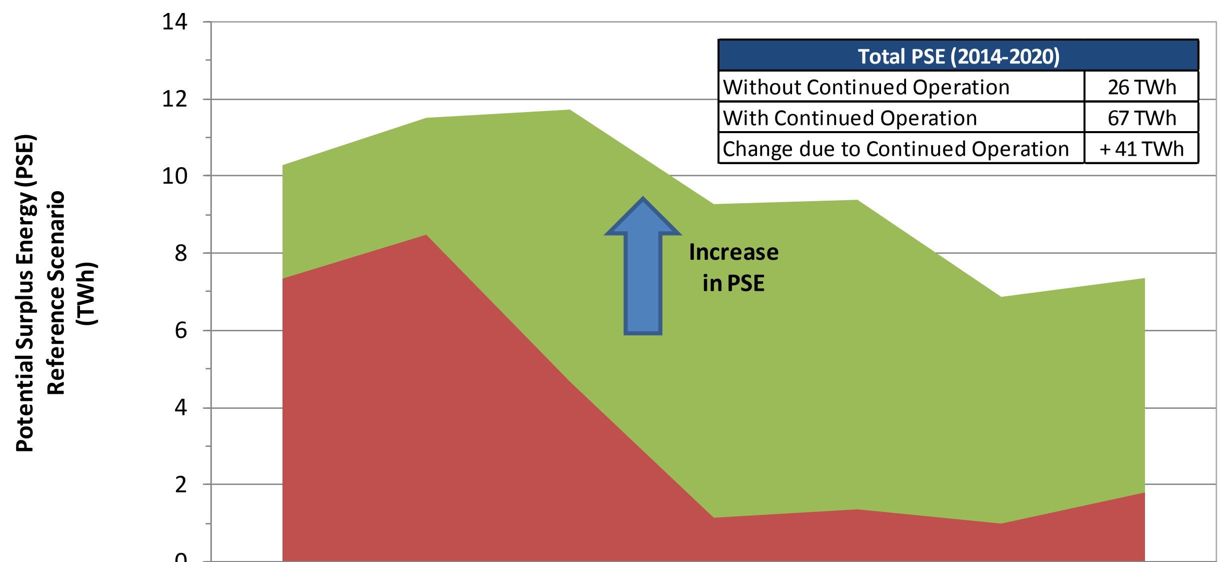
Increase in Potential Surplus Energy due to Pickering Continued Operation

- PSE increases in all years with Pickering continued operations
- Between 2014 and 2020, PCO increases PSE by 41 TWh (compared to 43 TWh in the 2012 study)
- This is equivalent to 37% of the increase in Pickering energy production during this period



	2014	2015	2016	2017	2018	2019	2020
With Pickering NGS Continued Operation	10.3	11.5	11.7	9.3	9.4	6.9	7.4
Without Pickering NGS Continued Operation	7.4	8.5	4.7	1.2	1.4	1.0	1.8
Increase in PSE with Pickering Continued Operation	2.9	3.0	7.1	8.1	8.0	5.9	5.6

	2014	2015	2016	2017	2018	2019	2020	Total
Change in PSE Relative to the Increase in Nuclear Energy Production Due to Pickering NGS Continued Operations	62%	66%	42%	36%	36%	29%	32%	37%

