Policy issues of relevance to the BCUC Inquiry Respecting Site C

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EXECUTIVE SUMMARY

The purpose of this Report is to provide the BC Utilities Commission with information relevant to its Inquiry into the Site C Project, and to respond to issues and questions raised by the Preliminary Commission Report. In particular, the report addresses in detail a number of policy and planning issues that bear directly on the Inquiry, namely employment, GHG emissions, LNG, and electrification, and employment.

Employment. BC Hydro characterizes the loss of jobs related to Site C as an impact "not included in the overall impact to ratepayers". However, its analysis fails to acknowledge the far greater impact of the employment that would be created by terminating the Site C Project. The "Clean" alternative portfolio studied by BC Hydro in the EIS, which is similar to the portfolios developed in Appendix Q of its Submission, would develop more than three times the person-years of employment of continuing the Site C Project, or more than 80,000 person-years of employment more than the Site C Project during its lifetime.

Greenhouse gas emissions. The information presented in Appendix G of BC Hydro's Submission concerning the potential greenhouse gas emission benefits of Site C is incomplete and now out of date. The analysis provided by BC Hydro excludes from consideration the operational emissions from the Site C Project, overstates the emissions of the alternative portfolios, overstates the potential emissions reduction benefits associated with exporting the Site C surplus. Using updated information, we find that the Site C Project has a likely net GHG cost of 587 kt compared to a clean portfolio of alternative resources, over a 100-year operating period.

Forecast load for LNG. With respect to BC Hydro's decision to include the LNG load of all three proposed facilities in the low load, high load and mid load forecasts, we note the absence of evidence detailing the relative disadvantages of BC LNG over the past several years compared to global competitors who have been successful at moving forward more than 100 MRTA of export capacity. Understanding how those disadvantages will be or are being addressed is necessary to drawing conclusions regarding when or if BC LNG facilities will proceed in the future. Specific issues of concern include the following:

- **Completion risk**. Both timing and completion risks are identified by BC Hydro. LNG load is deferred but is assumed to be 100% certain to occur – this does not reflect a completion risk.
- **Global LNG demand**. The existence of future global LNG demand is a necessary but insufficient reason to conclude that BC LNG will be developed.
- **Project milestones**. The reaching of these milestones is necessary but not sufficient to concluding that any LNG facilities will proceed to construction and operations.
- **Competitive position**. BC LNG has been outcompeted by both U.S and Australian LNG export facilities for nearly a decade. BC Hydro notes that "B.C.s competitive advantages remain unchanged…" However, we suggest that this is *not* a sign of pending development, but rather a reason to believe that the status quo will continue with no development of BC LNG.

In the context of this uncertainty, Deloitte excluded LNG Canada upstream and downstream energy and capacity requirements as a result of the FID delay. We took the same position in Raphals' and Hendriks (2017). While a probabilistic approach would be preferable, this is a reasoned approach to addressing the considerable uncertainty respecting LNG project completion.

Electrification. The key observations of our review of BC Hydro's electrification analysis are as follows:

- **Lack of information to assess "implications"**. The information provided in BC Hydro's submission concerning the electrification scenarios lacks some supporting information that is important for evaluating the "implications" of these electrification portfolios, pursuant to section 3a) of the OIC 244.
- **Price effects of electrification cannot yet be determined**. Historic BC Hydro rate increases have been modest compared to those that have occurred for the past several years and those that would result from the electrification resource plan envisaged by BC Hydro. Real rate increases in BC have been occurring for about 5 years, and will continue for another 5 years under the 10-Year Rates Plan. It may take several more years to understand the implications of these real rate increases on consumer behavior**.**
- **BC Hydro's electrification scenario may overstate the benefits of continuing with the Site C Project**. The electrification load forecast used by BC Hydro appears to overstate the projected requirements due to electrification by more than 20 TWh/year. Moreover, the degree of likely electrification under a future of mid-GHG prices and low natural gas prices is entirely captured in the current mid-load forecast. The effect of the overstatement of future electricity requirements is to overstate the findings of potential benefits of moving forward with the Site C Project under an electrification scenario.
- **Some sectors may not electrify as anticipated**. Our analysis illustrates that even with substantial increases in natural gas prices and a GHG price increasing at $20/year beyond 2022, space and water heating with electricity does not become more cost effective compared to natural gas.

ABOUT THE AUTHORS

Richard Hendriks is the director of Camerado Energy Consulting, an Ontario-based firm providing environmental assessment, energy planning, policy analysis, and research services to clients across Canada. For the past two decades, he has been engaged in the planning and assessment of several proposed large-scale hydroelectric developments, and provided testimony before regulatory bodies concerning their environmental effects, economic viability, socio-economic impacts and implications for Indigenous rights. Mr. Hendriks has played a key role in environmental assessment and negotiation processes regarding large hydroelectric and mining projects for several First Nations across Canada, including for the Innu Nation in Labrador with respect to the Lower Churchill Project, and for the Treaty 8 Tribal Association, with respect to the Site C Hydroelectric Project.

From 1999 to 2002, Mr. Hendriks was the environmental and engineering analyst for Innu Nation in relation to hydroelectric development proposals in Labrador. There, he participated in environmental assessment, negotiation of an environmental protection chapter of an impacts and benefits agreement in relation to the proposed Lower Churchill Project, and technical and research support for negotiation of a compensation agreement for the existing Churchill Falls Project.

In 2003, Mr. Hendriks joined Chignecto Consulting Group as an Associate where he provided resource negotiation and environmental assessment support services to Indigenous groups across Canada. His work included negotiation of impacts and benefits agreements, regulatory interventions, and assessment of environmental, economic and social impacts and benefits related to hydroelectric, transmission and mining developments.

Since 2009, as director of Camerado Energy Consulting, Mr. Hendriks has conducted and managed environmental, technical and economic review of several large-scale proposed resource projects, including the Lower Churchill Hydroelectric Generation Project, the Labrador-Island Transmission Link, the Site C Clean Energy Project, the Côte Gold Project, and the proposed Slave River Hydro Project. He has also assessed the potential for compensation to Indigenous communities for historic and ongoing effects of hydroelectric and transmission development in Ontario, Labrador, Manitoba and the Northwest Territories.

In 2010, Mr. Hendriks testified before the Alberta Utilities Commission during its Inquiry on Hydroelectric Power Generation that was reviewing the policy, planning and regulatory context for additional hydroelectric development in that Province. The following year, Mr. Hendriks presented testimony on several economic and environmental matters before the Joint Review Panel for the Lower Churchill Project, who accepted many of his recommendations. More recently, Mr. Hendriks testified on several occasions before the Joint Review Panel for the Site C Project, who adopted several of his recommendations. In May 2014, the Manitoba Public Utilities Board qualified Mr. Hendriks as an expert in the policy and planning aspects of large-scale hydroelectric developments, including the socioeconomic implications and environmental consequences for Indigenous communities of these developments.

Philip Raphals is cofounder and executive director of the Helios Centre, a non-profit energy research and consulting group based in Montreal. Over the last 25 years, he has written extensively on issues related to hydropower and competitive energy markets, and has appeared many times as an expert witness before energy and environmental regulators in several provinces.

Mr. Raphals has been formally recognized as an expert witness by energy regulators in the provinces of Quebec, Nova Scotia and Newfoundland and Labrador:

- In Quebec, he has provided expert testimony in 14 proceedings before the Régie de l'énergie du Québec. The Régie has recognized his expertise in fields including transmission ratemaking, security of supply, energy efficiency and avoided costs;
- The Nova Scotia Utilities and Review Board has qualified Mr. Raphals as expert in sustainable energy policy, least-cost energy planning and utility regulation (including transmission ratemaking). He provided expert testimony in two proceedings there concerning the Maritime Link, including critical analysis of long-term demand forecasts, resource options and financial analyses submitted by NSP Maritime Link Inc., a subsidiary of Emera, in support of its proposal to build an undersea transmission link between Newfoundland and Nova Scotia, and the accompanying long-term electricity supply contracts. In its decision, the Board quoted Mr. Raphals' report and relied in part on his analyses;
- The Newfoundland and Labrador Public Utilities Board has qualified Mr. Raphals as an expert in electric utility rate making and regulatory policy. He has provided expert testimony in in 2011 Muskrat Falls Review and in its hearings on the 2013 General Rate Application of Newfoundland and Labrador Hydro.

Mr. Raphals is currently acting as an expert witness in rate proceedings before the Manitoba and Newfoundland and Labrador Public Utilities Boards.

Mr. Raphals appeared as an expert witness on behalf of Grand Riverkeeper Labrador Inc. in the hearings of the Joint Review Panel (JRP) on the Lower Churchill Generation Project, which relied on his analysis of project justification. The Panel cited him in its report and relied on his analyses for several of its findings.

In British Columbia, Mr. Raphals appeared as an expert witness on behalf of the Treaty 8 Tribal Association in the hearings of the Joint Review Panel on the Site C Hydroelectric Project. The Panel cited him in its report and relied on his analyses for several of its findings. He also presented expert affidavits in two related proceedings before the B.C. Supreme Court, one of which was not received by the Court.

From 1992 to 1994, Mr. Raphals was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale Hydroelectric Project, where he coauthored with James Litchfield and Roy Hemmingway a study on the role of integrated resource planning in assessing the project's justification.

In 1995, Mr. Raphals was commissioned by the Quebec Department of Natural Resources to prepare a report on electricity regulation in British Columbia, focussing on the structure and practices of the British Columbia Utilities Commission. The report formed part of the documentation supporting Quebec's Public Debate on Energy, which eventually led to the creation of the Régie de l'énergie.

In 1997, Mr. Raphals advised the Standing Committee on the Economy and Labour of the Quebec National Assembly in its oversight hearings concerning Hydro-Quebec. In 2001, he authored a major study on the implications of electricity market restructuring for hydropower developments, entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets*. In 2005, he advised the Federal Review Commission studying the Eastmain 1A/Rupert Diversion hydro project with respect to project justification. Later, he drafted a submission to this same panel on behalf of the affected Cree communities of Nemaska, Waskaganish and Chisasibi.

Mr. Raphals chairs the Renewable Markets Advisory Panel for the Low Impact Hydropower Institute (LIHI) in the United States. He has been an invited speaker before the Senate Standing Committee on Energy, the Environment and Natural Resources and at numerous energy industry conferences, including the Canadian Association of Members of Public Utility Tribunals (CAMPUT). He has also been an invited speaker at Yale University, Concordia University and McGill University.

In 2013, Mr. Raphals was an invited participant in an expert roundtable on electricity surpluses and economic development, convoked by the Quebec Commission on Energy Issues. The Commission's report relied on several of his analyses.

In 2015, he was a finalist for the R.J. Tremplin Prize, awarded by the Canadian Wind Energy Association for "scientific, technical, engineering or policy research and development work that has produced results that have served to significantly advance the wind energy industry in Canada."

Together with Prof. Karen Bakker of the University of British Columbia, MM. Raphals and Hendriks were the authors of "Reassessing the Need for Site C", a study published by the UBC Programme on Water Governance in April 2017.

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1 Introduction

This report is part of an initiative of the Program on Water Governance at the University of British Columbia.

The Program on Water Governance (watergovernance.ca) conducts interdisciplinary research on water sustainability, and makes this research available to the public. In addition to academic publications, the Program publishes briefing notes and reports, with the goal of fostering dialogue on water policy with communities and decision-makers.

The purpose of this Report is to provide the BC Utilities Commission with information relevant to its Inquiry into the Site C Project, and to respond to issues and questions raised by the Commission's Preliminary Report. In particular, the report addresses a number of policy and planning issues that bear directly on the Inquiry, namely GHG emissions, LNG, electrification, and employment.

Section 2 explores the employment implications of continuing or terminating the Site C Project. The terms of reference for this Inquiry require the Commission to consider the objectives of the *Clean Energy Act*, which include the following objective: (k) to encourage economic development and the creation and retention of jobs.

Section 3 reviews and updates evidence concerning the potential greenhouse gas benefits and cost of the Site C Project and the alternatives. This section addresses section 3(b)(iv) of the Commission terms of reference, which ask the Commission to investigate "what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy coast as the Site C project?"

Section 4 reviews the submissions filed by BC Hydro respecting the forecasted load for LNG. In particular, this section reviews this information in the context of evaluation of LNG project completion risk.

Section 5 investigates in detail BC Hydro's electrification forecast in light of the findings of prior study of electrification in the 2013 IRP. In particular, this section reviews; the adequacy of the information provided by BC Hydro to allow the Commission to assess "implications" of the project options, pursuant to section 3a) of the Commission terms of reference; the potential relationship between price effects and electrification; the plausibility of BC Hydro's electrification scenario; and the potential that some sectors of the economy will not electrify as anticipated.

2 Employment implications of the Site C options

While BC Hydro appropriately characterizes the loss of jobs related to Site C as an impact "not included in the overall impact to ratepayers", its analysis fails to acknowledge the far greater impact of the employment that would be created by terminating the Site C Project.

The terms of reference for this Inquiry require the Commission to consider the objectives of the *Clean Energy Act*, which include the following objective:

(k) to encourage economic development and the creation and retention of jobs;

In comparing the employment created by the Site C Project and the alternative portfolios, it is necessary to consider the employment that has already occurred on the Site C Project as "sunk" employment. That means evaluating the portfolios on a go-forward basis, and including only the future employment in the respective portfolios.

BC Hydro did not prepare detailed employment figures for each of the portfolios included in Appendix Q of its submission. However, BC Hydro's Evidentiary Update to its Site C EIS presented employment information for Site C compared to a Clean "block" portfolio of supply-side resources that creates the same 5100 GWh/year of energy and 1100 MW of capacity as the Site C Project. The Appendix Q portfolio for the mid-load forecast where Site C is terminated[1] develops very similar resources in the years following 2024 as the Clean portfolio from the EIS. The resources in these portfolios are summarized it the following table.

Table 1: BC Hydro's Site C EIS block portfolios[2]

Blocks	Clean		Site C	
	Dependable Capacity	Annual Energy	Dependable Capacity	Annual Energy
Resources	MW	GWh/year	MW	GWh/year
Site C			1100	5100
GM Shrum	220	0		
Revelstoke 6	488	26		
Municipal Solid Waste (MSW)	36	312		
Natural Gas (SCGT)				
Pumped Storage	500	-364		
Wind		5126		
Totals	**1244**	**5100**	**1100**	**5100**

[1] F1-1, Appendix Q, p.8 of 28.

[2] BC Hydro. September 13, 2013. Site C Clean Energy Project Evidentiary Update, Table 14. Available at: http://www.ceaa-acee.gc.ca/050/documents/p63919/94428E.pdf.

The construction and operations employment determined by BC Hydro for each of these portfolios is summarized below. BC Hydro did not provide year-by-year employment figures for the Site C construction phase; however, with approximately 25% of the construction phase complete by December 2017, it is estimated that 25% of the construction-related employment for the Site C Project has already occurred.

