canwea
CANADIAN WIND ENERGY ASSOCIATION | ASSOCIATION CANADIENNE DE L'ÉNERGIE ÉOLIENNE

Clean Energy BC

August 30, 2017

Commission Secretary
B.C. Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
Attention: Mr. Patrick Wruck

RE: Site C Inquiry Submission

Dear Mr. Wruck:

In order to assist the BC Utilities Commission's ("BCUC") review of the Site C project, the Canadian Wind Energy Association ("CanWEA") and the Clean Energy Association of BC ("CEABC") have jointly engaged Power Advisory to provide an assessment of the benefits that renewable projects could provide in comparison to the Site C project ("Report"). We believe this independent report, based on real world market data and a financial model, will provide the factual information on the price of renewables the BCUC needs to fulfill its mandate.

For administrative convenience only a summary of the report will appear in Part 2 of the separate submission that the CEABC is making in its own right in relation to the above noted inquiry and it will be attached as an appendix to this submission.

CEABC and CanWEA hereby request that the working copy of the model referenced in the Report be kept confidential on the basis its form is proprietary to Power Advisory. The pro forma model is a proprietary model that was developed by Power Advisory and commonly used in projects such as this. Power Advisory's ability to deploy this element of intellectual capital helps it secure projects and provide services to clients more cost-effectively. Making this model broadly available will harm that source of competitive advantage. A hard copy of the model is attached to the Report. In accordance with the BCUC protocol for confidential documents, the working copy of the model will be available to interested parties in the Site C proceeding pursuant to a confidentiality agreement.

Sincerely,

Jean-François Nolet
Vice-President – Policy and Communications, CanWEA

Bryan MacLeod
Manager, CEABC

INDEPENDENT ASSESSMENT OF RENEWABLE GENERATION COSTS AND THE RELATIVE BENEFITS OF THESE PROJECTS COMPARED TO SITE C

Prepared for the Clean Energy Association of BC and the Canadian Wind Energy Association

August 30, 2017

Power Advisory LLC

www.poweradvisoryllc.com | 978-369-2465
55 University Avenue, Suite 605
Toronto, ON M5J 2H7

Executive Summary ..... ES 1
1. Introduction 1
1.1 Review of Power Advisory's Relevant Experience 1
2. Levelized Unit Energy Costs 2
2.1 Wind Pricing 3
2.1.1 Recent Pricing Trends and Projections 4
2.1.2 Projected Wind Costs 6
2.2 Solar Pricing 9
2.2.1 Recent Pricing Trends and Projections 9
2.2.2 Projected Costs 10
2.2 Hydroelectric Generation 11
2.4 Battery Storage Technology 12
3. Other Costs and Benefits of These Resources 13
3.1 Variable Generation Integration Cost 13
3.1.1 Comparison to Other Variable Generation Integration Cost Estimates 14
3.1.2 Evaluation of BC Hydro's Wind Integration Estimate 16
3.2 Capacity and Diversity Benefits of Variable Output Renewables 17
3.2 Benefit of Small, Targeted Resource Additions 18
3.4 Comparative Risk Assessment 19
3.6 REC Eligibility and Pricing 20
3.5 IPP Tax Payments 22
Appendix A: Pro Forma Model for Calculating Real Levelized Price for Wind 23

Executive Summary

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CanWEA) and Clean Energy Association of British Columbia (CEBC) to provide an independent assessment of the cost of various renewable generation projects and the relative benefits of these projects compared to Site C.

The analysis focuses on four renewable and clean energy technologies that are likely to be the most cost-effective: onshore wind; solar PV; hydroelectric generation; and battery storage. Power Advisory developed a financial pro-forma model to estimate prices that would be required for renewable energy technologies to achieve a target rate of return based on assumptions regarding the cost of constructing and operating these technologies in BC.

Wind Pricing

Installed costs of wind projects have been declining and their capacity factors increasing as a result of technological improvements. Data from across Canada and the US shows a steady decline in unit energy cost of wind projects down to about CAD$65 to $73/MWh for 2016, depending on the region. Reflecting future changes in project costs yields a real levelized price of about CAD$68/MWh for BC. Onshore wind costs are forecast to continue to decline through 2050 and a recent study indicates that the median estimate of the reduction from 2014 to 2020 is 10%. Bloomberg New Energy Finance forecasts a 47% decline in the cost of electricity from onshore wind.

Solar Pricing

There have been dramatic decreases in the costs of solar energy. Costs for utility scale projects have declined by 68% from Q4 2009 to Q1 2016, with further reductions experienced in 2016. Continued cost reductions are anticipated going forward. GTM Research expects a 27 percent drop in average global project prices by 2022.

Hydroelectric Generation Pricing

Hydroelectric project capital and operating costs are project specific and reflect the project configuration required to most cost-effectively develop the underlying resource.

Battery Storage Technology

Batteries are particularly well-suited for grid integration of wind and solar technologies, primarily because of the ramping, load following and frequency control functions they provide. More importantly, battery storage technology can also serve as incremental load and therefore assist with managing surpluses much more effectively than storage hydro. The cost of battery technology has fallen 50% since 2014 – a direct result of growing demand and competition. With predictions of an annual decline of 11.4% through 2020, battery storage will play an important role in providing variable generation like wind and solar with increased dependable capacity.

Alternative Technology Benefits

These benefits include: (1) smaller, targeted resource additions that avoid the risks and costs associated with large resource additions such as Site C; (2) lower development, construction, and operating risks; (3) tax payments to federal, provincial, and municipal governments; and (4) the opportunity to earn revenues from the sale of renewable energy credits.

Incremental Resource Additions

Site C would provide 1,100 MW of capacity and produce about 5.1 TWh per year of energy in an average water year. Adding such a large volume of energy to the system relative to forecast net load growth would result in a large surplus of energy which would likely be sold at Mid-Columbia (Mid-C) for about $26/MWh

in 2024 and beyond. This price, when compared to the cost of Site C power represents a significant cost to BC ratepayers.

Comparative Risk Assessment

Independent Power Producers (IPP) are responsible for managing project development, construction, financing and operating risks for IPP projects, with little to no risk to ratepayers. Such projects have a very different risk profile than a utility project, which is built under the cost-of-service regulation model. Under cost-of-service regulation, the costs incurred by the utility generally flow through to ratepayers. Cost overruns must be borne by ratepayers and/or taxpayers, and the larger the project, the larger the risk. This is readily apparent from large hydroelectric projects such as Muskrat Falls in Labrador (72% cost overrun) and Keeyask in Manitoba (35% cost overrun), both with schedule delays.

IPP Tax Payments

IPPs make major contributions to the federal, provincial and municipal budgets. These financial contributions should be weighed when considering such investment and the value that these projects provide BC. The taxes include corporate and personal income taxes, property taxes, and other taxes such as water rentals or royalties paid to the provincial government. Based on analysis prepared for CEBC, Power Advisory estimates that the annual tax revenues produced by operating clean energy projects represent approximately $244 million per year, as compared to Site C that will not return one dollar on equity until 2094.

REC Eligibility and Pricing

Another potential source of value offered by clean energy projects developed by IPPs is the sale of renewable energy credits or certificates (RECs) associated with the production of this renewable energy. This is a source of incremental revenue that is available to the various renewable energy resources evaluated in this report, but which wouldn't be available to Site C.

California's Renewable Portfolio Standard is based on three distinct Portfolio Content Categories or bundles. Portfolio Content Category 1 is the highest value REC market in the West and one in which Powerex participates presumably by reselling renewable energy that is under contract to BC Hydro. Category 1 RECs were recently priced at US$14.

Integration Cost

Power Advisory studied wind integration costs across many jurisdictions and they are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%, with solar integration costs being lower. This review of variable output renewable energy integration costs indicates that BC Hydro's estimates are considerably higher than most estimates.

Capacity and Diversity of Renewables

Wind, solar and many hydroelectric projects are variable output renewable energy resources that generate electricity when the underlying renewable energy resource is available. The capacity value of these resources can be enhanced through the diversity of such resources. This diversity can include different wind projects in different wind regimes as well as the diversity offered by combining the output of wind, solar PV, and run-of-river hydroelectric projects. This diversity benefit has been demonstrated in numerous studies including the Pan-Canadian Wind Integration Study which found, among things, that distributed solar can complement wind and that the combination of wind and hydro provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. This diversity enhances the capacity value of these resources as well as reduces the requirements for operating reserves to balance the variability of these resources. The net effect is to increase the value offered by these resources as well as to reduce the costs associated with integrating these resources.

1. Introduction

On August 2, 2017 the BC government instructed the British Columbia Utilities Commission (BCUC) to conduct a review of Site C based on the requirements set out in the government's Terms of Reference.[1] The Terms of Reference directed the BCUC to answer a series of questions including "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 cost as the Site C project?"

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CanWEA) and Clean Energy Association of British Columbia (CEBC) to provide an independent assessment of the cost of these commercially feasible generating projects and the relative benefits of these projects compared to Site C.

1.1 Review of Power Advisory's Relevant Experience

In late 2016, Power Advisory was engaged by BC Hydro, in conjunction with CEBC, to provide an independent assessment of the appropriate price for BC Hydro's Standing Offer Program (SOP), which is open to renewable and qualifying clean energy projects that are 15 MW and smaller. For this project, Power Advisory conducted a comprehensive review of the costs of developing qualifying SOP projects in BC. This analysis recognized the additional costs and foregone economies of scale that smaller generation projects experience.

Power Advisory is regularly engaged to develop independent or critically assess renewable generation project cost estimates. We advised the Ontario Power Authority with respect to the initial prices for its feed-in tariff program, which procured the full range of renewable energy technologies. From 2009 to 2013, we advised the Vermont Public Service Board with respect to the appropriate prices for its standard offer program for various renewable energy technologies and testified as an independent expert of behalf of the Vermont Public Service Board with respect to appropriate standard offer prices for the full range of qualifying renewable energy technologies. In addition, we advised the Alberta Department of Energy with respect to appropriate assumptions and cost estimates for a wide range of alternative energy technologies, including all of the generation technologies that we assess in this report.

With respect to how variable output renewable energy technologies fit within the existing electricity infrastructure, Power Advisory was recently engaged by Natural Resources Canada to draft a white paper regarding variable output renewable energy resources, changes to the electricity supply mix and the implications for the need for the essential reliability services identified by the North America Electric Reliability Corporation (NERC).[2] In 2013, Power Advisory drafted a report for Natural Resources Canada on the role of storage hydroelectric resources in facilitating the integration of variable output renewable energy resources.

---

[1] Province of British Columbia, Order of the Lieutenant Governor in Council, Order in Council No. 244, August 2, 2017.

[2] NERC has identified as essential reliability services as the operational attributes of conventional generation to provide reactive power to maintain system voltages, physical inertia to maintain system frequency, and load following to balance demand and supply in real time.

2. Levelized Unit Energy Costs

Power Advisory employed a financial pro forma model to estimate prices that would be required for the renewable energy technologies evaluated to achieve a target rate of return based on assumptions regarding the cost of constructing and operating these technologies in BC. This is the same financial pro forma model that we used for BC Hydro to estimate an appropriate range of prices for SOP projects. For the SOP pricing analysis, prices were escalated at 50% of CPI over the assumed contract term, consistent with the current provisions in the SOP contract. To approximate the Levelized Unit Energy Costs (LUECs) calculated by BC Hydro, for this analysis we assumed that the price would escalate at an assumed inflation rate of 2% such that the price derived is a real levelized price (i.e., the price is constant in real terms). In addition, project cost and performance assumptions were updated to reflect current technology cost data and modified to reflect the fact that the renewable energy projects could be larger than the 15 MW project size limit that applied to SOP projects and as a result are able to achieve lower capital and operating costs.

To ensure that our analysis is transparent and assist the BCUC in reviewing our assumptions and hopefully provide a basis for the use of this information in their assessment, we devote considerable effort to reviewing the assumptions that we have employed and the basis for any adjustments to the underlying referenced data sources.[3] Furthermore, we have sought to use reliable and credible sources to ensure that the assumptions employed are reasonable and the prices derived are an accurate reflection of the prices required to develop, construct, and operate these renewable generating technologies.

The capital, operating and maintenance costs, operating performance and financial assumptions for these technologies are reviewed below. Projects are assumed to have a long-term power purchase agreement (PPA) with BC Hydro. This PPA presumably would be able to support project financing as under the financial assumptions reviewed below. The target rate of return was determined to be an 10% after-tax return on equity (ROE). We used an 11% after-tax ROE to estimate appropriate prices for BC Hydro's SOP. The SOP has a number of distinct differences that warrant a higher after-tax ROE for SOP projects. First of all, the projects are relatively small and as such require a higher return to attract capital. In addition, with any PPAs for larger wind projects to be awarded through a competitive process we expect that the competitive discipline will induce IPPs to accept a lower ROE in an effort to be successful. In Power Advisory's professional judgment it represents a reasonable return assumption for such projects.

A 26% corporate tax rate was assumed and reflected in the pro forma analysis.[4] A 5.5% cost of debt, 20-year debt term and a debt/equity ratio that provides an average 1.5 debt service coverage ratio over the term were also assumed.[5] We used an 18-year debt term for the SOP pricing analysis. Various developers indicated that with a 25-year PPA, they have been able to secure longer debt terms and that a 20-year debt term was a reasonable assumption if a 25-year PPA was available.[6,7] Given the useful life of the technologies, a 25-year

---

[3] Attached as Appendix A is a copy of our financial pro forma model specified for a wind project in BC using the assumptions outlined in this report.

