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August 30, 2017

To BCUC, Attention, Chair of Site C Review Panel, David Morton

Please find attached the expert submission to this proceeding of energy economist Mr. Robert McCullough. The Peace Valley Landowner Association and the Peace Valley Environment Association both have a strong interest in the careful and transparent determination of the questions before the BCUC based upon the best and most up to date evidence. To that end, our organizations have jointly retained Mr. McCullough to provide specific evidence and analysis on key issues, and in particular on terms of reference sections 3(a)(i) (implications of completing Site C by 2024), 3(b)(iv) (portfolio of alternatives to Site C) and 3(c) (factors influencing demand and BC Hydro's load forecast). As Mr. McCullough's CV (attached), demonstrates, his expertise in North American energy markets and infrastructure is well recognized, and in his 37-year career, he has been relied upon as an energy consultant and as an expert before both U.S. and Canadian courts, regulatory bodies, and legislatures. He has also testified before the U.S. House and Senate on six occasions. His testimony in front of the Senate Energy Committee is credited with initiating the Enron trading investigations during which he worked for the U.S. Department of Justice and three western attorneys general.

Mr. McCullough's experience and knowledge is directly applicable to the matters before the BCUC, and we respectfully submit his report for this Panel's consideration.

Regards,

Ken Boon President, Peace Valley Landowner Assoc.

Regards,

Ruth Ann Darnall

Ruth Ann Darnall President, Peace Valley Environment Assoc.

ROBERT F. MCCULLOUGH, JR.
PRINCIPAL

Date: August 30, 2017

To: British Columbia Utility Commission

From: Robert McCullough

Subject: Costs of Continuing Site C and the Alternatives

Professional Qualifications

My qualifications for providing this submission are summarized in my curriculum vita attached below.

My career has spanned thirty-seven years and included management at a hydroelectric base utility, consulting for U.S. and Canadian clients on hydroelectric issues in many states and provinces including British Columbia, Manitoba, Ontario, Quebec, and Nova Scotia. I have testified as an expert in both U.S. and Canadian courts, regulatory bodies, and legislatures. I have testified before the U.S. House and Senate on six occasions. I have also written and presented on issues currently before the BCUC on many occasions.

Introduction

On August 2, 2017 Order in Council 244 set out the terms of reference for an inquiry into Site C, which include:

> The terms of reference in accordance with which the commission must inquire into the matter referred to it by section 2 are as follows:
> (a) the commission must advise on the implications of
> **(i) completing the Site C project by 2024, as currently planned**,
> (ii) suspending the Site C project, while maintaining the option to resume construction until 2024, and
> (iii) terminating construction and remediating the site;
> (b) more specifically, the commission must provide responses to the following questions:
> (i) After the commission has made an assessment of the authority's expenditures on the Site C project to date, is the commission of the view that the authority is, respecting the project, currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?

> (ii) What are the costs to ratepayers of suspending the Site C project, while maintaining the option to resume construction until 2024, and what are the potential mechanisms to recover those costs?
> (iii) What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs?
> **(iv) 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**
> (c) in making applicable determinations respecting the matters referred to in paragraphs (a) and (b), the commission must use the forecast of peak capacity demand and energy demand submitted in July 2016 as part of the authority's Revenue Requirements Application, and must require the authority to report on developments since that forecast was prepared that will impact demand in the short, medium and longer terms, and other factors that could reasonably be expected to influence demand from the expected case toward the high load or the low load case;[1]

This submission addresses Sections (a)(i), (b)(iv), and (c) of the terms of reference.

(a)(i) completing the Site C project by 2024, as currently planned

Site C is an expensive undertaking. Similar endeavors in other Canadian provinces provide a cautionary tale concerning the risks of pursuing projects that cost a multiple of other alternatives. The body of this submission contains a case study of the problems facing Manitoba Hydro from a similar project as reported in their current regulatory submissions.

Key findings –

- Manitoba Hydro faces a serious risk of a crown corporation bankruptcy.
- BC Hydro is taking on a similar level of debt, pursuing a similar strategy, but BC Hydro is doing so with a worse financial position than Manitoba Hydro had when it began placing bets on expansion.

(b)(iv) 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

[1] http://www.bcuc.com/Documents/SpecialDirections/2017/08-02-2017-OIC-244.pdf.

Alternatives to Site C have expanded in scale while declining precipitously in price since the studies submitted by British Columbia Hydro in the environmental process. **Renewable prices have fallen by 74% for solar and 65% for wind since 2010, when the BC Government announced it wished to pursue approval and development of Site C.** The body of this report contains two sections on (b)(iv): Falling Prices of Renewable Generation; and, Greenhouse Gas Estimates for Reservoirs. Since British Columbia is not isolated from its surroundings in terms of both reliability and markets, a section entitled "Economic and Reliability Context" has also been added to provide British Columbia Hydro's actual operating environment.

Key Findings –

- Renewables now have lower costs than hydro power.
- BC Hydro will not be able to sell its surplus electricity at prices that will insolate BC ratepayers from these high costs.

The following information was requested from BC Hydro but has not yet been made available for public review:

1) BC Hydro's long-term forecast of U.S. capacity and energy prices by year

2) BC Hydro's updated long-term forecast of LNG demand in British Columbia

3) BC Hydro's updated forecast of solar and wind energy costs in British Columbia

Based on my review of publicly available information regarding Site C and the extensive documentation of available alternatives, it is my professional opinion that a portfolio of solar and wind could meet the power needs of BC at significantly less than the cost of Site C. The so often referred to problem of intermittency is solved by the very high reserve margin in the Northwest Power Pool, which means intermittent resources can be stored with available and replaced from storage when not available. It is beyond the scope of this report to propose detailed proposals for alternatives, but based on my 37 years of experience in energy projects across Canada and North America, I am confident that BC Hydro, if instructed to so by the BC government, can develop an alternative power generation portfolio that meets or exceeds firming; shaping; storage; grid reliability; and 2016/17 greenhouse gas emission targets forecast for Site C. It can do so at a cost much lower than Site C, after taking into account both costs to date and decommissioning costs.

3(c) …the commission must use the forecast of peak capacity demand and energy demand submitted in July 2016 as part of the authority's Revenue Requirements Application, and must require the authority to report on developments since that forecast

was prepared that will impact demand in the short, medium and longer terms, and other factors that could reasonably be expected to influence demand from the expected case toward the high load or the low load case;

Technological change has not been restricted to just generation alternatives. British Columbia Hydro's load forecast have also become dangerously vintage. The section entitled "Industrial Load Forecasts" addresses the decreasing viability of the numerous proposed LNG terminals in British Columbia and Oregon as well as the precipitous decline in paper production – especially newsprint – across North America.

Key Findings –

- Using a Monte Carlo analysis of prices and costs, the probability BC Hydro's forecast of LNG industry electricity consumption in British Columbia is only 3%.
- This previously expected growth in demand, that has little chance to exist, makes up more than half of Site C's electric generation capacity.
- The pulp and paper industry's load demands will decline, not grow.

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List of Figures:

Economic and Reliability Context

Canada and its southern neighbors share an integrated electric system with respect to both economics and reliability. Reliability concerns are addressed on a regional basis and have been so for many years. Despite the self-sufficiency objective in the Clean Energy Act, BC Hydro neither is, nor can be isolated from the integrated electrical system. A significant part of BC Hydro's case for Site-C involves selling the excess energy and capacity into this integrated market, and the Act also sets as a goal having BC as a net exporter of energy. It is therefore important to examine the relative cost of Site C power within the integrated system.

Traditionally, Canadian crown corporations have overbuilt, relying on U.S. markets for revenues for their surplus electricity. Unfortunately, this strategy is no longer effective as the prices for Canadian exports have declined significantly.

Levelized Cost of Energy (LCOE)

Given the schedule of this review, detailed information on the costs of proceeding with Site C will not be known until the end of August. Absent detailed data, all estimates of the Levelized Cost of Energy are estimated.

The U.S. Energy Information Administration (EIA) defines LCOE as:

> [LCOE] represents the per kilowatt hour cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[2]

The LCOE is estimated by calculating the cost per kilowatt of installed capacity, which is $8,000/kW, and then reducing this value to 2016 dollars and reducing the result by 25% to reflect sunk investments.[3] The result is approximately 31% more than the generic hydroelectric project costs estimated by the EIA.[4]

Using this standard methodology and a C$8.8 billion total cost, Site C's LCOE is C$105/MWh. However, we can impose an optimistic assumption into this estimate by not adjusting non-capital costs for the relative expense of Site C. This assumption would reduce Site C's LCOE to C$101/MWh.

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[2] Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017, EIA, April 2017, page 7.
[3] (C$8.8 billion construction cost) / (1,100 MW) = C$8,000 kw
[4] Capital Cost Estimates for Utility Scale Electricity Generating Plants, EIA, November 2016, page 9.

While this is just an estimate based on the limited information available today, it is worth noting that this value is significantly higher than market and renewables prices. For example, Wall Street estimates of actual costs for wind at C$ 40-77.50/MWh and solar C$ 57.50-76.25/MWh.[5] Currently quoted prices for Mid-Columbia are even lower on the Intercontinental Exchange (ICE).[6]

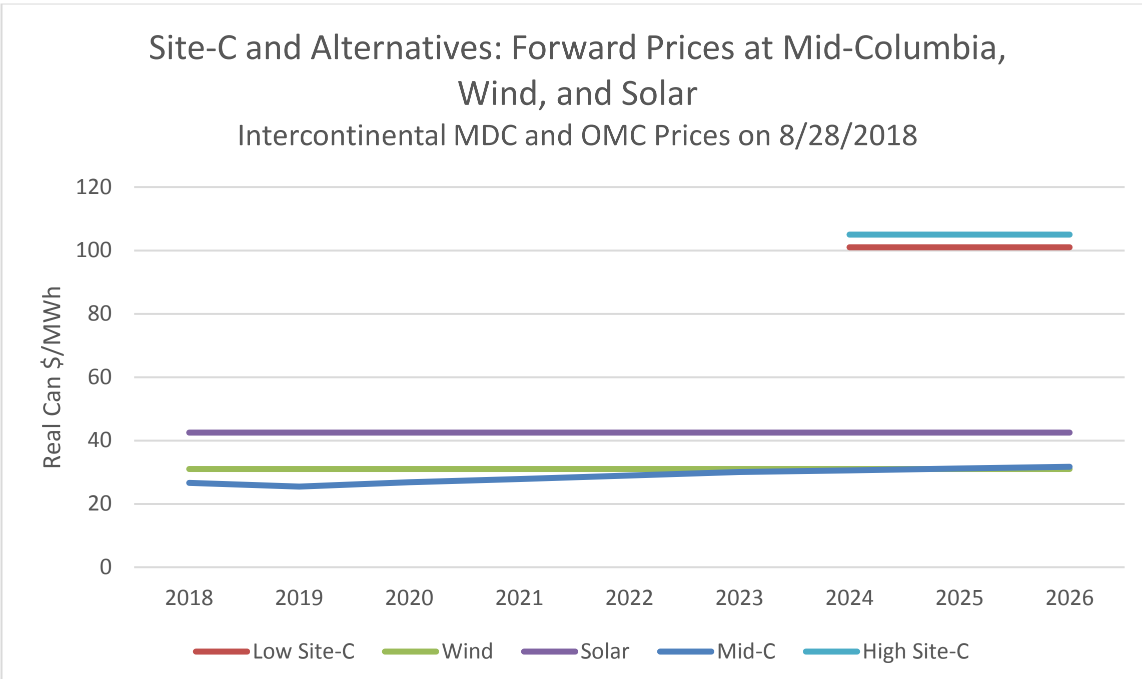


Figure 1: Site C and alternatives

Reliability and Reserve Margins

British Columbia Hydro is a member of the Northwest Power Pool (NWPP).[7] The Northwest Power Pool is one of the component regions of the Western Electricity Power Pool (WECC). Reliability standards are set by the North American Electric Reliability Corporation (NERC). If BC Hydro could not depend on its neighbor for planning and reliability, costs would be significantly higher, violating objective 2(f) of the Clean Energy Act, as would be the probability of outages.

[5] Lazard, "Levelized Cost of Energy Analysis," December 2016.
[6] MDC and OMC prices as of August 28, 2017.
[7] The Northwest Power Pool (Power Pool) sub-region has 22 Balancing Authority Areas and is comprised of all or major portions of the states of Washington; Oregon; Idaho; Wyoming; Montana; Nevada; and, Utah; a small portion of Northern California; and, the Canadian provinces of British Columbia and Alberta.

Detailed reliability documents are prepared by utilities, NWPP staff, WECC staff, and NERC.[8,9,10] The NWPP utilities enjoy a very favorable reserve margin:

NWPP: Case 1 – Existing/Class 1 Resources Winter	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Net Internal Demand	71,071	71,945	72,844	73,504	74,122	75,069	75,722	76,308	76,994	77,374
Anticipated Internal Capacity	88,752	89,866	90,412	90,470	90,753	91,065	91,475	91,471	90,634	90,575
Wind Expected On-Peak MW	3,006	3,515	3,865	3,867	3,869	3,870	3,872	3,881	3,882	3,884
Percentage of Capacity	21.5%	23.4%	22.5%	22.5%	22.5%	22.5%	22.5%	22.4%	22.4%	22.4%
Solar Expected On-Peak MW	0	0	0	0	0	0	0	0	0	0
Percentage of Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro Expected On-Peak MW	34,358	34,379	34,400	34,488	34,382	34,386	34,392	35,385	35,838	35,841
Percentage of Capacity	65.1%	64.8%	64.6%	64.7%	64.5%	64.4%	64.4%	64.9%	65.1%	65.1%
Imports	6,760	6,700	6,800	6,766	7,517	8,188	8,598	8,694	8,966	9,419
Exports	1,700	0	0	0	0	0	0	100	993	1,161
Anticipated Resource Reserve Margin MW	5,812	5,906	5,403	4,690	4,252	3,459	3,107	2,419	782	279
Anticipated Resource Reserve Margin %	24.9%	24.9%	24.1%	23.1%	22.4%	21.3%	20.8%	19.9%	17.7%	17.1%

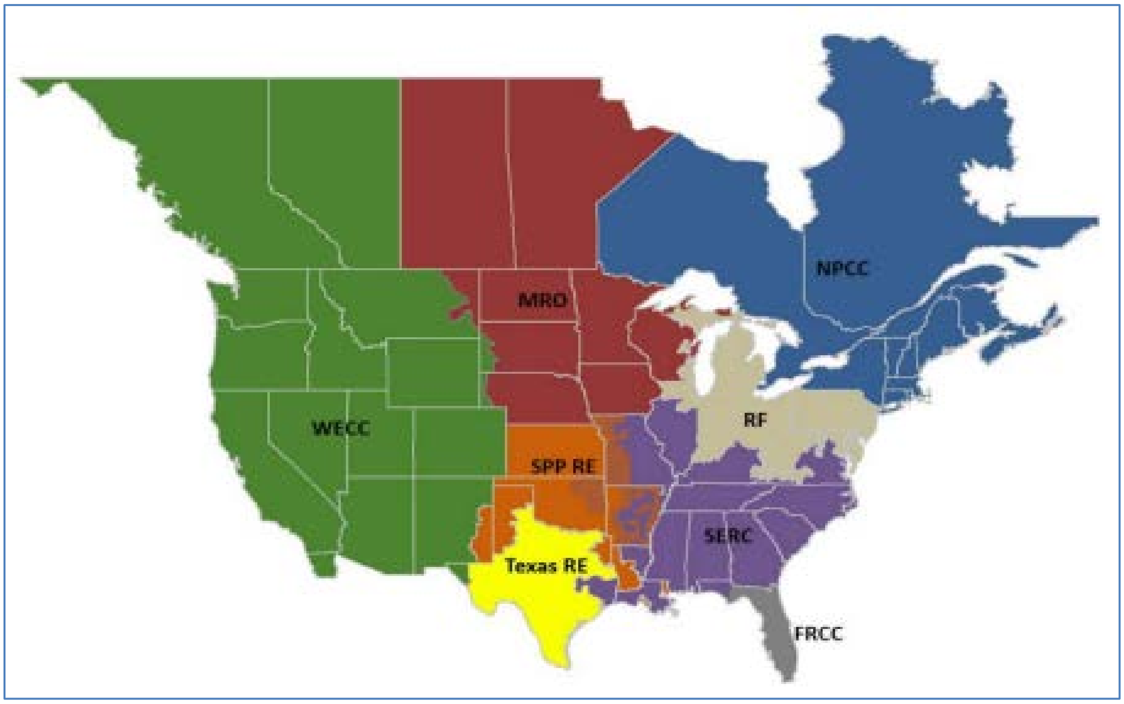
Figure 3: 2017 NWPP Winter Reserve Margins[11]

While it would be possible for every member of the Northwest Power Pool to meet reliability standards by assuming that reliability sharing protocols did not exist, the reality is that they do exist and have existed since the beginning of the NWPP in 1942. This means BC Hydro is connected to a reliability area with extremely favorable reserve margins, and does not need to incur costs as if it has no additional capacity.

Market Prices

As a general rule, the reliability areas like the NWPP define market hubs. In our case, the major market hubs are Mid-Columbia (electricity) and Malin (natural gas):

8 NERC, "2016 Long-Term Reliability Assessment," December 2016.
9 WECC, "2016 Power Supply Assessment," December 2016.
10 NWPP, "Northwest Power Pool Area Assessment of Reliability and Adequacy 2016-2017," October 17, 2016.
11 Ibid, page 12.



[12]

Figure 2: Primary North American Trading Hubs

Additional market hubs relevant to British Columbia are AECO – Alberta wholesale natural gas prices – and Sumas – at the Canadian border with Washington State.

[12] https://www.eia.gov/electricity/wholesale/.