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SENSITIVITY ANALYSES

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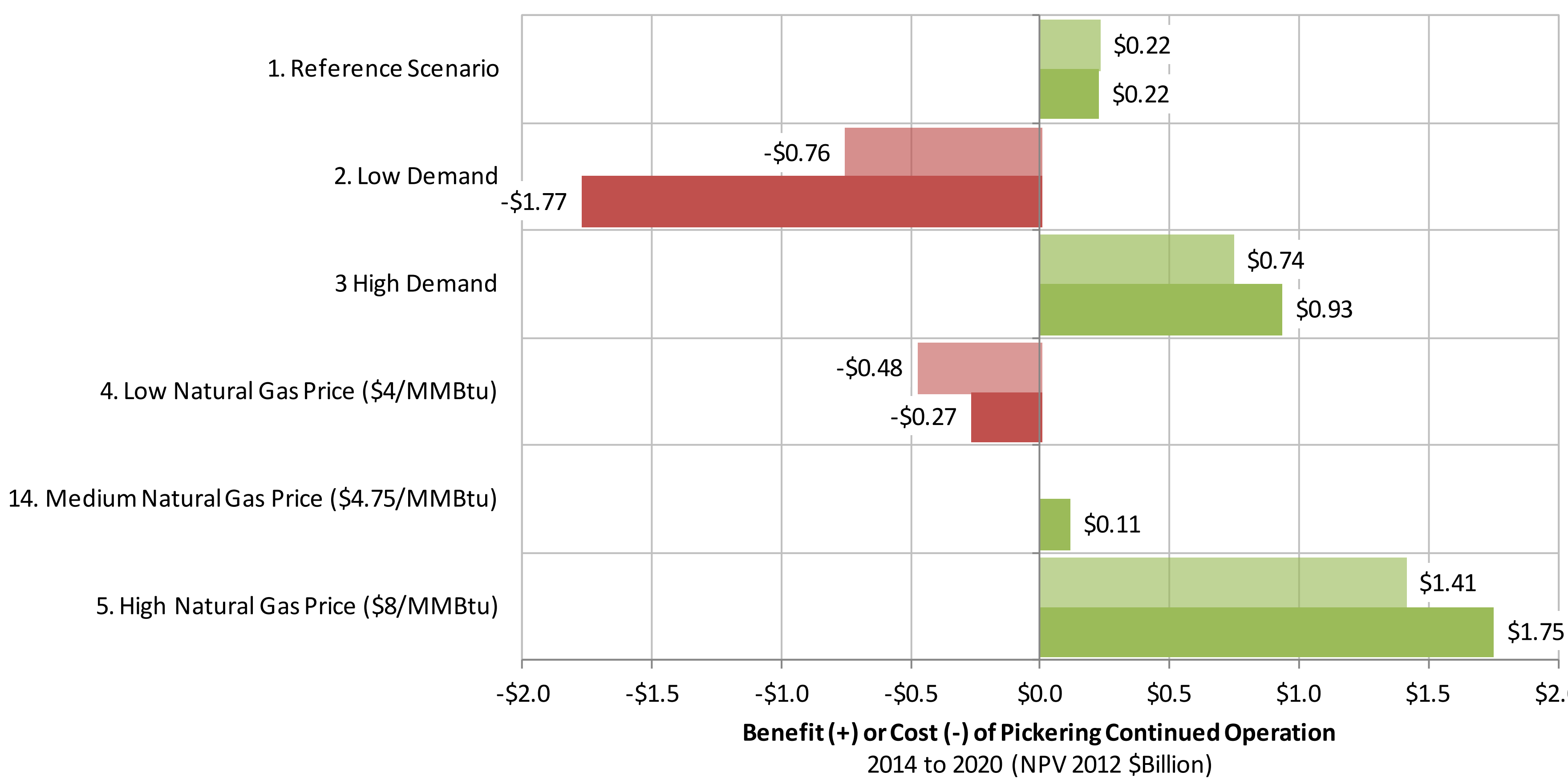
Results Summary & Comparison to 2012 Study