[4] Power Advisory has not reviewed the methodology that BC Hydro used to develop its LUEC for Site C. We understand that the models used to calculate these LUECs have not been made available. We note that to the degree that the Site C LUEC doesn't consider tax payments or payments in lieu of taxes, then the LUECs that we developed overstate the relative cost of the IPP clean energy generation projects relative to Site C.

[5] The 1.5 debt-service coverage ratio was a target. We'd expect that debt repayments would be sculpted to reflect project cash flows, whereas we calculated a constant debt and interest payment over the term of the loan.

[6] For wind projects this will also likely require that wind turbine manufacturers secure type certificates with at least an equivalent design life.

[7] The reasonableness of a 20-year debt term and 5.5% cost of debt for such projects was confirmed by Travelers Capital Corporation and Corpfinance International Limited. SaskPower and Hydro-Quebec commonly offer PPAs with 25-year terms for wind projects.

amortization period was assumed for wind and solar projects. Technology specific assumptions are reviewed in the following sections.

Our analysis focuses on four renewable and clean energy technologies that are likely to be the most cost-effective: (1) onshore wind; (2) solar PV; (3) hydroelectric generation; and (4) battery storage. Recognizing that BC Hydro has relied on requests for proposals (RFPs) that create competitive tension between proponents and promote the selection of the lowest cost generating resources, the project assumptions that we employ reflect "efficient projects" that are able to offer the lowest prices. This will result in the development of the most attractive sites, which offer the most favorable renewable resources or minimize the cost of developing these resources.

2.1 Wind Pricing

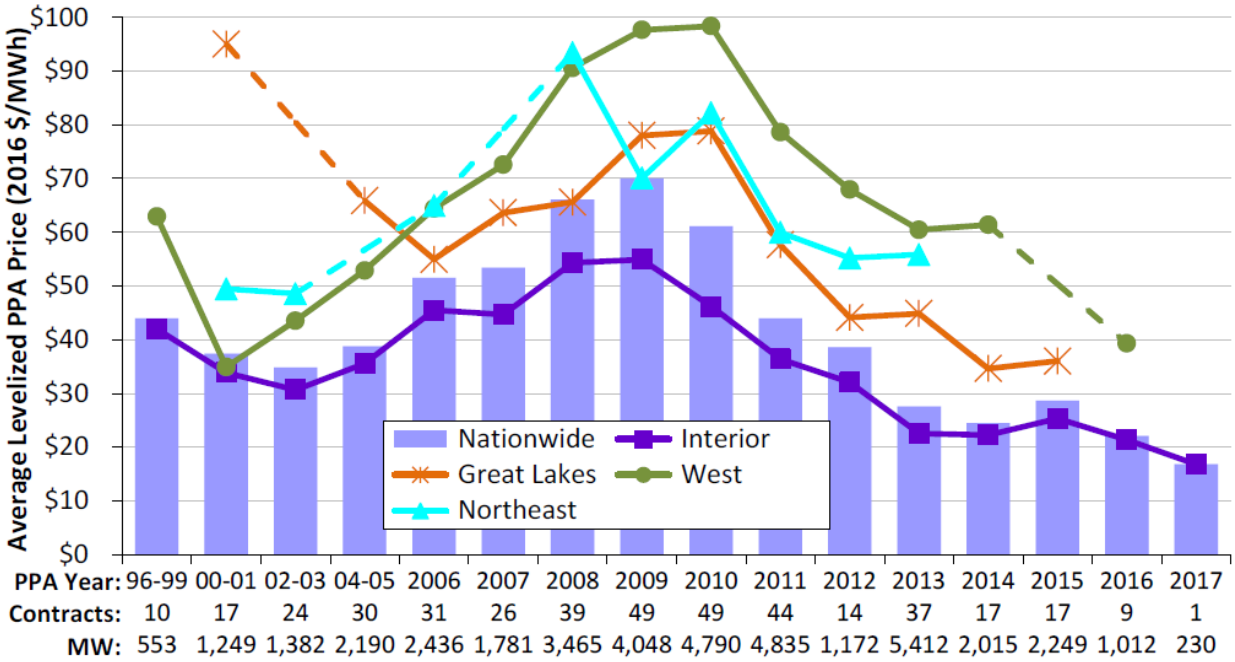
To provide context regarding the cost of wind generation, we first review announced prices for various PPAs that have been awarded. The two most recent competitive solicitations for wind generation for which pricing data is publicly available were in Ontario and Quebec. Ontario's Large Renewable Procurement 1 had a proposal submission date of September 1, 2015. Contracts were offered to four proponents offering five projects, with contract pricing ranging from $64.5 to $105.50/MWh. The broad range of pricing reflects the impact of: (1) transmission constraints that limited development of more cost-effective locations; and (2) non-price evaluation considerations that were weighed when awarding contracts and allowed proposals with higher prices to be evaluated more favorably to the degree that they performed better than other proposals with respect to these non-price considerations.[8] In December 2014, Hydro-Quebec awarded three contracts for 446 MW. Hydro-Quebec reported the average price was $76/MWh, including $13/MWh for transmission costs.[9] Competitive bidding processes are underway in both Alberta for 400 MW and Saskatchewan for 200 MW, but proposals have not been submitted.

Another point of reference is wind power purchase agreement (PPA) pricing reported in the US Department of Energy's (DOE's) *2016 Wind Technologies Market Report*. Figure 1 summarizes these PPA prices and breaks them out by region. Rising PPA prices from 2003 to 2009 follow a trend of increasing costs for wind turbines, with decreasing costs thereafter reflecting declining turbine prices and installed costs and increased project capacity factors. When evaluating US PPA pricing one needs to consider that these projects benefit from a federal production tax credit (PTC), which is currently 2.4 cents/kWh (or $24/MWh), for the first ten years of commercial operation.[10] The US DOE estimates that this has an effective value of at least 1.5 cents/kWh (or $15/MWh).[11] Therefore, the price for the Western Region of about $40/MWh in 2016, would be about $55/MWh without the PTC. Converting this to CAD$ using the average exchange rate for 2016, yields a PPA price of about CAD$73/MWh for 2016.[12,13]

---

[8] These non-price considerations included evidence of community support and aboriginal participation.
[9] Power Advisory notes that bidders have reported that transmission costs were liberally interpreted and in some instances included the costs of collection facilities.
[10] The PTC increased from 2.3 cents/kWh ($23/MWh) to 2.4 cents/kWh ($24/MWh) in 2017.
[11] The PTC's estimated impact on PPA pricing is less than its value because the credit is realized over a ten-year period, whereas many PPAs are for 20 years. In addition, project developers are typically unable to utilize the PTC and require parties that have a "tax credit appetite" to participate in the project financing, with developers realizing an effective value for the PTC that is somewhat less than its "face value."
[12] Based on an annual average exchange rate of US$.7551 to CAD$1.00.
[13] Care needs to be taken when comparing these PPA costs with the real levelized price that we calculate. Wind project PPA prices generally don't escalate or escalate at a specified percent of inflation, such that these reported PPA prices would be higher than would be required for a PPA price that escalates with inflation.

Figure 1: Levelized PPA Prices by Execution Date and Region



Source: Berkley Lab, Energy Information Administration

2.1.1 Recent Pricing Trends and Projections

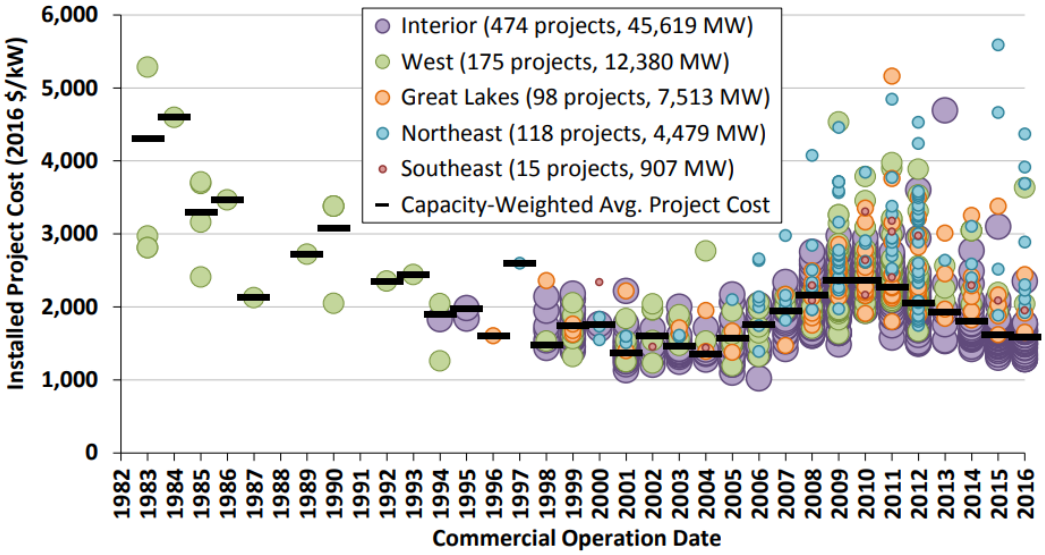
Historical US wind project installed costs (2016$/kW) are presented in Figure 2.[14] The installed costs for onshore wind in the US declined by 33% from 2010 to 2016.[15] From a Canadian perspective to a large degree these cost declines have been offset by the depreciation of the Canadian dollar relative to the U.S. dollar, which over the same six-year period has increased from an annual average of around $1.05 to $1.32 CAD to $1.00 US. Nonetheless, declines in the LUECs in CAD$ have been realized by increases in project capacity factors from higher hub heights and larger rotor diameters per capacity rating.[16]

These declines in LUECs are supported by the increases in capacity factors that have been realized recently and these declines are meaningful.[17] The US DOE notes that in 2016 the average capacity factor among projects built in 2014 and 2015 was 42.6% compared to 32.1% among all projects built from 2004 to 2011.[18] Recognizing that the most favourable wind regimes are typically developed first this increase in project capacity factors for 2014 and 2015 vintage projects is significant and clear evidence of the improvements in wind turbine technology and the resulting reductions in LUECs for wind.

---

[14] Reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses.
[15] *2016 Wind Technologies Market Report*, p. 49.
[16] The energy output of a turbine is roughly proportional to the swept area of the rotors. Similarly, all other things being equal, the energy yield is roughly proportional to the square root of the hub height due to higher wind speeds at greater heights.
[17] To the degree that wind project fixed costs are stable, increases in capacity factors will result in lower LUECs.
[18] *2016 Wind Technologies Market Report*, p. 39.

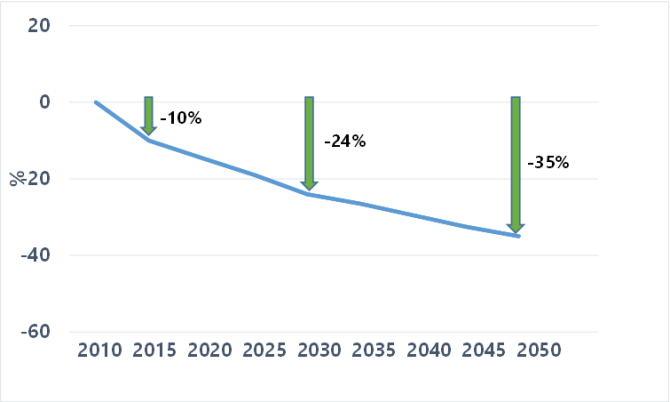
Figure 1: Wind Project Installed Costs Over Time (US$)



Source: US DOE, 2016 Wind Technologies Market Report

Onshore wind LUECs are forecast to continue to decline through 2050. Figure 3 is from a recent study that summarized LUEC projections based on expert opinion. It indicates that the median estimate of the LUEC reduction from 2014 to 2020 is 10%, and 35% by 2050. These estimates also consider cost reductions from higher capacity factors (e.g., higher tower heights, larger rotor diameters) as wind turbine technology improves. Similar cost reductions are forecast by Bloomberg New Energy Finance who forecasts a 47% decline in the levelized cost of electricity from onshore wind and the International Renewable Energy Agency (IRENA) who indicates that onshore wind farm costs could be 12% lower by 2020 than they are in 2011 and 23% lower by 2040.[19,20] The cost reductions estimated by IRENA are just for installed costs and don't reflect additional cost reductions attributable to enhanced project performance from higher capacity factors and lower operating and maintenance costs.

Figure 2 : Reduction in LUECs for Onshore Wind



Source: Nature, Energy Expert Elicitation Survey on Future Wind Energy Costs, September 2016.

[19] New Energy Outlook 2017, p. 2.
[20] Renewable Energy Technologies: Cost Analysis Series, Volume 1: Power Sector Issue 5/5, Wind Power, June 2012.

2.1.2 Projected Wind Costs

The starting point for our wind pricing estimate was the analysis of SOP pricing in which we estimated a range of required prices for a 15 MW wind project participating in BC Hydro's SOP. For this analysis, we relied upon a BC Hydro commissioned study performed by Hatch in early 2015 to estimate wind project costs for the Resource Options Update conducted as part of the Integrated Resource Plan. Hatch developed estimates for a range of sites across BC for project sizes ranging from 48 MW to 195 MW. We used the capital cost estimate for a 117 MW project in the Southern Interior as the starting point for our analysis.[21] At a cost of CAD$2,248/kW, these capital costs tied to the capital cost derived from the US Department of Energy's (DOE's) *2015 Wind Technologies Market Report*.[22] The alignment between these two installed cost estimates supports our use of the *Wind Technologies Market Report* to present more recent information regarding the installed costs of wind projects in BC.