Table 2: BC Hydro block portfolios – employment (person-years)[3,4]

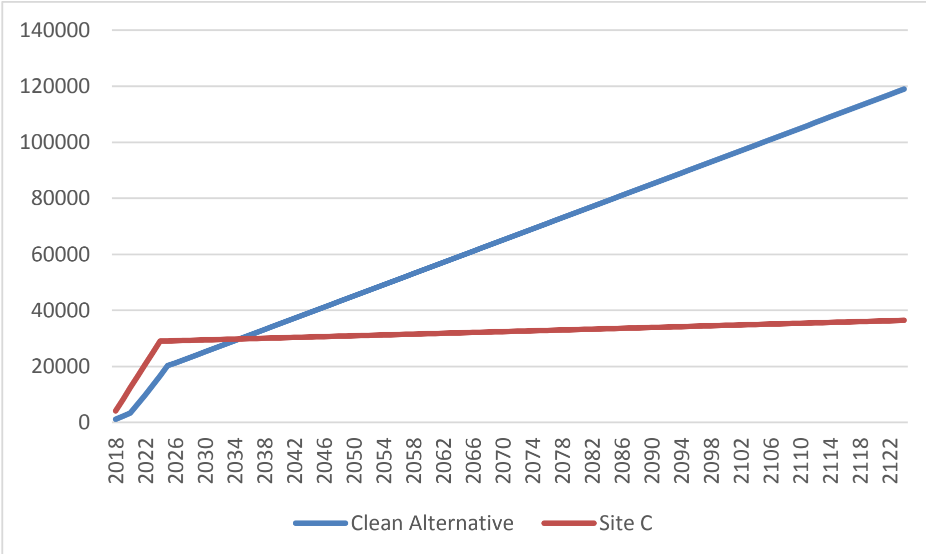
	Clean	Site C
Construction (total)	30,788	44,249
Construction (remaining)	30,788	33,187
Operations (per year)	998	74
Total to 2030	24,346	33,631
Total to 2040	43,263	34,371
Total to 2050	53,243	35,111
Total to 2094	97,155	38,367
Total to 2124	127,095	40,587

Figure 1 below illustrates these findings graphically, based on BC Hydro's construction and operations employment estimates presented in the EIS. For the Clean portfolio, it was assumed that the resources would be developed prior to 2030, with planning and construction on pumped storage beginning in the early 2020s. Site C is presumed to complete construction as currently planned in 2024, with only operations employment thereafter.

[3] Summarized from: BC Hydro. September 13, 2013. Site C Clean Energy Project Evidentiary Update, p.38.

[4] "person-years" and "jobs" are interchangeable terms

Figure 1: Employment – Site C versus the alternative portfolios (cumulative)



Much of the operations employment in the alternative portfolios results from the development of wind resources. While employment creation will vary by portfolio, all of BC Hydro's portfolios involving the termination of Site C, as illustrated in Appendix Q of its submission, develop large amounts of wind resources early in the planning period.

BC Hydro characterizes the loss of jobs related to Site C as an impact "not included in the overall impact to ratepayers". However, **it remains an important implication of the Site C Project, in light of s. 3(a) of the Terms of Reference of this Inquiry.** The "Clean" alternative portfolio studied by BC Hydro in the EIS, which are similar to the portfolios developed in Appendix Q of its submission, would develop more than three times the person-years of employment of continuing the Site C Project, or more than 80,000 person-years of employment more than the Site C Project during its lifetime.

3 Site C GHG emission costs and benefits

3.1 Updating of filed evidence

The information presented in Appendix G of BC Hydro's Submission, taken from its Site C EIS, is incomplete and now out of date. Specifically, BC Hydro notes the following:

> BC Hydro estimates that the Project would avoid between approximately 34 and 76 million tonnes of carbon dioxide (CO_2) equivalent over a 100-year evaluation period, with the majority of the avoided greenhouse gas (GHGs) in BC Hydro's service area.

BC Hydro also presents the following summary table of its determination of GHG emission benefits of the Site C Project.

Table 3: BC Hydro's comparative GHG benefits of the Site C Project (2024-2124)[5]

		Site C energy used in BC	Site C energy exported to WECC	Total
Generation	(GWh)	476,300	33,700	510,000
Avoided GHGs – Clean portfolios	(000 tonnes)	19,000	15,000	34,000
Avoided GHGs – Clean + Thermal portfolios	(000 tonnes)	61,000	15,000	76,000

To support its analysis, BC Hydro refers to the GHG emission comparison in Table 5.43 of the EIS, portions of which are reproduced below.

Table 4: Environmental Attribute Comparison

Environmental Attribute	Clean Generation	Site C Project
Land footprint (ha)	2,230	5,660
Affected stream length (km)	15	125
Reservoir created (ha)	0	9,300
Operational GHG Emissions (kt/year)	200	650
NOx (kt/year)	0.5	0
Carbon Monoxide	0.4	0

This table lists operational emissions from the "Clean" alternative portfolio of 200kt/year. On the basis of this table, BC Hydro then draws the following conclusions:

> The portfolio including the Project has lower operational GHG emissions than both portfolios not including the Project. The Clean Generation portfolio selects a municipal solid waste resource option, which includes GHG emissions from fuel combustion.[6]

However, this table omits the operational emissions from the Site C Project, which BC Hydro reports in Appendix G to average 8.5t CO_2e/GWh (44.2 kt/yr) in the "likely" emissions scenario and 11.4t CO_2e/GWh (59.2 kt/yr) in the "conservative" emissions scenario. However, these 100-

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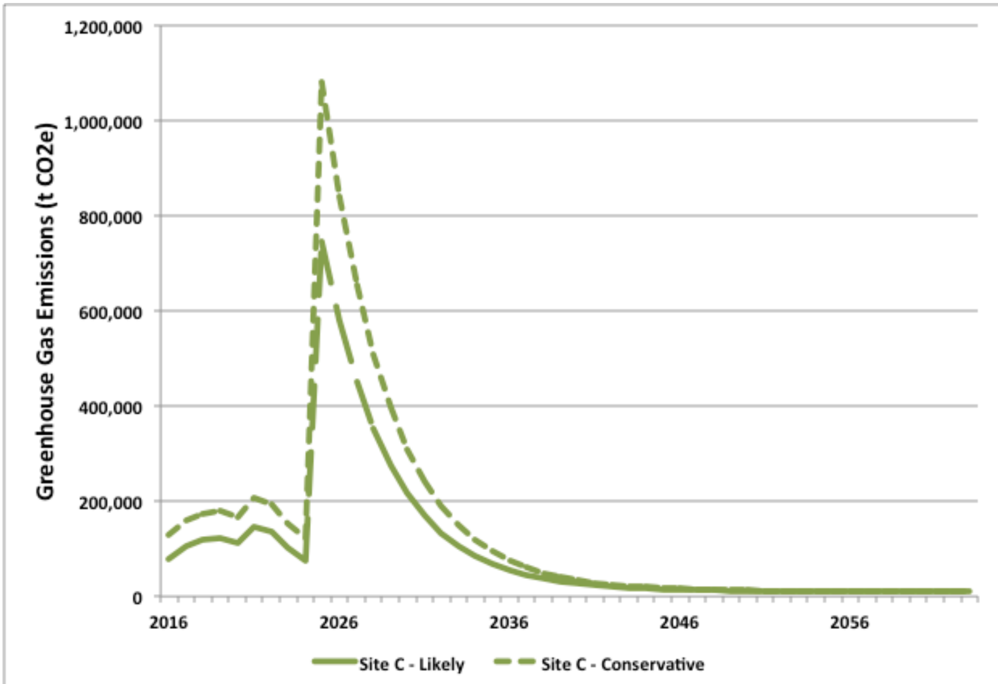
[5] F1-1, Appendix G.

[6] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement Volume 1, Section 5, p.5-70.

year averages mask a dramatic spike in emissions during the early decades, as seen in the following figure, which presents the annual GHG emissions for the construction and operations, beginning in 2024, of the Site C Project.

Figure 2: Annual GHG emissions of the Site C Project[7]



An appropriate comparison of the GHG emissions of the Site C Project to the alternatives must include the GHG emissions of the Site C in the period 2024 to 2040.

3.2 Implications of OIC 244

In BCUC IR.2.70, the Commission requested BC Hydro to provide an analysis of how much, if any, natural gas fired generation can be relied upon for backup capacity given:

- a) Section 6 and the 93 percent clean objective in the CEA
- b) the Terms of Reference for this report, under which there should be no increase in GHG intensity.

[7] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement. Volume 2 Appendix S: Site C Clean Energy Project: Greenhouse Gases Technical Report. Prepared for BC Hydro by Stantec Consulting Ltd., Table C-4 and Table C-6. Available at: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=85328.

In its response, BC Hydro notes the following:

> The wording clearly states greenhouse gas emission levels and does not reference intensity levels. Our interpretation is consistent with the *Clean Energy Act* British Columbia Energy Objective "to reduce BC greenhouse gas emissions". BC Hydro's assessment is that we have no room for the addition of any new gas fired generation and this is the basis of the portfolios we have created.[8]

We concur with BC Hydro's interpretation of section 3(b)(iv) of the OIC, which reads as follows:

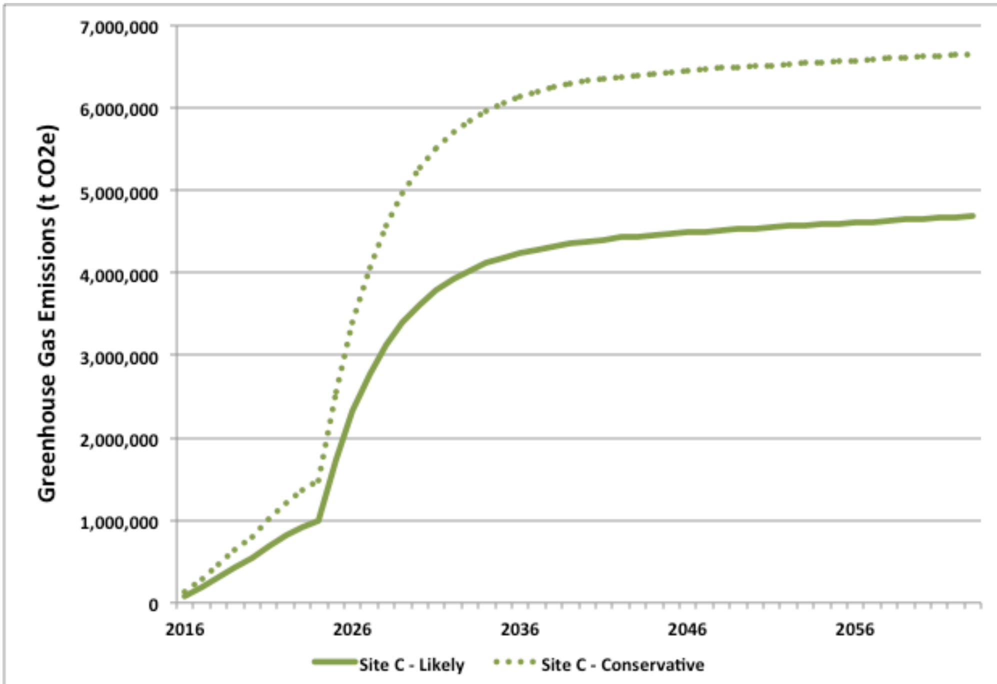
> Given the energy objectives set out in the *Clean Energy Act,* what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy coast as the Site C project?

For this reason, the alternative portfolios cannot contain thermal resources (e.g. simple cycle gas turbines), which even with carbon capture and storage would increase GHG emissions. As such, an analysis of the potential GHG benefits of the Site C Project also cannot include comparisons to any "Clean + Thermal" portfolios.

However, the OIC also appears to be internally inconsistent. On the one hand, it imposes on the alternative portfolios a requirement to maintain or reduce 2016/17 greenhouse gas emission levels. At the same time, no such requirement is made of the Site C Project, which BC Hydro acknowledges in Appendix G of its submission will increase GHG emissions by 4.3 Mt in the "likely" scenario and 5.8 MT in the "conservative" scenario. As shown in **Error! Reference source not found.** below, nearly all of these emissions occur in the early years of operations.

[8] F1-5, BCUC IR.2.70.0.

Figure 3: Cumulative GHG emissions of the Site C Project[9]



In other words, in order to maintain future GHG emissions at their current levels or reduce them, Site C would need to be terminated. Since the OIC calls for a comparison of the merits of proceeding with the Site C Project with those of the "Clean" portfolios of alternative resources, this analysis should take into account the GHG emissions of the Site C Project, as well.

The present value portfolio analysis presented in Raphals (2017), includes a cost for the GHG emissions from Site C, based on BC's current GHG price, which will increase to $50/tonne ($45 in 2016$) in 2021. We have further assumed that this GHG price will remain stable in 2016$. Inclusion of these costs is appropriate, whether or not BC Hydro will actually be called upon to pay this tax, for the same reason that the evaluation of demand-side resources is based on the Total Resource Cost and not the Utility Cost. As Site C will actually cause these GHG emissions, the cost that they represent is properly part of an economic analysis, whether or not those costs are borne by BC Hydro, by its ratepayers directly, or by others.

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[9] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement. Volume 2 Appendix S: Site C Clean Energy Project: Greenhouse Gases Technical Report. Prepared for BC Hydro by Stantec Consulting Ltd., Table C-4 and Table C-6. Available at: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=85328.

3.3 Updating the "Clean" portfolio for GHG comparison

In arriving at the conclusion that the Site C Project has a GHG emission advantage of 19 Mt/year (Table 4) over the Clean portfolio in relation to electricity consumed in BC, BC Hydro makes a key assumption that is no longer valid. The MSW generation developed by BC Hydro in the "Clean" portfolio used in the EIS is no longer selected in any of BC Hydro's portfolios developed in Appendix Q of its submission to the BCUC. Thus, the substantial emissions from MSW generation are no longer part of the alternative portfolios.

With the removal of MSW generation from the Clean portfolio alternative, the GHG emission advantage of the Site C Project in terms of electricity sold in BC disappears entirely.

The Clean alternative portfolios developed in Appendix Q and in the present submission offer a GHG emissions reduction benefit equivalent to the 4.3 Mt to 5.8 Mt of GHG emissions from Site C over the 100 years of its operations.

3.4 Potential GHG benefits from export of Site C energy

In its estimate of potential GHG benefits from Site C, BC Hydro presumes 33,700 GWh of total energy exports during the surplus period, based on a total generation of 510,000 GWh over 100 years. A review of the portfolios in Appendix Q indicates that, for the mid-load forecast, the energy surplus from Site C commences in F2025 and ends in F2033, with new wind energy resources entering service in F2035. The total of this energy surplus is approximately 20,400 GWh/year, less than the 33,700 GWh/year reported by BC Hydro in Appendix G.

In determining the emissions reductions in the rest of WECC, BC Hydro takes the view that the GHG emissions from the WECC grid determined in 2008 (0.443 tCO_2e/MWh) will remain unchanged until at least the early 2030s while Site C is exporting an energy surplus.

The EPA recently updated this figure to 0.414 tCO2e/MWh as of 2014, a decline of 6.5% in the intervening six-year period.[10,11] This downward trend is expected to continue given the additional non-emitting resources developed since 2014 and commitments made in much of the WECC to substantially reduce GHG emissions in the coming years. For example, between 2008 and 2015, California reduced the GHG intensity of its electricity from 0.59 tCO_2e/MWh to 0.32 tCO_2e/MWh, a decline of nearly 50%.[12] **Presuming that the GHG emissions intensity in**

[10] EPA. eGRID2014v2 GHG Annual Output Emission Rates. Available at: https://www.epa.gov/sites/production/files/2017-02/documents/egrid2014_ghgoutputrates_v2.pdf.

[11] EPA. Emission Factors for Greenhouse Gas Inventories. Available at: https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf.

[12] California Air Resources Board. June 2017. 2017 Edition California GHG Emission Inventory. Available at: https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2015/ghg_inventory_trends_00-15.pdf.

WECC continues to decline at a rate of 1%/year, the intensity will average about 0.35 tCO2e/MWh in the WECC during the years in which the Site C surplus energy is exported.