- Results are directionally consistent with the previous study



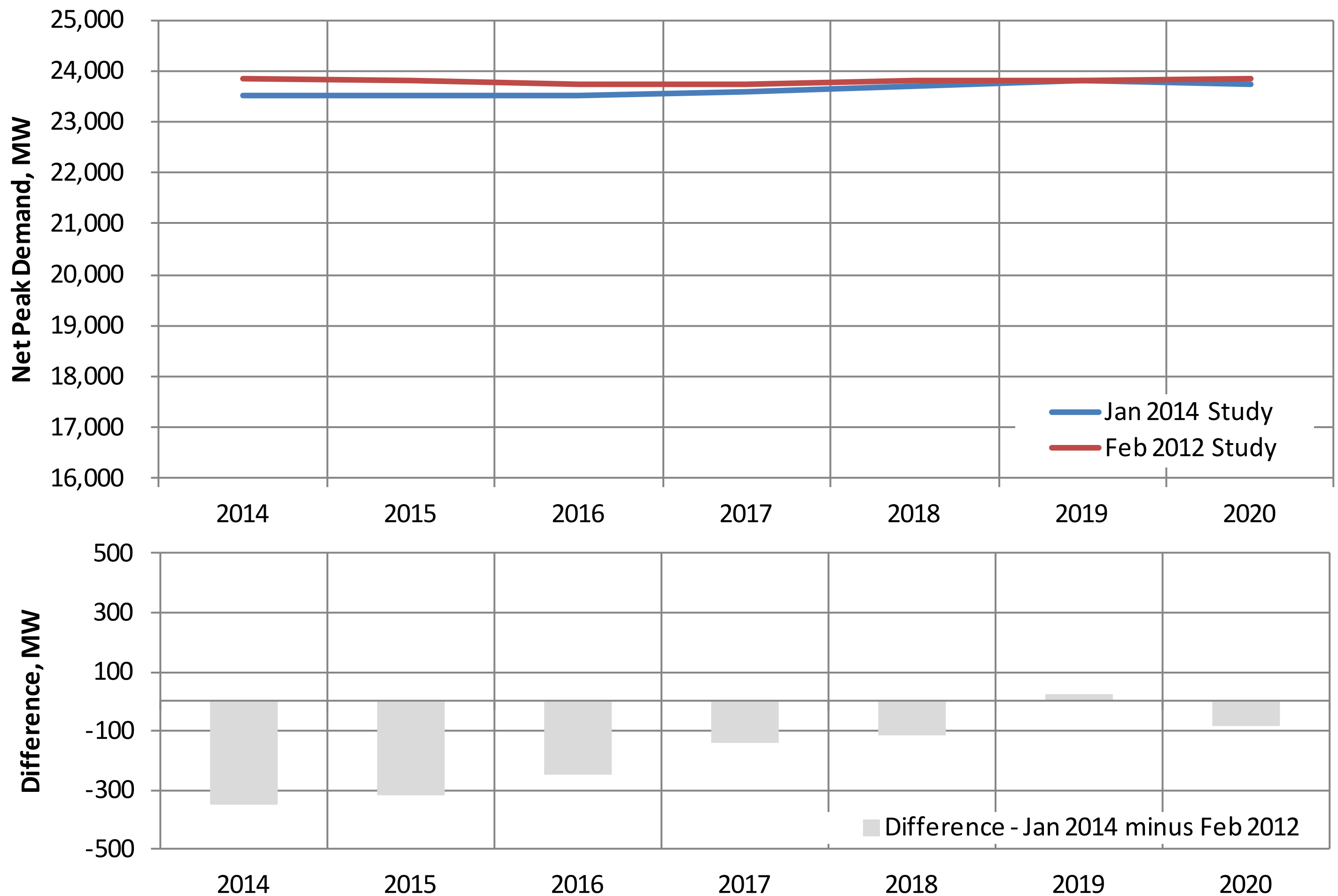
Observations

- The NPV of benefit/cost of the sensitivity scenarios were compared in relative to the Reference scenario for this study as well as the 2012 study
  - For example, the net cost for the low natural gas price scenario is 2.2 times of the benefit for the reference case
  - The result for each scenario in this update is similar to the previous study, except for the lower demand sensitivity
- In this update the net energy demand for the Low forecast is about 85 TWh (~10%) lower than the Reference forecast. In the 2012 study, it was 57 TWh (~6%) lower.
- The need for additional capacity without Pickering Continued Operation for the Low demand scenario is only 344 MW for the year of 2017. While in the 2012 study, additional capacity between 170 MW to 2200 MW is needed every year.

Sensitivity Scenario	2014 Study NPV ($ Billion)	Change from Reference	2012 Study NPV ($ Billion)	Change from Reference
1. Reference Case	$0.22		$0.22	
2. Lower Demand	-$1.77	-9.1	-$0.76	-3.4
3. Higher Demand	$0.93	3.2	$0.74	3.3
4. Lower Natural Gas Prices ($4/MMBtu)	-$0.27	-2.2	-$0.48	-2.1
14. Medium Natural Gas Price ($4.75/MMBtu)	$0.11	-0.5		
5. High Natural Gas Prices ($8/MMBtu)	$1.75	6.9	$1.41	6.3