We updated the cost estimate to reflect changes in wind project costs reported by the US DOE and changes in foreign exchange rates that are likely to affect wind project costs in BC given that wind turbine costs are more likely to be dominated in US$ or Euros. The *2016 Wind Technologies Market Report* indicated a weighted average installed cost of $1,590/kW (US$), reflecting a 5.9% decline relative to the installed costs reported in the 2015 report.[23] US DOE indicates that "early indications from a limited sample of twenty projects (3.0 GW) currently under construction and anticipating completion in 2017 suggest that capacity-weighted installed costs in 2017 will be similar to those in 2016."[24] Compounding the decline in installed costs with the escalation in CAD$ relative to the 2015 average exchange rate (and recognizing that the exchange rate is only likely to result in lower turbine and associated equipment costs) results in a 6.9% decline in the capital cost of wind projects, resulting in capital costs in CAD$ of about $2,328/kW for 2016-2017. Based on the US DOE indications that installed costs in 2016 appear to be similar to 2017, we assume that the CAD$2,328/kW installed cost is appropriate for 2017.

There is the potential for additional cost reductions from larger projects given economies of scale. Based on information presented by Hatch on wind project installed costs in BC,[25] we estimate that a 200 MW project offers an installed cost about 10% lower than a 100 MW wind project. There is a trend of larger wind project sizes to realize such economies of scale. For example, among the proposals recently selected by Emera Inc. as part of a recent request for proposals for renewable energy delivered to New Brunswick were proposals for a 402 MW and four 150 MW wind projects.

We scale this capital cost up by 2.5% to reflect interest during construction. To put these wind costs on a consistent basis with Site C, assumptions are required with respect to costs for the 2024 period. We note that the expert elicitation survey referenced above indicated a 10% reduction in LUEC's from 2014 to 2020, with continued reductions anticipated beyond that. To reflect that this capital cost was a 2017$ estimate, this cost

[21] These capital costs were increased to reflect foregone economies of scale.
[22] The reported weighted average installed cost for 2015 in US$ was $1,690/kW. The cost for installed cost for wind projects in the West Region was about $2,000/kW. Recognizing that this is an installed cost and doesn't reflect owners' costs of about 8% and that a portion of this cost (i.e., the 60% associated with wind turbines and associated equipment) must be converted to CAD$, the adjusted cost was estimated to be $2,520/kW. The average US$ to CAD$ exchange rate for 2015 was $.783 to $1.00. The CAD$ has subsequently strengthened and on August 22, 2017 was at US$.796 to CAD$1.00. Foreign exchange futures markets reflect a future strengthening of the CAD$ relative to the US$.
[23] Interestingly, the 2015 report indicated that "Early indications from a preliminary sample of projects currently under construction and anticipating completion in 2016 suggest no material change in installed costs in 2016." (p. ix)
[24] *2016 Wind Technologies Market Report*, p. 49.
[25] Hatch, Figure 1: CapEx Trend with Project Size

was then escalated by 2% per annum to reflect costs in 2024, with a 5% real cost reduction to reflect the cost reductions (approximately 50% of the 10% forecast) anticipated by industry experts.[26]

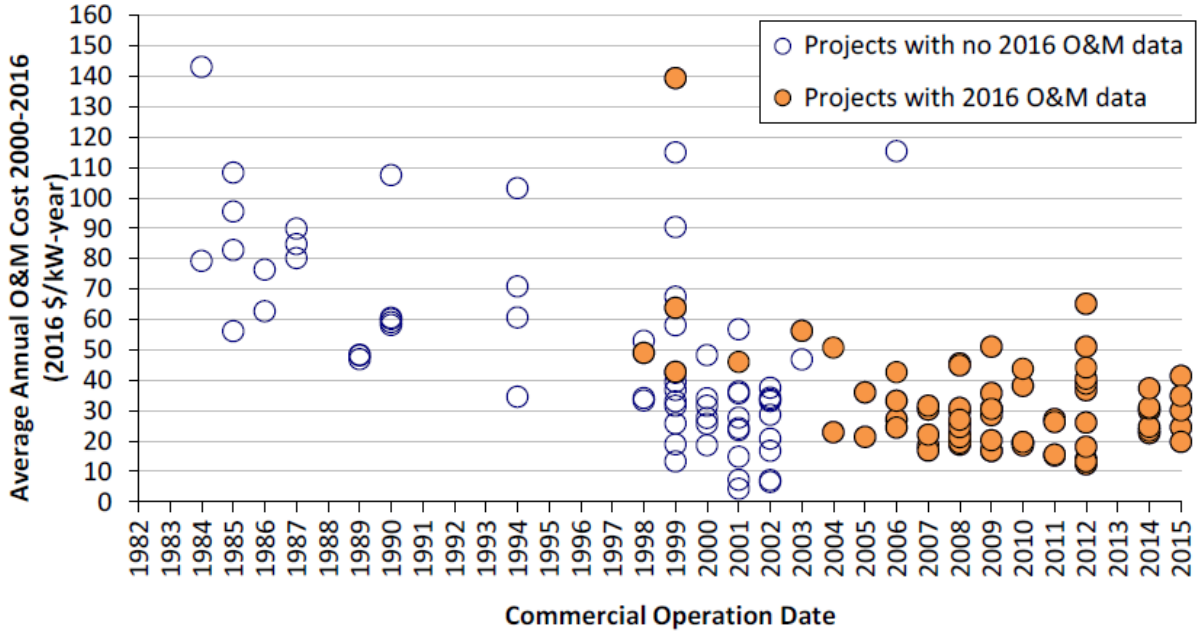
Another critical cost component are project fixed operations and maintenance (O&M) costs. For a 102 MW wind project, Hatch estimated these to range from $68 to $79/kW-year. These costs are considerably higher than those identified by the US Energy Information Administration (EIA) in its *Assumptions to the Annual Energy Outlook*, which were US$46.71/kW-year or about CAD$58.39/kW-year at the current exchange rate. [27] Alternatively, the US DOE's Wind Technologies Market Report indicates fixed O&M costs for recently installed projects of about US$30/kW-year. See Figure 4. For a project in Ontario that would be able to take advantage of a better developed wind industry service sector, we estimated fixed O&M costs of CAD$43.20/kW-year.[28,29] This fixed O&M cost estimate was based on current technology, which has more reliable component design, manufacturing and predictive maintenance software to allow for lower fixed O&M costs than earlier wind turbine models.

Power Advisory understands that O&M costs in BC are likely to be higher given the more remote locations of projects and the reduced ability to capitalize on economies of scale associated with the provision of these services given the smaller size of BC's wind sector.[30] However, we believe that the magnitude of the difference between the Hatch estimate and the figures reported for the US when converted to CAD$ calls into question the Hatch estimate. We used Hatch's fixed O&M estimate for the SOP pricing analysis because it was viewed as reasonable for a smaller 15 MW SOP project. However, we believe that it is high for a 200 MW wind project. Considering the EIA and US DOE data, but recognizing that fixed O&M costs in BC are likely to be higher given the remoteness of sites, we apply a 15% discount to the Hatch fixed O&M cost estimates and then adjust these to account for the reductions in fixed O&M for a 200 MW project.[31]

---

[26] In an effort to be conservative we only consider 50% of the anticipated cost decline.
[27] An exchange rate of US$.80 to CAD$1.00.
[28] Ontario currently has 4,781 MW of installed wind capacity almost ten times that of BC, which has 489 MW.
[29] This fixed O&M cost was anticipated to increase by about 13% in real terms in year 12 or 13 and then to remain constant in real terms of the remainder of the project's life.
[30] Power Advisory believes that the fixed O&M cost premium that Hatch appears to have reflected for BC is likely to be reduced as the wind industry in BC develops and additional wind projects are developed in Alberta and Saskatchewan, which will provide better access to various specialized O&M services for BC projects.
[31] This economies of scale adjustment was also derived from the Hatch analysis. Hatch presented fixed O&M estimates for a 102 MW and a 195 MW project on the North Coast. Power Advisory used the ratio of these two fixed O&M estimates to reflect the economies of scale offered by a 200 MW project. Economies of scale for the provision of O&M services are likely to be more significant in BC where there is a less well-developed wind industry support infrastructure than Ontario.

Figure 4: Average Annual O&M Costs from 2000 to 2016 by COD



Source: US DOE

In addition, to the fixed O&M costs estimated by Hatch we included the cost of land leases or royalties at $1.4/MWh.[32] With respect to project output, we assumed a 40% capacity factor, which reflects increases in output realized from higher tower heights and greater rotor diameters relative to project capacity ratings. BC developers indicated that they were able to achieve a 40% capacity for SOP projects,[33] which suggests that higher capacity factors could be realized for larger projects that can support longer transmission lead lines to access more favourable wind regimes. Assuming a 25-year amortization period and contract term, these assumptions yield a real levelized price of $68/MWh.[34] Recent estimates of the levelized cost of energy from IPP projects for direct comparison to Site C were $85/MWh. This reduction in costs likely reflects lower project installed costs and increased project capacity factors. The major assumptions and projected real levelized price are presented in Table 1. The capital (before consideration of interest during construction) and fixed O&M costs are costs in 2017CAD$ before escalation to 2024.

Table 1: Wind Project Levelized Costs 2024

Capital Cost $/kW	Fixed O&M $/kW- Year	Capacity Factor %	Amortization Years	Real Levelized Price $/MWh
$ 2,095	$ 56.31	40%	25	$68

Source: Power Advisory analysis

To put a wind project costs on a consistent basis as Site C, cost estimates are required for a replacement wind project given the longer useful life of a comparable hydroelectric project. Estimating wind project costs in

[32] We assumed a royalty payment of $1.00/MWh for the SOP pricing review.
[33] Furthermore, a number of BC wind project developers indicated that a 40% capacity factor was reasonable for BC with the application of new wind turbines and higher tower heights.
[34] Project developers typically reflect 25-year amortization periods in their project pricing and some wind turbine manufacturers are able to secure type certificates with a 30-year design lifetime. This assists developers in securing financing for projects that are based on such amortization periods.

2049 (25-year useful life) or 2054 (assuming a 30-year useful life) is difficult. As above various industry experts are predicting a 35% reduction in costs by 2050 (See Figure 3). Alternatively, Bloomberg New Energy Finance forecasts a 47% reduction by 2040. To be conservative (i.e., understate potential cost reductions) we use the lower cost reduction estimate of 35%.

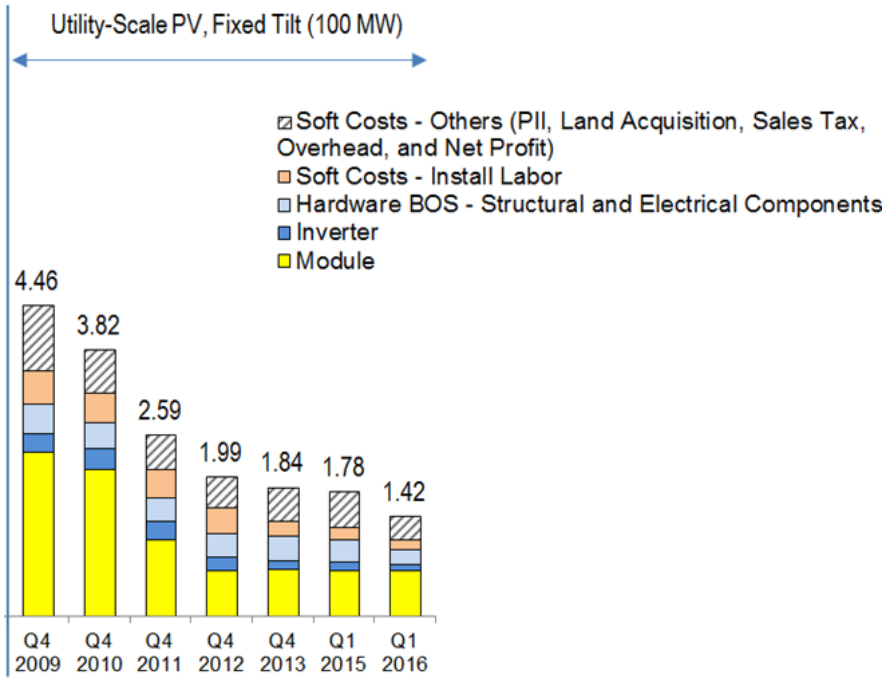
In addition, to these cost reductions such a project would be able to realize economies associated with the existing site including transmission substation, interconnection, some cabling, access roads, and various support facilities. This is likely to represent savings of 10 to 15% to project installed costs. Combining these cost reductions and savings, but recognizing that we have already assumed a 5% cost reduction in our 2024 estimate results in cost reductions of from 40 to 45%. Inflation at 2% per annum for 25 years results in an 64% increase in costs. This suggests that cost of wind in 2049 would be about 2 to 10% less than the 2024 cost.[35]

2.2 Solar Pricing

2.2.1 Recent Pricing Trends and Projections

There have been dramatic decreases in the costs of solar energy. The decline for utility scale (100 MW) PV system costs in US$ for the last six years are illustrated in Figure 5. Costs for utility scale projects have declined by 68% over that period, with further reductions experienced in 2016. A 100 MW solar project is likely to be large for BC given the relatively limited experience in the Province with utility scale projects. In addition, dual axis trackers are more appropriate for BC. The cost reductions shown are indicative of those that are being realized by large solar PV projects.