In calculating the potential GHG benefits of Site C for energy delivered within BC, BC Hydro correctly compares Site C to the other potential portfolios of other *new* resources, not to that of existing resources that might be displaced. In examining exports, a similar approach needs to be taken for the importing region, where the import of electricity from Site C would defer the development of new resources, which would have lower, and potentially much lower, GHG emissions intensity compared to the average of all resources within WECC.

The emissions of potential new resources that come on-line in WECC will depend upon the evolution of the costs of low-emission resources such as wind, solar and energy storage, as well as legislative commitments to reducing greenhouse gas emissions and renewable portfolio standards. Every major state in WECC has a renewable portfolio standard, with commitments beyond 2025 having been made by California and Oregon to 50% renewables by 2030 and 2040, respectively.[13] Achieving this level of renewables integration will mean aggressive development of additional low-emission resources.

Hendriks (2016)[14] reviewed the GHG emissions reduction potential for exporting the surplus from Site C to Alberta, where current policy requires that by 2030, two-thirds of Alberta's coal generating capacity will be replaced by renewable energy, and one-third by natural gas.[15] Considering that policy in most jurisdictions in WECC is more aggressive in terms of GHG emission reductions, this provides a likely measure of the maximum GHG emission reductions from the Site C Project. Presuming a GHG emissions intensity factor for natural gas of 0.545 tCO_2e/MWh, this results in an overall emissions intensity factor of 0.182 tCO_2e/MWh.

3.5 Summary

The following table revises the information in BC Hydro's Appendix G, by applying the information discussed above:

- clean portfolio GHG emissions of 0 tCO_2e/MWh, removing the MSW generation;
- Site C GHG emissions of 4.3 Mt of emissions over a 100-year operating period;
- total energy exports to WECC of 20,400 GWh during the surplus period;
- lower GHG emissions reductions for exports from Site C, based on a likely emissions

[13] NCSL. State Renewable Portfolio Stantdards. Available at: http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

[14] Hendriks, R.M. July 2016. Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives. UBC Program on Water Governance. Available at: http://watergovernance.ca/projects/sitec/.

[15] Government of Alberta. 2016. Climate Leadership: Ending Coal Pollution. Available at: http://www.alberta.ca/climate-coal-electricity.cfm.

intensity of 0.182 tCO_2e/MWh of deferred energy, based on estimated marginal WECC emissions during the surplus period.

Table 5: GHG reductions (increases) of the Site C Project vs. a Clean portfolio (kt)

Scenarios	Site C Domestic GHG Reductions	Site C Exported GHG Reductions	Site C GHG Emissions	Total GHG Reductions (Increases)
Likely export emissions benefit + "Likely" Site C Emissions	0	3,713	-4,300	**(587)**
Likely export emissions benefit + "Conservative" Site C Emissions	0	3,713	-5,800	**(-2,087)**

Our analysis indicates that a clean portfolio of alternative resources would like lead to a net GHG reduction of 587 to 2,087 kt compared to the Site C Project, over a 100-year operating period. If the GHG reductions resulting from exports were to be calculated based on WECC average (rather than marginal) emissions, then Site C would instead create an emissions reduction of 1,340 to 2,840 kt over a 100-year period. British Columbia GHG emissions are currently on the order of about 64,500 kt/year.[16] These 100-year emissions effects thus represent only 3% of current **annual** emissions, and thus are insignificant.

In summary, our analysis demonstrates that:

- The Site C Project has no meaningful impact on GHG emissions, compared to an alternative clean portfolio; and
- A commercially feasible portfolio of generating projects could provide for maintenance or reduction of 2016/17 greenhouse gas emission level to an extent similar to the Site C Project.

[16] Government of British Columbia. Trends in Greenhouse Gas Emissions in B.C. (1990-2014). Available at: http://www.env.gov.bc.ca/soe/indicators/sustainability/ghg-emissions.html

4 Forecast load for LNG

In its Current Load Forecast, BC Hydro includes the energy and capacity requirements of the three LNG export facilities for which it has received electricity service requests (FortisBC Tilbury LNG Phase 2, Woodfibre LNG, and LNG Canada), in each of its low load, mid load and high load forecasts.

According to BC Hydro, by removing LNG requirements the estimated benefit of Site C continuation vs. termination declines by $600 million.[17] This is a material effect, equivalent in magnitude to the recent acknowledgement by BC Hydro of a one-year delay in completing the river diversion. Determining the appropriate levels of LNG requirements to include in the Load Forecast thus has important implications.

The information presented by BC Hydro in its submission of August 30 and its response to BCUC IR 2.16.0 does not explain why it thinks that BC LNG exports will become competitive in the mid-2020s, when the natural gas markets are expected to become tighter. The key question is: **What has changed or will change in the intervening years that will favour development of BC LNG exports over LNG exports from competing regions?**

BC Hydro has included meaningful potential load from LNG exports in its load forecasting since the 2009 Load Forecast, with substantial forecasts beginning with the 2011 Load Forecast when it predicted the addition of more than 1,000 GWh/year and 300 MW beginning in F2016 rising to 5,300 GWh/year and 700 MW by F2020.[18] The most recent publicly available LNG load forecast contained in BC Hydro's August 30 submission would see about half this amount (2800 GWh/year and 360 MW), and not before F2023.[19]

Canada competes with Australia, the United States, China, Russia and other countries for access to target (mainly Asian) LNG markets. According to the International Gas Union, Australia will have 85 MTPA of liquefaction capacity by 2018, up over 41 MTPA since 2016.[20] In the United States, 57.6 MTPA of liquefaction capacity is under construction.[21] This nearly 100 MTPA of liquefaction capacity is more than 6 times the combined expected export capacity of LNG Canada (13 MTPA)[22] and Woodfibre LNG (2.1 MTPA).[23] All of this new capacity is being built in the timeframe when BC LNG was first anticipated to become operational.

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[17] F1-1, Table 20.

[18] BC Hydro. December 2011. Electric Load Forecast Fiscal 2012 to Fiscal 2032, pp.20-23.

[19] A revised redacted LNG load forecast is provided in response to BCUC IR.2.16.0.

[20] IGU. 2017. 2017 World LNG Report, p.19. Available at: http://www.igu.org/news/igu-releases-2017-world-lng-report.

[21] IGU, p.19

[22] BC Oil and Gas Commission. Undated. LNG Canada Export Terminal. Available at: https://www.bcogc.ca/node/11289/download.

In addition to the 329 MTPA proposed in British Columbia, an additional 335 MTPA is proposed in the United States, mostly on the Gulf Coast, with additional projects proposed on the US West Coast. [24]

Again, the key question is: why will BC LNG will be successful in the future, when it has not been successful to date? In this context, we address some of BC Hydro's specific comments.

Table 6: Issues concerning the potential development of LNG exports

Issue raised by BC Hydro	Discussion
"there is both a timing and a completion risk" associated with each of the projects (F1-1, p.52); Since the May 2016 Load Forecast, LNG capacity requirements are delayed by 2 years to F2025, and energy requirements delayed by 3 years to F2031 (F1-1, Figure 1);	Despite the acknowledgement of a completion risk, there is no inclusion of this risk in the Load Forecast. LNG load is deferred, but it is assumed to be 100% certain to occur – this does not reflect a completion risk.
"The reasons for the variances in the various forecast vintages can be generally attributed to deferred requests for LNG terminal service, deferred upstream requests for shale gas production for meeting LNG and North American gas demand. These project deferrals are due to the impacts stated above and have led to over forecasting." (F-10, BCUC IR.2.17.0)	BC Hydro acknowledges the over-forecasting, but does not acknowledge that not all of the variances are the result of "deferred" requests for LNG terminal service. Some are also the result of cancellation of LNG projects.
"The LNG supply glut is expected to continue for the next 5 to 10 years, but demand is expected to exceed supply over the next decade, creating an opportunity window for LNG projects in that time frame" (Appendix J, p.43);	The existence of future global LNG demand is a necessary but insufficient reason to conclude that BC LNG will be developed.
Several project milestones (e.g. export licence, environmental assessment completion, permits) have been reached by the three LNG export projects requesting electricity service;	The reaching of these milestones is necessary but not sufficient to concluding that any LNG facilities will proceed to construction and operations. The recently cancelled Pacific Northwest LNG facility had reached these same milestones.
"Competition with other jurisdictions [i.e. Australia, USA, Russia and China] continues. B.C.s competitive advantages remain unchanged from the Current Load Forecast. They include proximity to Asian markets, low cost upstream gas (Montney basin) and the approval of export licenses for most proposed LNG facilities. (BCUC IR 2.16.0)	BC LNG has been outcompeted by both U.S and Australian LNG export facilities for nearly a decade. Evidence detailing the relative disadvantages of BC LNG over that period, and how those disadvantages will be or are being addressed, is required to draw a conclusion that BC LNG facilities will proceed in the future. That "B.C.s competitive advantages remain unchanged…" is *not* a sign of pending development, but a reason to believe that the status quo will remain unchanged.
"BC Hydro adopted a binary approach to including the three LNG projects requesting service from BC Hydro in its load forecast. This approach differs from the	As a result of this approach, BC Hydro includes the full energy and capacity of all of the three facilities in each of the low, mid and high loads.

[23] Pacific Oil and Gas. Woodfibre LNG. Available at: http://www.po-and-g.com/lng/woodfibre-lng-project

[24] IGU, p.21

probability-based approach we typically use in developing our industrial load forecast." (BCUC IR 2.16.0) "The small number of proponents that are proposing to electrify from the grid precludes confidential aggregation of a probabilistic Load Forecast" (F1-1, Appendix H, p.6); GDS agrees with the approach to include "energy and peak demand for only known LNG customers in the base case forecast" and of "capturing potential growth in a high range forecast scenario." (F1-1, Appendix I)	We find this approach inadequate, since it does not reflect either the timing or the completion risks that BC Hydro acknowledges.

In summary, we note the following with respect to BC Hydro's decision to include the LNG load of all three proposed facilities in the low load, high load and mid load forecasts:

- **Completion risk**. Both timing and completion risks are identified by BC Hydro. LNG load is deferred but is assumed to be 100% certain to occur – this does not reflect a completion risk.
- **Global LNG demand**. The existence of future global LNG demand is a necessary but insufficient reason to conclude that BC LNG will be developed.
- **Project milestones**. The reaching of these milestones is necessary but not sufficient to concluding that any LNG facilities will proceed to construction and operations.
- **Competitive position**. BC LNG has been outcompeted by both U.S and Australian LNG export facilities for nearly a decade. BC Hydro notes that "B.C.s competitive advantages remain unchanged…" However, is *not* a sign of pending development, but a reason to believe that the status quo will continue with no development of BC LNG.

Evidence detailing the relative disadvantages of BC LNG over the past several years, and how those disadvantages will be or are being addressed, is required to draw a conclusion that BC LNG facilities will proceed in the future.

In the context of this uncertainty, Deloitte excluded LNG Canada upstream and downstream energy and capacity requirements as a result of the FID delay. We took the same position in Raphals and Hendriks (2017). While a probabilistic approach would be preferable, the approach that Deloitte and we have taken reflects a reasoned approach to addressing the considerable uncertainty respecting LNG project completion.

5 Electrification

5.1 Resources and requirements

The Preliminary Commission Report notes the following with respect to electrification:

> The Panel is concerned that, given the long-life of the Site C asset, BC Hydro has only identified potential upside risks to the load forecast from electrification, and has not identified any potential downside risks. The Panel requests that BC Hydro and other parties specifically address questions related to potential disrupting trends.

In its submission of August 30, BC Hydro notes that electrification has the greatest potential to affect the load forecast. BC Hydro determined that including low-carbon electrification increased the estimated benefit of Site C continuation vs. termination from $7.3 billion to $11.1 billion, or a total of $3.8 billion (F1-1, Table 20). These findings follow from BC Hydro's electrification load resource balance presented in Appendix Q of its August 30 submission. The projected resources and requirements of the electrification LRB with and without Site C scenarios are summarized in the following tables.

Table 7: Electrification scenarios – capacity and energy resources

	With Site C		Without Site C	
Resources	**Installed Capacity**	**Firm Energy**	**Installed Capacity**	**Firm Energy**
	(MW)	**(GWh/year)**	**(MW)**	**(GWh/year)**
Load Curtailment	85	0	85	0
Pumped Storage	7000		7000	
Revelstoke 6	500	26	500	26
Site C	1145	5286	0	0
Run-of-river	0	0	166	640
Wood Biomass	26	211	26	211
Wind	11436	35656	11952	37221
TOTALS	**20,192**	**41,179**	**19,729**	**38,098**

It is interesting to note that the electrification without Site C replaces only 461 MW of Site C's 1145 MW, and only 3,081 GWh/year of Site C's 5,286 GWh/year.

Under both electrification scenarios, the same quantity of pumped storage (7,000 MW) is developed, as are large quantities of wind (> 11,000 MW, in both portfolios).

By 2040, the electrification scenarios forecast additional requirements of 5,800 MW and 26,000 GWh/year (35%), compared to the mid-load scenario. As discussed further below, this is a far greater increase than was forecast by BC Hydro's electrification study prepared for the 2013 IRP.

Table 8: Mid-load and electrification scenarios – requirements (in 2040)

Requirements	Capacity	Energy
	(MW)	(GWh/year)
Electrification scenario	20,500	100,000
Mid-load scenario	14,700	74,000
Difference	**5,800**	**26,000**

In terms of energy requirements, the electrification scenario contemplates by 2040 an increase of 26,000 GWh/year over the mid-load forecast.

The portfolios also develop substantial additional transmission resources, including several 500 kV transmission lines. The electrification scenarios add 12,457 MW of transmission resources, compared to just 2,117 MW in the mid-load scenario.

Pursuant to section 3a) of the OIC 244, we note that the information provided concerning the electrification scenarios lacked some supporting information important to evaluating the "implications" of these electrification portfolios, including the following:

- **Wind resources**. Regardless of the development of Site C, the electrification portfolios develop wind capacity equivalent to the capacity of all wind installed to date in Canada. There is no discussion of any potential technical, environmental or planning implications of developing this amount of wind over a thirty-year period.
- **Transmission resources**. There is no map or description of the transmission resources contemplated in the electrification portfolios. BC Hydro has had challenges recently with developing high-voltage transmission infrastructure, in terms of cost control,[25] and adequate consultation with affected Indigenous communities.[26] The political, social and environmetnal implications of this additional linear corridor development require further information in order to evaluate whether or not the portfolios are constructible.
- **Distribution resources**. A policy of electrification of vehicles and broader electrification of space and water heating is likely to result in additional distribution costs related to addressing power transformer congestion and voltage drops, as well as providing electric vehicle servicing equipment, including charging stations, dedicated meters and other system upgrades.[27] There is no indication that the costs of additional distribution

[25] A-13, p.32. Table 14.

[26] E.g. BCUC. 2011. Order G-15-11 concerning BCTC Recondiseration of the Interior to Lower Mainland Transmission Project. Available at: https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/117950/index.do.

[27] Hall, D. and N. Lutsey. February 2017. Literature review on power utility best practices regarding electric vehicles. The International Council on Clean Transportation. Available at: http://www.theicct.org/sites/default/files/publications/Power-utility-best-practices-EVs_white-paper_14022017_vF.pdf.

resources and upgrades have been properly included in the analysis.

Overall, considering the high levels of resources required by the electrification scenarios, we are concerned that the available information does not sufficiently demonstrate that electrification could be implemented on the scale contemplated. Furthermore, as explained below, there is reason to believe that these electrification scenarios are unrealistic.