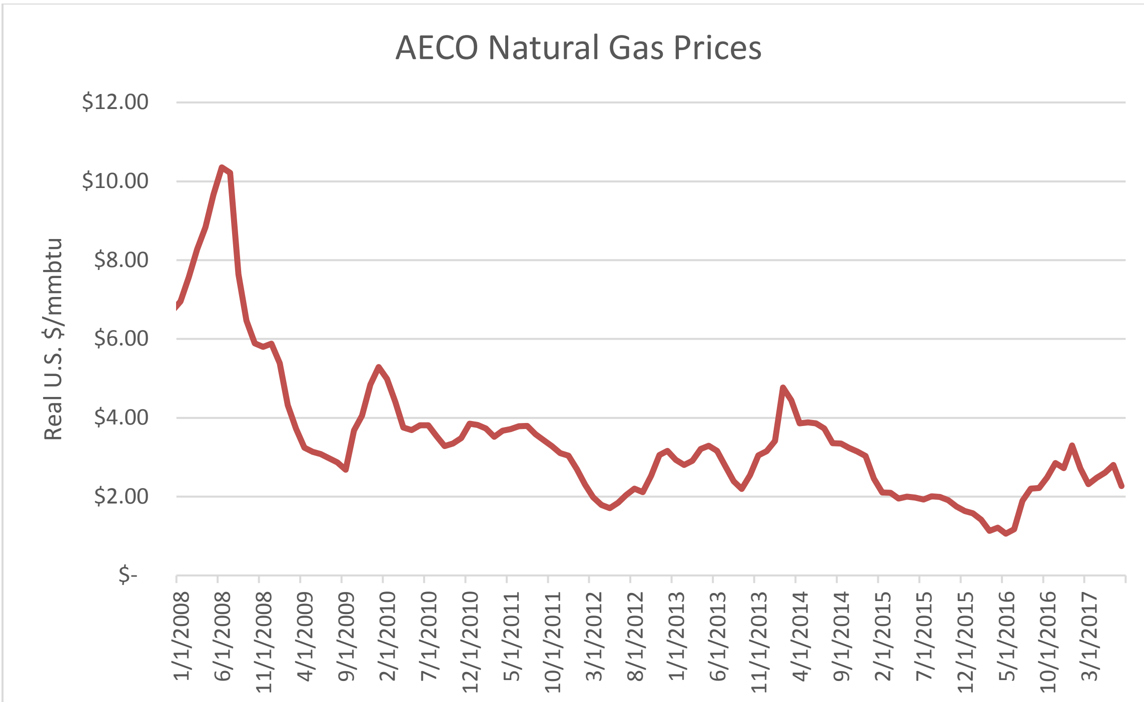
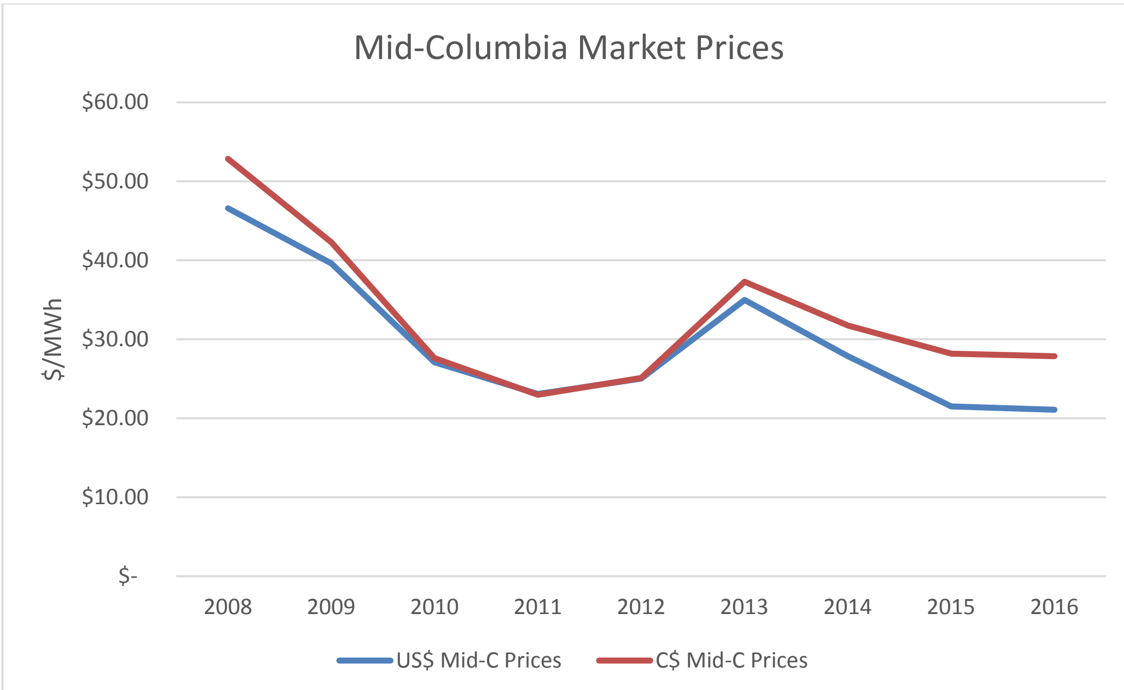


Figure 3: AECO Natural Gas Prices

Market prices over the last decade have fallen dramatically as a variety of new technologies have come to dominate the market. New methods of extracting natural gas have had an impact across North America. In addition, the rapid increase of renewable resources and shifts to LED lighting have reduced demand and the use of expensive fossil fuels. The last two coal units in Oregon and Washington are scheduled for closure over the next decade as well as coal units across the United States. While environmental concerns are important, coal units are facing closure from less expensive and more efficient technologies.



[13]

Figure 4: Mid-Columbia Market Prices

It's worth saying again for emphasis, Canadian crown corporations have long had a strategy of overbuilding, relying on U.S. markets for revenues for their surplus electricity. Unfortunately, this strategy is no longer effective as the prices for Canadian exports have also declined significantly. This was worth repeating, because institutional habits are slow to change.

[13] Real Dow Jones and Platt's price indices.

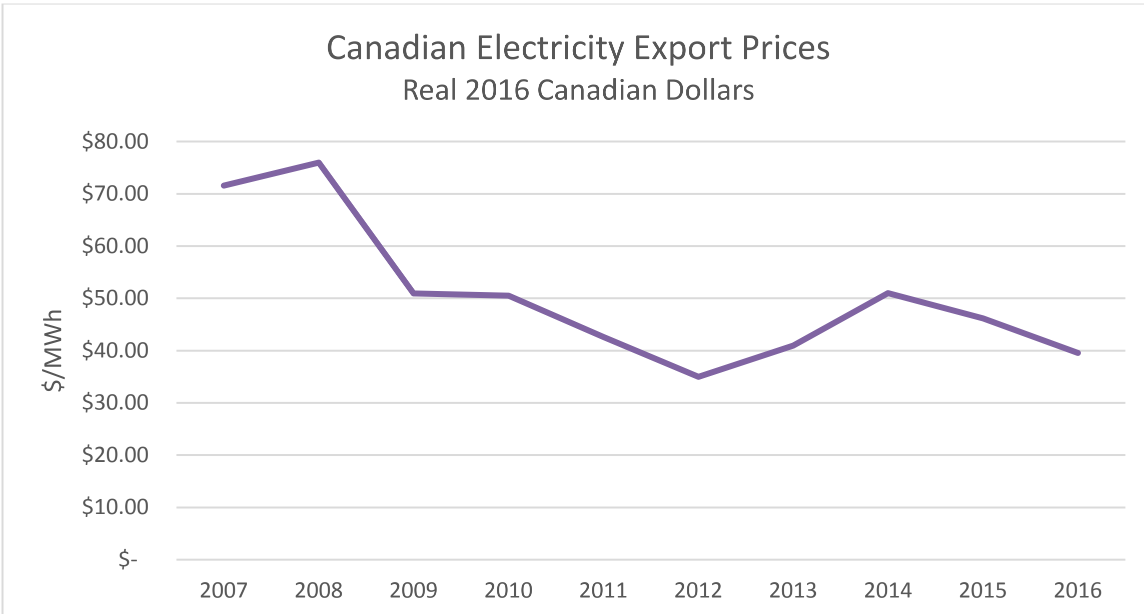


Figure 5: Canadian Electricity Export Prices

British Columbia has fared better than some and worse than others during the same period:

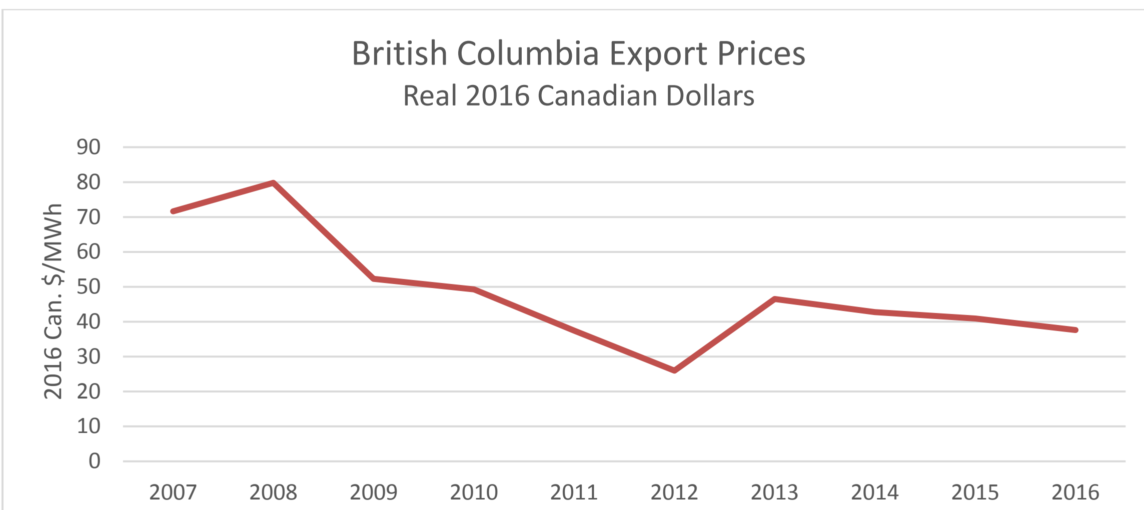


Figure 6: British Columbia Export Prices

After the peak prices in 2008, British Columbia's real export prices have declined 52.8%. These prices have continued to drop since the last report from the Joint Review Panel.[14]

Transmission Access

British Columbia enjoys excellent transmission access to the Mid-Columbia hub. The annual WECC report provides high-level charts of transmission capacity across the west coast of the U.S. and Canada.

The Western portion of the United States includes the Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA) and the Arizona, New Mexico, Southern Nevada Power Area (AZ/NM/SNV) within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain many balancing authorities responsible for transmitting generation.

The NWPP is composed of all or major portions of the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada and Utah, a small portion of Northern California and the Canadian provinces of British Columbia and Alberta. There is nearly 80 GW of generation capacity in the NWPP, which includes 43 GW of hydroelectric generation.

British Columbia's summer and winter access to the U.S. markets is 2,000 megawatts:

[14] Joint Review Panel, "Report of the Joint Review Panel: Site-C Clean Energy Project BC Hydro" May 1, 2014.

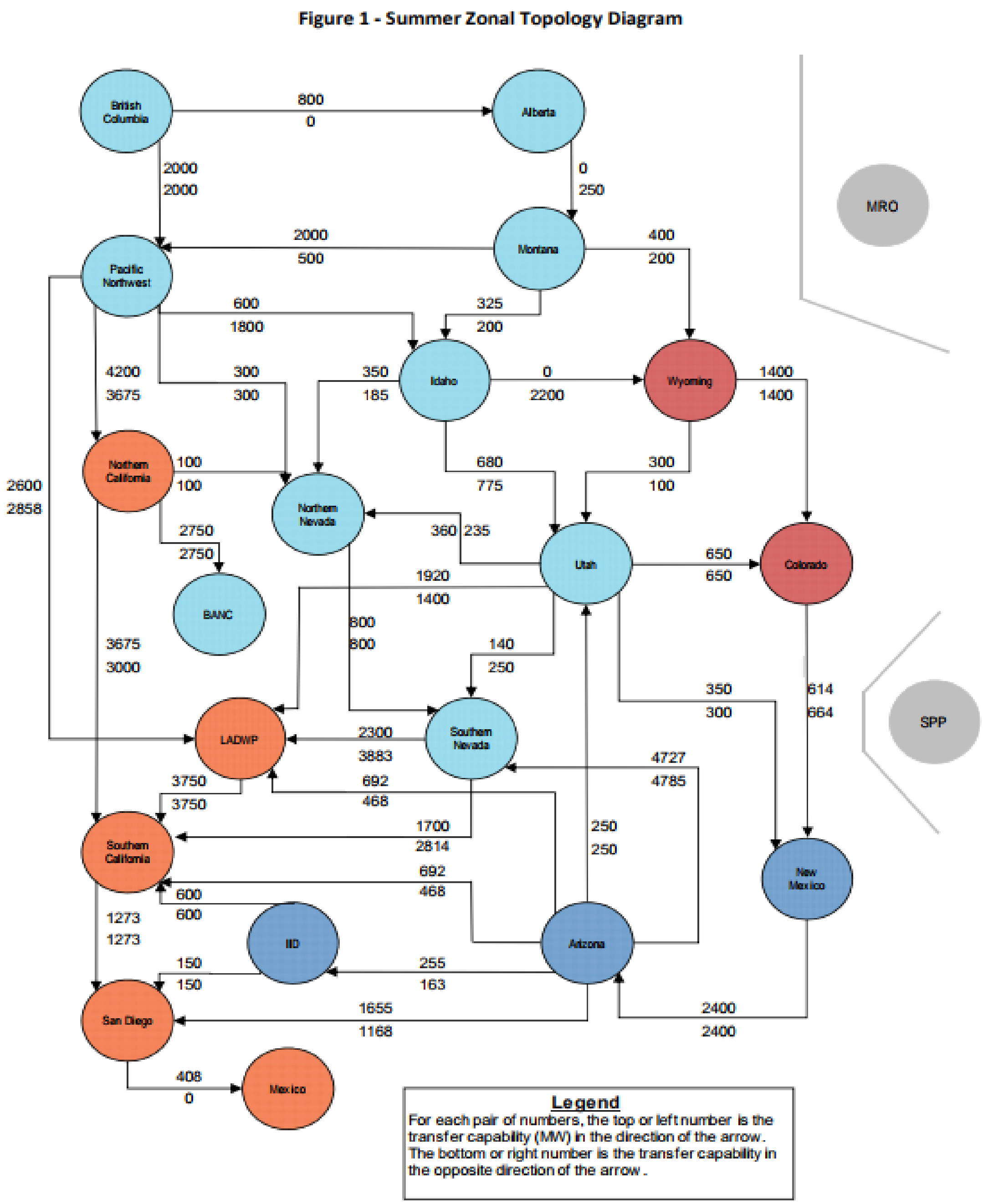


Figure 7: WECC Summer Transmission Capacity Limits[15]

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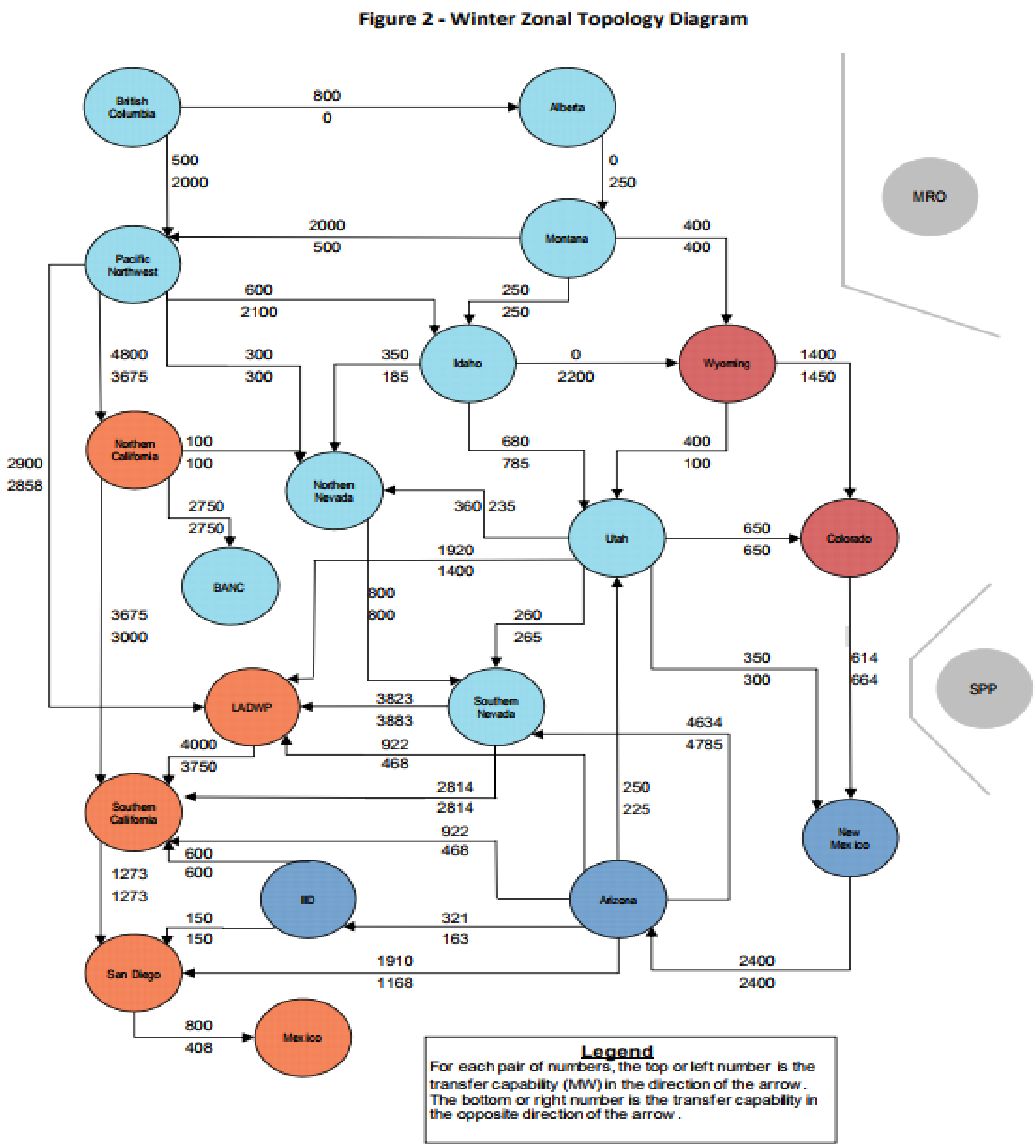
[15] WECC, "2016 Power Supply Assessment," December 2016, page 19.

Winter capacity is also not constrained to British Columbia:



[16]

Figure 8: WECC Winter Transmission Capacity Limits

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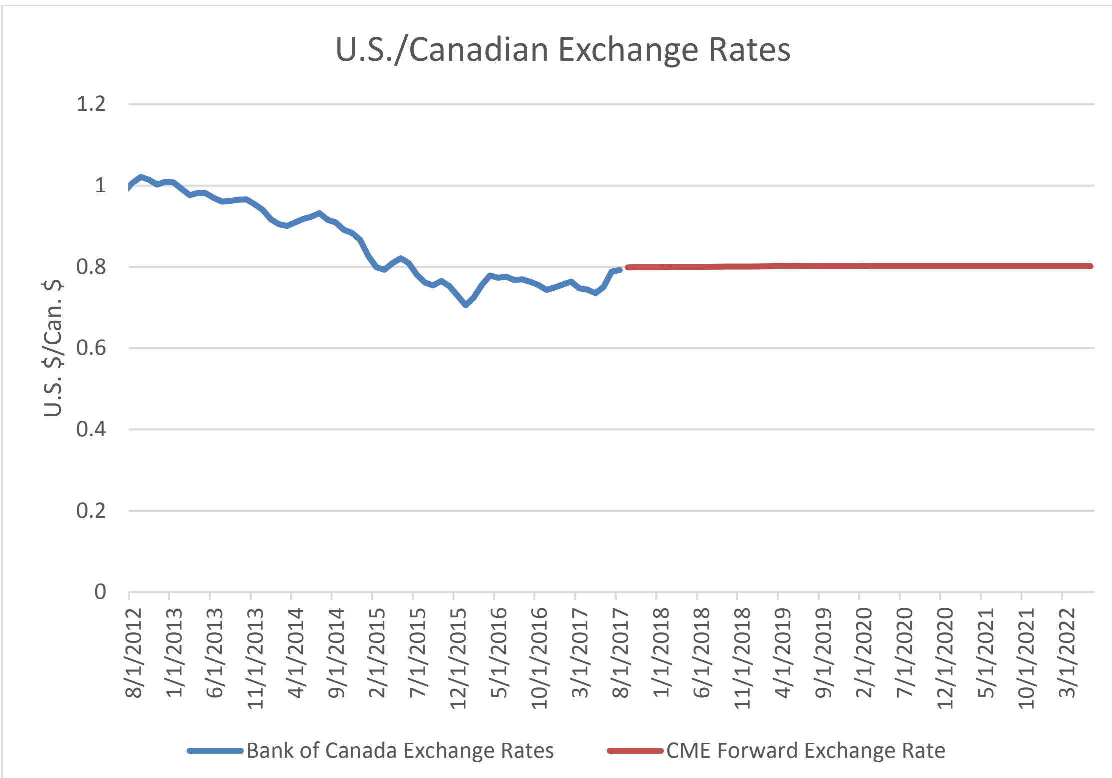
[16] Ibid, page 20.

Exchange Rates

Exchange rates have gradually declined over the past decade with a small recover in 2017. Exchange rate futures are quoted on a number of exchanges. The following chart shows historical rates from the Bank of Canada and forward rates from the Chicago Mercantile Exchange:



[17]

Figure 9: U.S. Canadian Exchange Rates from 2012 through 2024

What financial markets make clear is that BC Hydro's higher costs will not be subsidized by a favorable exchange rate.

[17] http://www.bankofcanada.ca/rates/exchange/daily-exchange-rates/ http://www.cmegroup.com/trading/fx/g10/canadian-dollar.html.

Lessons from Manitoba Hydro's Financial Problems

Recent regulatory hearings in Manitoba are a case study for what decision makers may expect if Site C, Magpie, Petit Mecatina, and Muskrat Falls projects go forward.[18] BC Hydro's finances are already a cause for concern.