Figure 5: PV System Cost Summary (2016 USD/Watt DC) [36]



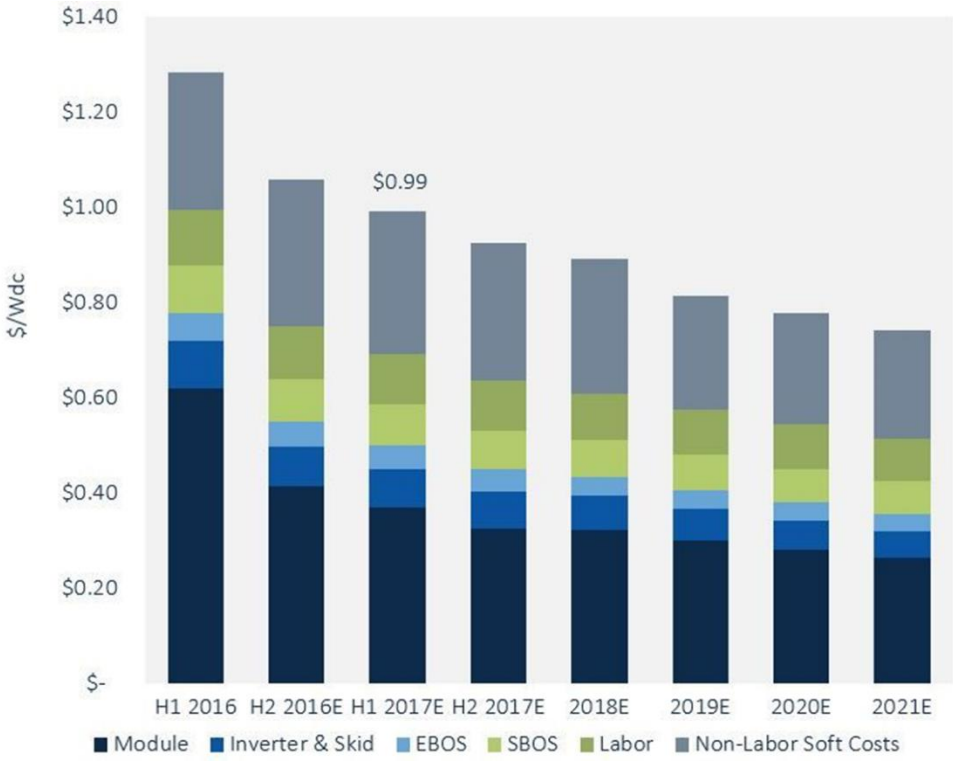
Source: NREL, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016

[35] 1.64 x (1-40%) = 98% or 1.64 x (1-45%) = 90% .

[36] The various colours represent cost components for a PV system, with the all-in cost for the system displayed at the top of the bar chart.

Recent solar prices are considerably below the projections presented in Figure 5, with continued cost reductions anticipated going forward. For example, GTM Research expects a 27 percent drop in average global project prices by 2022, or about 4.4 percent each year.[37] Figure 6 below reflects a 5% compound annual reduction in solar PV costs from 2017 to 2022.

Figure 6: US Utility Solar PV Fixed Tilt EPC Pricing - 2016 H1 to 2021E ($/Watt DC)



Source: GTM 2016

2.2.2 Projected Costs

A range of sources were used to consider likely solar PV costs in BC for a utility scale project. BC Hydro commissioned a report from Compass Renewable Energy Consulting Inc. (Compass) to provide price and performance estimates for solar PV technology in BC. This June 2015 study was reviewed and is used as the basis of our project output estimates. In our review of SOP pricing we indicated that "the report's cost estimates to be overly optimistic (low) and to heavily rely on Ontario cost estimates that couldn't be independently verified." However, continued reductions in PV costs have caused these cost estimates to become more reasonable.

We also reviewed the previously identified National Renewable Energy Laboratory (NREL) study that benchmarked solar PV costs. This study disaggregated project costs into discrete items that readily allowed these costs to be estimated for BC. Costs were presented for a 10 MW project and for a 50 MW project, which allowed costs to be estimated for a 25 MW utility scale project. In light of the continued declines in solar PV costs in the final three quarters of 2016, additional cost reductions from the NREL estimates are

[37] Green Tech Media 2016 https://www.greentechmedia.com/articles/read/solar-costs-are-hitting-jaw-dropping-lows-in-every-region-of-the-world

appropriate. We reflected recent pricing information on module costs (i.e., assume module cost of US$.3/watt dc rather than the US$.64/watt dc reflected in the NREL cost estimate) and used that along with the NREL cost estimates for other cost elements adjusted to CAD$.[38]

Recognizing the pace of decline in solar PV costs that are being experienced, low and base capital cost estimates were derived. The base estimate reflects a 3% annual decline in solar costs through 2024, just below the GTM estimates indicated above. The low estimate reflects an additional 10% decline in installed costs and a 5% annual decline in solar costs through 2024.[39,40] Table 2 presents capital and fixed O&M costs estimates and assumed capacity factor and the resulting real levelized price for a low and base case. The capital cost estimates reflect 2024 costs and the fixed O&M estimates reflect 2017 costs.

Table 2: Solar Pricing 2024

	Capital Cost $/kW	Fixed O&M $/kW- Year	Capacity Factor %	Amortization Years	Real Levelized Price $/MWh
Low Case	$1,276	$22.88	16.5%	25	$100
Base Case	$1,606	$27.45	16.0%	25	$129

Source: Power Advisory

These solar costs and capacity factors are for projects with a one-axis tracker. Dual axis trackers are more likely to be employed in BC given its latitude, with the incremental capital cost more than offset by the higher project output. Compass estimated that a dual-axis tracker project would have an annual energy output that was 14.6% higher than fixed tilt. However, Power Advisory was unable to find detailed project cost estimates for utility scale dual-axis tracker projects in the time allotted to complete this report. We believe that our pricing estimate for solar could be high because we haven't reflected the economies offered by such technology.

2.2 Hydroelectric Generation

Hydroelectric project capital and operating costs are project specific and reflect the project configuration required to most cost-effectively develop the underlying hydraulic resource. This makes "generic" estimates of the costs of hydroelectric generation less meaningful. For its 2015 Resource Options Update, BC Hydro commissioned a study that developed project specific cost estimates presented as LUECs.[41] Aggregate project information was presented for projects that had similar LUECs, making it impossible to independently derive estimates of the costs and required prices for these projects. The LUECs presented in the referenced study are presented below in Table 3.

The study indicated that the unit energy costs were derived using a 5% real discount rate. While the amortization period for this study wasn't indicated, the previous report relied on a 40-year amortization period.[42]

[38] We assumed a 35% premium for labour costs in BC.
[39] UBS, US Solar & Alternative Energy, It's Not Just Solar Panel Costs Dropping, September 27, 2016.
[40] Power Advisory has employed a $1.00 US to $1.25 CAD$ exchange rate forecast for 2020. An earlier reference to a $.75 US to $1.33 CAD$ exchange rate is more reflective of current conditions.
[41] Kerr Wood Leidal, Run-of-River Hydroelectric Potential for British Columbia, Summary of 2015 Updates
[42] BC Hydro, IRP, Appendix 3A-27, 2013 Resource Options Report Update, Run-of-River 2013 Update Memorandum and 2010 Report

Table 3: Hydroelectric LUECs

Price Bundle ($/MWh)	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Dependable Capacity (MW)
80 - 84	2	220	187	65	1
85 - 89	1	69	64	16	2
90 - 94	3	484	422	126	9

Source: Kerr Wood Leidal

2.4 Battery Storage Technology

Storage technologies have an important role to play in supporting increased levels of renewable energy investment and allowing variable output renewable energy technologies such as wind, solar PV and run-of-river hydro to provide the large volume of energy that would otherwise be provided by Site C.[43] Specifically, energy storage technologies are well-suited to provide the ramping, load following and frequency control functions that higher penetrations of renewable energy technologies require. Battery storage is particularly well-suited for wind and solar integration given that it can also serve as an incremental load and therefore assist with managing surpluses more effectively than storage hydro. In addition, as a modular technology they can be located to address specific transmission and distribution constraints and potentially avoid costly upgrades to resolve these constraints. Furthermore, with the significant decline in cost of battery storage, these technologies are able to more cost effectively provide longer duration energy storage services. California relied on battery technology to provide 70 MW of required peaking capacity to replace a portion of the natural gas-fired generation that was unavailable when the Aliso Canyon gas storage facility was shut down last year.

One of the primary contributors to the increased attention being paid to battery storage technologies is the dramatic cost reductions being experienced. Storage prices are falling faster than solar PV or wind technologies. Bloomberg New Energy Finance reports that as of year-end 2016 lithium-ion battery prices had fallen by almost 50% since 2014. Further cost declines are being realized and forecast. A recent study by a research team from the University of California and Technical University of Munich in Germany forecast the cost per MWh of a lithium-ion battery to decline at an average annual rate of 11.4% through 2020.[44] This research indicated that the primary contributors to these cost declines are increases in production output capacity and patent activity and that the learning rates for lithium-ion batteries are greater than for solar PV and wind technologies. This fall in prices is allowing combinations of solar, wind, and energy storage projects to offer costs that are more competitive than coal and natural gas plants.[45]

Clearly, a critical contributor to future cost declines will be increases in the deployment of the technology as a result of the "learning" that occurs with the increases in production capacity. With learning rates often measured in terms of percentage increases in capacity or production capacity, the cost declines realized overtime typically decline. However, in the case of lithium ion batteries these cost declines will support the

[43] Such battery storage facilities would be able to supplement the ability of BC Hydro's existing storage hydroelectric facilities to provide these services. (See discussion in Section 3.2.)
[44] Noah Kittner, Felix Lill and Daniel M. Kammen, Nature Energy, Volume 2, Energy storage deployment and innovation for the clean energy transition, July 31, 2017.
[45] Noah Kittner, Felix Lill and Daniel M. Kammen.

increased adoption of electric vehicles as well as other applications, which in turn will support greater learning. This suggests that significant cost declines are likely continue to be realized.

3. Other Costs and Benefits of These Resources

This section reviews other costs and benefits associated with these clean energy resources. Costs include variable generation integration costs, which BC Hydro typically considers when comparing wind resources to hydroelectric generation, and capacity value. To reflect the lower capacity value of wind and other variable output renewable resources, BC Hydro typically adds a cost to such resources.

Benefits offered include: (1) smaller, targeted resource additions that avoid the risks and costs associated with large resource additions such as Site C; (2) lower development, construction, and operating risks; (3) tax payments to federal, provincial, and municipal governments; and (4) the opportunity to earn revenues from the sale of renewable energy credits. These costs and benefits are discussed further below.

3.1 Variable Generation Integration Cost

As part of its 2013 Integrated Resource Plan (IRP), BC Hydro conducted a study of wind integration costs in BC.[46] The study evaluated the impacts and costs of 15, 25, and 35 percent wind penetration levels,[47] representing about 1,500, 2,500, and 3,500 MW of installed wind capacity. The study considered two scenarios for how these wind resources could be developed within BC. The first assumed that the lowest cost wind resources were developed first and the second assumed that there was diversity to the portfolio of wind resources developed. Two types of wind integration costs were identified: (1) operating reserve costs, which reflect capital and variable operating expenses associated with reserving generating resources so that sufficient generation is available to respond to system contingencies. These include the requirements for regulation, load-following and imbalance reserves and assume sufficient reserves are carried to cover a 97.7% (three standard deviation) confidence level; and (2) day-ahead opportunity costs, which reflect the opportunities lost from having to reduce BC Hydro's participation in the day-ahead market given the need to reserve hydroelectric resources to respond to the variability of wind generation. The results of this study are presented in Table 4.

Table 4: BC Hydro Wind Integration Cost Estimates

Scenario	Wind Penetration Level	Operating Reserve Costs ($/MWh)	Day Ahead Opportunity Costs ($/MWh)	Total Costs ($/MWh)
Lowest Initial Cost	15% (1,500 MW)	$7.83	$8.02	$15.85
	25% (2,500 MW)	$9.33	$14.85	$24.17
	35% (3,500 MW)	$8.67	$11.90	$20.57
High Diversity	15% (1,500 MW)	$4.03	$3.46	$7.49
	25% (2,500 MW)	$4.36	$4.66	$9.03
	35% (3,500 MW)	$5.36	$5.23	$10.59

Source: BC Hydro

[46] BC Hydro, 2013 IRP, Appendix 3E, Wind Integration Study Phase II. This was a Phase II study because BC Hydro undertook a wind integration study previously as part of its 2008 Long-Term Acquisition Plan. The Wind Integration Phase II Study was completed in November 2010.