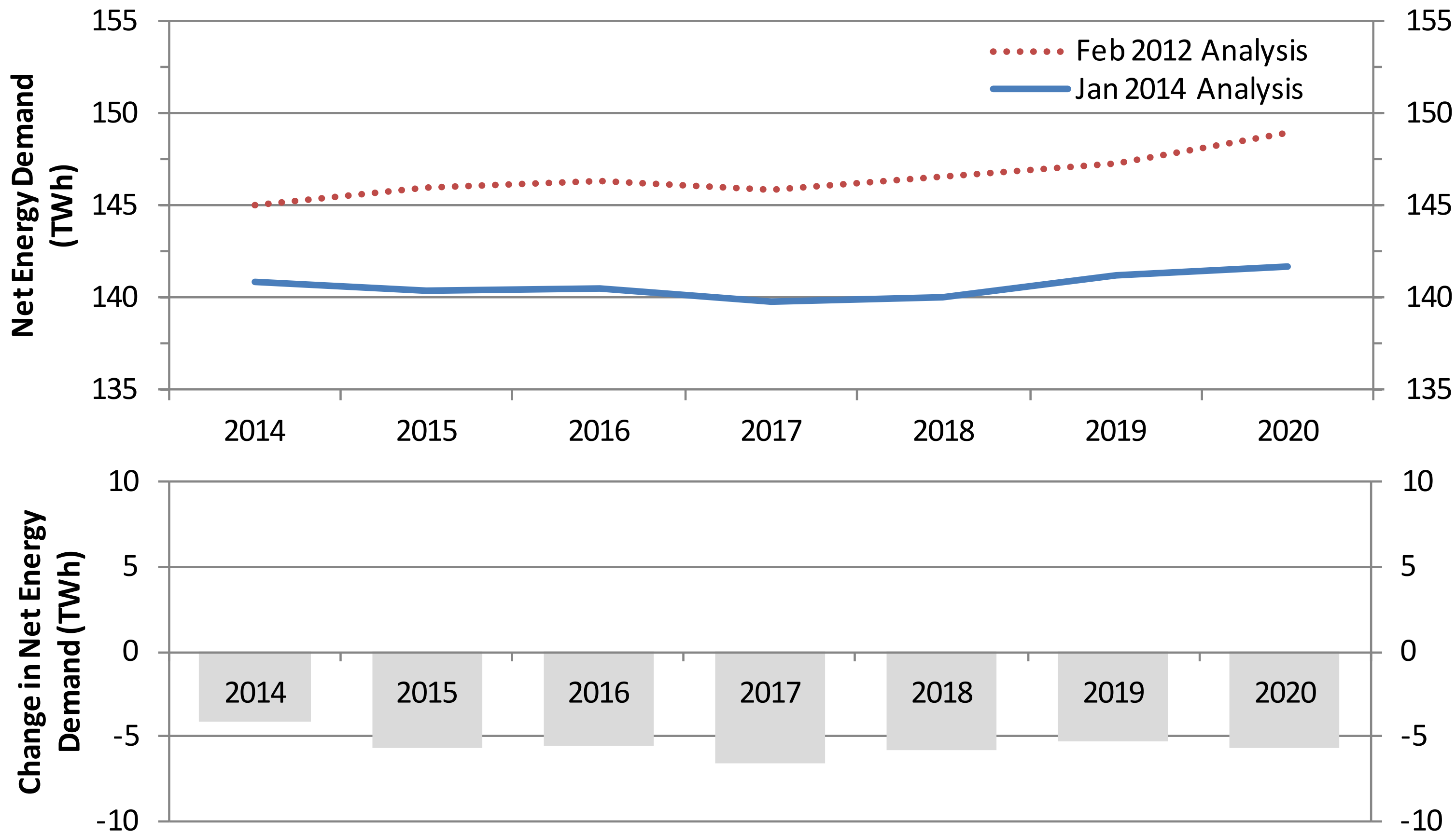
APPENDIX

Net Peak Demand

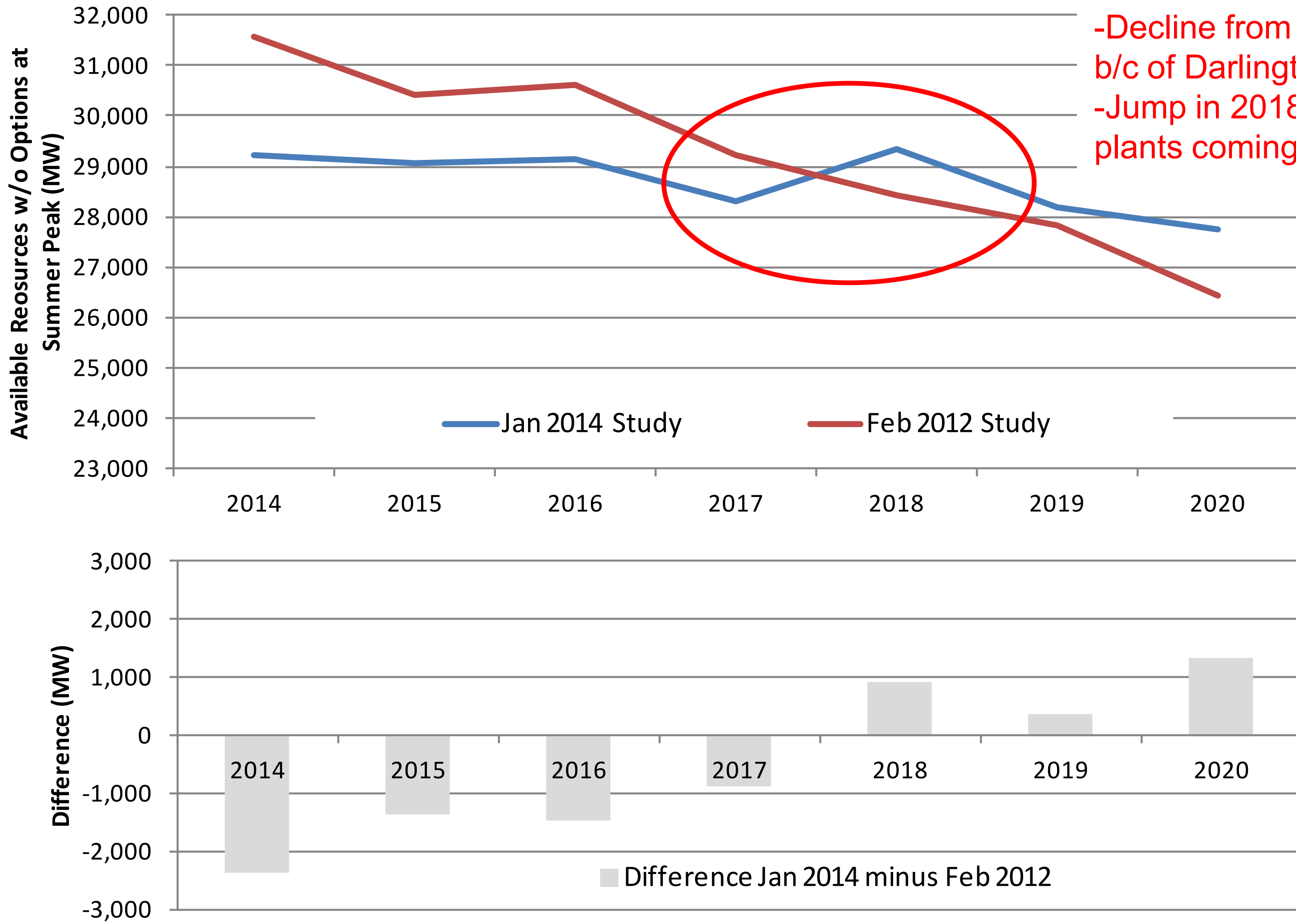


Net Energy Demand

- Compared to the 2012 study, the net energy demand in 2014 study is lower by the order of 5 TWh annually. 40 TWh in total for the study period.