In 2011, the British Columbia Auditor General noted that in a number of areas Manitoba Hydro's financial situation is actually better than BC Hydro's. It was discovered that the deferral of BC Hydro's expenses had "greatly exceeded that of both Quebec and Manitoba for the same five-year period" it studied.[19] This report found BC Hydro had accumulated a deferred expense balance of C$4.9 billion through 2017.

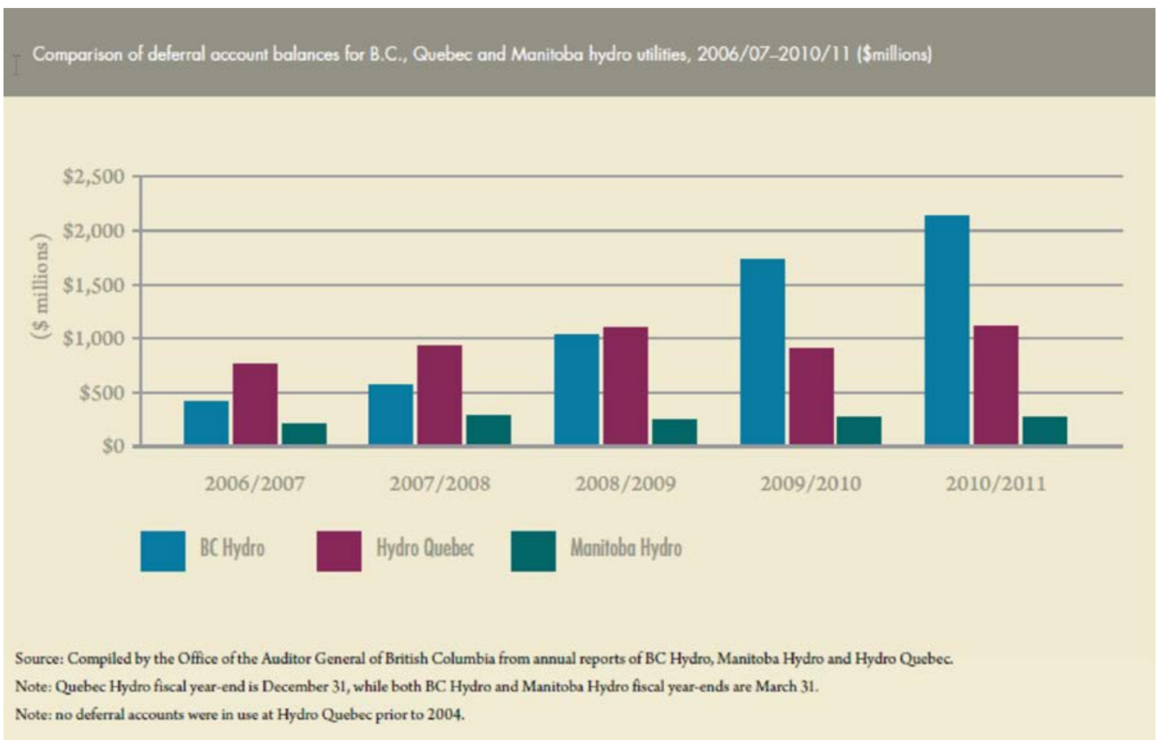


Figure 10: Comparison of deferral account balances for B.C., Quebec and Manitoba Hydro

The significance of this financial engineering was published in BC Studies years later by a former BC Treasury official. [20] If these expenses were not deferred, BC Hydro would have

[18] Site-C is in British Columbia. Magpie and Petit Mecatina are unannounced projects in Quebec. Muskrat Falls is in Newfoundland.
[19] Office of the Auditor General of British Columbia, "BC Hydro: The Effects of Rate-Regulated Accounting," October 2011 page 19.
[20] McCandless, Richard, "Rate Suppression and Debt Transformation: the Political Use of BC Hydro, 2008-2014," BC Studies, Summer 2017.

reported approximately C$3.1 billion less in accumulative net income which would have led to operating losses in 2010 and 2013.[21]

On July 31, 2017, the Manitoba Public Utility Board rejected a request for an interim 7.9% rate increase, allowing only 3.36%.[22] Manitoba Hydro is requesting an annual 7.9% rate increase in an ongoing general rate case for the next two years and forecasting another three years following thereafter.

Manitoba Hydro gambled on major generation and transmission upgrades a decade ago. Although their forecasts indicated increasing U.S. wholesale prices, market opportunities have decreased dramatically as new technologies in natural gas and renewables offer much cheaper alternatives. This effect is not restricted to Manitoba. Overall, real Canadian electric export prices have declined 45% over the past decade.

The consequences of Manitoba Hydro's gamble should have been no surprise to the executive suite at Manitoba Hydro. A 2007 study by Nalinaksha Bhattacharyya advised them how to quantify export market risks.[23] Manitoba Hydro later commissioned ICF International to directly weigh whether or not to depend on the export market. Manitoba Hydro's risk manager during the period, Samantha Kumaran, also issued similar warnings before she was dismissed.[24]

ICF International concluded that, according to the information available at the time, the probability of the benefits appeared to outweigh the probability of the costs, but this research also warned: "Another large risk to the financial performance of Manitoba Hydro is uncertainty and the associated volatility in wholesale power prices. Thus, the Corporation not only faces volume risk related to a drought, but also price risk with respect to exports."[25]

The need to export at high prices becomes critical if a company has racked up enormous levels of debt to cover the capital expenditures. Manitoba Hydro has paid dearly in recent years on new capital projects. Clocking in at C$5 billion, the Bipole III transmission line's costs continue to grow past prior estimates.[26] The cost estimate for the still-incomplete Keeyask dam is now C$8.7 billion.[27]

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[21] McCandless, Richard, "Rate Suppression and Debt Transformation: The Political Use of BC Hydro, 2008-2014," BC Studies, Summer 2017, page 31.

[22] An Application By Manitoba Hydro FOR A 7.9% Interim Rate Increase Effective August 1, 2017, Manitoba Public Utilities Board, July 31, 2017.

[23] Bhattacharyya, Nalinaksha. "Report on Risks Faced by Manitoba Hydro in Power Exports" July 4, 2007.

[24] A Star Group V Manitoba Hydro Order and Opinion, U.S. District Court Southern District of New York, June 30, 2014, page 3.

[25] ICF International. "Independent Review of Manitoba Hydro Export Power Sales and Associated Risks", September 11, 2009.

[26] CBCNews. "Bipole III route a mistake that can't be changed, Manitoba Hydro board says.", September 21, 2017.

[27] "Building a Strong Energy Future: Manitoba Hydro-Electric Board 66th Annual Report, July 28, 2017.

Manitoba Hydro's financial forecasts indicate that long term increases at 7.9% per annum will be required to remain solvent. The following charts show the no rate increase case (MH15), the current forecast with a 3.95% increase (MH16 at MH15 3.95% Rate Increases), and a series of 7.9% increases over the next five years and 2% increases for the following five years (MH16).[28] The base case – MH16 – would raise rates in Manitoba by 53% by 2022.

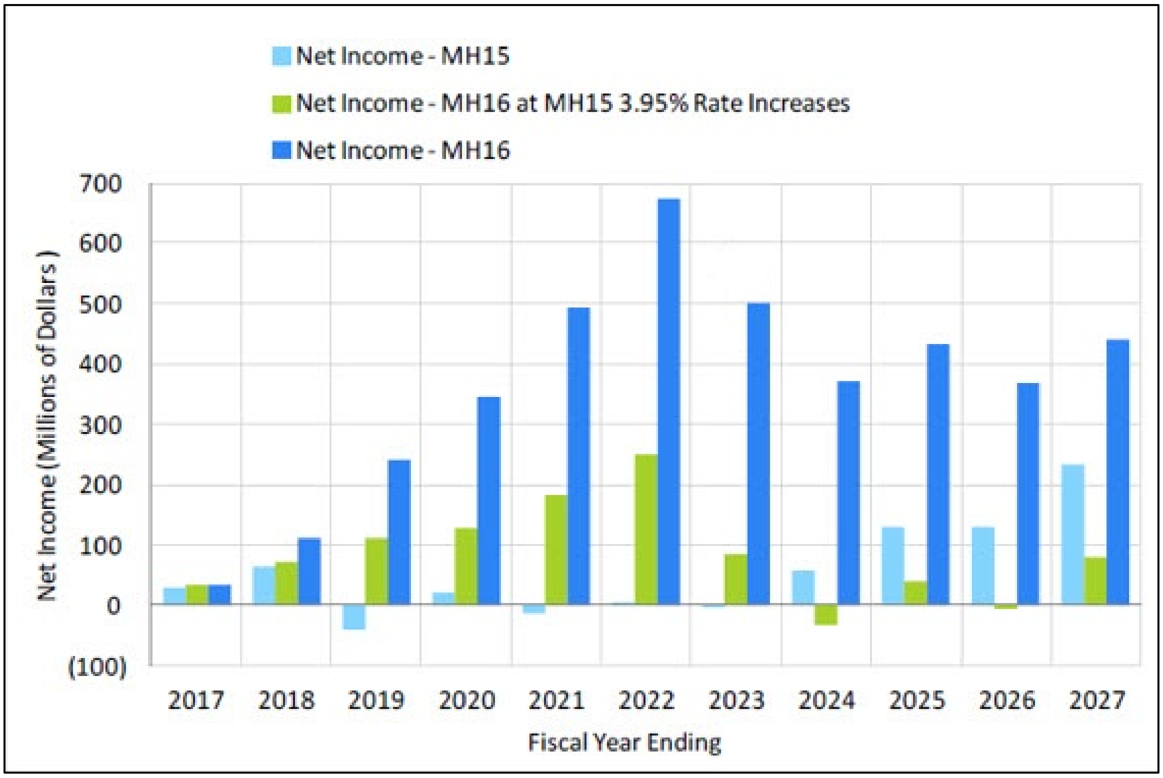

Figure 11: Manitoba Hydro Net Income

From the perspective of their cash flow, things appear even bleaker:

[28] Manitoba Hydro. "2017/18 & 2018/19 General Rate Application Integrated Financial Forecast", May 12, 2017, page 7.

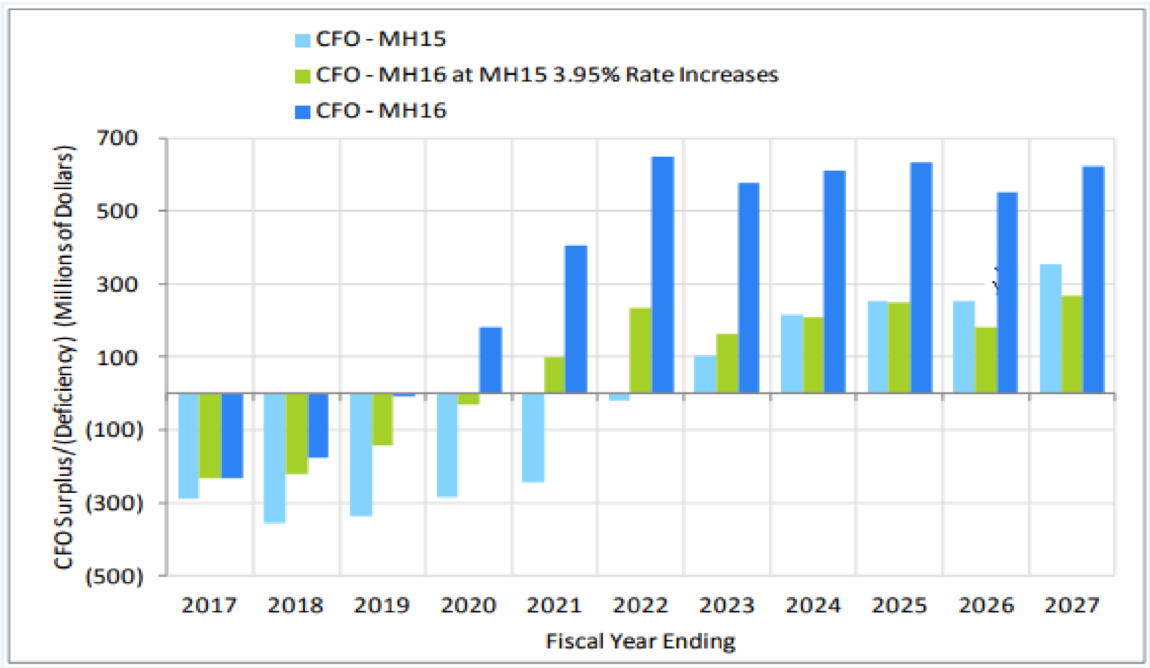

Figure 12: Manitoba Hydro Cash Flows

Net equity in Manitoba Hydro is forecasted to remain below target levels even after years of 8.9% rate increases:

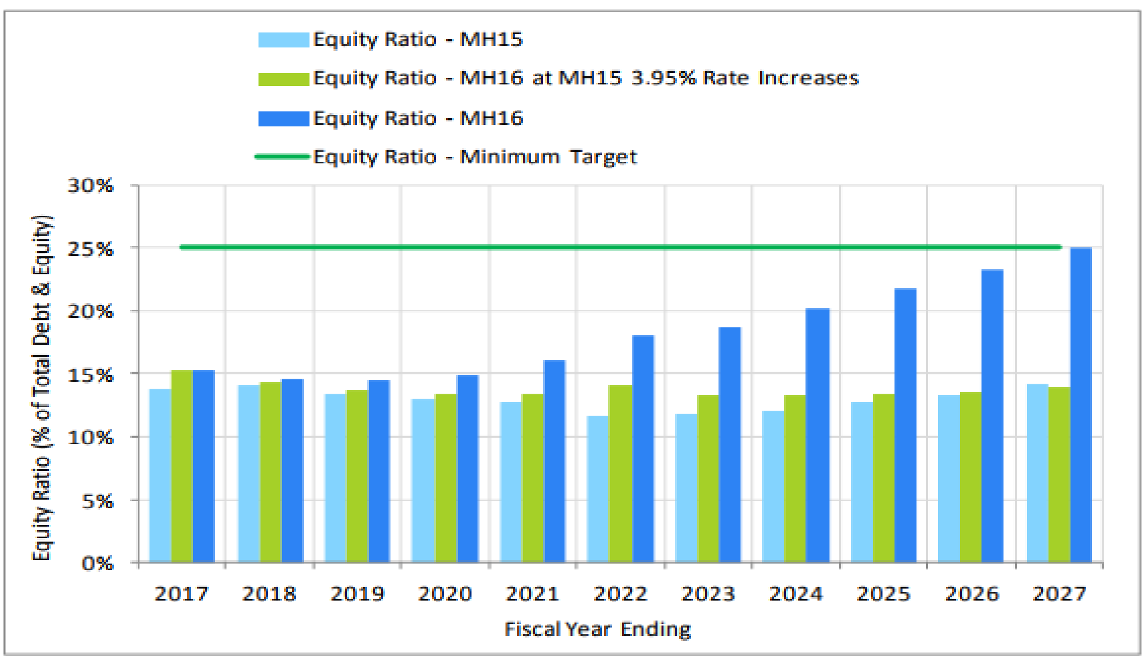

Figure 13: Manitoba Equity Target Levels

The proposed rate increases are a result of Manitoba Hydro being "[unprepared] to absorb the significant increase in operating and borrowing costs that result from the completion of major capital projects currently underway."[29]

So far, Manitoba Hydro has stated to the PUB that Bipole III and the Keeyask dam have experienced cost overruns of C$300 million and C$500 million, respectively. Those overruns will contribute nearly C$1 billion in new debt payments.[30] In order to stay solvent, Manitoba Hydro is planning to increase residential rates by 7.9% annually for the next five years.[31]

The probability of higher interest rates and lower water levels are not exactly black swan events. Financial prudence should compel a crown corporation of Manitoba Hydro's prominence to be prepared for even lower probability risks of this high an impact. Instead, large capital projects have made them vulnerable to an all too likely eventual change in circumstances.

Manitoba Hydro's wager that export prices would be high continues to be problematic since have declined 7.4% since construction began on the Keeyask dam in 2016.[32]

Manitoba Hydro knew about the market risks associated with relying on exports to the Midwest.[33] When Keeyask was planned a decade ago, forecasted peak prices were almost three times what they are today.[34] Moreover, current electricity price forecasts don't predict a return to the higher prices Manitoba Hydro predicted when these projects commenced.[35]

In its General Rate Application, Manitoba Hydro makes it very clear to regulators that it has the tendency to over-estimate export prices, explaining to its PUC why Manitoban rate payers need to pay more:

> The reduction in export prices accounts for about $1.1 billion of the cumulative 10 reduction of net extraprovincial revenues over the 10-year forecast period to 2026/27. MH16 reflects electricity export prices that are lower by approximately 20% relative to the comparable 2015 forecast. The decline to long-

[29] Manitoba Hydro. Key Messages & Reasons for a Rate Increase, "Manitoba Hydro 2017/18 & 2018/19 General Rate Application", page 2.
[30] The Black Rod "Manitoba Hydro is on its deathbed. There, we said it." August 10, 2017.
[31] Ibid.
[32] MISO. Market Clearing Prices https://www.misoenergy.org/MarketsOperations/Prices/Pages/Prices.aspx, data downloaded: August 11, 2017.
[33] Bhattacharyya, Nalinaksha. "Report on Risks Faced by Manitoba Hydro in Power Exports" July 4, 2007.
[34] Independent Review of Manitoba Hydro Export Power Sales and Associated Risks, ICF, September 11, 2009, Page 90.
[35] MISO, Market Clearing Prices: https://www.misoenergy.org/MarketsOperations/Prices/Pages/Prices.aspx, data downloaded: August 11, 2017.

term power prices is due primarily to a reduction to long-term natural gas prices and increased renewable development (primarily wind generation) in the MISO market, aided by substantial subsidies.[36]

The next chart shows the actual average export revenue since 2009 on a solid black line with a progression of forecasted revenues with the projected annual rate increases associated with the respective forecasts:[37]

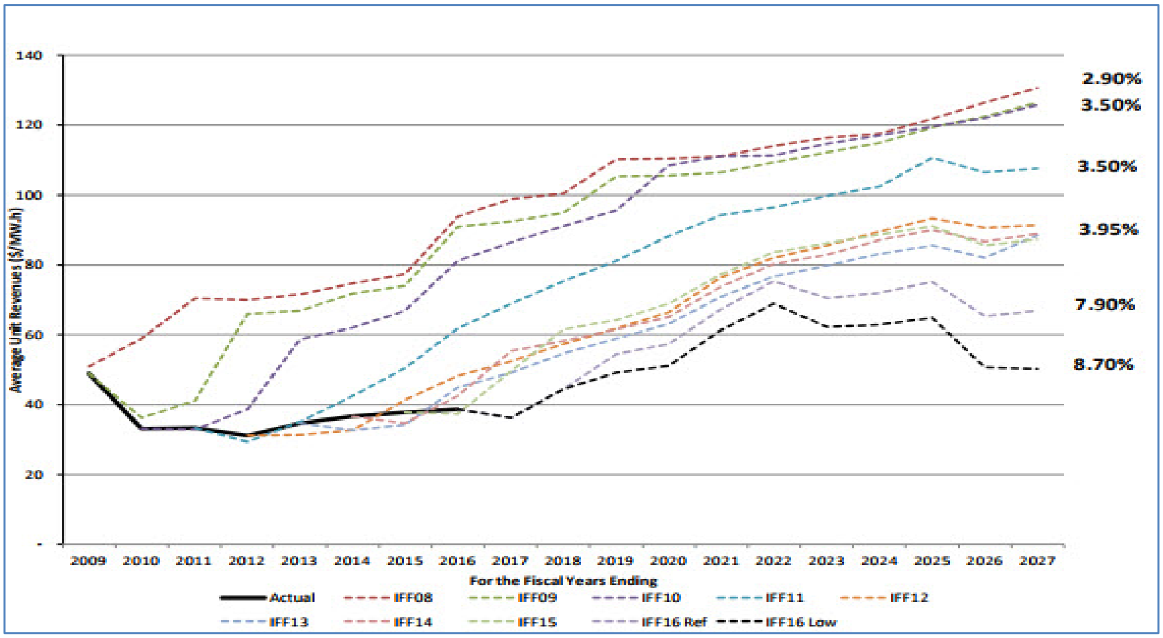

Figure 14: Manitoba Hydro Export Forecasts

Manitoba Hydro has consistently overestimated the revenue it will receive from exports since 2009. Actual electricity prices received in U.S. markets have declined 45% over the past decade in real terms.[38,39]

[36] Integrated Financial Forecast, Manitoba Hydro 2017/18 & 2018/19 General Rate Application, page 14.
[37] Integrated Financial Forecast, Manitoba Hydro 2017/18 & 2018/19 General Rate Application, page 15.
[38] Canadian CPI: http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ46a-eng.htm, downloaded August 22, 2017.
[39] Canadian Export prices: https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx?language=english, downloaded August 22, 2017.