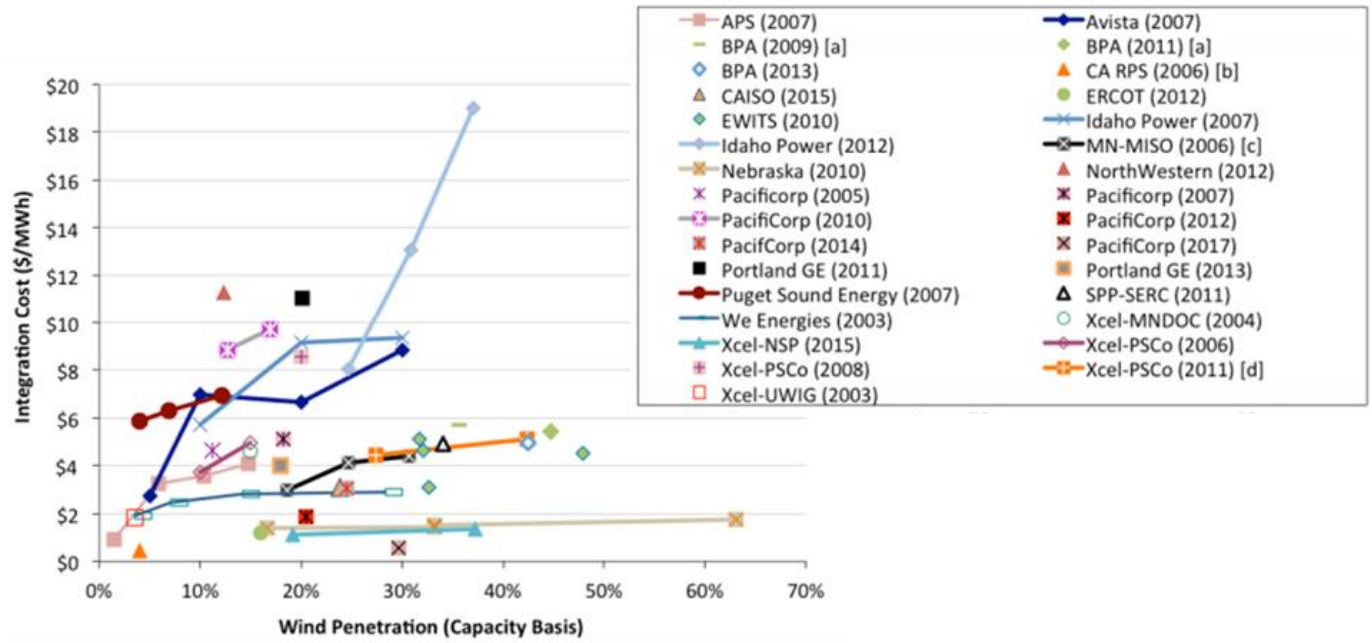
[47] Wind penetration was measured in terms of the proportion of BC Hydro's capacity.

3.1.1 Comparison to Other Variable Generation Integration Cost Estimates

While BC Hydro's analysis focused on the costs of integrating wind generation, the analysis is generally applicable to all variable output resources. Similar analyses are commonly performed by other electric utilities for a broader range of variable output renewable energy technologies.

Power Advisory offers the following comments on BC Hydro's wind integration cost estimates. They are generally high relative to those for other jurisdictions. Figure 7 reviews wind integration costs of various other electricity systems. These estimates are from US DOE's 2016 *Wind Technologies Market Report*. Each series on the graph represents a different cost study for different utilities or markets between 2003 and 2016. The US DOE report indicates that wind integration costs are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%.[48] The study indicates that variances in cost estimates are attributable, in part, to differences in methodologies, definitions of integration costs, differences in power system and market characteristics, fuel prices, wind output forecasting details and assumptions, and the degree to which thermal plant cycling costs are considered.

Figure 7: Integration Costs at Various Levels of Wind Penetration



Notes: [a] Costs in $/MWh assume 31% capacity factor; [b] Costs represent 3-year average; [c] Highest over 3-year evaluation period; [d] Cost includes the coal cycling costs found in Xcel Energy (2011). Listed below the figure are the organizations for which each study was conducted, and the year in which the analysis was conducted or published.

Source: U.S. DOE, "2016 Wind Technologies Market Report" August 2017, p.70 (Modified Figure 53).

Given the factors influencing wind integration costs discussed above, a case can be made that integration costs are more likely to align within a region or market. Therefore, Power Advisory surveyed recent renewables integration costs for both wind and solar resources in Western Electricity Coordinating Council (WECC) jurisdictions beyond BC. In the case of Portland General Electric, wind and solar are captured by the integration cost category of 'variable energy resources'. Partially due to a decline in natural gas prices, the

[48] The Western Wind and Solar Integration Study Phase 2 found that "from the perspective of the average fossil-fueled plant, 33% wind and solar penetration causes cycling costs to increase by $0.47–$1.28/MWh, compared to total fuel and variable operations and maintenance (VOM) costs of $27–$28/MWh." (p. vii)

integration cost estimates used in recent resource planning are significantly lower than in previous integrated resource plans. This trend is documented in the notes column of the table. Power Advisory notes that the wind integration costs average about US$3/MWh or about CAD$4/MWh, with one less than $1/MWh. Solar integration costs are generally lower than those for wind resources.

Table 5: Survey of Recent WECC Renewables Integration Costs

Jurisdiction	Integration Cost ($/MWh)	Year $*	Penetration Level (Capacity Basis)	Notes
Wind				
Arizona Public Service (APS)	3.25 / 4.08	2010	6% (468 MW) / 15% (1,185 MW)	As of the 2017 IRP, APS continues to base integration costs on its 2007 Wind Integration Cost Impact Study. Cost said to be updated "to increased penetration levels of wind in the APS systems and current fuel prices", but the specific value is not provided in the IRP.
PacifiCorp	0.57	2016	30% (3,007 MW)	2017 Flexible Reserve Study (FRS) conducted as part of the 2017 PacifiCorp IRP. Down from $3.06/MWh in the 2014 Wind Integration Study.
Pacific Gas and Electric (PG&E)	4.00	2014	Benchmark Average	Interim variable integration cost for wind approved by the California Public Utilities Commission in the 2014 RPS and IRP off-year proceeding.
Public Service Company of Colorado (PSCo) [Xcel Energy]	2.93	2016	28% (2,000 MW)	2016 ERP. Value based on 2011 Wind Integration Study methodology and updated natural gas prices. PSCo did not allow for gas prices below $3.24/MMBtu, while recognizing current and forecasted gas prices below this value. Average wind integration costs from 2011 were $3.68/MWh for 2 GW of wind.
Solar				
Arizona Public Service (APS)	2.00	2020	13% (1,038 MW)	Similar to wind, APS solar integration costs are currently benchmarked to a 2012 Black & Veatch Corporation study based on penetration levels and fuel prices. The costs reported in the 2012 study range from $1.53/MWh to $3.04 MWh. The planning value of $2.00/MWh in 2020 has been cited in the last two IRPs.
PacifiCorp	0.6	2016	20% (2,050 MW)	2017 Flexible Resource Study (FRS) conducted as part of the 2017 PacifiCorp IRP.
Pacific Gas and Electric (PG&E)	3.00	2014	Benchmark Average	Interim variable integration cost for solar approved by the California Public Utilities Commission in the 2014 RPS and IRP off-year proceeding.
Public Service Company of Colorado (PSCo) [Xcel Energy]	0.01 / 0.41	2016	14% (1,000 MW) / 25% (1,800 MW)	May 2016 "An Integration Cost Study for Solar Generation Resources on the Public Service Company of Colorado System" cited in 2016 ERP. Assumes annual natural gas costs of $4.37/MMBtu. The average solar integration costs in the 2011 ERP ranged from $1.25/MWh to $6.06 /MWh based on solar capacity and gas prices.
VER				
Portland General Electric (PGE)	0.92	2021	23% (1,160 MW)	2016 IRP Variable Energy Integration Study. Assumes 1,160 MW of VER capacity (3,210 GWh). Study is Phase 5 to previous wind integration studies. The reported cost of renewables integration was $4/MWh in the 2013 PGE IRP.

*All costs presented are in USD, with variance in the currency year indicated in this column.

This review of variable output renewable energy integration costs indicates that BC Hydro's estimates are considerably higher than most estimates. This is surprising given that BC Hydro has a predominately hydro system and such systems have greater operating flexibility than predominately fossil systems given the greater ramping and storage capability of many hydroelectric resources. A Power Advisory report for Natural

Resources Canada found that hydroelectric systems such as BC Hydro's are well suited to the integration of variable output wind resources and that they can allow large amounts of wind generation to be integrated at relatively low costs.[49]

A similar finding was made in the Pan-Canadian Wind Integration Study, which found that: (1) "Hydro generation, particularly hydro with pondage, provides a valuable complement to wind generation."; and (2) "The combination of wind and hydro provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. neighbours."[50] The Pan-Canadian Wind Integration Study also found that: (1) "Regulation reserve requirements to mitigate wind variability appear to be a small fraction of the additional installed wind capacity;" and (2) Overall the additional regulation reserve requirements across all of Canada were less than 1.7% of the installed wind." The regulation reserve requirements (i.e., increased regulation requirement relative to wind capacity) for BC under the 35% penetration scenario were just .9%, representing about 50 MW. While curtailment of wind was required in high wind resource scenarios there was little need for such curtailment in BC.

3.1.2 Evaluation of BC Hydro's Wind Integration Estimate

CanWEA engaged Brendan Kirby, a noted utility industry expert who participated in the referenced Western Wind and Solar Integration Study Phase 2 among other similar studies, to assess BC Hydro's wind integration cost estimates.[51] The Kirby study found that there have been a number of changes since the 2010 BC Hydro study was conducted and that when the study assumptions are modified to reflect this new information, estimated wind integration costs are dramatically lower. In particular, Kirby noted that the 2010 study calculated costs based on MW installed, but expressed results as $/MWh. Therefore, the higher capacity factors realized by wind projects in BC than assumed in BC Hydro's wind integration study is likely to result in lower per MWh integration costs.

In addition, Kirby noted that BC Hydro relied upon ancillary service prices from the California ISO (CAISO) and that these prices have declined significantly (from 50 to 80%) since the data relied upon in the study. Furthermore, Power Advisory notes that the CAISO market has a dramatically higher proportion of thermal generation than BC and as such is likely to have significantly higher costs for ancillary services than would be appropriate for BC. The BC Hydro wind integration noted that "To ensure that the CAISO ancillary service pricing used in this study are reasonable, a comparison between the CAISO ancillary services market prices and existing contracts for ancillary services in the Pacific Northwest held by Powerex was undertaken. The findings confirm good agreement between these Pacific Northwest contract prices and the CAISO ancillary service market pricing." The fact that Powerex's contracts for ancillary services in the Pacific Northwest (PacNW) reflect "good agreement" with CAISO ancillary service market pricing doesn't mean that CAISO prices are appropriate for this analysis. This "good agreement" suggests that ancillary service pricing in the PacNW is aligned with that of CAISO. This isn't surprising given the close integration between these markets. The question regarding the wind integration study should be what is the cost to BC Hydro of providing these services? The difference is between costs and market value. When making resource investment decisions for the benefit of BC consumers and the required services are being provided by BC Hydro, Power Advisory believes that the cost of providing the service should be considered, not its theoretical value in a somewhat distant market.

---

[49] *Case Study Analysis of Hydro-Variable Renewable Electricity Integration Strategies*, July, 2013.
[50] Pan-Canadian Wind Integration Study, Overview Presentation, p. 41.
[51] He retired from the Oak Ridge National Laboratory's Power Systems Research Program. He has 39 years of electric utility experience and has published over 180 papers, articles, book chapters, and reports on ancillary services, wind integration, restructuring, the use of responsive load as a bulk system reliability resource, and power system reliability.

Kirby also noted that sub-hourly scheduling reduces reserve requirements and the requirements for operating reserves for wind. In 2010, when the study was performed BC Hydro only had a 1-hour schedule. However, when he performed his assessment in 2014 15-minute scheduling was in place in BC. Kirby estimated that 15-minute scheduling would reduce incremental operating reserve requirements for wind by 51%. As discussed below, further reductions in these reserve requirement costs could likely be achieved through participation in Western Energy Imbalance Market, which is a 5-minute market.

As indicated in Table 4, day-ahead opportunity costs represent about half of the total wind integration costs. BC Hydro notes that "given the liquidity limitations of the real time market, BC Hydro does not anticipate relying on real time power trading markets to manage wind integration impacts to any significant degree. Therefore, the DA power trading market is the focus of this wind integration study."[52] Power Advisory notes that the Western Energy Imbalance Market was instituted in 2014 and now includes CAISO, PacifiCorp, Puget Sound, NV Energy, and Arizona Public Service, with many other market participants including Powerex scheduled to join. This energy imbalance market has clearly addressed the liquidity limitation of the real-time market. Furthermore, experience elsewhere suggests that with the presence of real-time and day-ahead markets allows market participants to arbitrage price differences between these markets such that there is unlikely to be significant sustained price differentials between these markets such as are assumed in BC Hydro's day-ahead opportunity cost estimate.