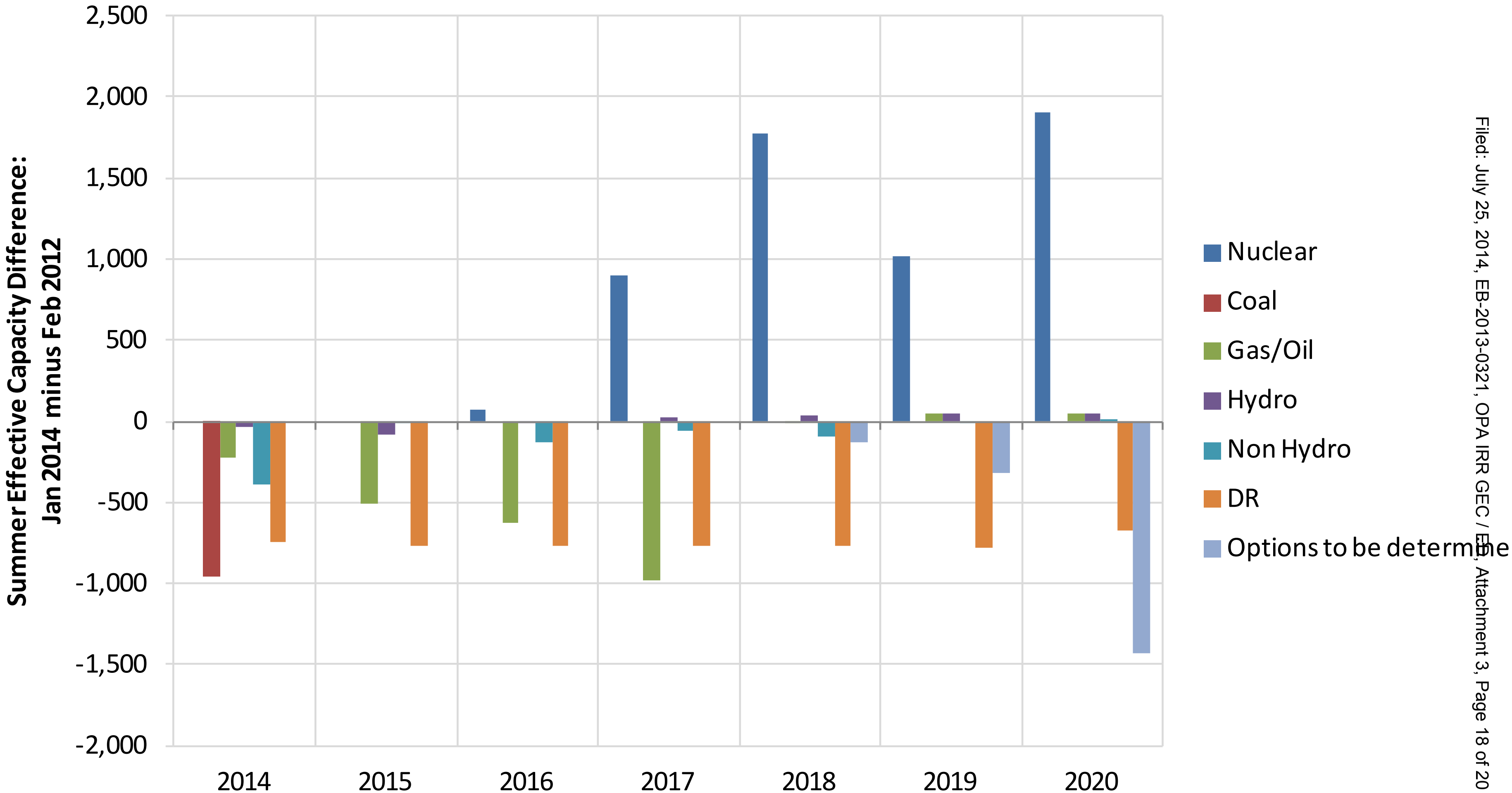


Resource Effective Capacity at Time of Summer Peak

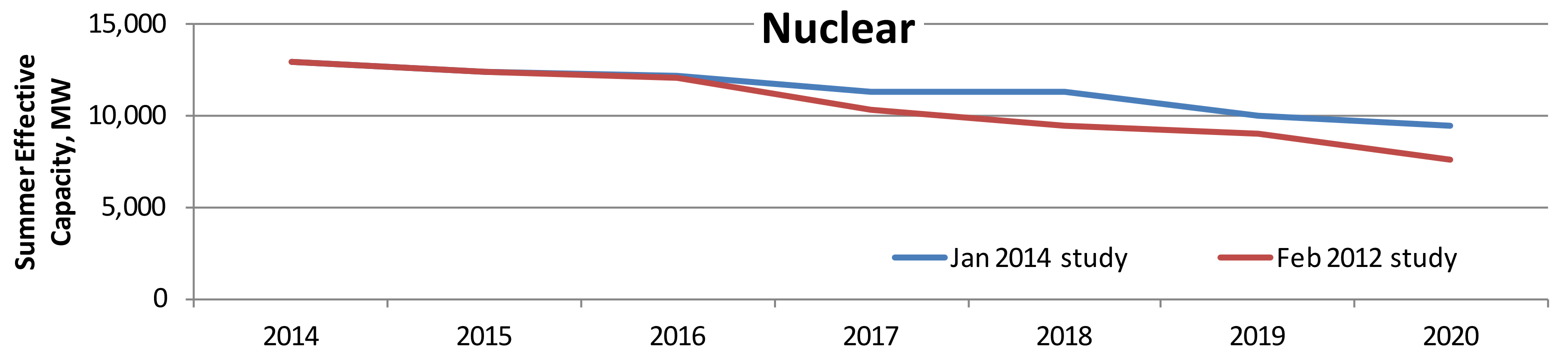


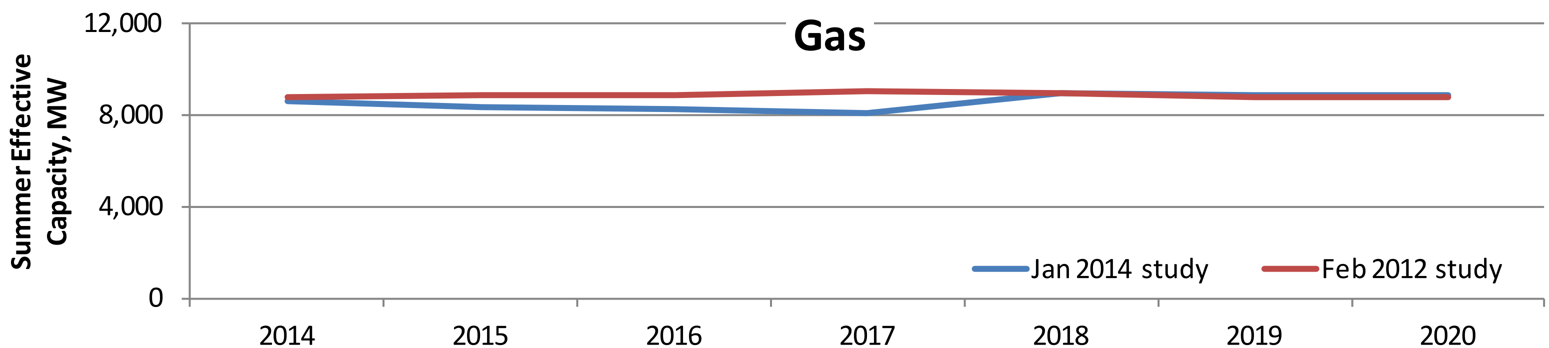
-Decline from 2016 to 2017 b/c of Darlington
-Jump in 2018 b/c of gas plants coming online