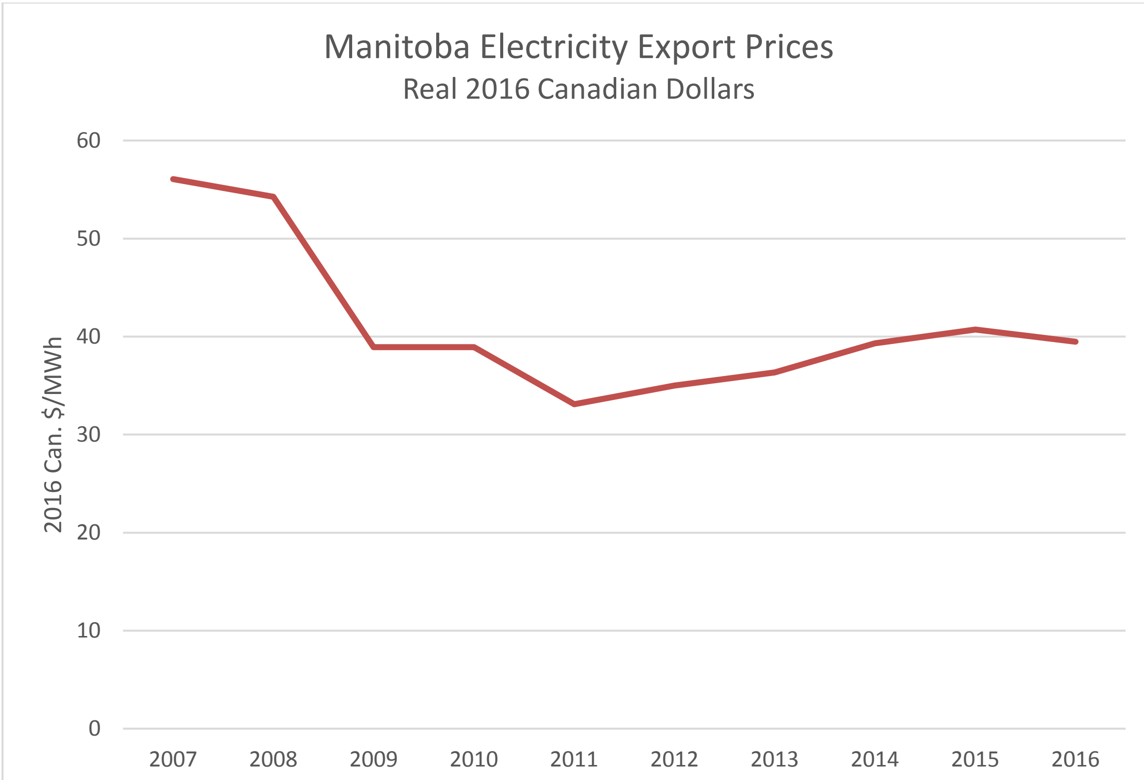

Figure 15: Manitoba Electricity Export Prices Since 2007[40]

Manitoba Hydro's unsound strategic planning offers officials in British Columbia the opportunity for a lesson. Costly hydro projects like Site C come with considerable financial risk. Megaprojects like these have often experienced large cost overruns while the ability to offload high costs to export markets have been effectively eliminated. This comes at a time when BC Hydro already has some financial turbulence ahead, without this added debt burden, due to the financial engineering of its expense deferrals.

40 https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx?language=english http://www.bankofcanada.ca/rates/price-indexes/cpi/.

Falling Prices of Renewable Energy Generation

On a cost basis, hydroelectric greenfield generation can no longer compete favorably with natural gas and renewable energy. While natural gas prices plummeted over the past decade, the cost of renewables also fell – sharply – as economies of scale in wind and solar dominated the market. Once thought to be too expensive, renewables are becoming a viable option for utilities. The cost effectiveness of renewable resources has traditionally been controversial. However, numerous recent studies indicate that renewables are now competitive with hydro generation. As John Maynard Keynes once quipped, "When my information changes, I alter my conclusions. What do you do, sir?"

Prices for renewables are still higher than spot wholesale market prices, but they have fallen sharply enough that they are now below the operating costs of existing nuclear and new coal and hydropower. Figure 1, taken from a 2016 report by the Under Secretary of the U.S. Department of Energy (DOE), illustrates the cost reductions in renewable prices since 2008.[41]

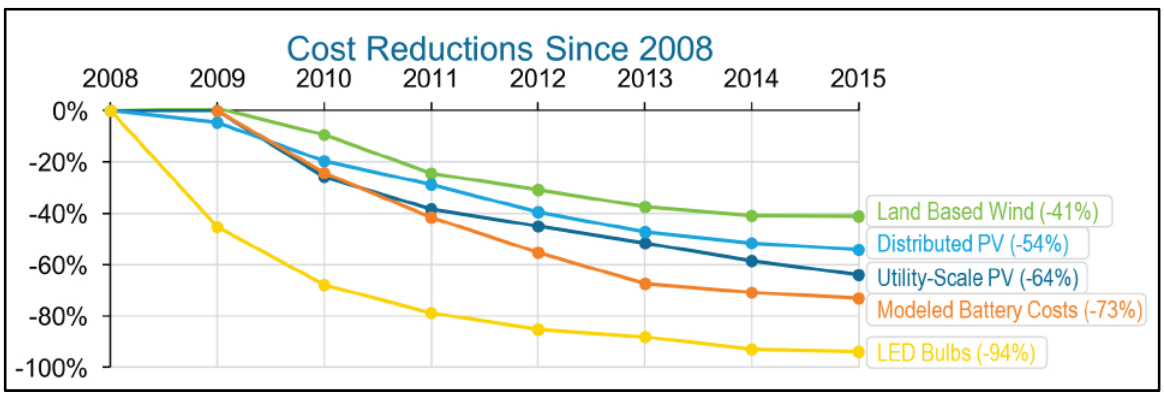

Figure 16: Indexed Cost Reductions Since 2008

In light of the changing landscape for energy, this report explores the cost effectiveness of adding renewable energy to the Pacific Northwest and British Columbian grid.

Significant expansion of renewable generation, especially for solar photovoltaics (PV) and onshore wind, is both plausible and economically sound. Economies of scale, technological innovation, "learning by doing" effects, and fuel price movements for conventional generation have brought significant reductions in the relative cost of solar PV and wind installations, and have made them economically competitive with conventional fossil fuel generations, even without subsidies.

[41] Donohoo-Vallett, Paul et al. "Revolution… Now – 2016 Update." U.S. Department of Energy. Accessed October 5, 2016. p 1.

Because renewable energy is such a rapidly advancing industry, the best possible cost projection should use up-to-date estimates like those derived by Lazard, rather than retrospective LCOE estimates. Lazard's LCOE figures have historically tracked closely with estimates by EIA and the National Renewable Energy Laboratory (NREL), which together are the three most authoritative and frequently updated sources.[42] See Figure 3. Rather than directly comparing reported LCOEs, NREL applies a consistent calculation methodology to each group's assumptions; report writer Wesley Cole notes, "Because of differences in financing assumptions, construction schedules, capacity factors, fuel prices, etc., directly comparing the reported LCOE values is not very meaningful. The calculated ranges shown here are calculated using the same methodology and assumptions in order to avoid differences due to financing, etc."[43] The results show largely similar results between the three groups.

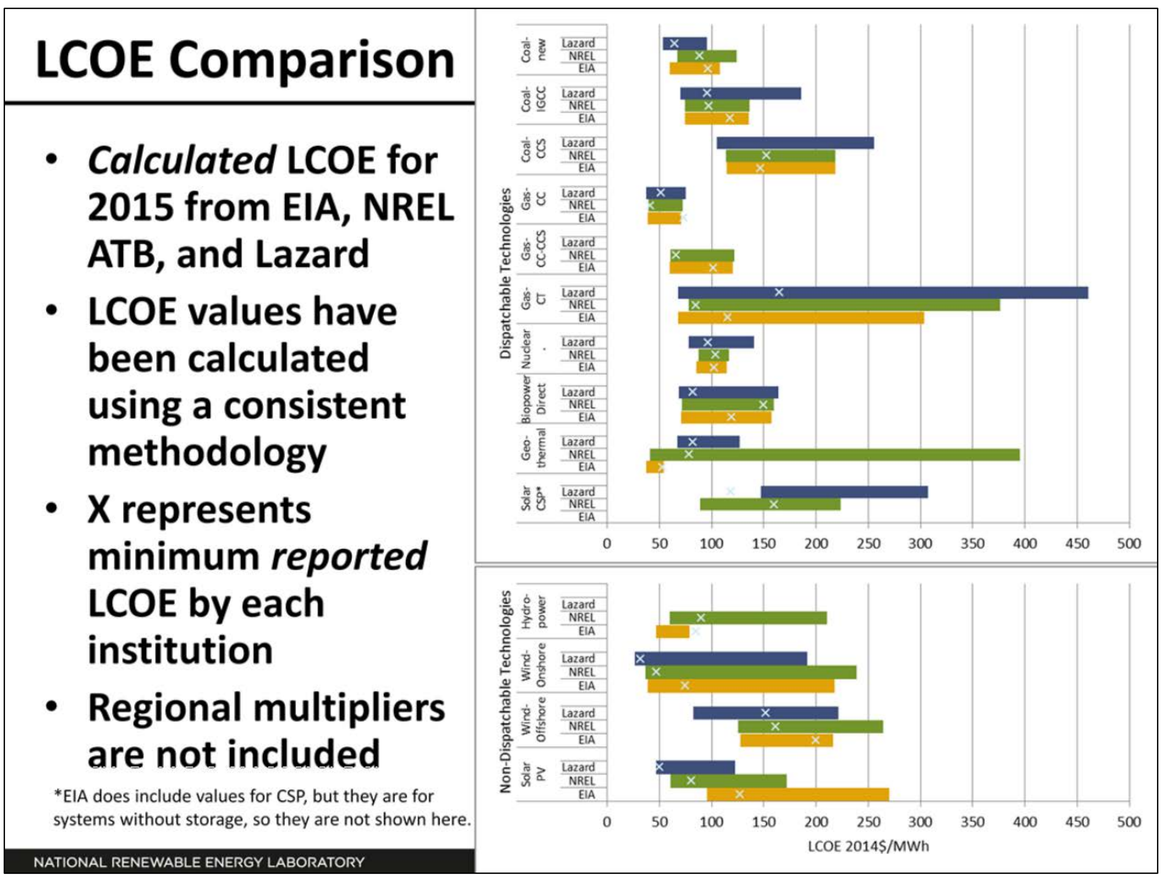

Figure 17: NREL Comparison of LCOE Calculations

[42] Cole, Wesley et al. "2016 Annual Technology Baseline." NREL. September 2016. Accessed February 3, 2017. <http://www.nrel.gov/docs/fy16osti/66944.pdf>. See page 130.
[43] Ibid. See page 130.

The capital costs for solar PV and wind installation are already lower than those for new coal or nuclear generation, and are approaching those of natural gas. Table 2 presents estimates of the overnight capital cost for installing a number of renewable and conventional generation types, as reported by Lazard.

Technology	Capital cost, 2016 $/kW[44]
Utility-Scale Solar PV	$1,625.00-1,812.50
Wind	$1,562.50-2,125.00
Nuclear	$6,750.00-10,250.00
Gas Combined Cycle	$1,250.00-1,625.00
Coal	$3,750.00-10,500.00

Figure 18: Lazard Overnight Capital Cost for Installation of Conventional and Renewable Energy Sources

Figure 19 presents the levelized cost of energy (LCOE), in 2016 dollars, for various forms of newly built generation. A LCOE compares the cost of new generating resources over the financial and technological lifetime of the project, averaged on a per MWh basis.

For renewables, the key LCOE input that varies by region is the capacity factor, since operation and maintenance (O&M) is negligible and capital costs are constant across regions. Lazard's LCOE for solar assumes between 21% and 32% capacity factor, while the onshore wind estimates assume 30% to 55% capacity factor. The LCOE estimates in Table 1 are reasonable approximations for costs in the northwest grid.

The drop in renewables costs has largely been due to economies of scale. The Joint Institute for Strategic Energy Analysis, a partnership between the U.S. DOE and several academic institutions, comments that renewable generation technologies "have zero fuel costs and relatively small variable operation and maintenance costs, so their LCOEs are roughly proportionate to estimated capital costs and the cost of financing."[45]

The capital costs for solar PV and wind installation are already lower than those for new hydro, coal or nuclear generation, and are approaching or have already matched those of natural gas. Figure 18 presents estimates of the overnight capital cost of installing a number of renewable and conventional generation types from various sources.

[44] Lazard. "Levelized Cost of Energy Analysis – Version 10.0." December 15, 2016. Accessed December 20, 2016. <https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf>.
[45] Stark, Camila et al. "Renewable Electricity: Insights for the Coming Decade." Joint Institute for Strategic Energy Analysis. February 2015. Accessed August 28, 2016.

Capital Costs (2016 $/kW)[46]	Lazard LCOE Analysis (2015)[47]	Lazard LCOE Analysis (2017 estimate)[48]	V. John White and Associates and James Caldwell[49]	EIA American Energy Outlook 2016[50]	NREL RE Futures (2030 Estimate)[51]	NREL RE Futures (2050 Estimate)[52]
Utility-Scale Solar PV (crystalline)	$1,903.71-$2,200.00	$1,713.35	$1,926.31	$3,147.48	$3,238.93	$2,846.33
Utility-Scale Solar PV (thin film)	$1,776.80-$2,030.63	$1,713.35	$1,926.31	$3,147.48	$3,238.93	$2,846.33
Wind	$1,586.43-$2,157.55			$2,086.18	$2,636.00	$2,636.00
Nuclear	$6,853.70-$10,407.00			$7,757.50		
Gas Combined Cycle	$1,269.15-$1,649.89			$1,214.34		
Coal	$3,807.95-$10,660.65			$6,475.63		
Hydroelectric				$3,062.50	$4,911.65-$7,718.31	$4,911.65-$7,718.31

Figure 19: Overnight Capital Cost for Installation of Conventional and Renewable Energy Sources

For the NWPP specifically, EIA estimates capital costs of $2,515.06/kW for wind and $3,103.18/kW for solar photovoltaic, compared to $3,062.53/kW for new hydropower (Site-C is well above even this), stated in 2016 dollars.[53]

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[46] All estimates adjusted to 2016 dollars using the Bureau of Labor Statistics Consumer Price Index Inflation Calculator. Accessed August 30, 2016.
[47] Lazard. "Levelized Cost of Energy Analysis – Version 9.0." November 2015. Accessed August 28, 2016.
[48] Lazard. "Levelized Cost of Energy Analysis – Version 9.0." November 2015. Accessed August 28, 2016. .
[49] V. John White and Associates and Caldwell, James. "A Cost Effective and Reliable Zero Carbon Replacement Strategy for Diablo Canyon Power Plant." Study commissioned by Friends of the Earth. 2016. Accessed August 28, 2016. p 40.
[50] EIA. "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2016." June 2016. Accessed August 28, 2016. p 2.
[51] Ibid., page A-11.
[52] Ibid., page A-11.
[53] EIA. "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2016." June 2016. Accessed August 28, 2016. p 3.

Developments in Utility-Scale Solar

The majority of growth in solar PV generation in recent years has been at a utility-scale. Nationally, utility-scale generation grew from only 157 GWh in 2009 to 23,232 GWh in 2015, representing two-thirds of all solar PV generation in 2015.[54]

In Oregon, Washington, Idaho, and Montana, solar PV had a total installed capacity of 18.4 MW in 2009, but grew to 109.2 MW in 2015.[55] The BPA Interconnection Queue is a strong indicator of the market's readiness to transition to renewable electricity. Of the transmission service requests processed since 2011, there are 3,020 MW of solar resources in queue.[56] See Figure 24.

The cost of solar generation fell dramatically in the 2010-2016 period. According to the annual analysis conducted by Lazard, utility-scale solar PV's median LCOE fell from $201 to $53.25/MWh over this period, a 73.6% drop.[57] Lazard estimates the LCOE for utility-scale solar PV in 2016 to be between $45 and $61/MWh based on scheduled tax policy and standard assumptions on financing.[58]

Research from the Lawrence Berkeley National Laboratory finds that recently signed Power Purchase Agreements (PPAs) for solar PV at $62.50/MWh are economically sound, even when unsubsidized.[59] In its annual review of solar technology, the group cites a substantial reduction in the price of utility-scale solar installations for power purchase agreements (PPA):

> "PPA Prices: Driven by lower installed project prices and improving capacity factors, levelized PPA prices for utility-scale PV have fallen dramatically over time, by $25-$35/MWh per year on average from 2006 through 2013, with a smaller price decline of ~$13/MWh per year evident in the 2014 and 2015 samples. Most PPAs in the 2015 sample—including many outside of California and the Southwest—are priced at or below $62.50/MWh levelized (in real 2015 dollars), with a few priced as aggressively as ~$37.5/MWh. Even at these low price levels, PV may still find it difficult to compete with existing gas-fired

[54] EIA. "Electric Power Monthly with Data for June 2016." August 24, 2016. Accessed December 20, 2016. <http://www.eia.gov/electricity/monthly/>.
[55] Renewable Northwest Project. "Renewable Energy Projects." Accessed December 20, 2016. <http://www.rnp.org/project_map>.
[56] BPA. "Interconnection Request Queue." Accessed December 20, 2016. <https://www.bpa.gov/transmission/doing%20business/interconnection/pages/default.aspx>.
[57] Lazard. "Levelized Cost of Energy Analysis – Version 10.0." December 15, 2016. Accessed December 20, 2016. <https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf>.
[58] Ibid., page 4. Figures stated in 2015 dollars.
[59] Bolinger, Mark et al. "Is $50/MWh Solar for Real? Falling Project Prices and Rising Capacity Factors Drive Utility-Scale PV Toward Economic Competitiveness." Ernest Orlando Lawrence Berkeley National Laboratory. May 2015. Accessed December 20, 2016. <https://emp.lbl.gov/sites/all/files/lbnl-183129_0.pdf>.

> generation, given how low natural gas prices (and gas price expectations) have fallen over the past year. When stacked up against new gas-fired generation (i.e., including the recovery of up-front capital costs), PV looks more attractive—and in either case can also provide a hedge against possible future increases in fossil fuel costs."[60]

The technology for utility-scale solar is based on two major approaches: crystalline silicon ("c-SI") and thin film ("CdTE"). There are numerous reasons why the efficiency and cost effectiveness of solar has improved in recent years. Mark Bolinger and Joachim Seel, the report writers, cite technological improvement, especially the rapid increase in solar tracking technology. They note that 70% of capacity added in 2015 used tracking technology.[61] Solar equipment costs have also declined in price due to improvements in manufacturing costs.[62]

There is a continuing efficiency competition between the two major solar technologies. Again, Bolinger and Seel report that the efficiencies of the two approaches are currently comparable.[63]

According to the annual analysis by Lazard, the midpoint of solar's LCOE fell from $201 to $53.25/MWh over the 2010-2016 period, a 74% decline.[64]

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[60] Bolinger, Mark and Seel, Joachim. "Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States." Lawrence Berkeley National Laboratory, U.S. Department of Energy. August 2016. Accessed December 20, 2016. <https://emp.lbl.gov/sites/all/files/lbnl-1006037_report.pdf>. See page ii.

[61] Ibid., page 5, page ii.

[62] Chung, Donald et al. "U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems." NREL. 2015. Accessed December 20, 2016. <http://www.nrel.gov/docs/fy15osti/64746.pdf>. See pages iv and 2.

[63] Bolinger, Mark and Seel, Joachim. "Utility-Scale Solar 2015: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States." Lawrence Berkeley National Laboratory, U.S. Department of Energy. August 2016. Accessed December 20, 2016. <https://emp.lbl.gov/sites/all/files/lbnl-1006037_report.pdf>. See page 5.