Kirby also notes that BC Hydro determines the maximum swing in wind generation within any hour based on a 99.7% day-ahead forecast confidence level. In the 2010 Wind Integration Study this required 100% backup of wind. However, BC Hydro's day-ahead forecast error for 487 MW of wind in February-April 2014 was just ±51.3 MW (i.e. ± 10.5% of installed capacity), indicating that a considerably lower forecast error estimate is appropriate. Considerable effort is being devoted to reducing the errors associated with forecasting wind output and this is producing more reliable forecasts, suggesting further reductions in integration costs. Kirby conservatively assumed a ±32% day-ahead reserve, three-times the forecast error from February-April 2014 period.[53] This along with the move to 15-minute scheduling and the resulting 51% reduction in reserve requirements, results in an 84% reduction in day-ahead opportunity costs.[54]

3.2 Capacity and Diversity Benefits of Variable Output Renewables

Wind, solar and many hydroelectric projects are variable output renewable energy resources that generate electricity when the underlying renewable energy resource is available. As a result, the inherent capacity value of these resources, or ability to generate electricity when needed to satisfy customer electricity demands, or respond to generator or transmission outages can be less than that of a conventional fossil or storage hydroelectric generation resource. The Pan-Canadian Wind Integration Study also found that at penetration rates of 20%, wind would have a capacity value of about 20 to almost 30% of its rated capacity.[55] However, the capacity value of these resources can be enhanced through the diversity of such resources. This diversity can include different wind projects relying on different wind regimes (e.g., differences in wind speeds on Vancouver Island, Kootenays, Okenagan, and lower Mainland) as well as the diversity offered by combining the output of wind, solar PV, and run-of-river hydroelectric projects. This diversity benefit has been demonstrated in numerous studies including the Pan-Canadian Wind Integration Study which found, among other things, that distributed solar can complement wind and that the combination of wind and hydro

[52] BC Hydro, 2013 IRP, Appendix 3E, Wind Integration Study Phase II, p. 3E-12. DA stands for day-ahead, i.e., a market that is organized around day-ahead financial or physical commitments for the delivery or purchase of power.
[53] This estimate takes no credit for improvements in wind forecasting that are being realized elsewhere and presumably can be realized in BC.
[54] The 84% is based on 51% x 32%, which is 16% of the original estimate, or an 84% reduction.
[55] Pan-Canadian Wind Integration Study, Final Report, p. 61

provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. With respect to this last point, Massachusetts has recognized the value of such potential clean energy imports by enacting legislation to support the procurement of a large block of clean energy (i.e., 9.45 TWh per year) and specifically allowing a combination of variable output renewable energy resources along with hydroelectric resources that firm up this variable output energy.[56]

This diversity enhances the capacity value of these resources as well as reduces the requirements for operating reserves to balance the variability of these resources. The net effect is to increase the value offered by these resources as well as to reduce the costs associated with integrating them.

3.2 Benefit of Small, Targeted Resource Additions

Site C would provide 1,100 MW of capacity and produce about 5.1 TWh per year of energy in an average water year. This 5.1 TWh per year of energy represents about 9% of forecast load for 2024 or at current electricity demand growth rates about 6 years of demand growth after DSM impacts are considered. Absent major system retirements, this implies that it will take BC about six years to "grow into" the volume of energy provided by Site C. (See Table 6 where it takes six years for BC Hydro's load growth less increases in DSM to increase by the 5.1 TWh provided by Site C.) Adding such a large volume of energy to the system relative to forecast net load growth would result in a large surplus of energy. The energy surplus that would be produced by Site C, as reported by BC Hydro in its 2017-2019 Revenue Requirements Application (RRA), is shown in Table 6. BC Hydro's energy surplus as a percentage of net load increases from 105% in 2024 to 109% in 2025 after Site C is scheduled to enter commercial operation.

Given the limits on BC Hydro's energy storage capability this energy surplus will result in an increase in energy exports and the majority of these energy exports are likely to be during the off-peak when BC electricity demand is low. Off-peak electricity futures prices at Mid-Columbia (Mid-C) in 2024 are about $26/MWh, increasing to about $27/MWh in 2025, and $28/MWh in 2026.[57] With the cost of Site C well over twice this, the sale of such surplus energy represents a high cost to BC ratepayers and needs to be considered when comparing Site C to alternatives such as the smaller hydroelectric, wind, solar resources evaluated in this report that can be added in increments to better fit load growth and represent less risk to ratepayers. This cost can be quantified by calculating the difference between the cost of Site C and the export revenues earned on the resulting increase in exports attributable to Site C.

[56] In July 2016, the Massachusetts legislature directed the state's investor-owned electric distribution companies to solicit long-term contracts for 9.45 TWh per year of clean energy from renewable energy resources and/or large hydroelectric projects.
[57] Mid-C off-peak futures prices as reported for August 23, 2017.

Table 6: BC Hydro Energy Load Resource Balance

		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Existing and Commited Resources													
Heritage Resources (Including Site C)	(a)	48,445	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	13,252	14,681	14,457	14,456	14,188	13,874	13,639	13,302	12,906	12,506	12,399	12,075
Future Supply-Side Resources													
IPP Renewals		61	234	569	647	779	936	1,114	1,349	1,628	1,951	2,032	2,223
Standing Offer Program		62	87	173	284	394	505	616	726	837	948	1,058	1,169
Revolstoke 6												26	26
Subtotal	(c)	123	321	742	931	1,173	1,441	1,730	2,075	2,465	2,899	3,116	3,418
Total Supply (Operational View)	(d) = a + b + c	**61,820**	**61,897**	**61,213**	**63,878**	**63,852**	**63,806**	**63,860**	**64,234**	**67,754**	**69,182**	**69,292**	**69,270**
Demand-Integrated System Total Gross Requirements													
2016 May Mid Load Forecast Before DSM		-58,334	-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256
Expected LNG Load		-61	-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848
Subtotal	(e)	-58,395	-59,161	-60,561	-61,623	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104
Existing and Commited Demand Side Management & Other Measures													
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		67	152	171	188	219	240	254	259	263	268	285	290
2016 DSM Plan F16 Savings		982	970	939	940	935	926	923	917	912	885	863	855
Planned Demand Side Management Measures													
2016 DSM Plan F17 to F19 savings		389	988	1,679	1,896	1,931	1,969	1,956	1,935	1,917	1,908	1,896	1,853
2016 DSM Plan F20+ Savings		0	0	0	292	904	1,454	1,897	2,310	2,637	2,946	3,229	3,500
Subtotal	(f)	1,521	2,193	2,872	3,399	4,072	4,672	5,113	5,504	5,812	6,090	6,356	6,581
Surplus/(Deficit) (Operational View)	(g) = d + e + f	**4,946**	**4,929**	**3,524**	**5,654**	**4,350**	**2,504**	**1,416**	**882**	**3,609**	**4,114**	**3,533**	**2,747**
Surplus/ Deficit as % of Net Load (Planning View)		**113%**	**115%**	**115%**	**114%**	**111%**	**108%**	**106%**	**105%**	**109%**	**110%**	**109%**	**107%**
Small Gap Surplus/(Deficit) (Operational View)		7,266	7,487	6,536	9,044	8,219	6,890	6,181	5,920	8,949	9,749	9,380	8,839
Large Gap Surplus/(Deficit) (Operational View)		2,559	2,036	-70	1,250	-661	-3,248	-5,224	-6,122	-3,768	-3,650	-4,392	-5,505

Source: BC Hydro, 2017-19 RRA

As the BC Hydro energy load resource balance indicates, BC's need for the energy from Site C is based on forecast demand growth. This load growth is uncertain. A considerably lower risk supply alternative is to rely on smaller renewable resources that can be developed and built more quickly than Site C and as such would allow BC Hydro to expand its supply as needed to address increases in customer requirements. This includes the wind, solar and smaller hydroelectric projects considered as part of this assessment.

3.4 Comparative Risk Assessment

The LUECs that Power Advisory has derived for these alternative clean energy technologies are predicated on costs of capital and financing assumptions that are appropriate for IPP projects where the project proponent is responsible for managing project development, construction, financing and operating risks. IPPs are able to bear development, financing, construction and operating risks and to offer long-term fixed prices because the projects that they are developing typically have shorter development time frames;[58] a high proportion of capital costs are associated with modular components that provide a high measure of cost certainty and allow developers to take advantage of competitive tension from competing equipment manufacturers; have shorter construction timeframes which reduce construction risks; and finally, the performance of these generating technologies in different operating conditions can be accurately modeled to produce reliable estimates of output and operating costs.

IPP projects have a very different risk profile than a utility project, which is built under the cost-of-service regulation model. Under cost-of-service regulation, the costs incurred by the utility generally flow through to

[58] This advantage is less apparent for the smaller hydroelectric projects developed by IPPs given their long development time frames. However, because IPPs are generally awarded contracts after a considerable amount of development work has been performed, these risks are more manageable.

ratepayers, except when these costs are disallowed by the regulator. When large projects are being built by investor-owned utilities, the costs of building these projects are generally added to the utility's rate base and the utility is allowed to recover these costs and earn a return on the rate base. Where the investor-owned utility is found to have been imprudent with respect to the construction of such a project, the imprudently incurred costs are generally not allowed to be recovered from customers and these costs are effectively paid by shareholders. However, when the cost-of-service model is applied to Crown-owned utilities, where the Province is the shareholder, there is little opportunity for the risk-sharing that can occur with investor-owned utilities. As a result, cost overruns must be borne by ratepayers and/or taxpayers, and there's generally relatively limited differences between these two groups. This is significant given the risks posed by the development and construction of large hydroelectric projects.

Given their long development time frames, difficult construction environments, extended construction schedules, and relatively high proportion of construction costs that are site related, the risks profiles of large hydroelectric projects such as Site C are dramatically greater than for most IPP projects. This is readily apparent from the construction cost overruns that have recently been experienced by such projects. Total costs, including financing costs,[59] for the Muskrat Falls Hydroelectric project (824 MW producing 4.9 TWh per year) in Labrador have escalated from $7.4 billion at project sanctioning to $12.7 billion, a 72% increase and these increased costs are forecast to contribute to an almost doubling of domestic electricity rates in Newfoundland to 23.34 cents/kWh in 2022 from 11.7 cents/kWh currently.[60] Similarly, the costs of the 695 MW Keeyask Hydroelectric Project in Manitoba have increased from $6.5 billion to $8.7 billion, a 34% increase, with a 21-month delay in the project's scheduled commercial operation date.[61]

Recent experience with Muskrat Falls and Keeyask clearly indicate the cost and schedule risks associated with large hydroelectric projects. These are risks that BC Hydro ratepayers are exposed to with the continued development of Site C.

3.6 REC Eligibility and Pricing

Another potential source of value offered by clean energy projects developed by IPPs is the sale of renewable energy credits or certificates (RECs) associated with the production of this renewable energy. This is a source of incremental revenue that is available to the various renewable energy resources evaluated in this report, but which wouldn't be available to Site C.

While project developers would sell BC Hydro a bundled product that would include energy, capacity, and renewable and environmental attributes, BC Hydro, or its affiliate Powerex, could sell these RECs in the various markets in the Pacific Northwest and California where they have incremental value. As discussed, further below in most markets this would require the sale of the REC and the associated energy.

The Western Renewable Energy Generation Information System is the independent REC issuance, tracking, and retirement system for the WECC interconnection region, to which BC Hydro, Pacific Northwest utilities and the CAISO belong.[62] A REC represents 1 MWh of qualifying renewable energy. The qualifications for

[59] It is appropriate to consider financing costs because the costs associated with accrued interest during construction increase significantly from project delays.
[60] Nalcor Energy, Muskrat Falls Project Update, June 23, 2017.
[61] https://www.hydro.mb.ca/corporate/news_media/news/2017-03-07-control-budget-for-keeyask-generating-station-revised.shtml
[62] The one exception is that Nevada uses both the WREGIS and NVTREC systems.

producing such RECs vary by state and are typically specified in the rules and regulations that establish their Renewable Portfolio Standards (RPS).[63]

California's RPS is based on three distinct Portfolio Content Categories or bundles. Portfolio Content Category 1 requires a minimum procurement of eligible renewable energy resources that are at least 50%, 65%, and 75% of a utility's retail sales RPS obligations by the end of 2013, 2016, and 2020, respectively. This category is to be filled by electricity generation directly connected, scheduled into, or dynamically transferred to a California Balancing Authority (CBA) that is primarily located in California. This is the highest value REC market in the West and one in which Powerex participates presumably by reselling renewable energy that is under contract to BC Hydro. Portfolio Content Category 2 comprises firmed and shaped electricity products providing incremental electricity. Portfolio Content Category 3 comprises eligible electricity products, including unbundled RECs, that do not qualify under Categories 1 or 2. Maximum procurement for Category 3 is 10 % of retail sales RPS obligations for the 2017-2020 compliance period.

Imports of renewable energy resources, namely solar and wind, from BC are eligible as bundled or unbundled products in Categories 1, 2 or 3. However, the California Energy Commission (CEC) has found that BC run-of-river hydro projects do not qualify, as they do not meet the environmental protections as similar hydroelectric facilities in California. Four BC wind projects, representing 487.2 MW of nameplate capacity, are known to be certified facilities under California's RPS - Cape Scott Wind Farm, Bear Mountain Wind Park, Dokie Wind Energy Project and Quality Wind Project.[64] The 180 MW Meikle Wind Project near Tumbler Ridge was also pre-certified as of early 2017.

Each of the three Portfolio Content Categories are associated with distinct REC pricing. Category 1 RECs were recently priced at US$14; Category 2 RECs at US$6/MWh and Category 3 RECs at US$1.50/REC.[65]

Washington State's Renewable Energy Standard requires that the facility must be located in the Pacific Northwest or the electricity from the project is delivered to Washington on a real-time basis.[66] The location definition of Pacific Northwest excludes BC. RPS compliance REC prices for the years of 2011-2014 were US$2.13.[67] For the 2015-2018 compliance years the Washington RPS REC prices are indexed to be US$4.25/REC.

In Oregon the RPS, as increased by SB 1547 in 2016, is 50% by 2040 for the large investor-owned utilities (IOU) that serve a majority of the state and lower for other types of utilities.[68] Solar, wind, and hydropower are all eligible technologies, with additional restrictions on the amount of hydro based on type and vintage. Eligible resources must be located within WECC, which includes BC. Unbundled RECs can meet 20% of a large IOUs obligation and a majority percentage of smaller utilities' compliance obligations, with the generation facility also located in the WECC territory.