5.2 Price effects

In the Preliminary Commission Report, the Commission notes the differences in views concerning BC Hydro's elasticity assumptions. In Hendriks' et al., we raised a concern regarding what appeared to be the use of a relatively low price elasticity on the part of BC Hydro, based on our review of the literature. We noted as follows:

> BC Hydro's determination of price elasticity is at the very low end of the short-run elasticity determined in the studies reviewed. This is relevant considering the substantial real increase in electricity rates in the 10-Year Rates Plan —on the order of 19% real (46% nominal).[28] Given these significant rate increases to come, BC Hydro's low estimate of price elasticity may lead it to overestimate future requirements.
>
> Importantly, the studies show that long-run price elasticity is much higher than short-run elasticity in all three sectors. This suggests that over the longer-term, consumers are much more responsive to changes in electricity prices, opting to consume less electricity through conservation, fuel switching and equipment replacement.[29]

In response to concerns raised by the Commission and participants, BC Hydro:

- references internal studies undertaken in relation to the price elasticity related to the Tier 2 residential price and the Tier 2 industrial transmission service rate that support its selection of a -0.05 price elasticity, and other studies related to industrial customers that indicate a greater sensitivity to increasing prices;
- cautions against using studies or price elasticity from other jurisdictions, including comparing with studies that have not controlled for DSM; and
- notes the potential effects of increased price elasticity on DSM program savings and the

[28] Government of BC. November 26, 2013. 10 Year Plan for BC Hydro, p.32. Available at: https://news.gov.bc.ca/stories/10-year-plan.

[29] Hendriks, R., Raphals, P. and K. Bakker (2017) Reassessing the Need for Site C. Program on Water Governance, University of British Columbia: Vancouver.

> potential for higher free ridership.[30]

In that same response, BC Hydro notes that:

> The results of these studies show that BC Hydro customers' price elasticity has historically been modest compared to other jurisdictions. BC Hydro's longstanding involvement in DSM may be one reason for this modest price elasticity. [emphasis added]

That is one possibility. Another possibility is that past rate increases have been modest compared to those that have occurred recently and those that would result from the electrification resource plan envisaged by BC Hydro, due to increased revenue requirements resulting from low-carbon electrification.

Low-carbon electrification in BC really began a decade ago with the 2007 BC Energy Plan, which included policies for electricity self-sufficiency, no GHG emissions from new facilities, and ensuring that at least 90% of electricity would be generated from clean or renewable resources.[31] In other words, BC is not about to embark on a process of low-carbon electrification — it is continuing a process that began 10 years ago, and that will continue for several decades into the future.

BC Hydro's role in this policy implementation has to date been focused on the procurement of low-carbon resources in order to lower the emissions intensity of the electricity sector. These resources have not been "least-cost" resources, but higher-cost resources developed in response to government policy. Had it not been precluded by policy, the "least cost" resource for the past decade in North America (combined cycle natural gas) would have been procured ahead of almost all of the resources procured in BC Hydro's clean power calls and also instead of Site C and its clean alternatives.[32] This constraining of technology choices has lead to increased revenue requirements over those of the "least-cost" technological path, contributing to real rate increases over the past decade.

The study of electrification potential contained in the 2013 IRP (the "MKJA Study"),[33] defines the long-term elasticity issue in this electrification context:

> In British Columbia new demand will likely be supplied by increasingly costly hydro, wind and other renewable energy projects. As these projects are built, the

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[30] BCUC IR 2.19.0.

[31] Government of BC. 2007. The BC Energy Plan: A Vision for Clean Energy Leadership.

[32] This is evident from BC Hydro's IRP, Appendix 3A-4, which reported the UEC of $58/MWh for a 500 MW CCGT compared to $83/MWh for Site C.

[33] BC Hydro. 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc. Available at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf

> average cost of electricity will rise, providing a negative feedback to the policy induced electrification. [34]

In relation to price elasticity, the Commission also raises concerns about the appropriateness of BC Hydro's assumption that there will be no real rate increases between F2025 and F2036, since any rate increases introduced in this period could result in demand being lower than the Current Load Forecast. BC Hydro's response includes the following:

> Over the long-term, BC Hydro's residential rates have not increased on a real basis. In 1967 (50 years ago), the monthly BC Hydro residential bill for typical consumption of 1,000 kwh/month was $15.50. Using the Bank of Canada inflation calculator (see http://www.bankofcanada.ca/rates/related/inflation-calculator/), this would represent $110.53 in 2017 dollars. Today, based on consumption of 1,000 kwh / month, a BC Hydro customer will pay $110.81 (including the rate rider).
>
> Therefore, over the long term, customer residential bills have remained unchanged, on a real basis. … Although future increases in customer rates will not be based on past increases in rates, this historical pattern indicates that, over the very long term, it is not unreasonable to assume that BC Hydro rates will not increase on a real basis.[35]

The record of the last 50-years is not necessarily appropriate to respond to the Commission's question. In the context of low-carbon electrification, which is the policy context currently and for the next several decades, the more appropriate period for consideration of whether real rates are going to increase is the last 10 years, not the last 50 years.

The literature clearly demonstrates that long-term residential and commercial electricity price elasticity is generally significantly higher than short-term elasticity.[36] Of the issues raised by the Commission and intervenors, this is one in which BC Hydro's response acknowledges the lack of available evidence:

> To the extent that the rate level elasticity had a greater magnitude in the future (say -0.35 versus -0.05), <u>BC Hydro would need to review the impacts on the load from rate increases</u>. Specifically, <u>BC Hydro would have to understand what changes in customer loads would be expected to occur as a result of the rate level changes</u>.[37] [emphasis added]

We agree. BC Hydro notes that it has commenced an internal price elasticity study for the residential sector, as recommended by GDS. This study will provide additional information to

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[34] IRP, 6C, p.

[35] F1-6, IR.251.0.

[36] E.g. EIA. October 204. Price Elasticities for Energy Use in Buildings of the United States, p.5. The 1-year residential price elasticity of -0.12 compares to a 25-year price elasticity of -0.40.

[37] F1-1, Appendix H, p.3.

understanding price elasticity, but could be occurring too early to evaluate the effects of a prolonged period of real rate increases. Real rate increases in BC have been occurring for about 5 years, and will continue for another 5 years under the 10-Year Rates Plan. It may take several more years to better understand the implications of these real rate increases on consumer behavior.

The MKJA Study notes this potential for real rates increases: "When electricity demand increases relative to the reference case, so too does the electricity price." This effect is summarized in Table 9.

Table 9: Electricity rate impacts by scenario (2005 c/kWh relative to reference)

GHG price scenario	Natural gas price scenario	2010	2020	2030	2040	2050
Low	Low	0.0	0.1	0.0	-0.2	-0.3
	Medium	0.0	0.3	0.3	0.3	0.4
	High	0.0	0.7	1.1	1.2	1.3
Medium	Low	0.0	0.2	0.3	0.7	1.0
	Medium	0.0	0.4	0.8	1.3	1.8
	High	0.0	0.9	1.5	2.0	2.5
High	Low	0.0	0.5	1.0	1.8	2.4
	Medium	0.0	0.7	1.4	2.3	3.0
	High	0.0	1.1	2.0	2.9	3.6

5.3 Electrification energy and capacity requirements

The forecast of electrification requirements in BC Hydro's Submission can be compared to the increases in the energy requirements forecast in the MKJA Study completed four years ago and included in the 2013 IRP. Any differences between the findings of these two analyses would require some explanation from BC Hydro.

The MKJA Study presents several load forecast scenarios based on a range of natural gas and GHG prices, with the reference forecast consistent with BC Hydro's 2010 load forecast, in which energy requirements (after DSM) were 67,400 GWh/year in 2030.[38] The following table presents the extreme low, medium and extreme high scenarios.

[38] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. Available at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf (See data in spreadsheet attachment within the pdf document)

Table 10: Electricity demand by scenario, TWh/year (MKJA Study)

GHG Price Scenario	Natural Gas Price Scenario	2020	2040	Change 2020 to 2040
Low	Low	62	72	10
	Medium	64	77	13
	High	68	84	16
Medium	Low	63	80	17
	Medium	65	85	20
	High	69	92	23
High	Low	65	90	25
	Medium	67	95	28
	High	71	101	30
Reference		**60**	**73**	**13**

Of interest is the change in future requirements under the various scenarios, as this tends to drive the need for new resources, increases in revenue requirements and the cost benefit of proceeding with Site C seen in Table 20 of BC Hydro's submission. The change in future requirements from 2020 to 2040 in the MKJA scenario is summarized in the last column in the table above.

The MKJA Study notes that there are two primary drivers of electrification: GHG prices and natural gas prices. GHG reductions are sensitive to the strength of climate policy in the form of the price on carbon, and the relative difference in electricity and natural gas prices.

Since the MKJA Study was completed the Government of Canada established a carbon price of $50/t (nominal) by 2022 or about $45/t in 2017 CAD.[39] Comparing this to the GHG price scenarios in the MKJA Study indicates that this price is tracking near the medium scenario used in the MKJA study.

[39] Government of Canada. October 3, 2016. "Government of Canada Announces Pan-Canadian Pricing on Carbon Pollution. Available at: http://news.gc.ca/web/article-en.do?nid=1132149.

Table 11: GHG prices used in the MKJA Study (2017 CAD)[40]

GHG price scenario	2020	2030	2040	2050
Low	36	36	36	36
Medium	38	86	160	182
High	84	156	287	334

Natural gas prices have trended much lower than projected in the MKJA Study, and in 2016 averaged just $3.22/GJ,[41] which is substantially lower than the low price forecast of $5.36/GJ (in $2016) used in the MKJA study and the projected price for all years to 2050.

Table 12: Natural gas prices used in the MKJA Study (2017 CAD)[42]

Natural gas price scenario	2020	2030	2040	2050
Low	5.7	5.7	6.8	8.1
Medium	8.5	9.6	11.7	14.0
High	13.9	16.3	19.4	23.2

Based on a continuation of medium GHG prices and low natural gas prices,

[40] BC Hydro. 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., p.22. Available at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf

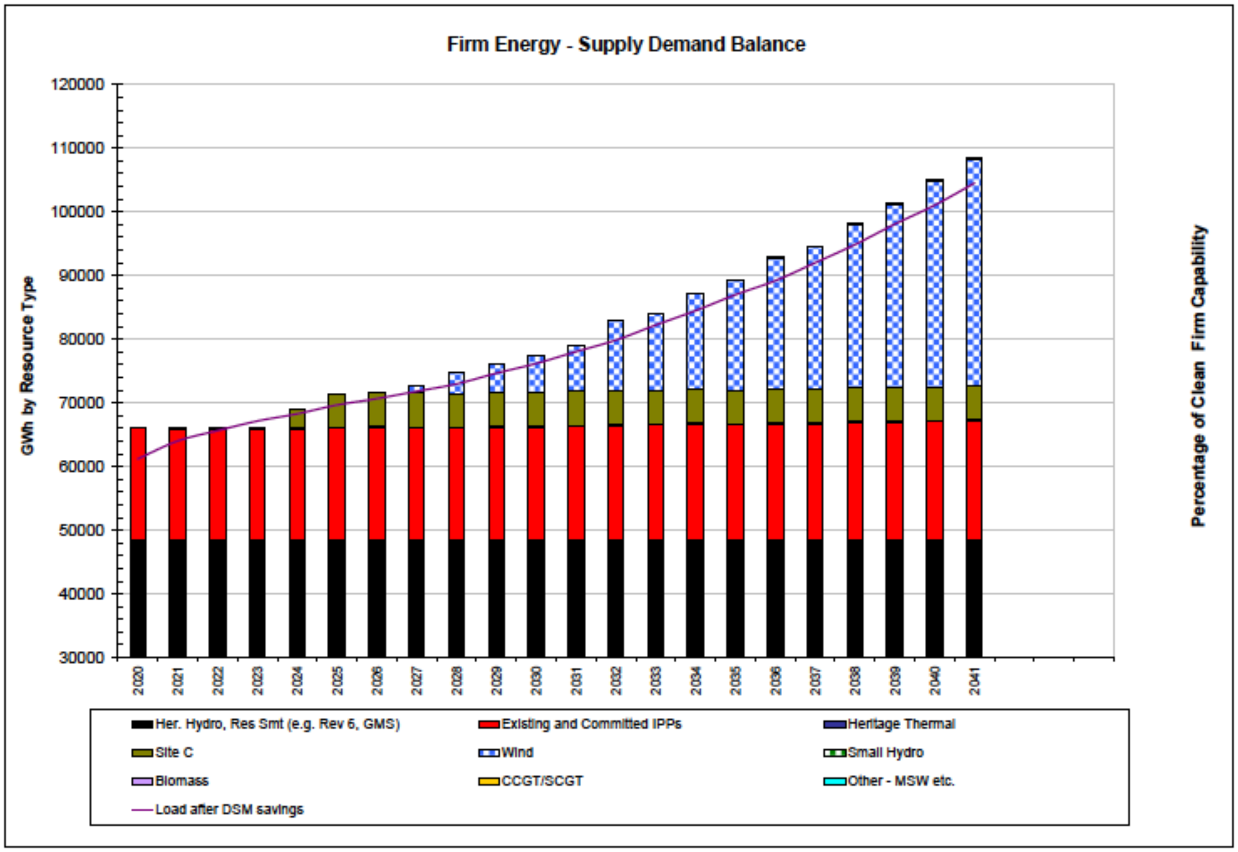
[41] U.S. EIA. Henry Hub Natural Gas Spot Price. Availabe at: https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

[42] MKJA Study, p.22.

Table 10 suggests that the total growth in electrical energy requirements over the 20-year period from 2020 to 2040 would be at most 17 TWh/year.

Detailed load forecast data was not presented for the electrification LRB in BC Hydro's Submission. However, the LRBs are presented graphically, and the energy LRB is shown below.

Figure 4: Electrification load requirements (after DSM) – energy (GWh/year)



The BC Hydro electrification scenario illustrates an increase in energy requirements of 40 TWh/year over the period from 2020 to 2040, a full 10 TWh/year more than any scenario contemplated in the MKJA Study over the same 20-year period.

The total growth of 17 TWh/year between 2020 and 2040, based on a continuation of medium GHG prices and low natural gas prices, is also about the same level of growth as in the current Mid Load Forecast.[43] **The degree of likely electrification under a future of mid-GHG prices and low natural gas prices is entirely captured in the current mid-load forecast.** It is therefore reasonable to conclude as well that the high load forecast captures the electrification

[43] F1-1, Appendix Q, p.9 of 28.

implications of more extreme gas and GHG price scenarios. Thus, the electrification load forecast used by BC Hydro appears to overstate the projected requirements due to electrification, based on the MKJA Study, by more than 20 TWh/year.

The effect of this overstatement of future electricity requirements is to overstate the findings of potential benefits of moving forward with the Site C Project under an electrification scenario, as presented in Table 20 of BC Hydro's Submission.

This substantial increase in forecast requirements under BC Hydro's electrification scenario raises doubt as to its plausibility, and the significance of any conclusions that may flow from it.

5.4 Some sectors may not electrify as anticipated

BC Hydro identifies space and water heating, vehicles and industrial equipment among other sectors with potential for electrification. However, where fossil fuel technology is efficient, has low capital costs, has low operating costs and uses natural gas (a lower-emitting fossil fuel), it is likely to be more resistant to electrification. In these instances, decarbonisation is more likely to occur through an alternative energy carrier, such as biofuel or hydrogen. We explore below the potential for electrification of space and water heating.