[64] Lazard. "Levelized Cost of Energy Analysis – Version 10.0." December 15, 2016. Accessed December 20, 2016. <https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf>.

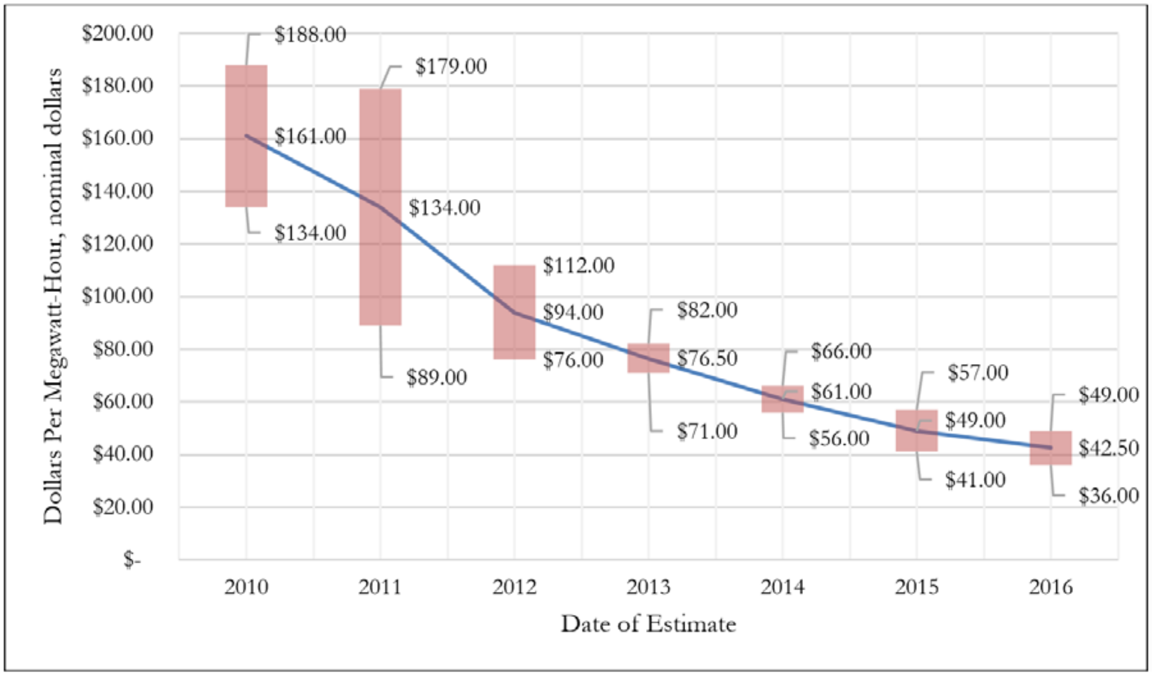


Figure 20: Levelized Cost of Energy for Solar (Lazard Historical Estimates)

Solar Peaking

Recent developments in storage also suggest renewables may be a viable alternative to conventional gas peaker plants. Solar PV generation already has a lower LCOE than that of gas peakers, estimated at $206.25-272.50/MWh; as Lazard notes, "utility-scale solar is becoming a more economically viable peaking energy product in many areas of the U.S."[65] Pumped hydro storage and battery storage present a means to add the requisite dispatchability to use renewable generation as a peaker option. Already, Southern California Edison Co. has picked a battery storage option to replace a 100 MW gas peaker in 2021.[66] The deployment of batteries in the Mid-Columbia grid will be a game changer.

Developments in Onshore Wind

Wind generation is a more mature technology compared to solar PV. In 2015, wind generation in the U.S. totaled 190,927 GWh, representing 4.7% of all electricity generation.[67] In recent years the cost of onshore wind generation has also declined steeply, if less dramatically, than that of solar PV generation. According to the annual analysis by Lazard, the midpoint of

[65] Lazard. "Levelized Cost of Energy Analysis – Version 9.0." November 2015. Accessed August 28, 2016.
[66] Fialka, John. "World's Largest Storage Battery Will Power Los Angeles." Scientific American. July 7 2016. Accessed August 28, 2016.
[67] EIA. "Electric Power Monthly with Data for June 2016." August 24, 2016. Accessed August 28, 2016.

onshore wind's LCOE fell from $109.50 to $38.75/MWh over the 2010-2016 period, a 65% decline.[68]

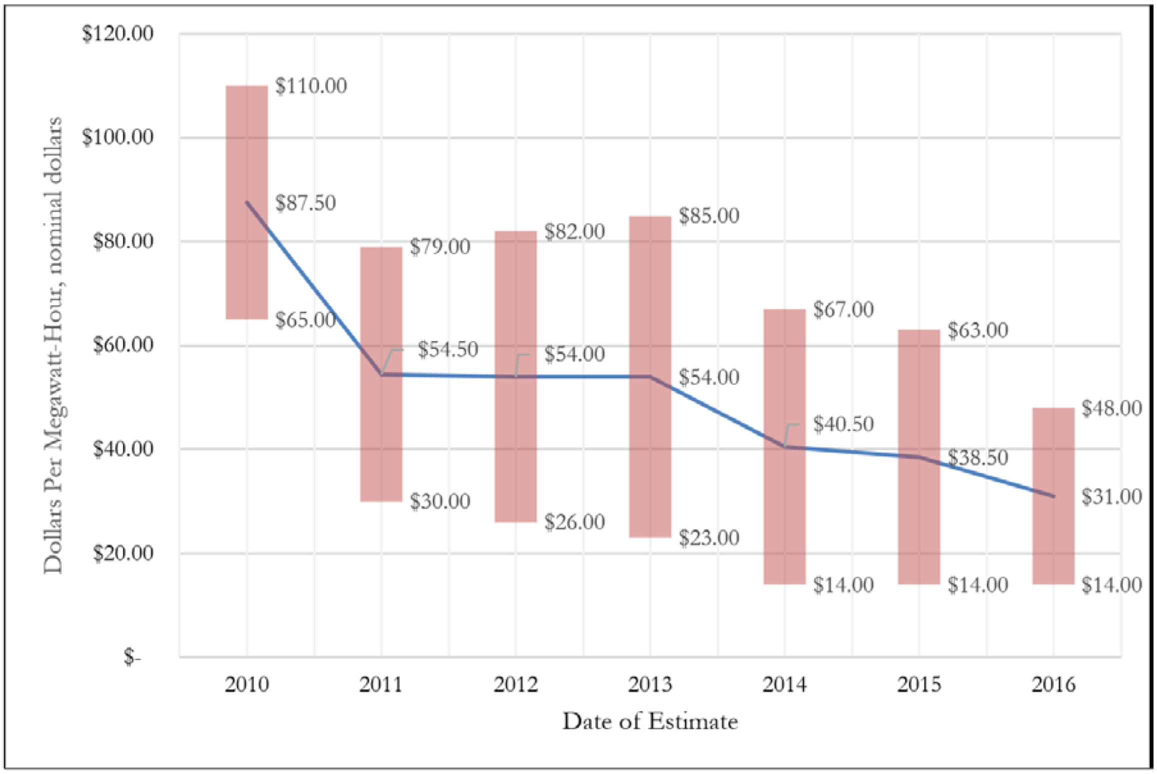


Figure 21: Levelized Cost of Energy for Wind (Lazard Historical Estimates)

In Oregon, Washington, Idaho, and Montana, onshore wind had a total installed capacity of 4,253.55 MW in 2009, and grew to 7,866.95 MW in 2015.[69] Since 2011, there are 2,766 MW of wind resources in BPA's Interconnection queue.[70] See Figure 24.

Table 1 compares LCOE estimates for renewable and conventional generation technologies. Lazard estimates the LCOE for wind generation at $17.50 to $60.00/MWh including scheduled tax credits, giving a midpoint of $38.75/MWh. This competes favorably with new nuclear, which was estimated at $121.00 to $170.00/MWh in 2016 dollars. Onshore wind is

[68] Lazard. "Levelized Cost of Energy Analysis – Version 10.0." December 15, 2016. Accessed December 20, 2016. <https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf>.
[69] Renewable Northwest Project. "Renewable Energy Projects." Accessed December 20, 2016. <http://www.rnp.org/project_map>.
[70] BPA. "Interconnection Request Queue." Accessed December 20, 2016. <https://www.bpa.gov/transmission/doing%20business/interconnection/pages/default.aspx>.

competitive with conventional fossil fuel generation technologies, with an LCOE lower than that of combined cycle natural gas generation, according to Lazard. Wind generation has many of the same advantages and drawbacks of solar PV. Wind generation enjoys no fuel price risk, but is not dispatchable. Both technologies are resource-dependent. Expansion of storage technology, namely from battery and pumped hydroelectric storage, are potential future solutions to the problem of dispatchability.

This is no longer on the drawing board. Earlier this summer, Elon Musk declared a public promise to Australia, that he could build a utility scale lithium ion to store wind power.[71]

In the future, transmission infrastructure will connect uncorrelated or negatively correlated loads across large geographic distances.[72] Going forward, we expect investments in storage and transmission to reduce the salience of dispatchability issues, even as the total share of renewable generation continues to grow.

Contribution to Resource Adequacy

Capacity Requirements

One concern with replacing conventional generation with renewables is the intermittent nature of solar and wind power. The Western Electricity Coordinating Council (WECC) uses a "Rule of Thumb" to evaluate the effects of wind and solar power on resource adequacy and loss of load expectation (LOLE).

Michael Milligan of the NREL summarized capacity valuations across the WECC in a recent presentation for the agency.[73]

[71] Pham, Sherrisa, "Elon Musk promises world's biggest lithium ion battery to Australia," CNN, July 7, 2017.
[72] Mai, Trieu et al. "Renewable Electricity Futures Study." NREL. 2012. Accessed August 28, 2016. p A-16 to A-17.
[73] Milligan, Michael. "Capacity Value: Evaluation of WECC Rule of Thumb." WECC. May 2015. Accessed August 28, 2016. p 9.

Contribution to Resource Adequacy

Capacity credit by technology and pool that
TEPPC uses to meet the reserve margin criteria

Generation Type	AZ-NM-NV	Basin	Alberta	BC	CA-North	CA-South	NWPP	RMPA
Biomass RPS	100%	100%	100%	100%	66%	65%	100%	100%
Geothermal	100%	100%	100%	100%	72%	70%	100%	100%
Small Hydro RPS	35%	35%	35%	35%	35%	35%	35%	35%
Solar PV	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**
Solar CSP0	90%	95%	95%	95%	72%	72%	95%	95%
Solar CSP6	95%	95%	95%	95%	100%	100%	95%	95%
Wind	**10%**	**10%**	**10%**	**10%**	**16%**	**16%**	**5%**	**10%**
Hydro	70%	70%	90%	90%	70%	95%	70%	70%
Pumped Storage	100%	100%	100%	100%	100%	100%	100%	100%
Coal	100%	100%	100%	100%	100%	100%	100%	100%
Nuclear	100%	100%	100%	100%	100%	100%	100%	100%
Combined Cycle	95%	95%	100%	95%	95%	95%	95%	95%
Combustion Turbine	95%	95%	100%	95%	95%	95%	95%	95%
Other Steam	100%	100%	100%	100%	100%	100%	100%	100%
Other	100%	100%	100%	100%	100%	100%	100%	100%
Negative Bus Load	100%	100%	100%	100%	100%	100%	100%	100%
Dispatchable DSM	100%	100%	100%	100%	100%	100%	100%	100%

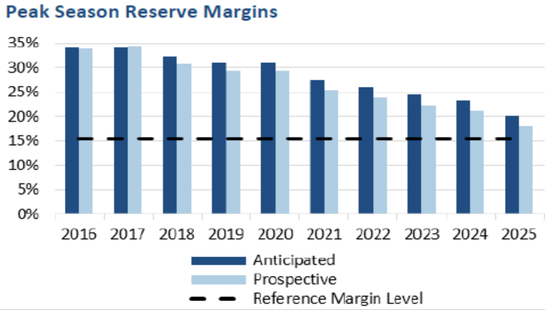
Figure 22: Milligan presentation on WECC rule of thumb for renewable capacity value

WECC

WECC-NWPP-US: Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Internal Demand	50,001	50,417	50,941	51,387	51,803	52,172	52,579	52,956	53,367	53,796
Demand Response	1,285	1,294	1,292	1,289	1,286	1,283	1,285	1,293	1,290	1,287
Net Internal Demand	48,716	49,123	49,649	50,098	50,517	50,889	51,294	51,663	52,077	52,509
Resources (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	65,322	65,928	65,680	65,651	66,174	64,814	64,701	64,311	64,211	63,103
Prospective	65,201	66,043	64,965	64,820	65,342	63,811	63,586	63,196	63,095	61,988
Reserve Margins (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	34.09%	34.21%	32.29%	31.04%	30.99%	27.36%	26.14%	24.48%	23.30%	20.18%
Prospective	33.84%	34.44%	30.85%	29.39%	29.35%	25.39%	23.96%	22.32%	21.16%	18.05%
Reference Margin Level	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%	15.40%
Excess/Shortfall (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Anticipated	9,104	9,240	8,385	7,838	7,877	6,088	5,508	4,692	4,114	2,508
Prospective	8,983	9,355	7,670	7,007	7,046	5,085	4,392	3,577	2,999	1,392

Peak Season Reserve Margins



10-Year Peak Season Cumulative Generation Mix Change

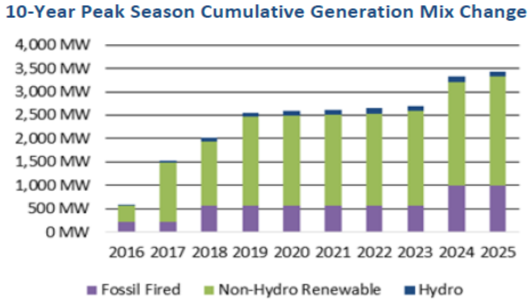


Figure 23: NERC forecast on NWPP peak season demand, resources, and reserve margins

Hydroelectric systems are natural components with renewable resources. The very high reserve margin in the Northwest Power Pool means that intermittent resources can be stored with available and replaced from storage when not available. The NWPP has such great capabilities in this regard that California utilities are fiercely lobbying for access to the NWPP's extensive hydroelectric storage.

Replacement of the relatively small energy component of Site C will not deplete the region's ability to store and redispatch intermittent resources.

Increasing Renewable Resource Diversity

An indication of the impact of additional geographic and technological diversity can be seen in EIA monthly generation data:

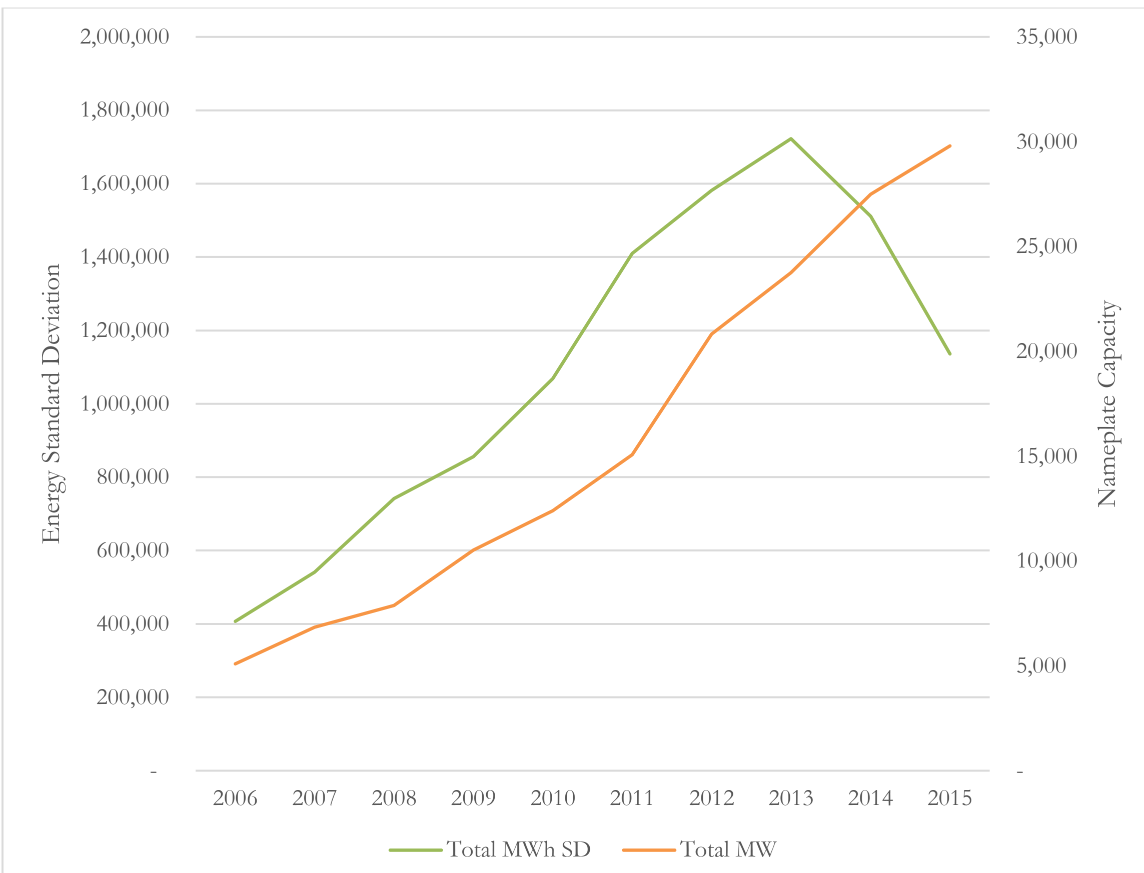


Figure 24: WECC Renewable Generation: Nameplate Capacity and Standard Deviation of Energy Generation

On a monthly basis, this indicates that the variability of renewables has been decreasing as additional diversity – both geographical and technological – has been added.

BPA Interconnection Queue

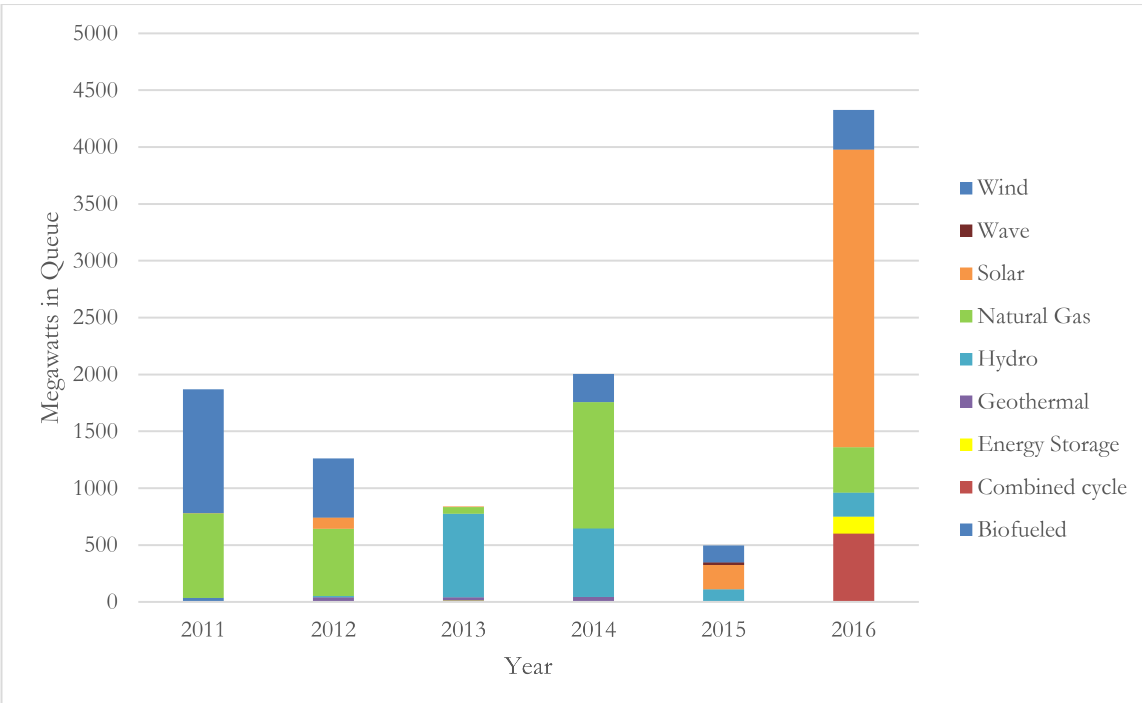


Figure 25: BPA Transmission Service Requests by Technology

Industrial Load Forecasts

Massive changes are taking places in several industrial sectors with high significance for electric load forecasts. Two of the most important are LNG export facilities and pulp and paper. The recent BCUC findings on British Columbia Hydro's load forecasts noted that there were significant issues with accuracy: [74]

[74] British Columbia Hydro and Power Authority – F2017 to F2019 Revenue Requirements Application – Project No. 1598869 (3698869), August 25, 2017, page 8.