Miller Creek Generating Facility Units 1 & 2 (combined 32.8 MW) and Brown Lake Generating Station (7.2 MW) are the only BC facilities currently approved under Oregon's RPS.[69] Power Advisory sought to find market data on REC prices for Oregon, but was unable to find reliable data. A PacifiCorp RPS compliance

---

[63] RPS are the broader programs that typically create RECs as a compliance mechanism and allow RECs to be traded to provide greater flexibility for prospective buyers (e.g., entities with an RPS compliance obligation) and sellers (e.g., renewable generators that produce RECs).
[64] CEC "California's Renewables Portfolio Standard (RPS) List of Facilities" Updated January 23, 2017.
[65] Platts, California Renewable Energy Certificate Markets, August 24.
[66] State of Washington Chapter 19.285 RCW "Energy Independence Act".
[67] SNL "Renewable Energy Credits (Data)" Accessed August 21, 2017. Indexes for "WA RPS REC."
[68] Oregon Department of Energy "Renewable Portfolio Standard" Accessed August 21, 2017. http://www.oregon.gov/energy/energy-oregon/Pages/Renewable-Portfolio-Standard.aspx
[69] Oregon Department of Energy "List of RPS Approved Facilities" July 31, 2017.

filing suggested that its costs for RECs was about $1.33/REC.[70] At best these costs reflect prior purchases and aren't necessarily reflective of current market prices.

3.5 IPP Tax Payments

IPPs make major contributions to the federal, provincial and municipal budgets. These financial contributions should be weighed when considering such investment and the value that these projects provide BC. The taxes include corporate and personal income taxes, property taxes, and other taxes such as water rentals or royalties paid to the provincial government. Based on analysis prepared for CEBC, Power Advisory estimates that the annual tax revenues produced by operating clean energy projects represent approximately $244 million per year.[71]

[70] PacifiCorp Renewable Portfolio Standard Oregon Compliance Report for 2015, June 1, 2016.
[71] Independent Power Producers Association of British Columbia, Economic Impact of Independent Power Projects in British Columbia, December 2009.

Appendix A: Pro Forma Model for Calculating Real Levelized Price for Wind

NPV		($0.00)	10.0%						
IRR		10.00%			Royalties				
Renewable Energy Payment	$/MWh	$68			$1.4	$/MWh			
Renewable Energy Payment Escalator		100%							
Project Start Year		2024							
Base Year for Costs		2017							
Inflation Rate		2.00%							
Rated Capacity	MW	200							
Capacity Factor		40.0%							
Output	MWh/year	700,800				Capital Cost			
					2016	$ 2,500			2017 to 2023 Escalation
All-in Capital Cost (incl IDC)	$/kW	$ 2,147			2017	$ 2,500			14.9%
Construction Period	years	1		Adj.		$ 2,328	6.9%		
Total Installed Cost	$	$471,858,027		Econ of Scale		$ 2,095	10.0%		5.0% LCOE Adj
									9.9% Effective Escalation
Fixed Operating Cost	2017$/kW/year	$ 56.31							
				Ave. Debt Serv. Cov.					
Debt:Equity Ratio	%	68%			1.5				
Debt Term	years	20							
Interest Rate	%	5.5%							
Debt Financing	$	$320,863,458							
Book Depreciation Rate	%	4%							
Income Tax Rate (various)	%	26.0%		QB		26.5%			
8% CCA Rate		8%		ON		26.5%			
50% CCA Rate		50%		NS		31.0%			
CCA 8% Rate Share	%	30%		NB		27.0%			
CCA 50% Rate Share	%	70%		PEI		31.0%			
				BC		26.0%			

Wind Pro Forma

					1	2	3	4	5
				2023	2024	2025	2026	2027	2028
Inflation	$461,645,879			1.13	1.15	1.17	1.20	1.22	1.24
Technology REP ($/MWh)	$79.8				68.31	69.68	71.07	72.49	73.94
FACILITY OPERATIONS									
Installed Capacity (MW)	1,650.37			0.00	200.00	200.00	200.00	200.00	200.00
Generation Output (MWh)	5,782,900			0	700,800	700,800	700,800	700,800	700,800
INCOME STATEMENT									
Revenue				$0	$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Operating Costs				$0	($13,918,755)	($14,197,130)	($14,481,073)	($14,770,694)	($15,066,108)
Book Depreciation				$0	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Interest				$0	($17,647,490)	($17,141,372)	($16,607,417)	($16,044,095)	($15,449,790)
Property Tax (incl in FOM)				$0	$0	$0	$0	$0	$0
Income Tax				$0	$18,701,726	$30,482,759	$13,835,548	$5,246,267	$687,439
NET INCOME				**$0**	**$16,135,141**	**$29,101,397**	**$13,680,827**	**$6,361,408**	**$3,117,556**
BALANCE SHEET									
Assets									
Gross Plant			$0	$0	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Accumulated Depreciation			$0	$0	($18,874,321)	($37,748,642)	($56,622,963)	($75,497,284)	($94,371,605)
Net Plant			$0	$0	$452,983,706	$434,109,385	$415,235,064	$396,360,743	$377,486,422
Work In Progress			$0	$471,858,027	$0	$0	$0	$0	$0
Cash			$0	$0	$0	$0	$0	$0	$0
TOTAL			**$0**	**$471,858,027**	**$452,983,706**	**$434,109,385**	**$415,235,064**	**$396,360,743**	**$377,486,422**
Liabilities and Equity									
Short Term Liabilities			$0						
Long Term Liabilities			$0	$320,863,458	$311,661,309	$301,953,042	$291,710,820	$280,905,276	$269,505,427
Equity and Retainted Earnings			$0	$150,994,569	$141,322,397	$132,156,343	$123,524,244	$115,455,467	$107,980,995
TOTAL	5.06262E-14		**$0**	**$471,858,027**	**$452,983,706**	**$434,109,385**	**$415,235,064**	**$396,360,743**	**$377,486,422**
Check				0	0	0	0	0	0
CASH FLOW STATEMENT					-64688.17561				
Cash Flow from Operations									
REP Revenue				$0	$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Variable Operting Cost				$0	$0	$0	$0	$0	$0
Revenue Sharing		$	1.40	$0	($981,120)	($1,000,742)	($1,020,757)	($1,041,172)	($1,061,996)
Fixed Operating Costs				$0	($12,937,635)	($13,196,388)	($13,460,316)	($13,729,522)	($14,004,112)
Interest paid				$0	($17,647,490)	($17,141,372)	($16,607,417)	($16,044,095)	($15,449,790)
Property Tax				$0	$0	$0	$0	$0	$0
Income Tax				$0	$18,701,726	$30,482,759	$13,835,548	$5,246,267	$687,439
TOTAL				**$0**	**$35,009,462**	**$47,975,718**	**$32,555,148**	**$25,235,729**	**$21,991,877**
Cash Flow from Investment									
Capital Investment				($471,858,027)	$0	$0	$0	$0	$0
Interest During Construction				$0	$0	$0	$0	$0	$0
TOTAL				**($471,858,027)**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash Flow From Financing									
Cash Flow to Owners				$150,994,569	($25,807,313)	($38,267,451)	($22,312,926)	($14,430,185)	($10,592,028)
Borrowing				$320,863,458	$0	$0	$0	$0	$0
Debt repayment				$0	($9,202,149)	($9,708,267)	($10,242,222)	($10,805,544)	($11,399,849)
TOTAL				**$471,858,027**	**($35,009,462)**	**($47,975,718)**	**($32,555,148)**	**($25,235,729)**	**($21,991,877)**
Change in Cash				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT									
Opening Balance	Annual Financing Obligation			$0	$320,863,458	$311,661,309	$301,953,042	$291,710,820	$280,905,276
Borrowing	($26,849,639)	##########		$320,863,458	$0	$0	$0	$0	$0
Repayment				$0	$9,202,149	$9,708,267	$10,242,222	$10,805,544	$11,399,849
Interest				$0	$17,647,490	$17,141,372	$16,607,417	$16,044,095	$15,449,790
Closing Balance	0		$0	$320,863,458	$311,661,309	$301,953,042	$291,710,820	$280,905,276	$269,505,427
check					26,849,639	26,849,639	26,849,639	26,849,639	26,849,639
INCOME TAXES									
Revenue				$0	$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Expenses				$0	($31,566,245)	($31,338,502)	($31,088,490)	($30,814,789)	($30,515,898)
8% CCA Rate				$0	($5,662,296)	($10,871,609)	($10,001,880)	($9,201,730)	($8,465,591)
50% CCA Rate				$0	($82,575,155)	($123,862,732)	($61,931,366)	($30,965,683)	($15,482,842)
Taxable Income				**$0**	**($71,929,715)**	**($117,241,383)**	**($53,213,647)**	**($20,177,951)**	**($2,643,995)**
Tax				$0	$18,701,726	$30,482,759	$13,835,548	$5,246,267	$687,439
UCC 8% Plant				$141,557,408	$135,895,112	$125,023,503	$115,021,623	$105,819,893	$97,354,301
UCC 50% Plant				$330,300,619	$247,725,464	$123,862,732	$61,931,366	$30,965,683	$15,482,842
Income Tax Rate					26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin					$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Debt Service Coverage									
Debt Service					$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639
Cash Flow					$52,656,952	$65,117,090	$49,162,565	$41,279,825	$37,441,667
Coverage Ratio					1.96	2.43	1.83	1.54	1.39

Wind Pro Forma

	6	7	8	9	10	11	12	13
	2029	2030	2031	2032	2033	2034	2035	2036
Inflation	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46
Technology REP ($/MWh)	75.42	76.93	78.47	80.04	81.64	83.27	84.94	86.64
FACILITY OPERATIONS								
Installed Capacity (MW)	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Generation Output (MWh)	*700,800*	*700,800*	*700,800*	*700,800*	*700,800*	*700,800*	*700,800*	*700,800*
INCOME STATEMENT								
Revenue	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Operating Costs	($15,367,430)	($15,674,779)	($15,988,275)	($16,308,040)	($16,634,201)	($16,966,885)	($17,306,223)	($17,652,347)
Book Depreciation	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Interest	($14,822,798)	($14,161,322)	($13,463,465)	($12,727,225)	($11,950,492)	($11,131,039)	($10,266,516)	($9,354,445)
Property Tax (incl in FOM)	$0	$0	$0	$0	$0	$0	$0	$0
Income Tax	($1,855,555)	($3,390,865)	($4,423,382)	($5,206,335)	($5,867,106)	($6,470,131)	($7,048,360)	($7,618,991)
NET INCOME	**$1,936,639**	**$1,812,591**	**$2,242,714**	**$2,976,078**	**$3,887,719**	**$4,915,740**	**$6,029,858**	**$7,215,680**
BALANCE SHEET								
Assets								
Gross Plant	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Accumulated Depreciation	($113,245,927)	($132,120,248)	($150,994,569)	($169,868,890)	($188,743,211)	($207,617,532)	($226,491,853)	($245,366,174)
Net Plant	$358,612,101	$339,737,780	$320,863,458	$301,989,137	$283,114,816	$264,240,495	$245,366,174	$226,491,853
Work In Progress	$0	$0	$0	$0	$0	$0	$0	$0
Cash	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	**$358,612,101**	**$339,737,780**	**$320,863,458**	**$301,989,137**	**$283,114,816**	**$264,240,495**	**$245,366,174**	**$226,491,853**
Liabilities and Equity								
Short Term Liabilities								
Long Term Liabilities	$257,478,586	$244,790,269	$231,404,095	$217,281,681	$202,382,534	$186,663,934	$170,080,811	$152,585,617
Equity and Retainted Earnings	$101,133,514	$94,947,510	$89,459,363	$84,707,456	$80,732,282	$77,576,561	$75,285,363	$73,906,236
TOTAL	**$358,612,101**	**$339,737,780**	**$320,863,458**	**$301,989,137**	**$283,114,816**	**$264,240,495**	**$245,366,174**	**$226,491,853**
Check	0	0	0	0	0	0	0	0
CASH FLOW STATEMENT								
Cash Flow from Operations								
REP Revenue	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Variable Operting Cost	$0	$0	$0	$0	$0	$0	$0	$0
Revenue Sharing	($1,083,236)	($1,104,900)	($1,126,998)	($1,149,538)	($1,172,529)	($1,195,980)	($1,219,899)	($1,244,297)
Fixed Operating Costs	($14,284,195)	($14,569,878)	($14,861,276)	($15,158,502)	($15,461,672)	($15,770,905)	($16,086,323)	($16,408,050)
Interest paid	($14,822,798)	($14,161,322)	($13,463,465)	($12,727,225)	($11,950,492)	($11,131,039)	($10,266,516)	($9,354,445)
Property Tax	$0	$0	$0	$0	$0	$0	$0	$0
Income Tax	($1,855,555)	($3,390,865)	($4,423,382)	($5,206,335)	($5,867,106)	($6,470,131)	($7,048,360)	($7,618,991)
TOTAL	**$20,810,960**	**$20,686,912**	**$21,117,035**	**$21,850,399**	**$22,762,040**	**$23,790,061**	**$24,904,179**	**$26,090,001**
Cash Flow from Investment								
Capital Investment	$0	$0	$0	$0	$0	$0	$0	$0
Interest During Construction	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash Flow From Financing								
Cash Flow to Owners	($8,784,119)	($7,998,595)	($7,730,860)	($7,727,985)	($7,862,893)	($8,071,461)	($8,321,056)	($8,594,807)
Borrowing	$0	$0	$0	$0	$0	$0	$0	$0
Debt repayment	($12,026,841)	($12,688,317)	($13,386,174)	($14,122,414)	($14,899,147)	($15,718,600)	($16,583,123)	($17,495,195)
TOTAL	**($20,810,960)**	**($20,686,912)**	**($21,117,035)**	**($21,850,399)**	**($22,762,040)**	**($23,790,061)**	**($24,904,179)**	**($26,090,001)**
Change in Cash	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT								
Opening Balance	$269,505,427	$257,478,586	$244,790,269	$231,404,095	$217,281,681	$202,382,534	$186,663,934	$170,080,811
Borrowing	$0	$0	$0	$0	$0	$0	$0	$0
Repayment	$12,026,841	$12,688,317	$13,386,174	$14,122,414	$14,899,147	$15,718,600	$16,583,123	$17,495,195
Interest	$14,822,798	$14,161,322	$13,463,465	$12,727,225	$11,950,492	$11,131,039	$10,266,516	$9,354,445
Closing Balance	$257,478,586	$244,790,269	$231,404,095	$217,281,681	$202,382,534	$186,663,934	$170,080,811	$152,585,617
check	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639
INCOME TAXES								
Revenue	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Expenses	($30,190,229)	($29,836,101)	($29,451,739)	($29,035,265)	($28,584,693)	($28,097,924)	($27,572,739)	($27,006,792)
8% CCA Rate	($7,788,344)	($7,165,277)	($6,592,054)	($6,064,690)	($5,579,515)	($5,133,154)	($4,722,501)	($4,344,701)
50% CCA Rate	($7,741,421)	($3,870,710)	($1,935,355)	($967,678)	($483,839)	($241,919)	($120,960)	($60,480)
Taxable Income	**$7,136,750**	**$13,041,790**	**$17,013,007**	**$20,024,366**	**$22,565,792**	**$24,885,118**	**$27,109,078**	**$29,303,811**
Tax	($1,855,555)	($3,390,865)	($4,423,382)	($5,206,335)	($5,867,106)	($6,470,131)	($7,048,360)	($7,618,991)
UCC 8% Plant	$89,565,957	$82,400,681	$75,808,626	$69,743,936	$64,164,421	$59,031,268	$54,308,766	$49,964,065
UCC 50% Plant	$7,741,421	$3,870,710	$1,935,355	$967,678	$483,839	$241,919	$120,960	$60,480
Income Tax Rate	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Debt Service Coverage								
Debt Service	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639
Cash Flow	$35,633,758	$34,848,234	$34,580,500	$34,577,624	$34,712,532	$34,921,100	$35,170,695	$35,444,446
Coverage Ratio	1.33	1.30	1.29	1.29	1.29	1.30	1.31	1.32