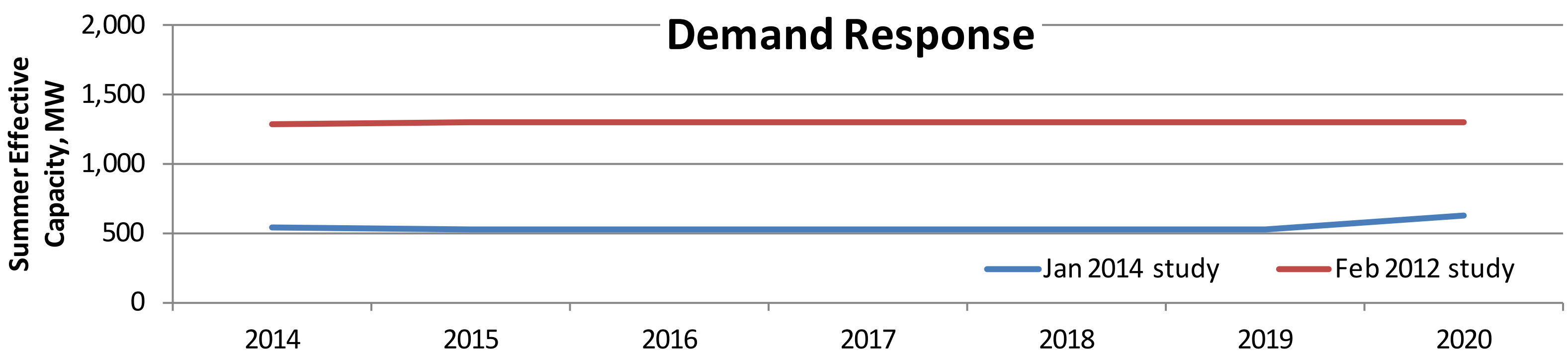
Key changes – Difference in summer effective capacity



Key changes – Summer effective capacity







Resource Above Requirements

- Compared to the 2012 study, with Pickering Continued