	Average last eight years					
46	Residential	17,713	17,916		(203)	-1.0%
47	Light Industrial and Commercial	18,231	18,256		(25)	-0.1%
48	Large Industrial	13,670	15,010		(1,339)	-8.8%
49	Other	1,653	1,859		(205)	-10.0%
50	Total Mid Domestic Sales Average last eight years	51,268	53,040		(1,773)	-3.3%

Figure 26: Total Domestic Sales Variance for Averages of Seven and Eight Years

The sophistication of the forecasts in two significant areas are troubling. Pulp and Paper, for example, merits little discussion in the 2016 Revenue Requirements application.[75] The LNG sector also seems to have received little substantive analysis.[76]

Pulp and Paper

The pulp and paper industry has been in steep decline in recent years with three major paper machine closures announced in recent months.

Newsprint has seen reductions in prices and production levels in response to internet based competition:

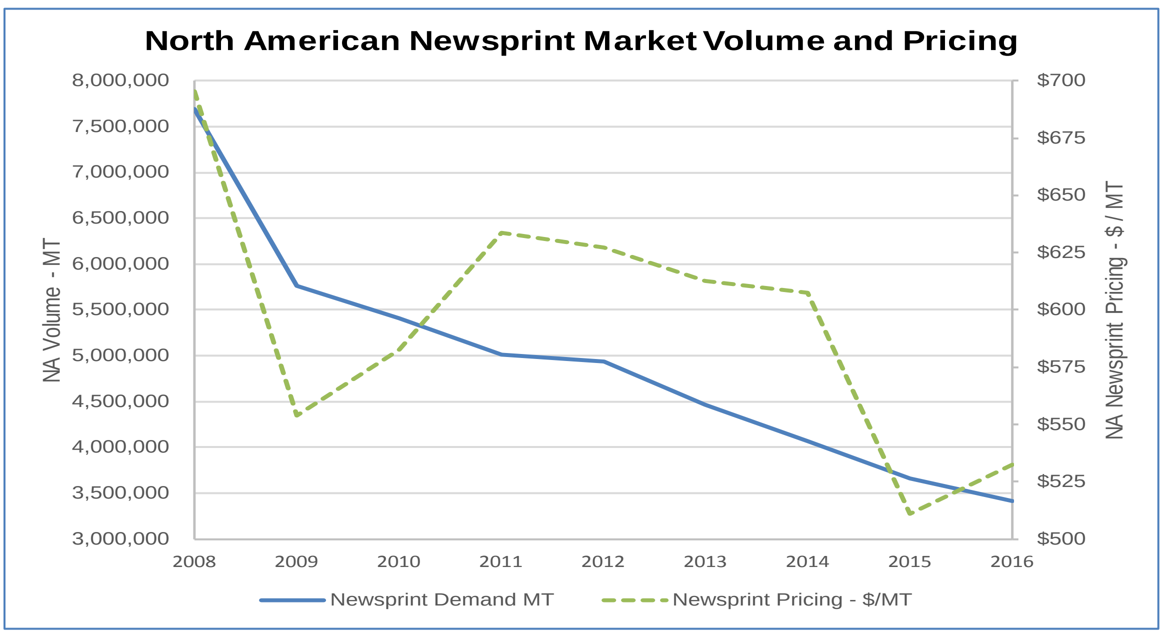


Figure 27: North American Newsprint Market Volume and Pricing

[75] Project No. 3698869 British Columbia Utilities Commission (BCUC or Commission) British Columbia Hydro and Power Authority (BC Hydro) Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, July 28, 2016, page 1-9.
[76] Ibid., page 1-9.

Owner	Location	Details	Tons	Years
Resolute	Liverpool, NS	mill closure	250,000	2012
Catalyst	Snowflake, AZ	mill closure	275,000	2012
SP Fiber Tech	Dublin, GA	net reduction in NP by switching NP to PM#1	70,000	2013
Resolute	Calhoun/Gat-ineau	Calhoun PM5 idle/Gatineau PM#6 restart (net)	40,000	2013
SP Fiber Tech.	Newburg, OR	PM#5, conversion to linerboard 1/15/14	130,000	2014
SP Fiber Tech.	Dublin, GA	PM#1 producing NP at 50%, 50% linerboard	70,000	2014
Great Northern	E. Millinocket, ME	Announced 4-month downtime	133,000	2014
PCA	Deridder, LA	PM#3 conversion to containerboard	230,000	2014
Kruger	Bromptonville, QC	PM#1 closure	94,000	2014
Resolute	Baie Comeau, QC	PM#1 idled becomes permanent	133,000	2014
Resolute	Iroquois Falls, ON	mill closure	210,000	2014
Resolute	Clermont, QC	PM#4 closure	125,000	2015
Howe Sound	Port Mellon, BC	PM#1 closure	140,000	2015
Westrock	Newberg, OR	PM#6 closure	215,000	2015
Resolute	Augusta, GA	PM#1 closure	189,000	2016
Kruger	Trois-Rivieres, QC	PM#10 conversion to linerboard	225,000	2017
Resolute	Thorold, ON	PM#1	210,000	2017
White Birch	Ashland, VA	PM#1 closure	240,000	2017
Resolute	Calhoun, TN	PM#3 & PM#5	100,000	2017
NORPAC	Longview, WA	PM#1 idled	200,000	2017

Figure 28: North American Newsprint Closures

Even more robust markets are facing declines as well:

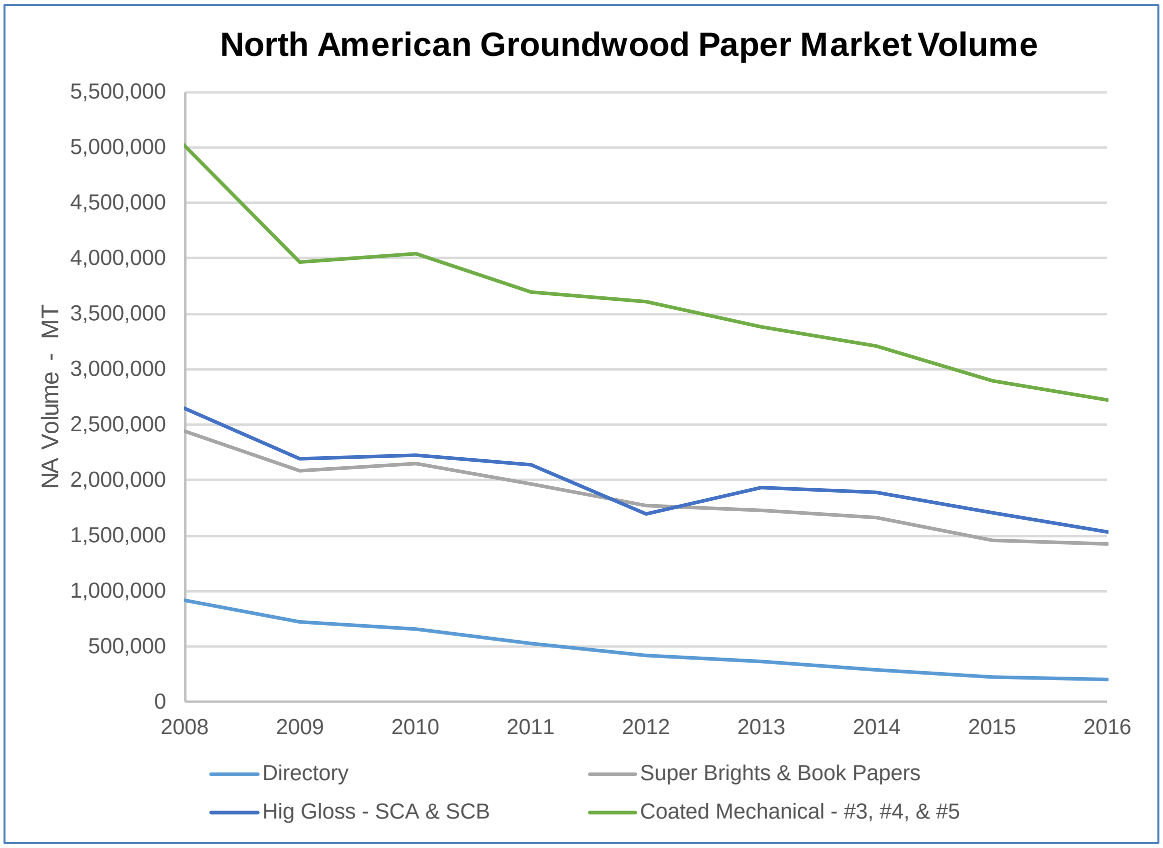


Figure 29: North American Groundwood Paper Market Volume

Since pulp and paper is British Columbia Hydro's most important industrial sector, the decline requires a very detailed analysis.

Liquefied Natural Gas

After price spikes in 2008, twenty LNG Export facilities were announced for British Columbia as well as two for Oregon. As of this date, only one very small project (Woodfibre) has reached a final investment decision. None have gone into operation. The market reality is that facilities based on brownfield sites and close proximity to natural gas production have set a price level that facilities within the Northwest Power Pool have not been able to match. Simply stated Cheniere has set a capital cost standard that NWPP competitors have not been able to match – a $5.60/million tons per year (MTPA).[77]

The prototypical British Columbia LNG facility is based on purchasing natural gas in Alberta and selling the natural gas to markets in Japan, China, and other Asian markets. Japan has little in the way of fossil fuels, so there is a potential profit in the transaction.

[77] See, for example, Cheniere Energy INC Corporate Presentation, June 2017, page 9.

The most recent reports show that the Japan Liquefied Natural Gas (LNG) import price is US$5.60/mmbtu.[78] The wholesale price for AECO natural gas in Alberta is US$1.21/mmbtu.[79] The average price differential between Japanese LNG and AECO is forecast to be $6.19/mmbtu between September 2017 and December 2024.

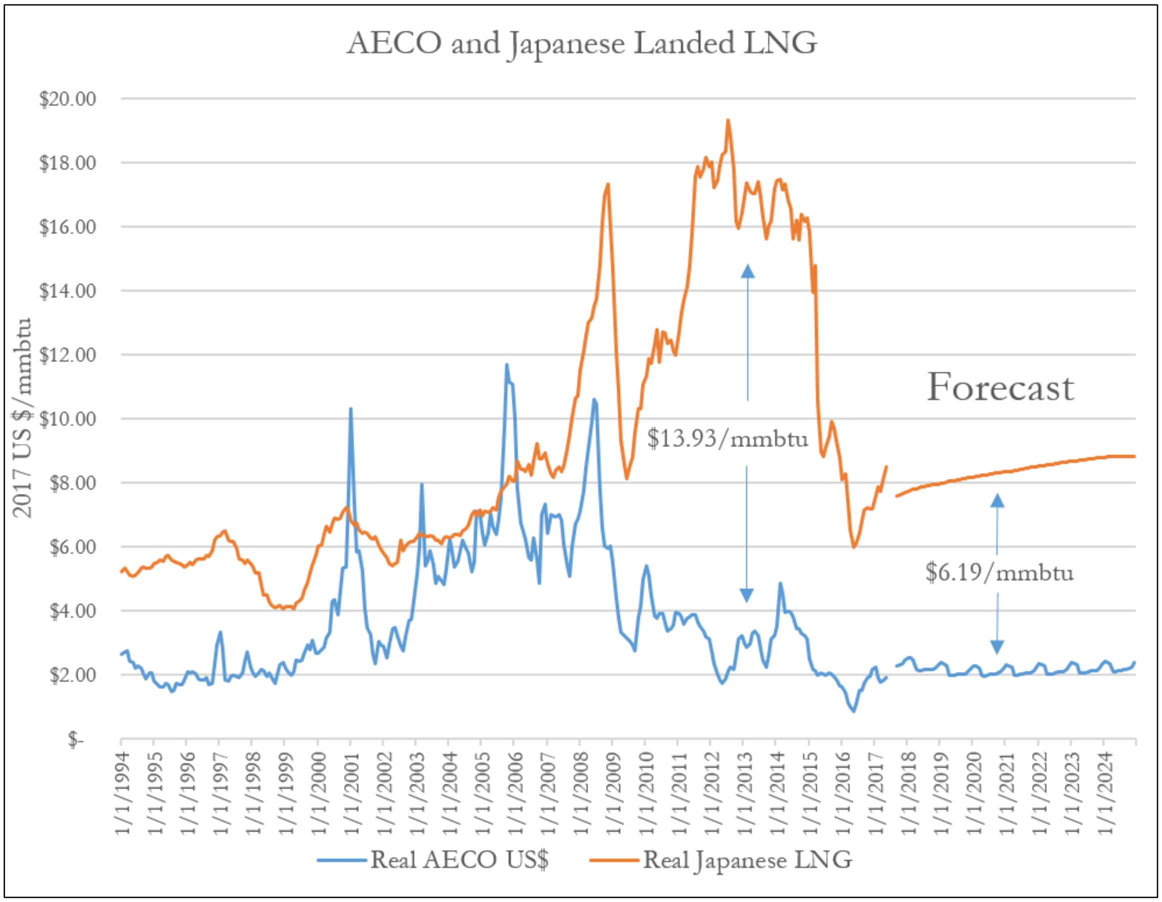


Figure 30: AECO and Japanese Landed LNG Prices

The forecast is based on forward markets for Brent crude oil and Henry Hub natural gas at the Chicago Mercantile Exchange. Henry Hub natural gas prices have historically correlated almost perfectly with AECO natural gas prices.[80,81]

[78] YCharts. Japan Liquefied Natural Gas Import Price. Based on World Bank data. Accessed August 27, 2017.
[79] NGX. NGX Alberta Market Price, Current Month Details, Index Calc. Accessed August 27, 2017. Market price is for August 27, 2017, the most recent available. Price is converted from C$2.2201/GJ to US$/mmbtu using Bank of Canada exchange rate for August 27, 2017.
[80] U.S. Energy Information Administration (EIA). Henry Hub Natural Gas Spot Price. Accessed July 11, 2017.
[81] Alberta Energy. Alberta Gas Reference Price History. Accessed July 11, 2017.

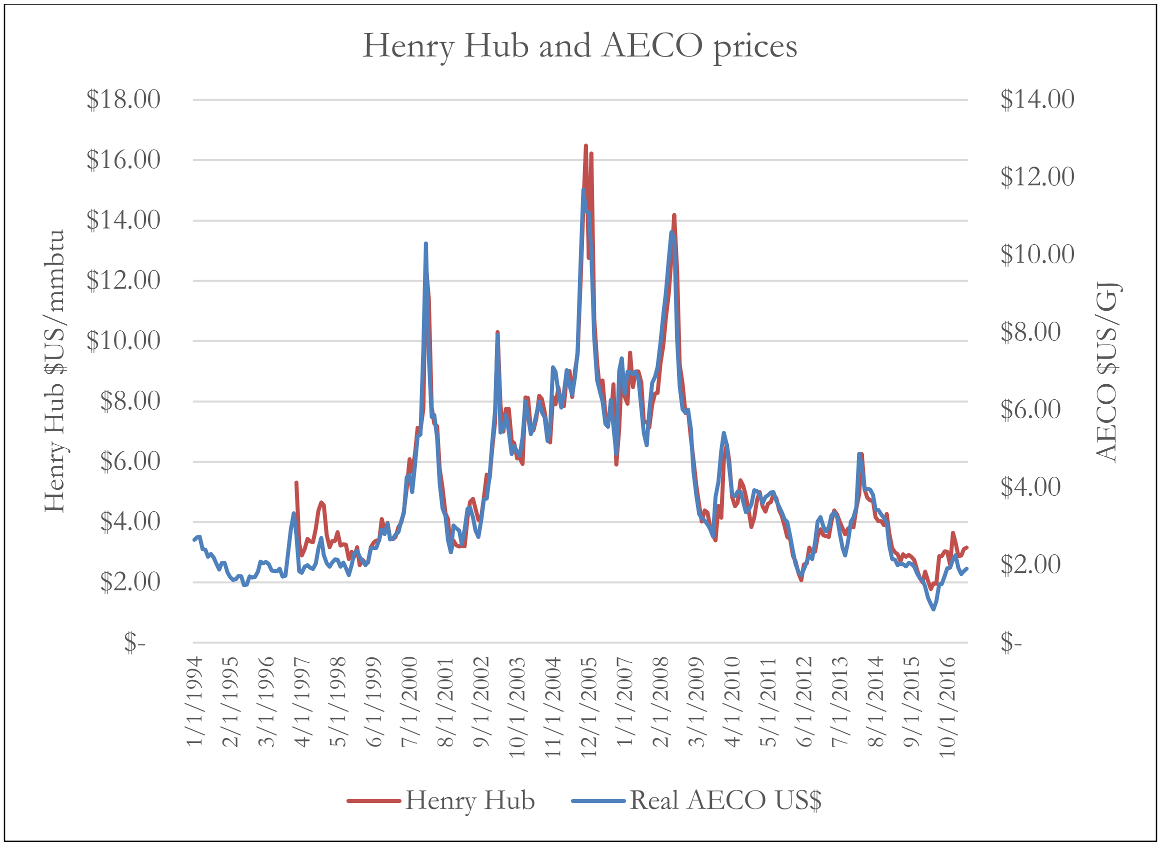


Figure 31: Henry Hub and AECO Prices

Similarly, Japanese LNG historically shows a very strong correlation with Brent Crude oil prices.[82,83]

[82] EIA. Europe Brent Spot Price FOB. Accessed July 11, 2017.
[83] YCharts. Japan Liquefied Natural Gas Import Price. Based on World Bank data. Accessed July 11, 2017.

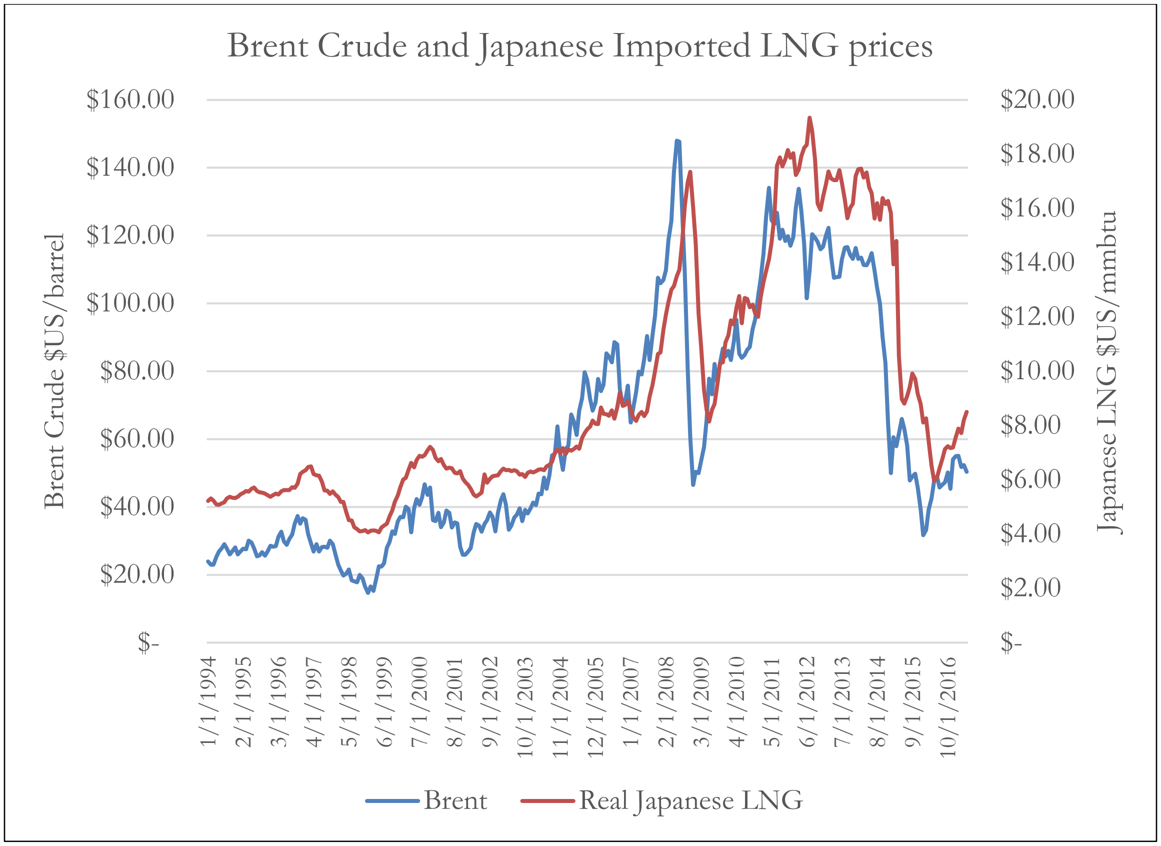


Figure 32: Henry Hub and AECO Prices

The price forecast for AECO Alberta natural gas and Japanese LNG is prepared using forward prices for Brent crude oil and Henry Hub natural gas.[84,85] Adjusting for exchange rates and indexing for inflation, the price differential between AECO Alberta natural gas and Japanese Imported LNG is projected to average only $6.19/mmbtu. This is significantly below the average LNG export terminal's target to remain profitable.