5.4.1 Space and water heating

Low-carbon electrification in residential buildings occurs when electric space or water heating equipment, such as resistance heating, heat pumps, or electric solar assisted heating equipment is used in place of fossil fuel equipment. The MKJA Study found that residential electrification, which consists almost entirely of space and water heating, accounts for about 30% of electricity requirements from electrification, making it the largest potential contributor to future requirements.[44] If this sector does not electrify, requirements for electricity would be substantially reduced.

The Preliminary Commission Report notes that Deloitte took a somewhat sceptical position concerning the electrification of water and space heating:

> However, Deloitte was more cautious in its assessment of the potential of space and water heating electrification to further increase load, citing the higher cost of electric heating compared to natural gas. Deloitte considered these price differences would likely prevent customers from switching from natural gas to electric heating for some time, assuming that natural gas prices remain low, and absent strong incentive introduced by policy.[45]

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[44] MKJA Study, p.22.

[45] A-13, p.65.

During the RRA, BC Hydro filed its forecast for future residential share of electric space and water heating,[46] illustrating that the percentage of homes using electricity for space and water heating is expected to remain basically unchanged in the coming 20-year period. BC Hydro goes on to explain this forecast:

> BC Hydro can acknowledge that based on today's energy prices and all else being equal, electricity as a fuel for heating is approximately four times more expensive than natural gas at today's rates if both the electric and gas appliance have the same efficiency rating.[47] [emphasis added]

In other words, space and water heating with natural gas has a substantial cost advantage over meeting the same needs with electricity. Whether this could change in response to higher gas prices and GHG pricees is explored below.

5.4.2 Water heating

In BC, consumers have two primary options for meeting their water heating needs: electricity and natural gas, the latter being available only within the service area of FortisBC. In order to evaluate the plausibility of conversion from gas to electric water heating becoming economic, we examined a scenario based on rapid increases in both natural gas prices and GHG pricees. Specifically, we examined the costs for these two water heating technologies taking into account the following rather extreme assumptions:

- Natural gas prices increasing at 8% per year to 2032, then 2% thereafter
- A GHG price increasing at $20/year after 2022, indefinitely;
- Electricity prices increasing at 3% (nominal) per year, indefinitely.[48]

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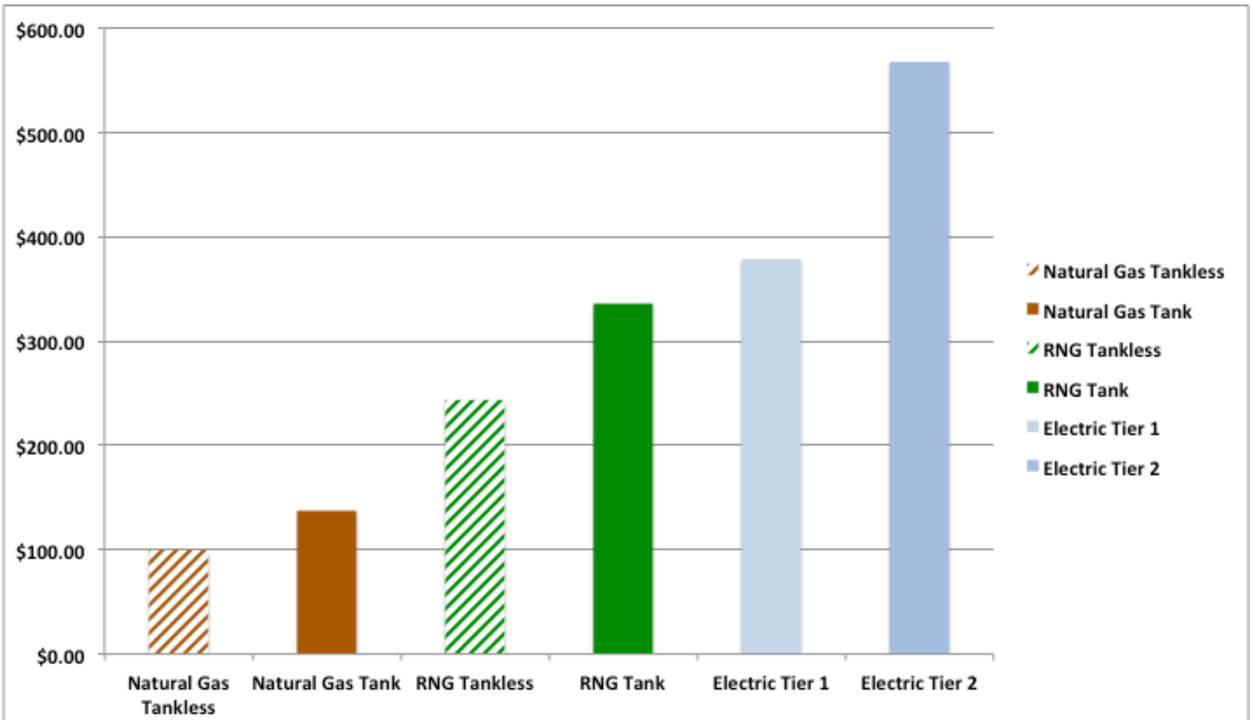
[46] RRA, IR AMPC IR.2.5.1

[47] RRA, IR CEC 2.130.7

[48] The complete set of assumptions and detailed analysis are presented in Appendix A.

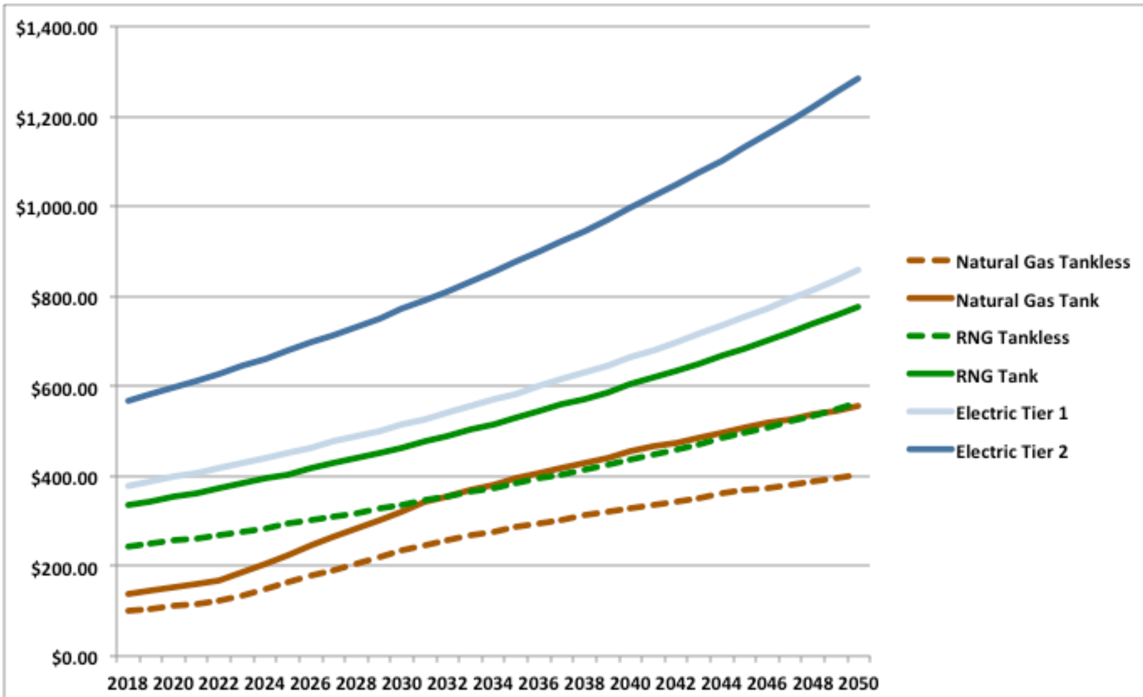
The costs for hot water heating in the initial year of our analysis, 2018, are illustrated in the figure below. Consistent with statements by BC Hydro and concerns raised by Deloitte, the annual costs of electric hot water heating are about four times those of natural gas hot water heating, depending on natural gas technology and whether the electricity used for water heating is charged at the tier 1 or tier 2 rates. The cost difference ranges from nearly $300/year up to $500/year.

Figure 5: Water heating annual costs by technology – 2018



We also investigated the trends in costs over time, as shown in Figure 6.

Figure 6: Water heating annual (nominal) costs – 2018 to 2050 (+$20/y GHG price)



The above figure illustrates that even with substantial increases in natural gas prices and a GHG price far beyond a level that many Canadians are likely to find acceptable (over $300/t in 2032) increasing at $20/year beyond 2022, heating water with electricity does not become more cost effective compared to natural gas or RNG. Increasing electricity prices at the rate of inflation did not change these findings. Further sensitivity analyses regarding carbon prices and electricity prices are presents in Appendix A.

5.4.3 Space heating

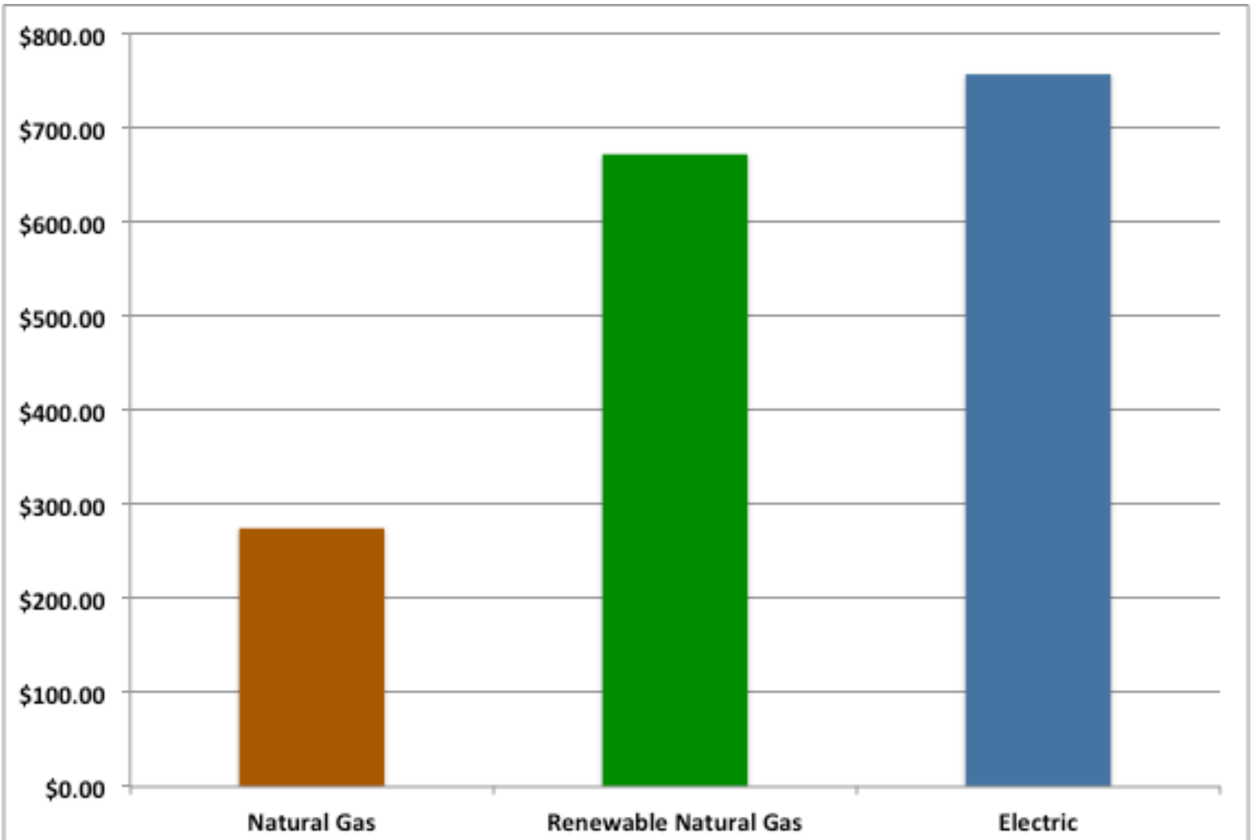
Several lines of evidence indicate that the conclusions for water heating also apply to space heating, namely that space heating with natural gas is likely to remain more affordable compared to electricity for the foreseeable future, even in the presence of a rising GHG price.

With the advent of high-efficiency furnaces, having annual fuel utilization efficiency (AFUE) above 95% to as much as 98%, the efficiency benefit of electric baseboard heating has materially declined in the past 20 years. As an illustrative example, a home that consumes 8,000 kWh/year of electricity for heating similarly requires about 30 GJ (800 m^3) of natural gas, using a high-efficiency furnace.[49] The cost of this electricity at Tier 1 rates is just over $755/year, while the comparable cost for natural gas is $275/year while that for RNG, at the rates used in

[49] Assuming a 96% AFUE

the model, is $670/year. Thus, the cost difference is on the order of $500/year in the chosen example, and would be higher in instances where the heating requirements are greater.

Figure 7: Space heating annual costs by technology – 2018



We recognize that this comparison represents one example, and that the comparative analysis will differ somewhat depending on individual circumstances.

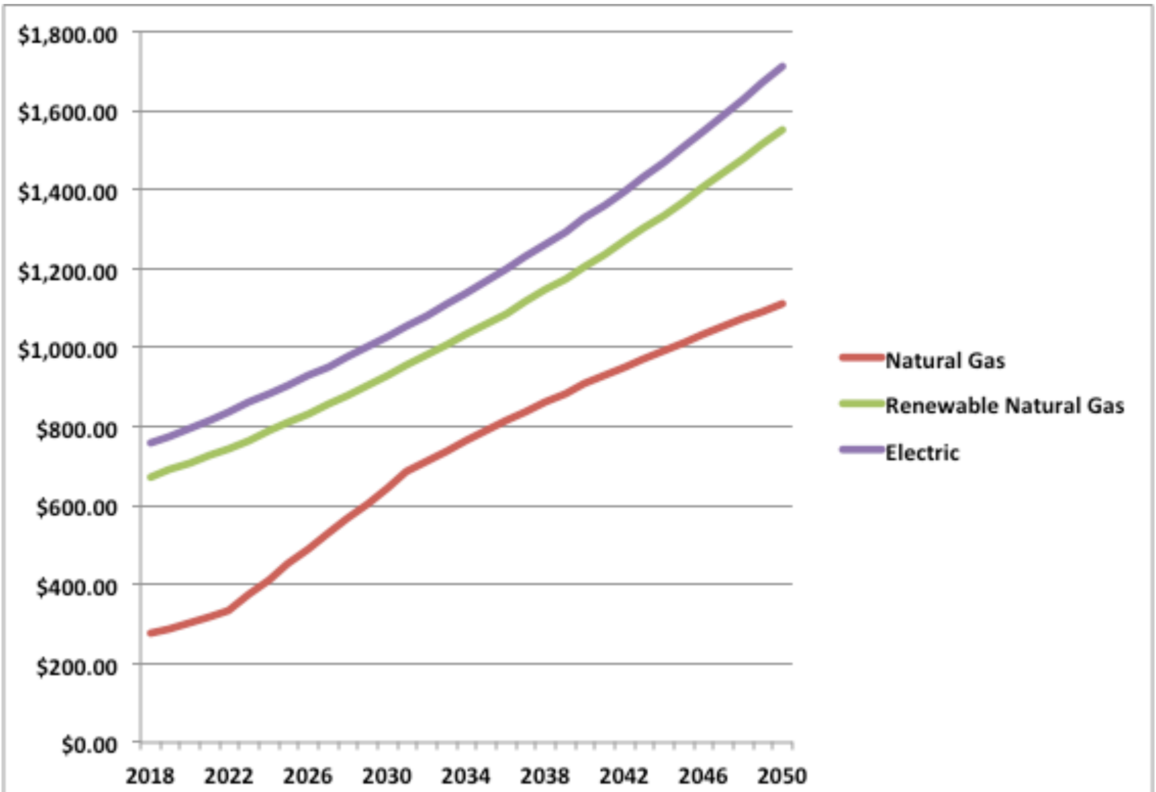
> BC Hydro can't confirm that electrification of space and water heating is more expensive than existing gas fired space and water heating in all cases because it would depend upon a number of factors including: changes in relative energy costs, capital costs, efficiency differences, life of the equipment, value of GHG reductions, and value of other non-energy benefits.[50]

We agree that electrification of space and water heating may not be more costly in *all* cases, but share the concerns raised by Deloitte that it would be more expensive in *most* cases, barring a dramatic increase in natural gas prices. Thus, as with water heating, we

[50] RRA, IR CEC 2.130.7

investigated the long-term trends in costs over time for this 8,000 kWh of electricity /800 m^3 natural gas example, as shown in the following figure.