Wind Pro Forma	14	15	16	17	18	19
	2037	2038	2039	2040	2041	2042
Inflation	1.49	1.52	1.55	1.58	1.61	1.64
Technology REP ($/MWh)	88.37	90.14	91.94	93.78	95.66	97.57
FACILITY OPERATIONS						
Installed Capacity (MW)	200.00	200.00	200.00	200.00	200.00	200.00
Generation Output (MWh)	700,800	700,800	700,800	700,800	700,800	700,800
INCOME STATEMENT						
Revenue	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Operating Costs	($18,005,394)	($18,365,502)	($18,732,812)	($19,107,468)	($19,489,617)	($19,879,410)
Book Depreciation	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Interest	($8,392,209)	($7,377,050)	($6,306,058)	($5,176,161)	($3,984,120)	($2,726,516)
Property Tax (incl in FOM)	$0	$0	$0	$0	$0	$0
Income Tax	($8,191,334)	($8,770,755)	($9,360,645)	($9,963,407)	($10,580,958)	($11,214,978)
NET INCOME	**$8,466,841**	**$9,781,073**	**$11,158,240**	**$12,599,360**	**$14,106,115**	**$15,680,609**
BALANCE SHEET						
Assets						
Gross Plant	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Accumulated Depreciation	($264,240,495)	($283,114,816)	($301,989,137)	($320,863,458)	($339,737,780)	($358,612,101)
Net Plant	$207,617,532	$188,743,211	$169,868,890	$150,994,569	$132,120,248	$113,245,927
Work In Progress	$0	$0	$0	$0	$0	$0
Cash	$0	$0	$0	$0	$0	$0
TOTAL	**$207,617,532**	**$188,743,211**	**$169,868,890**	**$150,994,569**	**$132,120,248**	**$113,245,927**
Liabilities and Equity						
Short Term Liabilities	$134,128,187	$114,555,598	$94,112,016	$72,438,538	$49,573,018	$25,449,895
Long Term Liabilities	$73,489,345	$74,087,613	$75,756,874	$78,556,031	$82,547,229	$87,796,031
Equity and Retainted Earnin	**$207,617,532**	**$188,743,211**	**$169,868,890**	**$150,994,569**	**$132,120,248**	**$113,245,927**
TOTAL	0	0	0	0	0	0
Check						
CASH FLOW STATEMENT						
Cash Flow from Operatio						
REP Revenue	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Variable Operting Cost	$0	$0	$0	$0	$0	$0
Revenue Sharing	($1,269,183)	($1,294,567)	($1,320,458)	($1,346,868)	($1,373,805)	($1,401,281)
Fixed Operating Costs	($16,736,211)	($17,070,935)	($17,412,353)	($17,760,601)	($18,115,813)	($18,478,129)
Interest paid	($8,392,209)	($7,377,050)	($6,306,058)	($5,176,161)	($3,984,120)	($2,726,516)
Property Tax	$0	$0	$0	$0	$0	$0
Income Tax	($8,191,334)	($8,770,755)	($9,360,645)	($9,963,407)	($10,580,958)	($11,214,978)
TOTAL	**$27,341,162**	**$28,555,394**	**$30,032,561**	**$31,473,681**	**$32,980,436**	**$34,554,930**
Cash Flow from Investme						
Capital Investment	$0	$0	$0	$0	$0	$0
Interest During Construction	$0	$0	$0	$0	$0	$0
TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash Flow From Financir						
Cash Flow to Owners	($8,883,732)	($9,182,805)	($9,488,980)	($9,800,203)	($10,114,917)	($10,431,807)
Borrowing	$0	$0	$0	$0	$0	$0
Debt repayment	($18,457,430)	($19,472,589)	($20,543,581)	($21,673,478)	($22,865,520)	($24,123,123)
TOTAL	**($27,341,162)**	**($28,555,394)**	**($30,032,561)**	**($31,473,681)**	**($32,980,436)**	**($34,554,930)**
Change in Cash	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT						
Opening Balance	$152,585,617	$134,128,187	$114,655,598	$94,112,016	$72,438,538	$49,573,018
Borrowing	$0	$0	$0	$0	$0	$0
Repayment	$18,457,430	$19,472,589	$20,543,581	$21,673,478	$22,865,520	$24,123,123
Interest	$8,392,209	$7,377,050	$6,306,058	$5,176,161	$3,984,120	$2,726,516
Closing Balance	$134,128,187	$114,555,598	$94,112,016	$72,438,538	$49,573,018	$25,449,895
check	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639
INCOME TAXES						
Revenue	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Expenses	($26,397,603)	($25,742,552)	($25,038,870)	($24,283,629)	($23,473,737)	($22,605,926)
8% CCA Rate	($3,997,125)	($3,877,355)	($3,383,167)	($3,112,513)	($2,863,512)	($2,634,431)
50% CCA Rate	($30,240)	($15,120)	($7,560)	($3,780)	($1,890)	($945)
Taxable Income	**$31,505,131**	**$33,733,674**	**$36,002,479**	**$38,320,795**	**$40,695,992**	**$43,134,532**
Tax	($8,191,334)	($8,770,755)	($9,360,645)	($9,963,407)	($10,580,958)	($11,214,978)
UCC 8% Plant	$45,966,940	$42,289,584	$38,906,418	$35,793,904	$32,930,392	$30,295,961
UCC 50% Plant	$30,240	$15,120	$7,560	$3,780	$1,890	$945
Income Tax Rate	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Debt Service Coverage						
Debt Service	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639
Cash Flow	$35,733,371	$36,032,444	$36,338,619	$36,649,842	$36,964,556	$37,281,446
Coverage Ratio	1.33	1.34	1.35	1.37	1.38	1.39

Wind Pro Forma	20	21	22	23	24	25
	2043	2044	2045	2046	2047	2048
	1.67	1.71	1.74	1.78	1.81	1.85
Inflation	99.52	101.51	103.54	105.61	107.72	109.88
Technology REP ($/MWh)						
FACILITY OPERATIONS	200.00	200.00	200.00	200.00	200.00	200.00
Installed Capacity (MW)	700,800	700,800	700,800	700,800	700,800	700,800
Generation Output (MWh)						
INCOME STATEMENT	$69,743,351	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
Revenue	($20,276,998)	($20,682,538)	($21,096,189)	($21,518,112)	($21,948,475)	($22,387,444)
Operating Costs	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Book Depreciation	($1,399,744)	$0	$0	$0	$0	$0
Interest	$0	$0	$0	$0	$0	$0
Property Tax (incl in FOM)	($11,867,039)	($12,538,672)	($12,847,451)	($13,157,753)	($13,469,985)	($13,784,533)
Income Tax	**$17,325,248**	**$19,042,687**	**$19,743,021**	**$20,462,015**	**$21,199,664**	**$21,955,996**
NET INCOME						
BALANCE SHEET						
Assets	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Gross Plant	($377,486,422)	($396,360,743)	($415,235,064)	($434,109,385)	($452,983,706)	($471,858,027)
Accumulated Depreciation	$94,371,605	$75,497,284	$56,622,963	$37,748,642	$18,874,321	$0
Net Plant	$0	$0	$0	$0	$0	$0
Work In Progress	$0	$0	$0	$0	$0	$0
Cash	**$94,371,605**	**$75,497,284**	**$56,622,963**	**$37,748,642**	**$18,874,321**	**$0**
TOTAL						
Liabilities and Equity						
Short Term Liabilities	($0)	($0)	($0)	($0)	($0)	($0)
Long Term Liabilities	$94,371,605	$75,497,284	$56,622,963	$37,748,642	$18,874,321	$0
Equity and Retainted Earnin	**$94,371,605**	**$75,497,284**	**$56,622,963**	**$37,748,642**	**$18,874,321**	**$0**
TOTAL	0	0	0	0	0	0
Check						
CASH FLOW STATEMEN						
Cash Flow from Operatio	$69,743,351	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
REP Revenue	$0	$0	$0	$0	$0	$0
Variable Operting Cost	($1,429,307)	($1,457,893)	($1,487,051)	($1,516,792)	($1,547,127)	($1,578,070)
Revenue Sharing	($18,847,691)	($19,224,645)	($19,609,138)	($20,001,321)	($20,401,347)	($20,809,374)
Fixed Operating Costs	($1,399,744)	$0	$0	$0	$0	$0
Interest paid	$0	$0	$0	$0	$0	$0
Property Tax	($11,867,039)	($12,538,672)	($12,847,451)	($13,157,753)	($13,469,985)	($13,784,533)
Income Tax	**$36,199,569**	**$37,917,008**	**$38,617,342**	**$39,336,336**	**$40,073,985**	**$40,830,317**
TOTAL						
Cash Flow from Investme	$0	$0	$0	$0	$0	$0
Capital Investment	$0	$0	$0	$0	$0	$0
Interest During Constructio	$0	$0	$0	$0	$0	$0
TOTAL						
Cash Flow From Financi	($10,749,674)	($37,917,008)	($38,617,342)	($39,336,336)	($40,073,985)	($40,830,317)
Cash Flow to Owners	$0	$0	$0	$0	$0	$0
Borrowing	($25,449,895)	$0	$0	$0	$0	$0
Debt repayment	**($36,199,569)**	**($37,917,008)**	**($38,617,342)**	**($39,336,336)**	**($40,073,985)**	**($40,830,317)**
TOTAL						
Change in Cash	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT						
Opening Balance	$25,449,895	($0)	($0)	($0)	($0)	($0)
Borrowing	$0	$0	$0	$0	$0	$0
Repayment	$25,449,895	$0	$0	$0	$0	$0
Interest	$1,399,744	($0)	($0)	($0)	($0)	($0)
Closing Balance	($0)	($0)	($0)	($0)	($0)	($0)
check	26,849,639	0	0	0	0	0
INCOME TAXES						
Revenue	$69,743,351	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
Expenses	($21,676,742)	($20,682,538)	($21,096,189)	($21,518,112)	($21,948,475)	($22,387,444)
8% CCA Rate	($2,423,677)	($2,229,783)	($2,051,400)	($1,887,288)	($1,736,305)	($1,597,401)
50% CCA Rate	($472)	($236)	($118)	($59)	($30)	($15)
Taxable Income	**$45,642,459**	**$48,225,661**	**$49,413,275**	**$50,606,742**	**$51,807,636**	**$53,017,435**
Tax	($11,867,039)	($12,538,672)	($12,847,451)	($13,157,753)	($13,469,985)	($13,784,533)
UCC 8% Plant	$27,872,284	$25,642,501	$23,591,101	$21,703,813	$19,967,508	$18,370,107
UCC 50% Plant	$472	$236	$118	$59	$30	$15
Income Tax Rate	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin	$69,743,351	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
Debt Service Coverage						
Debt Service	$26,849,639					
Cash Flow	$37,599,313					
Coverage Ratio	1.40					