In order to estimate the probability of a successful LNG export terminal in British Columbia, a useful tool is a Monte Carlo analysis where each "game" is a combination of LNG prices in Alberta (AECO) and Japan between January 1994 and July 2017.[86] The following analysis is the result of calculating the potential profitability of a standard LNG export terminal through almost two million "games", representing different market prices in Alberta and Japan. The plant is assumed to produce 12 mtpa per annum with an expected in-service date of 2024. The discount rate for the net present value is 12%.

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[84] Chicago Mercantile Exchange. Henry Hub Natural Gas Futures Quotes. Accessed August 27, 2017.
[85] Chicago Mercantile Exchange. Brent Last Day Financial Futures Quotes. Accessed August 27, 2017.
[86] Monte Carlo statistical analyses are based on the law of large numbers. By varying assumptions across a large number of possible values, it is possible to develop a probability distribution of possible outcomes.

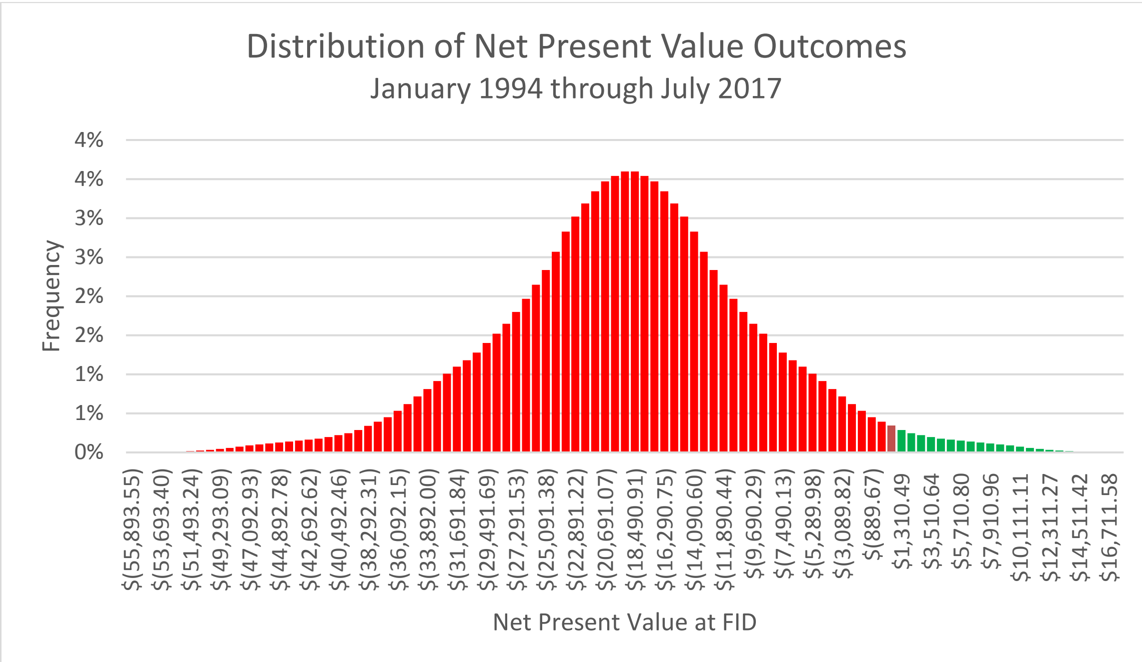

Figure 33: British Columbia LNG Export Terminal Monte Carlo

The results are daunting. The vast majority of outcomes are "in the red". At a broad range of capital expenses per ton, British Columbia and Oregon LNG export terminals have only a 3% chance of being profitable at the final investment decision.

From this analysis, we can conclude that most of the LNG terminals currently under consideration in British Columbia won't see the light of day. Thus, BC Hydro's expected increase in consumption to electrify LNG facilities will not materialize.

Greenhouse Gas Estimates for Reservoirs

In October last year, a pivotal study on greenhouse gas releases from reservoirs was published in the BioScience journal.[87] The study has been followed up by two additional articles focusing on the additional greenhouse gas implications of hydroelectric reservoirs.[88,89]

We have long known that submerged biomass at the site of reservoirs releases greenhouse gases. Specific data – especially for British Columbia -- has been scarce. The BioScience article draws on data from across the globe.

Greenhouse gases like methane, carbon dioxide, and nitrogen oxide have been studied extensively at reservoirs across the world.[90] The BioScience study has assembled data for two hundred and thirty-nine reservoirs.

The following chart shows estimated worldwide GHG emissions from reservoirs. As can be seen, British Columbia figures prominently in GHG releases.

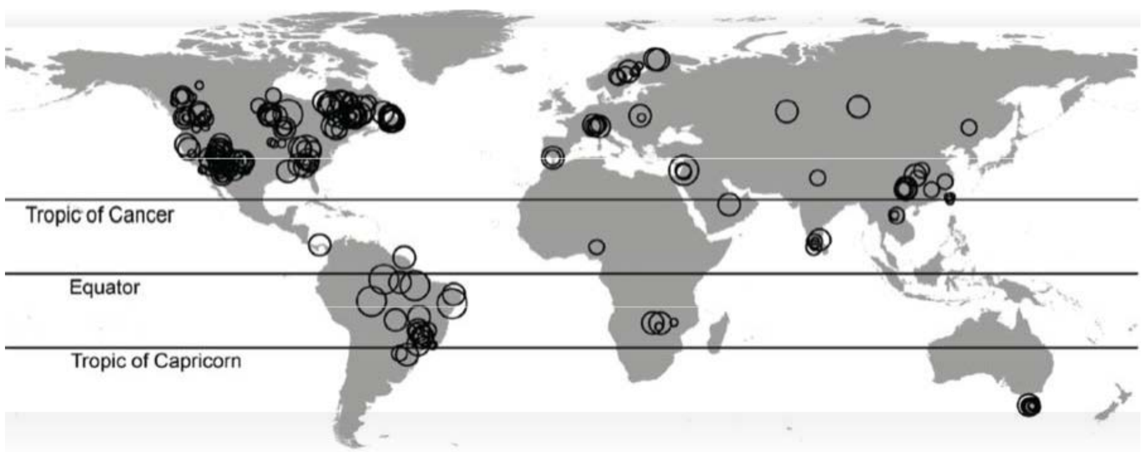

Figure 34: Reservoirs and GHG Emissions

[87] Greenhouse Gas Emissions from Reservoir Water Surfaces: A New Global Synthesis, Bridget R. Deemer, John A. Harrison, Siyue Li, Jake J. Beaulieu, Tonya Delsontro, Nathan Barros, José F. Bezerra-Neto, Stephen M. Powers, Marco A. Dos Santos, And J. Arie Vonk, BioSchence, October 5, 2016.

[88] Key differences between lakes and reservoirs modify climate signals: A case for a new conceptual model Nicole M. Hayes, Bridget R. Deemer, Jessica R. Corman, N. Roxanna Razavi, and Kristin E. Strock, Limnology and Oceanography Letters, February 7, 2017.

[89] Reservoir Water-Level Drawdowns Accelerate and Amplify Methane Emission, John A. Harrison, Brid- get R. Deemer, M. Keith Birchfield, and Maria T. O'Malley, Environmental Science and Technology, December 9, 2016.

[90] Key differences between lakes and reservoirs modify climate signals: A case for a new conceptual model Nicole M. Hayes, Bridget R. Deemer, Jessica R. Corman, N. Roxanna Razavi, and Kristin E. Strock, Limnology and Oceanography Letters, February 7, 2017.

The BioScience study does not consider the impact of hydroelectric operations. As a general rule, lakes are more stable than hydroelectric reservoirs. This is due to the relatively rapid rise and fall of reservoir levels in the course of the year.

The Environmental Science and Technology article considers the impact of hydroelectric operations on greenhouse gas release. Overall, this article indicates that methane emissions may increase by a factor of three.

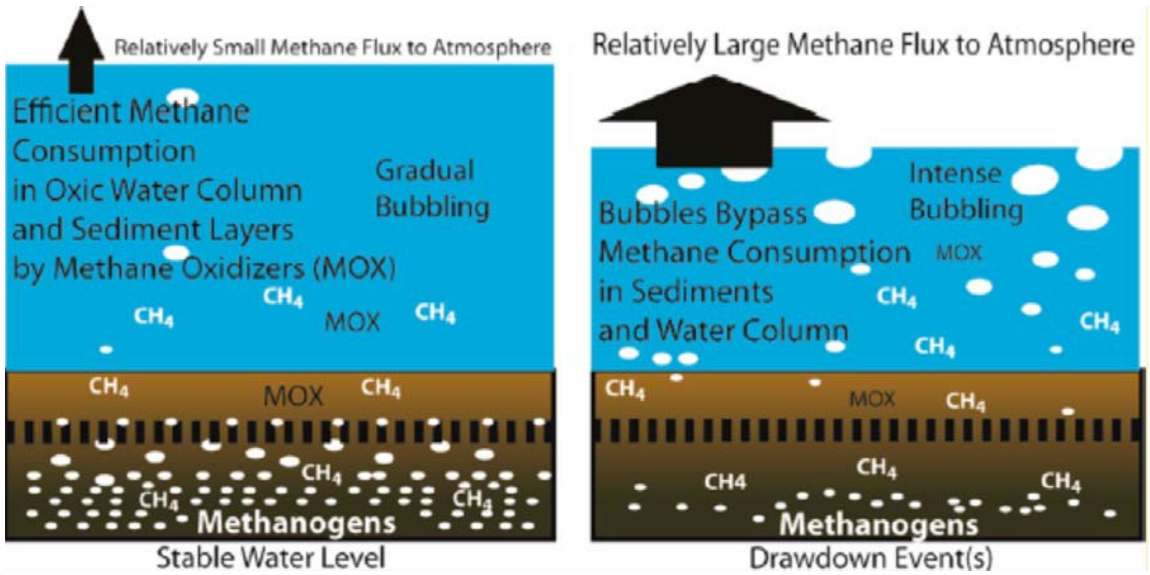

Figure 35: Methane Flux

A recent report by Camerado Energy Consulting and reviewed by a team of academics and experts from across Canada examined the greenhouse gas impact of the Site C dam over its expected 108-year lifetime.[91] They found that construction of Site C will release anywhere from 49,500 to 67,700 metric tons of CO2 equivalent over that time period. Most of those emissions would occur within ten years of the dam's completion; potentially putting BC Hydro over the Carbon emissions it's allowed under the Clean Energy Act. Since the Clean Energy Act requires 93% of BC's electricity to come from non-GHG emitting sources, and since nearly 6% of BC's current sources don't fit that definition, BC can only generate an additional 500 GWH of electricity from "dirty" sources.

Additionally, Hendricks compares the emissions of Site C to the alternative generation strategy written in BC Hydro's IRP. This alternative strategy includes a combination of wind power and natural gas using advanced steam turbines. The report found that its alternative strategy releases less C02 equivalent into the atmosphere than Site C over the long term.[92]

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[91] Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives. Rick Hendricks, Karen Bakker, Arthur Fredeen, Normand Mousseau. July 2016.
[92] Camerado Consulting, "Comparative Analysis of Greenhouse Gas Emissions of Site-C Verses Alternatives," July 2016, page 7.

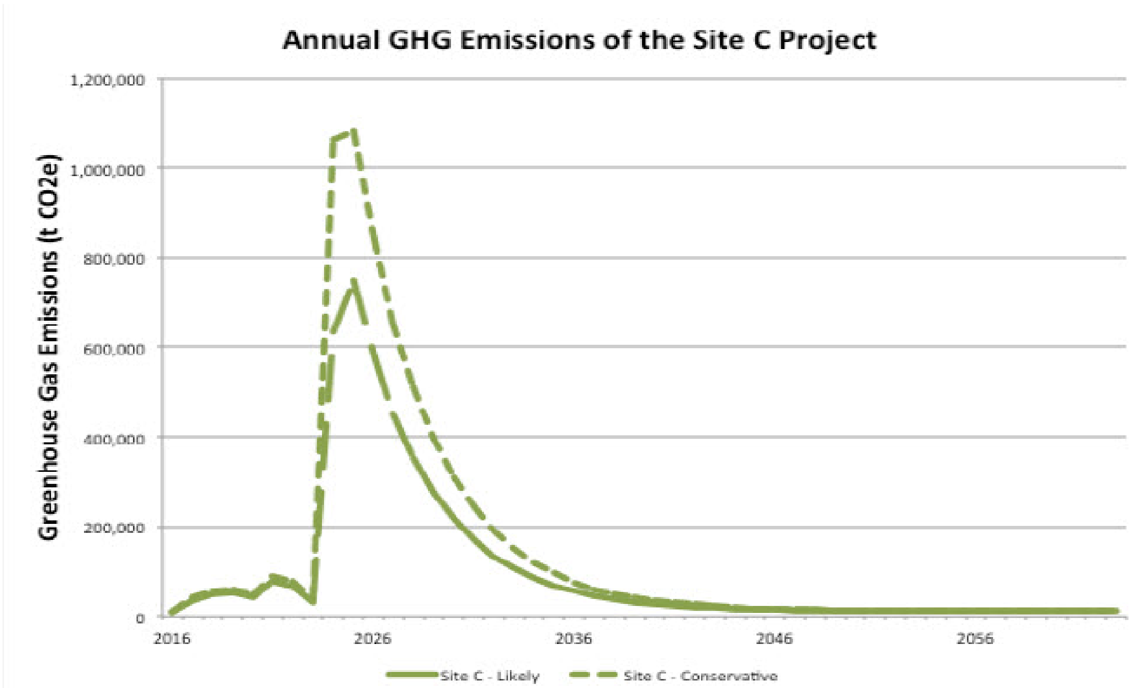

Figure 36: Expected Annual Emissions from Site C

We expect that this generation strategy would not only supply British Columbia anticipated loads at a lower cost, but also do so with less environmental risk.

Robert McCullough – Curriculum Vitae

Principal
McCullough Research, 3816 S.E. Woodstock Place, Portland, OR 97202 USA

Professional Experience

1985-present	Principal, McCullough Research: provide strategic planning assistance, litigation support, and planning for a variety of customers in energy, regulation, and primary metals
1996-present	Adjunct Professor, Economics, Portland State University
1990-1991	Director of Special Projects and Assistant to the Chairman of the Board, Portland General Corporation: conducted special assignments for the Chairman in the areas of power supply, regulation, and strategic planning
1988-1990	Vice President in Portland General Corporation's bulk power marketing utility subsidiary, Portland General Exchange: primary negotiator on the purchase of 550 MW transmission and capacity package from Bonneville Power Administration; primary negotiator of PGX/M, PGC's joint venture to establish a bulk power marketing entity in the Midwest; negotiated power contracts for both supply and sales; coordinated research function
1987-1988	Manager of Financial Analysis, Portland General Corporation: responsible for M&A analysis, restructuring planning, and research support for the financial function; reported directly to the CEO on the establishment of Portland General Exchange; team member of PGC's acquisitions task force; coordinated PGC's strategic planning process; transferred to the officer's merit program as a critical corporate manager
1981-1987	Manager of Regulatory Finance, Portland General Electric: responsible for a broad range of regulatory and planning areas, including preparation and presentation of PGE's financial testimony in rate cases in 1980, 1981, 1982, 1983, 1985, and 1987 before the Oregon Public Utilities Commission; responsible for preparation and presentation of PGE's wholesale rate case with Bonneville Power Administration in 1980, 1981, 1982, 1983, 1985, and 1987; coordinated activities at BPA and FERC

	on wholesale matters for the InterCompany Pool (the association of investor-owned utilities in the Pacific Northwest) since 1983; created BPA's innovative aluminum tariffs (adopted by BPA in 1986); led PGC activities, reporting directly to the CEO and CFO on a number of special activities, including litigation and negotiations concerning WPPSS, the Northwest Regional Planning Council, various electoral initiatives, and the development of specific tariffs for major industrial customers; member of the Washington Governor's Task Force on the Vancouver Smelter (1987) and the Washington Governor's Task Force on WPPSS Refinancing (1985); member of the Oregon Governor's Work Group On Extra-Regional Sales (1983); member of the Advisory Committee to the Northwest Regional Planning Council (1981)
1979-1980	Economist, Rates and Revenues Department, Portland General Electric: responsible for financial and economic testimony in the 1980 general case; coordinated testimony in support of the creation of the DRPA (Domestic and Rural Power Authority) and was a witness in opposition to the creation of the Columbia Public Utility District in state court; member of the Scientific and Advisory Committee to the Northwest Regional Power Planning Council

Economic Consulting

2017-present	Advisor to Enpex on power contract litigation
2017-present	Advisor to North Pacific Paper Corporation (NORPAC) on power contracts and business strategy
2017	Expert witness for CENSE on Washington State transmission issues
2016-present	Expert witness to the U.S. Department of Justice on nuclear waste double recovery
2016-present	Advisor to the City of Logansport on utility project development and decision-making
2016	Expert testimony before the Supreme Court of British Columbia on costs of Site C project delay

2015-present	Advisor to Huu-ay-aht on Sarita Bay LNG project in British Columbia
2015-present	Analysis and expert testimony for Illinois Attorney General in official FERC complaint against MISO
2015-present	Advisor to Calbag Metals on generation project
2015-2016	Advisor to Oregon Department of Justice in the investigation of taxes owed the state by Powerex Corp.
2015	Economic analysis of the proposed 1100 MW hydro project, Site C, for the Peace Valley Landowner Association
2014-2015	Market analysis of the NYISO for the New York State Assembly
2014	Advisor to the Grand Council of the Cree on uranium mining in Quebec
2014-present	Support for the investigation of Barclays Bank
2013-present	Retained to do a business case analysis of the Columbia Generating Station by the Physicians for Social Responsibility
2013	Advisor to Environmental Defense Fund on gasoline and oil issues in California
2013	Advisor to Energy Foundation on Ohio competitive issues
2013	Export market review in the Maritime Link proceeding
2011	Consultant to Citizens Action Coalition of Indiana on Indiana Gasification LLC project
2010	Analysis and expert witness testimony for Block Island Intervenors concerning Deepwater offshore wind project
2010	Analysis for Eastern Environmental Law Center of 25 closed cycle plants in New York State
2010	Advisor on BPA transmission line right of way issues