Figure 8: Space heating annual (nominal) costs – 2018 to 2050 (+$20/y GHG price)



The above figure illustrates that even with substantial increases in natural gas prices and a GHG price reaching over $300/tonne in 2032, space heating with electricity does not become more cost effective compared to natural gas. Increasing electricity prices at the rate of inflation did not change these findings. Further sensitivity analyses regarding carbon prices and electricity prices, along with consideration of heat pumps, are presented in Appendix A.

The findings of our analysis indicate that the substantial cost advantage of natural gas over electricity for use in space and water heating is so large that even in the context of forecasted increases in natural gas prices and meaningful carbon taxes, this advantage will persist. As such, electrification of the residential sector will remain limited for the foreseeable future and, depending on the evolution of policy and technology could be decarbonized through alternative means.

5.4.4 Disruptive trends to electrification in space and water heating?

The Commission has invited participants to identify potential disruptive trends in relation to the load forecast risks pertaining to electrification. Possible disruptive trends in relation to electrification of space and water heating include the following:

- **Natural gas persistence**. The most likely situation in the short to medium term is that natural gas persists as a residential heating fuel, and coupled with replacement of less efficient equipment, improvements in building efficiency and water use efficiency buys time for the development of additional alternatives to higher cost electricity

- **Renewable natural gas (biogas and biomethane)**. Included as a resource in the analysis, renewable natural gas, which is currently derived from biological sources is presumed to rise in cost at a rate above inflation. This assumption is illustrative of the current production cost premium facing RNG from biological sources. The CGA estimates that there is 1,300 billion cubic feet of RNG supply potential in Canada, equivalent to about 50% of current natural gas consumption.[51] What percentage of this RNG can developed and at what price remains uncertain.
- **Renewable natural gas (hydrolysis and methanation)**. The creation of renewable natural gas from low-carbon electricity also provides a potential alternative to displacing natural gas as the primary fuel for space and water heating. Also known as power-to-gas, this involves converting surplus renewable electrical power into a gaseous energy carrier such as hydrogen and/or methane. Electrical energy is converted to chemical energy in the form of hydrogen, which can be either used directly as feedstock or fuel in the industrial or transport sector, blended into the natural gas network, or further converted to methane via a methanation process by making use of captured carbon dioxide. There are currently over 30 MW of installed electrolysers in Europe, with more than 60% of the power-to-gas projects having hydrogen as the final product, 23% methane and 15% both hydrogen and methane.[52] As renewable electricity sources continue to decline in cost, power-to-gas may also be fuelled directly be solar and wind facilities. Implications for additional electricity requirements would depend on the most suitable locations for developing power-to-gas facilities and feeding renewable natural gas into the gas piping network.

5.5 Summary

The key observations of our review of BC Hydro's electrification analysis are as follows:

- **Lack of information to assess "implications"**. The information provided in BC Hydro's submission concerning the electrification scenarios lacks some supporting information important to evaluating the "implications" of these electrification portfolios, pursuant to section 3a) of the OIC 244.
- **Price effects of electrification cannot yet be determined**. Historic BC Hydro rate increases have been modest compared to those that have occurred for the past several years, and that would result from the electrification resource plan envisaged by BC

[51] Canadian Gas Association. 2014. Renewable Natural Gas Technology Roadmap for Canada.

[52] European Power to Gas. September 2017. White Paper: Power-to-gas in a decarbonized European energy system based on renewable energy sources, p.21.

Hydro, due to increased revenue requirements resulting from low-carbon electrification. Real rate increases in BC have been occurring for about 5 years, and will continue for another 5 years under the 10-Year Rates Plan. It may take several more years to better understand the implications of these real rate increases on consumer behavior.

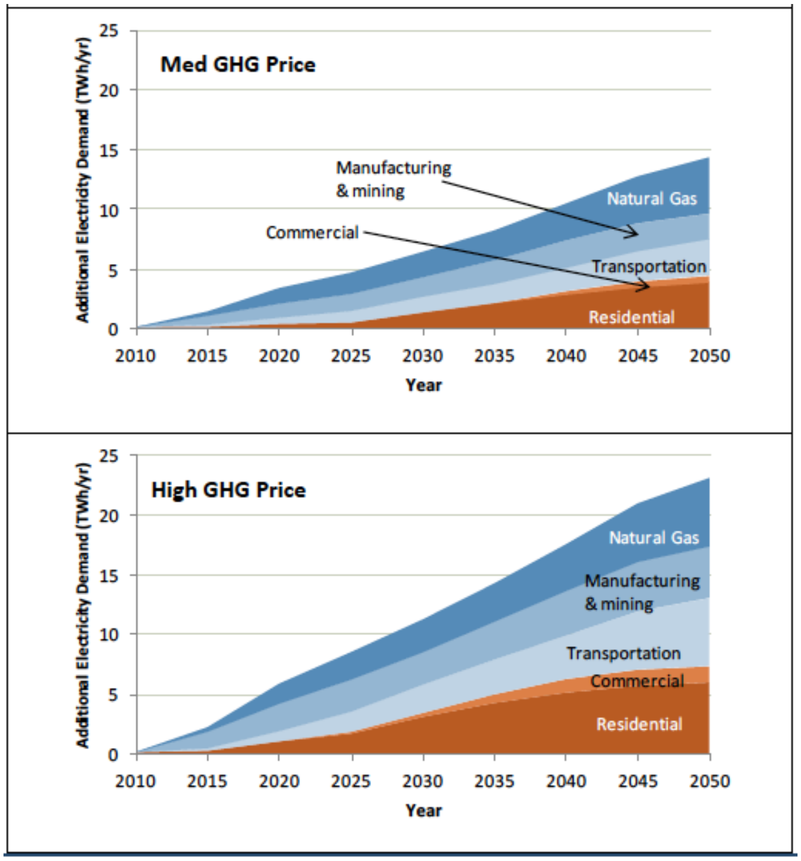
- **BC Hydro's electrification scenario may overstate the benefits of continuing with the Site C Project**. The electrification load forecast used by BC Hydro appears to overstate the projected requirements due to electrification, based on the MKJA Study, by more than 20 TWh/year. Moreover, the degree of likely electrification under a future of mid-GHG prices and low natural gas prices is entirely captured in the current mid-load forecast. The effect of the overstatement of future electricity requirements is to overstate the findings of potential benefits of moving forward with the Site C Project under an electrification scenario.
- **Some sectors may not electrify as anticipated**. Our analysis illustrates that even with substantial increases in natural gas prices and a GHG price increasing at $20/year beyond 2022, space and water heating with electricity does not become more cost effective compared to natural gas.

APPENDIX A: RESIDENTIAL WATER AND SPACE HEATING – POTENTIAL FOR ELECTRIFICATION

Low-carbon electrification in residential buildings occurs when electric space or water heating equipment, such as resistance heating, heat pumps, or electric solar assisted heating equipment is used in place of fossil fuel equipment.

As shown in the figure below, taken from the MKJA Study, residential electrification, which consists almost entirely of space and water heating, accounts for about 30% of electricity requirements from electrification, making it the largest potential contributor to future requirements.

Figure 9: Additional electricity demand, medium natural gas price[53]



During the RRA, BC Hydro filed its forecast for future residential share of electric space and water heating, as shown in Table 13. The forecast illustrates that, in both instances and in the

[53] MKJA Study, p.31.

absence of additional electrification policies, the percentage of homes using electricity for space and water heating is not expected to increase only very modestly, in the coming 20-year period.

Table 13: BC Hydro forecast of residential accounts with electric heating[54]

Forecast of Percentage of Residential Accounts with Electric Heating

	Lower Mainland	Vancouver Island	South Region	North Region
F2017	37.9%	61.7%	27.7%	26.5%
F2018	38.0%	61.7%	27.7%	26.5%
F2019	38.1%	61.8%	27.8%	26.5%
F2020	38.1%	61.8%	27.8%	26.5%
F2021	38.2%	61.8%	27.8%	26.6%
F2022	38.3%	61.8%	27.9%	26.6%
F2023	38.5%	61.8%	27.9%	26.6%
F2024	38.6%	61.9%	27.9%	26.6%
F2025	38.7%	61.9%	27.9%	26.6%
F2026	38.8%	61.9%	28.0%	26.7%
F2027	38.9%	61.9%	28.0%	26.7%
F2028	38.9%	61.9%	28.0%	26.7%
F2029	39.0%	61.9%	28.1%	26.7%
F2030	39.1%	61.9%	28.1%	26.7%
F2031	39.1%	61.9%	28.1%	26.7%
F2032	39.1%	62.0%	28.1%	26.7%
F2033	39.2%	62.0%	28.1%	26.7%
F2034	39.2%	62.0%	28.1%	26.7%
F2035	39.3%	62.0%	28.2%	26.7%
F2036	39.3%	62.0%	28.2%	26.7%
19 Year Compound Growth Rate	0.2%	0.02%	0.1%	0.1%

Forecast of Percentage of Residential Accounts with Electric Water Heating

	Lower Mainland	Vancouver Island	South Region	North Region
F2017	24.0%	68.9%	39.6%	45.8%
F2018	24.1%	69.1%	39.7%	45.9%
F2019	24.1%	69.2%	39.8%	46.0%
F2020	24.2%	69.4%	39.9%	46.1%
F2021	24.3%	69.6%	40.0%	46.2%
F2022	24.3%	69.8%	40.1%	46.3%
F2023	24.4%	69.9%	40.2%	46.4%
F2024	24.4%	70.0%	40.3%	46.0%
F2025	24.5%	70.2%	40.4%	46.6%
F2026	24.5%	70.3%	40.4%	46.7%
F2027	24.6%	70.4%	40.0%	46.8%
F2028	24.6%	70.0%	41.0%	46.9%
F2029	24.7%	71.0%	40.7%	47.0%
F2030	24.7%	70.9%	40.7%	47.1%
F2031	24.8%	71.0%	40.8%	47.1%
F2032	24.8%	71.1%	40.9%	47.2%
F2033	24.9%	71.3%	41.0%	47.3%
F2034	24.9%	71.4%	41.1%	47.4%
F2035	24.9%	71.5%	41.1%	47.5%
F2036	25.0%	71.6%	41.2%	47.6%
	0.2%	0.2%	0.2%	0.2%

Water heating

In BC, consumers have two primary options for meeting their water heating needs: electricity and natural gas, the latter being available only within the service area of FortisBC. The finding in the MKJA Study is that consumers will eventually switch to heating their water with electricity in response to the policy signal sent by a higher GHG price and higher natural gas prices.

We examined the costs for these two water heating technologies taking into account the assumptions summarized in the following table.

Table 14: Residential water and space heating comparison – inputs

Item	Natural Gas	Electricity
Technologies	Water - tank or tankless Heat – High-efficiency (96% AFUE) furnace	Water – tank Heat – baseboard resistance
Fuel	Natural gas Renewable natural gas (RNG)[55]	Electricity, presumed to be 100% non-GHG emitting

[54] RRA, IR AMPC IR.2.5.1

Consumption[56]	Tankless – 290 m^3/year Tank – 400 m^3/year Furnace – 800 m^3/year	Tank (40 gallons) – 4,000 kWh/year Heating – 8,000 kWh/year
Retail prices	Natural gas deliver \$0.16/m^3, increasing at inflation (2% nominal)/year Natural gas commodity - \$0.11/m^3, increasing at 8%/year to 2032, then 2%/year thereafter[57] RNG - \$0.63/m^3, or \$17/GJ[58] increasing at 1% real (3% nominal)/year	Tier 1 - \$0.0858, increasing at 1% real (3% nominal)/year Tier 2 - \$0.1287, increasing at 1% real (3% nominal)/year Sensitivity assuming no real rate increase in electricity
Carbon prices	Increasing \$5/t/year to 2022, and \$20/t/year thereafter Sensitivity assuming \$40/t/year increase after 2022 Natural gas - \$0.0019/m^3 per dollar of carbon tax, or \$1.4898/GJ[59] RNG - \$0.00019/m^3 per dollar of carbon tax (i.e. a 90% reduction)[60]	Not applicable
Rate rider	Not applicable	5%
GST	5%	5%
Elasticity[61]	- 0.28, inclusive of price and conservation	- 0.4, inclusive of price and conservation

With respect to technologies, only established and commonly used technologies were considered in the analysis, with additional discussion on potential disruptive technologies provided below. Both electric and natural gas water tanks provide some additional space heating benefit that is not captured in these results. In BC, this benefit could be meaningful in the winter months from November through March, depending on the extent to which this heat meets useful residential heating needs. To the extent that this additional space heating occurs during hot summer periods, in the months of June through August, it would increase cooling requirements, and potentially increasing costs. These findings apply to both electric and natural

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[55] For a description of the FortisBC renewable natural as program see: https://www.fortisbc.com/NaturalGas/RenewableNaturalGas/AffordableOptions/Pages/default.aspx.

[56] Derived from: Manitoba Hydro. August 1, 2017. "*Wondering about your energy options for water heating*?" Available at: https://www.hydro.mb.ca/your_home/water_use/home_water_heating_costs.pdf.

[57] EIA. 2017. Annual Energy Outlook 2017 Table: Natural Gas Delivered Prices by End-Use Sector and Census Division (Reference Case). Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=78-AEO2017&cases=ref2017&sourcekey=0.

[58] Based on an estimate of the current cost-based rate for RNG. See BCUC Decision and Order G-133-16, s.2.4.

[59] BC Ministry of Finance. How the Carbon Tax Works. Available at: http://www.fin.gov.bc.ca/tbs/tp/climate/A4.htm.

[60] Fortis BC. Renewable Natural Gas Affordable Options. Available at: https://www.fortisbc.com/NaturalGas/RenewableNaturalGas/AffordableOptions/Pages/default.aspx.

[61] EIA. 2014. Price Elasticities for Energy Use in Buildings of the United States, p.5.

gas water tanks and do not fundamentally alter the decision between natural gas and electric hot water heating.

We included renewable natural gas (RNG) in our analysis at a current cost-based rate noted in BCUC Decision and Order G-133-16, s.2.4. This cost is inflated (at 1%/year, real) so that at the end of the analysis period in 2050, the total price (delivery + fuel) of RNG remains 100% higher than the price of natural gas. We then applied the GHG price to natural gas and to RNG based on the carbon offset of 90%, further to FortisBC's RNG cost calculator.[62]

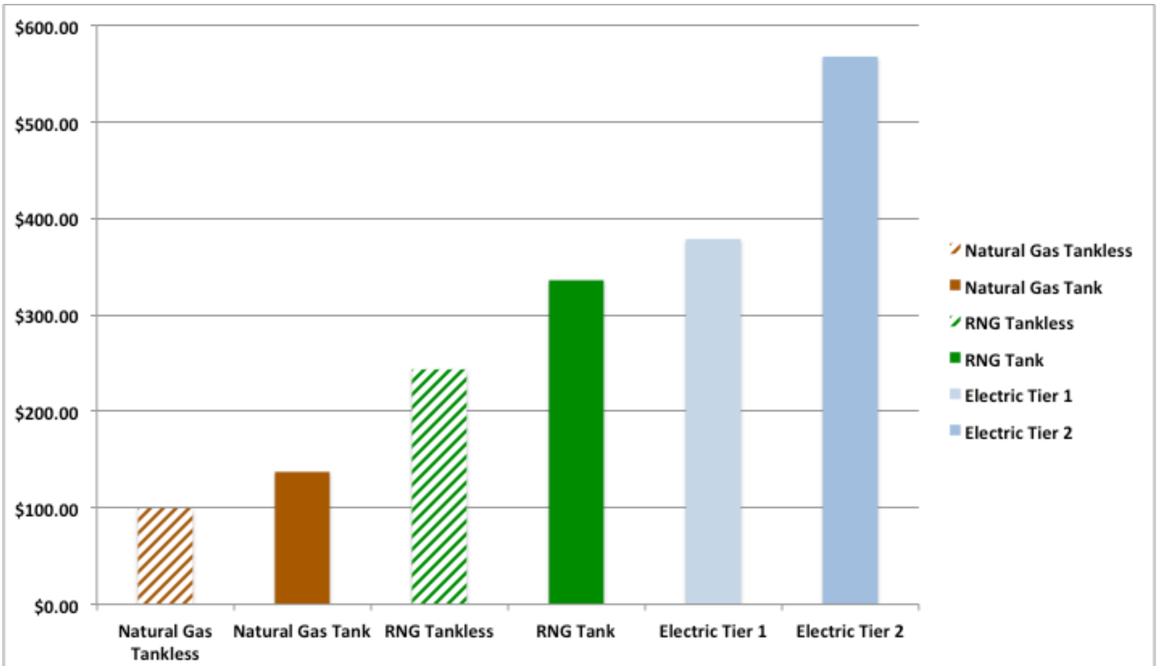
Capital costs can also play a role in the decision between electric and natural gas hot water heating. Typically, costs for purchase and installation of natural gas or electric water heating tanks are comparable, with tankless gas heaters about $500 more expensive on purchase.[63] Tankless water heaters typically have additional installation costs ranging from $500 to $1000 above that of tank systems, but tend to last 20 years or longer, compared to 10-12 years for both electric and natural gas water tanks.

The costs for hot water heating in the initial year of our analysis, 2018, are illustrated in the figure below. Consistent with statements by BC Hydro and concerns raised by Deloitte, the annual costs of electric hot water heating are about four times those of natural gas hot water heating, depending on natural gas technology and whether the electricity used for water heating is charged at the tier 1 or tier 2 rates. The cost difference ranges from nearly $300/year up to $500/year.

[62] Fortis BC. Renewable Natural Gas Affordable Options. Available at: https://www.fortisbc.com/NaturalGas/RenewableNaturalGas/AffordableOptions/Pages/default.aspx.

[63] Home Depot. Water heaters. Available at: http://www.homedepot.com/b/Plumbing-Water-Heaters/N-5yc1vZbqly.

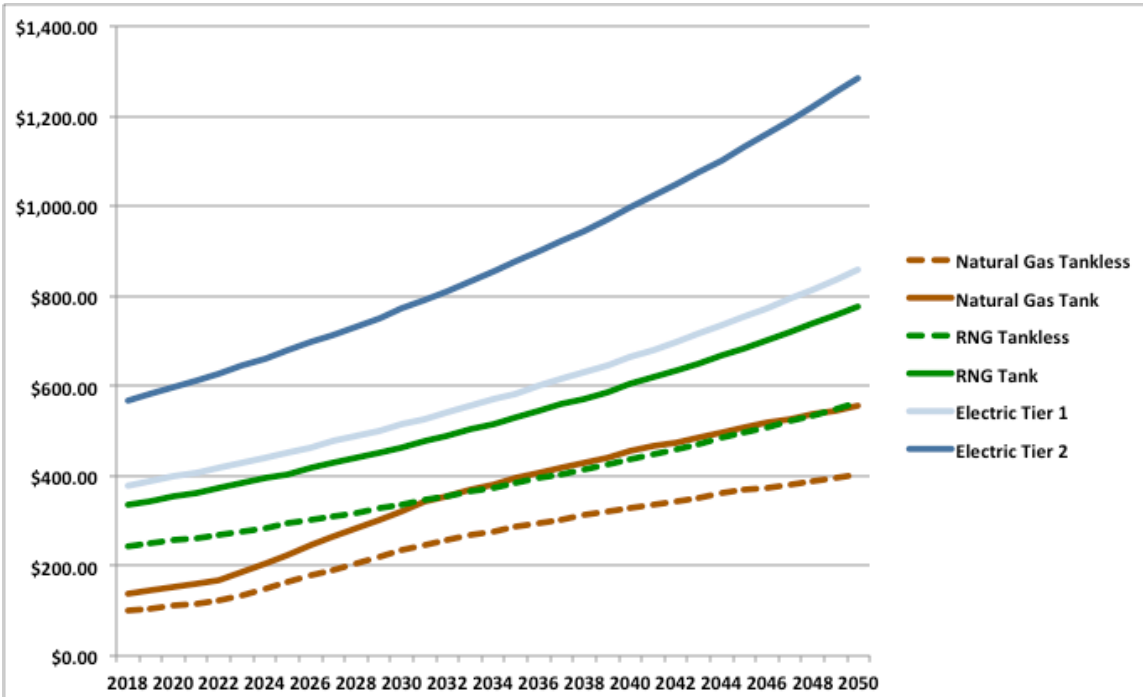
Figure 10: Water heating annual costs by technology – 2018



We also investigated the trends in costs over time, as shown in

Figure 6, based on the assumption noted above in Table 14. As pointed out in MKJA Study, the GHG price encourages different amounts of electrification in different sectors and end-uses depending on the relative efficiencies of electric and fossil fuel combustion technologies. However, the relative price of natural gas compared to electricity, and the availability of other low carbon fuels also influences the decision whether or not to switch from natural gas to electricity for domestic water heating.

Figure 11: Water heating annual (nominal) costs – 2018 to 2050 (+$20/y GHG price)

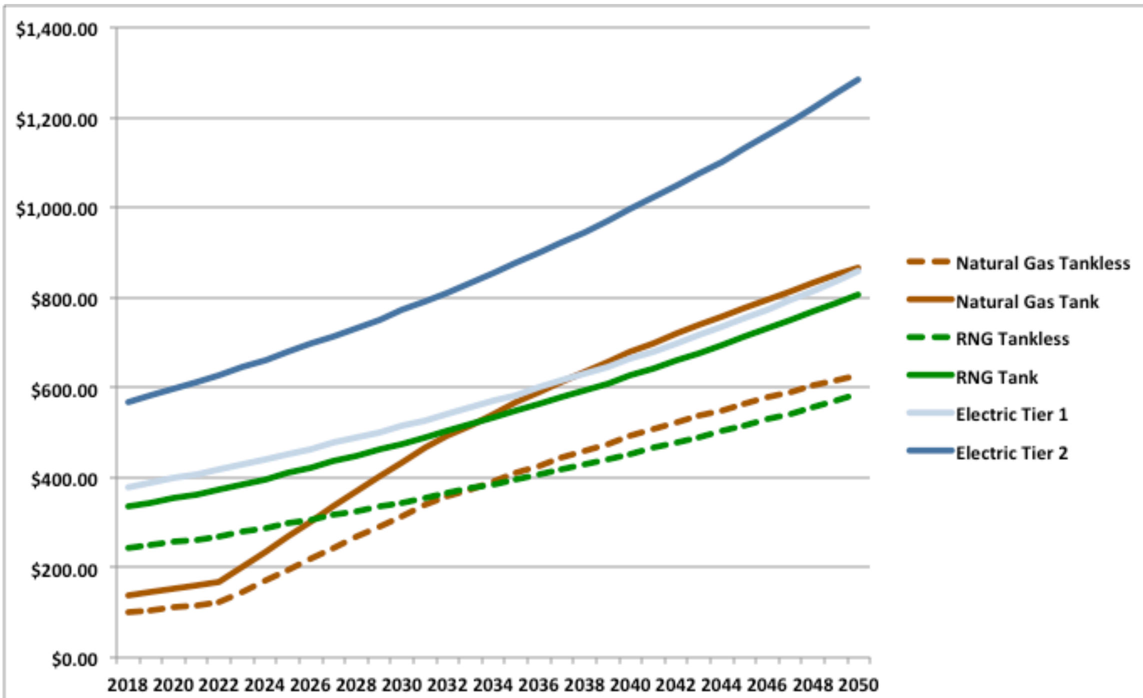


The above figure illustrates the following:

- **Heating water with electricity remains more expensive than natural gas to 2050**. As a result of the current cost disadvantage of electricity compared to both natural gas and RNG, despite increases in the cost of natural gas and the GHG price by $20/year, heating water with electricity remains more expensive.
- **The GHG price has some effect**. A GHG price that increases at $20/t/year has an effect on the cost of heating water with natural gas. That the effect is not greater is due to the fact that emissions from natural gas water heating are very low, on the order of 0.5 t/year. In the model, these emissions decline modestly over time as a result of an expected reduction in consumption in response to the real price increases resulting from the GHG price.
- **Renewable gas becomes somewhat more attractive**. The increase in the price of natural gas and in the GHG price make RNG more attractive compared to natural gas, but the GHG price signal is still not strong enough to result in RNG being more cost effective compare to natural gas.

As a further exploration, we investigated the level of GHG price that is necessary in order for the cost of heating water with natural gas to exceed the cost of heating water with electricity. The effect of this extreme measure, which results in a GHG price in $2050 of $1170/t, is presented below.

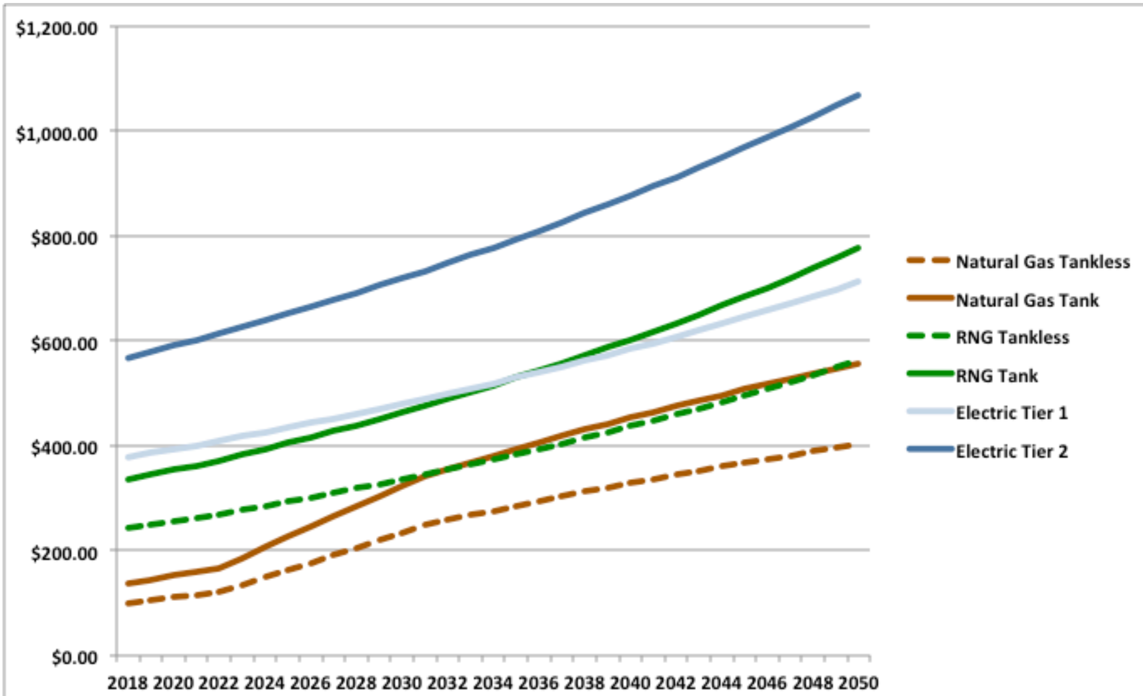
Figure 12: Water heating annual (nominal) costs – 2018 to 2050 (+$40/y GHG price)



As illustrated in this figure, the high GHG price has the desired effective of driving up the cost of heating water using a natural gas tank by about $600/year. However, before consumers would pay the high GHG price or switch to heating with higher-cost electricity, they may switch to the use of RNG. This switch depends on the future cost and availability of RNG.

We also analyzed the case where electricity prices do not increase above inflation beyond F2025, as postulated by BC Hydro. In this scenario, there are also no price effects on consumption. While we do not view this scenario as realistic in the context of electrification, the following figure illustrates that even with no real increases in the price of electricity to 2050, it remains more affordable for households to heat their water with natural gas or RNG, based on the assumptions in the model.

Figure 13: Water heating annual (nominal) costs – 2018 to 2050 (+$10/y GHG price, no real electricity price increases)



Space heating

Several lines of evidence indicate that the conclusions for water heating also apply to space heating, namely that space heating with natural gas is likely to remain more affordable compared to electricity for the foreseeable future, even in the presence of a rising GHG price.

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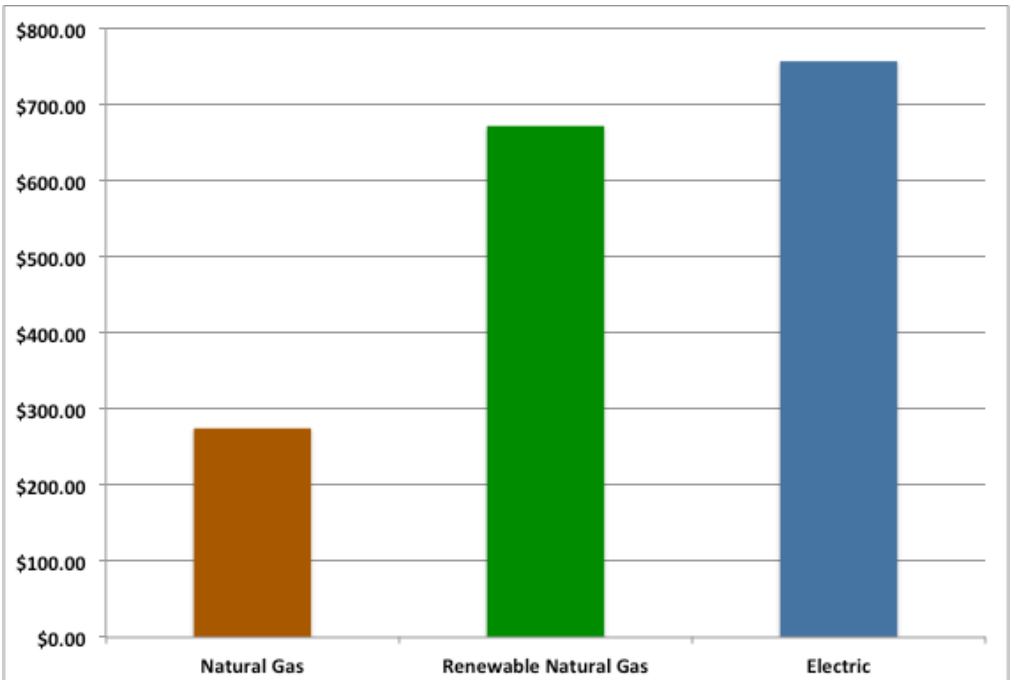
With the advent of high-efficiency furnaces, having annual fuel utilization efficiency (AFUE) above 95% to as much as 98%, the efficiency benefit of electric baseboard heating has materially declined in the past 20 years. As an illustrative example, a home that consumes 8,000 kWh/year of electricity for heating similarly requires about 30 GJ (800 m^3) of natural gas, using a high-efficiency furnace.[64] The cost of this electricity at Tier 1 rates is just over $755/year, while the comparable cost for natural gas is $275/year while that for RNG, at the rates used in

[64] Assuming a 96% AFUE

the model, is $670/year. Thus, the cost difference is on the order of $500/year in the chosen example, and would be higher in instances where the heating requirements are greater.

Figure 14: Space heating annual costs by technology – 2018



We recognize that this comparison represents one example, and that the comparative analysis will differ somewhat depending on individual circumstances.

> BC Hydro can't confirm that electrification of space and water heating is more expensive than existing gas fired space and water heating in all cases because it would depend upon a number of factors including: changes in relative energy costs, capital costs, efficiency differences, life of the equipment, value of GHG reductions, and value of other non-energy benefits.[65]

We agree that electrification of space and water heating may not be more costly in *all* cases, but share the concerns raised by Deloitte that it would be more expensive in *most* cases, barring a dramatic increase in natural gas prices. Thus, as with water heating, we investigated the long-term trends in costs over time for this 8,000 kWh of electricity /800 m3 natural gas example, as shown in the following figure.

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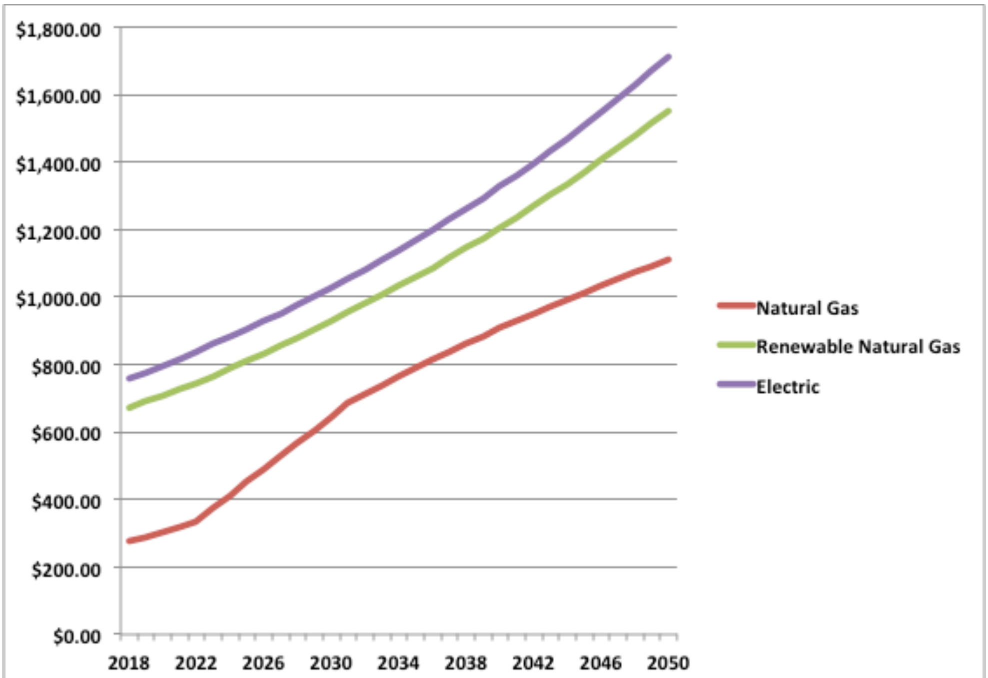
[65] RRA, IR CEC 2.130.7

Figure 15: Space heating annual (nominal) costs – 2018 to 2050 (+$20/y GHG price)

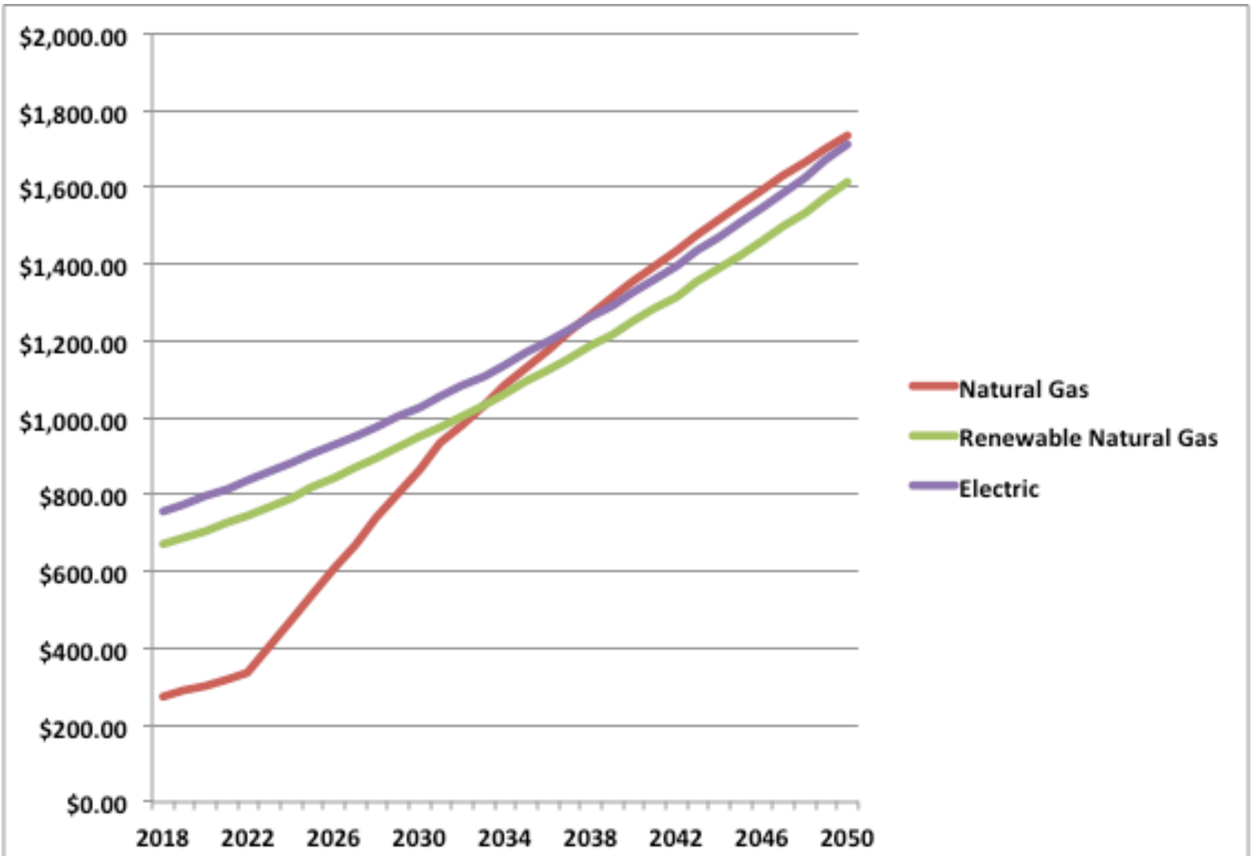


The above figure illustrates the following:

- **Space heating with electricity remains more expensive than natural gas until 2050**. For the example of 8,000 kWh of electrical heating requirements, and similar to the situation with water heating, the current cost disadvantage of electricity compared to both natural gas and RNG cannot be made up over time. Though the relative costs of heating with electricity improve, it is only twice as expensive in 2050 compared to three times as expensive in 2018, it remains more costly.
- **The GHG price has some effect**. A GHG price that increases at $20/t/year has an effect on the cost of space heating with natural gas. That the effect is not greater is due to the fact that emissions from natural gas heating in this particular examples are quite low, on the order of 1.5 t/year. In the model, these emissions decline modestly over time as a result of an expected reduction in consumption in response to the real price increases resulting from the GHG price.
- **Renewable gas does not become more attractive than natural gas**. While the price of both RNG and natural gas increase over time, the GHG price has a greater effect on the final price of natural gas, resulting in greater conservation over time. The GHG price signal is not strong enough to result in RNG being more cost effective compare to natural gas, though it does become relatively less expensive compared to natural gas.

Again, we explored the level of GHG price that would be necessary in order for the cost of space heating with natural gas to exceed the cost of space heating with electricity. The GHG price was increase by $40/year beginning in 2023 resulting in a GHG price in $2050 of $1170/t. The following figure illustrates the findings.

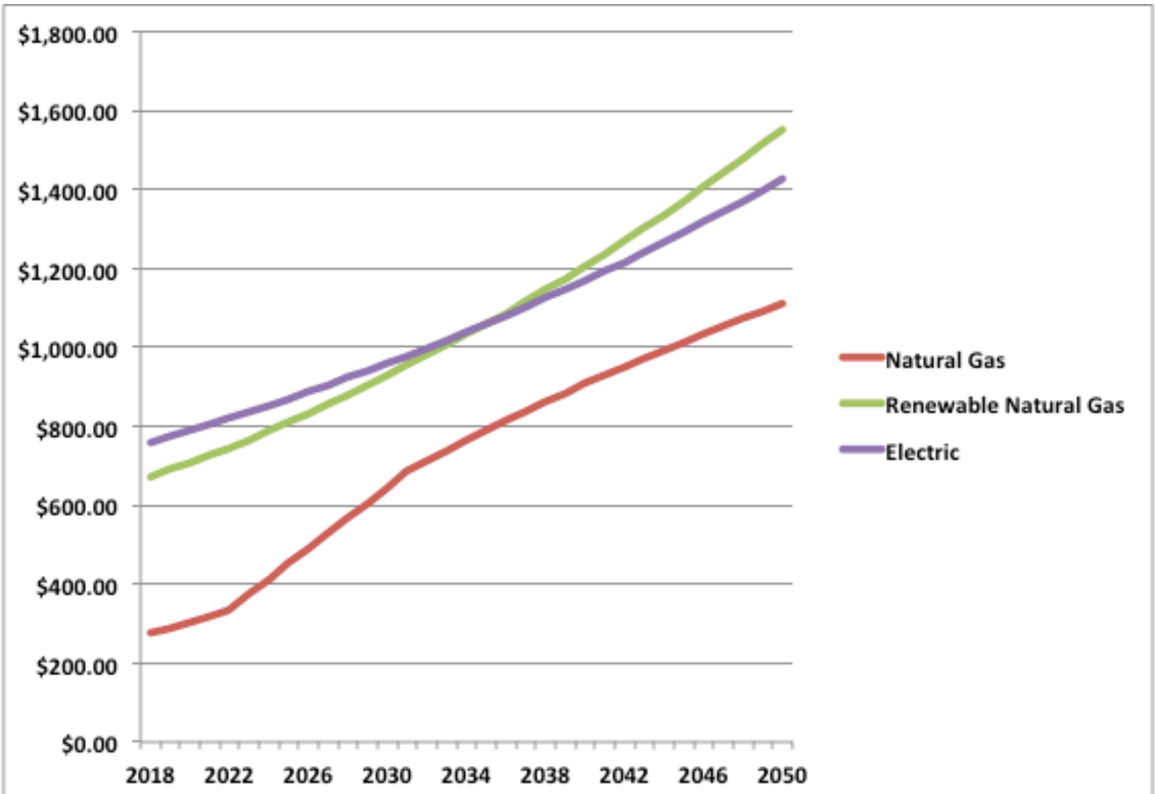
Figure 16: Space heating annual (nominal) costs – 2018 to 2050 (+$40/y GHG price)



As this figure shows, the higher GHG price has the desired effective of driving up the cost of space heating with natural gas by almost $1500/year. There is also a convergence with the cost of heating with renewable natural gas at the prices used in the model.

As above for water heating, we analyzed the case where electricity prices do not increase above inflation beyond F2025, as projected by BC Hydro. The following figure illustrates that even with no real increases in the price of electricity to 2050, it remains more affordable for households to use natural gas over electricity for space heating.

Figure 17: Space heating annual (nominal) costs – 2018 to 2050 (+$20/y GHG price, no real electricity price increases)



Heat pumps

Heat pumps could potentially play an important role in reducing greenhouse gas emissions from space and water heating. The MKJA Study speaks to this potential:

> …the rising electricity prices in the electrification scenarios constrain the use of baseboard heaters such that they are not used in more than 40-45% of homes. In the residential sector there is some early adoption of air-source heat pumps, which increases through time in response to … rising GHG prices as homes are renovated and replaced. Ground source heat pumps are not widely used in homes. By 2050, 20-25% of homes may use heat pumps if GHG prices continue to increase. [66]

We note that the analysis in the MKJA Study uses three scenarios for natural gas prices that considerably overstate current and likely future natural gas prices. We concur that there is a potential for residential use of heat pumps considering the future real increases in electricity prices determined in the MKJA Study, but we expect that it will be residential *electricity* customers who will be switching to heat pumps long before natural gas customers. The net

[66] BC Hydro. 2013 IRP, Appendix 6C, p.27.

effect of this uptake in heat pumps will be a *decrease* in electricity requirements and not an increase.

The Ontario Independent Electricity System Operator (IESO) recently examined the opportunity for residential heat pumps in Ontario,[67] and there are findings from this study that are relevant to the current Inquiry:

- **High initial cost**. The cost of converting to electric heat pumps ranges from $5,000 to $16,000 depending on the system being replaced, equipment type, residence size and complexity of installation; this investment was not found to be cost-effective from a TRC perspective at any cost level;
- **Significant savings**. Residential electric heat pumps can assist existing electrically heated homes in reducing their energy use for heating by up to 60%, and reduce energy use up to 50% compared to natural gas heating;
- **Prime candidates**. Single-family residential dwellings heated with electricity represent the prime potential candidates for energy efficient heat pumps;
- **Less likely candidates**. For natural gas heated homes, the cost of conversion to and operation of electric heat pumps is currently significantly greater than capital and operating costs associated with an existing gas system; natural gas costs would need to increase more than 50% for heat pumps to be financially competitive with gas furnaces from a homeowner's perspective; and
- **Cost differences**. The typical annual operating cost of an electric heat pump is more than $3/day ($1200/year) greater than typical operating costs of a natural gas home heating system.

Not all of the information in the IESO study is applicable to BC, considering differences in electricity rates, and differences in climate between the Lower Mainland and southern Ontario. However, the cost differences are substantial. In the example above, where the costs of heating a home using 800 m^3 of natural gas total $275/year, even if a $5,000 heat pump were able to meet 100% of heating needs or if the cost of the heat pump were to decline by 50%, it would not be cost effective to switch to electric heating. In 2050, when the costs have risen to $1000/year or about $550/year in current dollars, a heat pump would still not be cost effective since the remaining heat would need to be supplied by higher cost RNG or higher cost electricity.

[67] IESO. March 2017. An Examination of the Opportunity for Residential Heat Pumps in Ontario