2009-2010	Advisor to Gamesa USA on a marketing plan to promote a wind farm in the Pacific Northwest
2009-2010	Expert witness in City of Alexandria vs. Cleco
2009	Expert witness in City of Beaumont v. Entergy
2008-2009	Consultant to AARP Connecticut and Texas chapters on the need for a state power authority (Connecticut) and balancing energy services (Texas)
2008	Expert witness on trading and derivative issues in Barrick Gold litigation
2008-2014	Advisor to Jackson family in Pelton/Round Butte dispute
2007-2014	Advisor to the American Public Power Association on administered markets
2006-present	Advisor to the Illinois Attorney General on electric restructuring issues
2006-2007	Advisor to the City of Portland in the investigation of Portland General Electric
2006	Expert witness for Lloyd's of London in SECLP insurance litigation
2005-2007	Expert witness for Federated Rural Electric Insurance Company and TIG Insurance in Cowlitz insurance litigation
2005-2007	Advisor to Grays Harbor PUD on market manipulation
2005-2007	Advisor to the Montana Attorney General on market manipulation
2005-2006	Expert witness for Antara Resources in Enron litigation
2005-2006	Advisor to Utility Choice Electric
2004-2005	Expert witness for Factory Mutual in Northwest Aluminum litigation

2004	Advisor to the Oregon Department of Justice on market manipulation
2003-2006	Expert witness for Texas Commercial Energy
2003-2004	Advisor to The Energy Authority
2002-2005	Advisor to the U.S. Department of Justice on market manipulation issues
2002-2004	Expert witness for Alcan in Powerex arbitration
2002-2003	Expert witness for Overton Power in IdaCorp Energy litigation
2002-2003	Expert witness for Stanislaus Food Products
2002	Advisor to VHA Pennsylvania on power purchasing
2002	Expert witness for Sierra Pacific in Enron litigation
2002-2004	Advisor to U.S. Department of Justice
2002-2007	Expert witness for Snohomish PUD in Enron litigation
2002-2010	Expert witness for Snohomish in Morgan Stanley investigation
2001-2008	Expert witness for City of Seattle, Seattle City Light and City of Tacoma in FERC's EL01-10 refund proceeding
2001-2008	Advisor to VHA Southwest on power purchasing
2001-2005	Advisor to Nordstrom
2001-2005	Advisor to Steelscape Steel on power issues in Washington and California
2001	Advisor to California Steel on power purchasing

2001	Advisor to the California Attorney General on market manipulations in the Western Systems Coordinating Council power markets
2000-2007	Expert witness for Wah Chang in PacifiCorp litigation
2000-2001	Expert witness for Southern California Edison in Bonneville Power Administration litigation
2000-2001	Advisor to Blue Heron Paper on West Coast price spikes
2000	Expert witness for Georgia Pacific and Bellingham Cold Storage in the Washington Utilities and Transportation Commission's proceeding on power costs
1999-2002	Advisor to Bayou Steel on alternative energy resources
1999-2000	Expert witness for the Large Customer Group in PacifiCorp's general rate case
1999-2000	Expert witness for Tacoma Utilities in WAPA litigation
1999-2000	Advisor for Nucor Steel and Geneva Steel on PacifiCorp's power costs
1999-2000	Advisor to Abitibi-Consolidated on energy supply issues
1999	Expert report for the Center Helios on Freedom of Information in Québec
1999	Advisor to GTE regarding Internet access in competitive telecommunication markets
1999	Advisor to Logansport Municipal Utilities
1998-2001	Advisor to Edmonton Power on utility plant divestiture in Alberta
1998-2001	Energy advisor for Boise Cascade
1998-2000	Advisor to California Steel on power purchasing

1998-2000	Advisor to Nucor Steel on power purchasing and transmission negotiations
1998-2000	Advisor to Cominco Metals on the sale of hydroelectric dams in British Columbia
1998-2000	Advisor to the Betsiamites on the purchase of hydroelectric dams in Québec
1998-1999	Advisor to the Illinois Chamber of Commerce concerning the affiliate electric and gas program
1998	Intervention in Québec's first regulatory proceeding on behalf of the Grand Council of the Cree
1998	Market forecasts for Montana Power's restructuring proceeding
1997-2004	Expert witness for Alcan in BC Hydro litigation
1997-2003	Advisor to the Manitoba Cree on energy issues in Manitoba, Minnesota and Québec; Advisor to the Grand Council of the Cree on hydroelectric development
1997-1999	Advisor to the Columbia River Intertribal Fish Commission on Columbia fish and wildlife issues
1997-1998	Advisor to Port of Morrow regarding power marketing with respect to existing gas turbine plant
1997-1998	Expert witness for Tenaska in BPA litigation
1997	Advisor to Kansai Electric on restructuring in the electric power industry (with emphasis on the California markets)
1996-1997	Bulk power purchasing for the Association of Bay Area Cities
1996-1997	Advisor to Texas Utilities on industrial issues
1996-1997	Expert witness for March Point Cogeneration in Puget Sound Power and Light litigation
1996	Advisor to Longview Fibre on contract issues

1995-2000	Bulk power supplier for several Pacific Northwest industrials
1995-1999	Advisor to Seattle City Light on industrial contract issues
1995-1997	Advisor to Tacoma Utilities on contract issues
1995-1996	Expert witness for Tacoma Utilities in WAPA litigation
1994-1995	Advisor to Idaho Power on Southwest Intertie Project marketing
1993-2001	Northwest representative for Edmonton Power
1993-1997	Expert witness for MagCorp in PacifiCorp litigation
1992-1995	Advisor to Citizens Energy Corporation
1992-1994	Negotiator on proposed Bonneville Power Administration aluminum contracts
1992	Bulk power marketing advisor to Public Service of Indiana
1991-2000	Strategic advisor to the Chairman of the Board, Portland General Corporation
1991-1993	Chairman of the Investor Owned Utilities' (ICP) committee on BPA financial reform
1991-1992	Financial advisor on the Trojan owners' negotiation team
1991	Advisor to Shasta Dam PUD on the California Oregon Transmission Project and related issues
1990-1991	Advised the Chairman of the Illinois Commerce Commission on issues pertaining to the 1990 General Commonwealth Rate Proceeding; prepared an extensive analysis of the bulk power marketing prospects for Commonwealth in ECAR and MAIN
1988	Facilitated the settlement of Commonwealth Edison's 1987 general rate case and restructuring proposal for the Illinois Commerce Commission; reported directly to the Executive Director of the Commission; responsibilities included financial

	advice to the Commission and negotiations with Commonwealth and interveners
1987-1988	Created the variable aluminum tariff for Big Rivers Electric Corporation: responsibilities included testimony before the Kentucky Public Service Commission and negotiations with BREC's customers (the innovative variable tariff was adopted by the Commission in August 1987); supported negotiations with the REA in support of BREC's bailout debt restructuring
1981-1989	Consulting projects including: financial advice for the Oregon AFL-CIO; statistical analysis of equal opportunity for Oregon Bank; cost of capital for the James River dioxin review; and economic analysis of qualifying facilities for Washington Hydro Associates
1980-1986	Taught classes in senior and graduate forecasting, micro-economics, and energy at Portland State University

Education

Unfinished Ph.D.	Economics, Cornell University; Teaching Assistant in micro- and macro-economics
M.A.	Economics, Portland State University, 1975; Research Assistant
B.A.	Economics, Reed College, 1972; undergraduate thesis, "Eurodollar Credit Creation"

Areas of specialization include micro-economics, statistics, and finance

Papers and Publications

August 22, 2017	"Lessons from Manitoba Hydro's Financial Problems"
June 22, 2017	"Trump plan to sell BPA lines misguided"
April 11, 2017	"Affordable power or Site C power: British Columbia must choose"

February 28, 2017	"My View: Trade tariffs would hurt Americans", *The Portland Tribune*
January 8, 2017	"Many lives of Jordan Cove may have come to an end", *The Oregonian*
July 22, 2016	"Balancing an aging Hanford nuke plant against cheaper firm market power purchases", *The Oregonian*
July 7, 2016	"More roads needed to handle growth", *The Portland Tribune*
July 7, 2016	"Close the expensive Columbia Generating Station", *The Oregonian*
June 29, 2016	"Our future is in green energy, not aging, costly nuclear plants", *The Seattle Times*
May 12, 2016	"Diesel tax on heavy trucks is the right move", *The Portland Tribune*
May 2016	"Aspirational Planning: A Statistical Model of Hawthorne Bridge and Tilikum Crossing Bicycle Ride Counts", *Hatfield Graduate Journal of Public Affairs 1(1).*
January 19, 2016	"A good time for a sensibly managed Portland gas tax", *The Oregonian*
October 15, 2015	"A plan to fix Portland's roads", *The Portland Oregonian*
June 2015	"Estimating the Longevity of Commercial Nuclear Reactors", *Public Utilities Fortnightly*
December 2014	"Nuclear Winter", *Electricity Policy*
July 2013	"Mid-Columbia Spot Markets and the Renewable Portfolio Standard", *Public Utilities Fortnightly*
April 14, 2013	"Selling Low and Buying High", *The Oregonian*
December 2012	"Are Electric Vehicles Actually Cost-Effective?", *Electricity Policy*

November 30, 2012	"Portland's Energy Credits: The trouble with buying 'green'", *The Oregonian*
July 2009	"Fingerprinting the Invisible Hand", *Public Utilities Fortnightly*
February 2008	Co-author, "The High Cost of Restructuring", *Public Utilities Fortnightly*
March 27, 2006	Co-author, "A Decisive Time for LNG", *The Daily Astorian*
February 9, 2006	"Opening the Books", *The Oregonian*
August 2005	"Squeezing Scarcity from Abundance", *Public Utilities Fortnightly*
April 1, 2002	"The California Crisis: One Year Later", *Public Utilities Fortnightly*
March 13, 2002	"A Sudden Squall", *The Seattle Times*
March 1, 2002	"What the ISO Data Says About the Energy Crisis", *Energy User News*
February 1, 2001	"What Oregon Should Know About the ISO", *Public Utilities Fortnightly*
January 1, 2001	"Price Spike Tsunami: How Market Power Soaked California", *Public Utilities Fortnightly*
March 1999	"Winners & Losers in California", *Public Utilities Fortnightly*
July 15, 1998	"Are Customers Necessary?", *Public Utilities Fortnightly*
March 15, 1998	"Can Electricity Markets Work Without Capacity Prices?", *Public Utilities Fortnightly*
February 1998	"Coping with Interruptibility", *Energy Buyer*
January 1998	"Pondering the Power Exchange", *Energy Buyer*
December 1997	"Getting There Is Half the Cost: How Much Is Transmission Service?", *Energy Buyer*
November 1997	"Is Capacity Dead?", *Energy Buyer*

October 1997	"Pacific Northwest: An Overview", *Energy Buyer*
August 1997	"A Primer on Price Volatility", *Energy Buyer*
June 1997	"A Revisionist's History of the Future", *Energy Buyer*
Winter 1996	"What Are We Waiting for?" *Megawatt Markets*
October 21, 1996	"Trading on the Index: Spot Markets and Price Spreads in the Western Interconnection", *Public Utilities Fortnightly*

McCullough Research Reports

June 13, 2017	"Privatization of Bonneville Power Administration's Transmission Assets"
May 8, 2017	"Response to Public Power Council staff comments on replacing the Columbia Generating Station with lower cost renewables"
April 3, 2017	"Who actually pays for the Columbia Generating Station?"
February 15, 2017	"Replacing the Columbia Generating Station with Renewable Energy"
November 14, 2016	"Review of 'Economic Analysis of Proposed Changes to the Single Dwelling Zone Development Standard'"
October 5, 2016	"The Falling Price of Renewable Energy Relative to Conventional Generation"
October 3, 2016	"Statistical Evidence on the Increase in Portland Home Values Correlated with Historic Districts"
September 5, 2016	"Why are House Prices so high in the Portland Metropolitan Area?"
July 8, 2016	"Historic District Econometric Literature Review"
June 21, 2016	"Columbia Generating Station (CGS) Market Update"

November 19, 2015	"Market Cost of the Columbia Generating Station During the FY 2014/2015 Refueling Cycle"
September 30, 2015	"Decrypting New York's "Secret" Electric Bids"
September 9, 2015	"Market Power in West Coast Gasoline Markets: September Update"
September 8, 2015	"August 10, 2015 PADD 2 Gasoline Spike at BP Whiting's Pipestill 12"
July 23, 2015	"Market Power in West Coast Gasoline Markets: July Update"
June 23, 2015	"Market Power in West Coast Gasoline Markets: June Update"
May 25, 2015	"Site C Business Case Assumptions Review"
April 7, 2015	"2015 Paducah Update"
April 6, 2015	"Market Power in West Coast Gasoline Markets: April Update"
March 23, 2015	"Market Power in West Coast Gasoline Markets"
March 20, 2015	"Daniel Poneman and the Paducah Transaction"
January 2, 2015	"Data and Methodological Errors in the Portland Commercial Street Fee"
December 15, 2014	Report to the Bureau d'audiences publiques sur l'environment (BAPE), "Uranium Mining in Quebec: Four Conclusions"
February 11, 2014	"Energy Northwest's Revised Analysis of the Paducah Fuels Transaction"
January 25, 2014	"Energy Northwest Losses in the 2013 Forward Purchase of Nuclear Fuel"
January 2, 2014	"Review of the November 2013 Energy Northwest Study"
December 11, 2013	"Economic Analysis of the Columbia Generating Station"

February 21, 2013	"McCullough Research Rebuttal to Western States Petroleum Association"
November 15, 2012	"May and October 2012 Gasoline Price Spikes on the West Coast"
June 5, 2012	"Analysis of West Coast Gasoline Prices"
October 3, 2011	"Lowering Florida's Electricity Prices"
July 14, 2011	"2011 ERCOT Blackouts and Emergencies"
March 1, 2010	"Translation" of the September 29, 2008 NY Risk Consultant's Hydraulics Report to Manitoba Hydro CEO Bob Brennan
December 2, 2009	"Review of the ICF Report on Manitoba Hydro Export Sales"
June 5, 2009	"New York State Electricity Plants' Profitability Results"
May 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas"
April 7, 2009	"A Forensic Analysis of Pickens' Peak: Speculation, Fundamentals or Market Structure"
March 30, 2009	"New Yorkers Lost $2.2 Billion Because of NYISO Practices"
March 3, 2009	"The New York Independent System Operator's Market-Clearing Price Auction is Too Expensive for New York"
February 24, 2009	"The Need for a Connecticut Power Authority"
January 7, 2009	"Review of the ERCOT December 18, 2008 Nodal Cost Benefit Study"
August 6, 2008	"Seeking the Causes of the July 3rd Spike in World Oil Prices" (updated September 16, 2008)
April 7, 2008	"Kaye Scholer's Redacted 'Analysis of Possible Complaints Relating to Maryland's SOS Auctions'"
February 1, 2008	"Some Observations on Societe Generale's Risk Controls"

June 26, 2007	"Looking for the 'Voom': A Rebuttal to Dr. Hogan's 'Acting in Time: Regulating Wholesale Electricity Markets'"
September 26, 2006	"Did Amaranth Advisors, LLC Attempt to Corner the March 2007 NYMEX at Henry Hub?"
May 18, 2006	"Developing a Power Purchase/Fuel Supply Portfolio: Energy Strategies for Cities and Other Public Agencies"
April 12, 2005	"When Oil Prices Rise, Using More Ethanol Helps Save Money at the Gas Pump"
April 12, 2005	"When Farmers Outperform Sheiks: Why Adding Ethanol to the U.S. Fuel Mix Makes Sense in a $50-Plus/Barrel Oil Market"
April 12, 2005	"Enron's Per Se Anti-Trust Activities in New York"
February 15, 2005	"Employment Impacts of Shifting BPA to Market Pricing"
June 28, 2004	"Reading Enron's Scheme Accounting Materials"
June 5, 2004	"ERCOT BES Event"
August 14, 2003	"Fat Boy Report"
May 16, 2003	"CERA Decision Brief"
January 16, 2003	"California Electricity Price Spikes"
November 29, 2002	"C66 and Artificial Congestion Transmission in January 2001"
August 17, 2002	"Three Days of Crisis at the California ISO"
July 9, 2002	"Market Efficiencies"
June 26, 2002	"Senate Fact Sheet"
June 5, 2002	"Congestion Manipulation"
May 5, 2002	"Enron's Workout Plan"
March 31, 2002	"A History of LJM2"

February 2, 2002	"Understanding LJM"
January 22, 2002	"Understanding Whitewing"

Testimony and Comment

December 14, 2016	Testimony to the U.S. Court of Federal Claims on behalf of the U.S. Department of Justice regarding nuclear rate case
February 10, 2016	Testimony before the Supreme Court of British Columbia on the costs and benefits of delaying Site C dam
August 24, 2015	Testimony to the New York State Public Service Commission on behalf of the New York State Legislative Assembly
May 29, 2015	Testimony before the Federal Energy Regulatory Commission on behalf of Illinois Attorney General Lisa Madigan
December 15, 2014	Testimony before the Bureau d'audiences publiques sur l'environment (BAPE) in Quebec, "Uranium Mining in Quebec: Four Conclusions"
November 15, 2012	Testimony before the California State Senate Select Committee on Bay Area Transportation on West Coast gasoline price spikes in 2012
July 20, 2010	Testimony before the Rhode Island Public Utility Commission on the Deepwater offshore wind project
April 7, 2009	Testimony before the U.S. Senate Committee on Energy and Natural Resources on "Pickens' Peak"
March 5, 2009	Testimony before the New York Assembly Committee on Corporations, Authorities and Commissions, and the Assembly Committee on Energy, "New York Independent System Operators Market Clearing Price Auction is Too Expensive for New York"
February 24, 2009	Testimony before the Energy and Technology Committee, Connecticut General Assembly, "An Act Establishing a Public Power Authority" on behalf of AARP

September 16, 2008	Testimony before the U.S. Senate Committee on Energy and Natural Resources, "Depending On 19th Century Regulatory Institutions to Handle 21st Century Markets"
January 7, 2008	Supplemental Comment ("The Missing Benchmark in Electricity Deregulation") before the Federal Energy Regulatory Commission on behalf of American Public Power Association, Docket Nos. RM07-19-000 and AD07-7-000
August 7-8, 2007	Testimony before the Oregon Public Utility Commission on behalf of Wah Chang, Salem, Oregon, Docket No. UM 1002
February 23 and 26, 2007	Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180
October 2, 2006	Direct Testimony before the Régie de l'énergie, Gouvernement du Québec on behalf of the Grand Council of the Cree
August 22, 2006	Rebuttal Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
June 1, 2006	Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
May 8, 2006	Testimony before the U.S. Senate Democratic Policy Committee, "Regulation and Forward Markets: Lessons from Enron and the Western Market Crisis of 2000-2001"
December 15, 2005	Direct Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
December 14, 2005	Deposition before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility District No. 1 of Cowlitz County, No. 04-5052RBL
December 4, 2005	Expert Report on behalf of Utility Choice Electric in Civil Action No. 4:05-CV-00573

July 27, 2005	Expert Report before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility District No. 1 of Cowlitz County, Docket No. CV04-5052RBL
May 6, 2005	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
May 1, 2005	Rebuttal Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
March 24-25, 2005	Deposition by Enron Power Marketing, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
February 14, 2005	Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
January 27, 2005	Supplemental Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180, et al.
April 14, 2004	Deposition by Enron Power Marketing, Inc. and Enron Energy Services before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
April 10, 2004	Rebuttal Testimony on behalf of the Office of City and County Attorneys, San Francisco, California, City and County Attorneys, San Francisco, California v. Turlock Irrigation District, Non-Binding Arbitration
February 24, 2004	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.

March 20, 2003	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of the City of Seattle, Washington, Docket No. EL01-10, et al.
March 11-13, 2003	Deposition by IdaCorp Energy L.P. before the District Court of the Fourth Judicial District of the State of Idaho on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
March 3, 2003	Expert Report before the District Court of the Fourth Judicial District of the State of Idaho on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
February 27, 2003	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington and the Port of Seattle, Washington, Docket No. EL01-10-005
October 7, 2002	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
October 2002	Expert Report before the Circuit Court of the State of Oregon for the County of Multnomah on behalf of Alcan, Inc., Alcan, Inc. v. Powerex Corp., Case No. 50 198 T161 02
September 27, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
August 8-9, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
August 8, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.

June 28, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
May 6, 2002	Rebuttal Testimony before the Public Service Commission of Utah on behalf of Magnesium Corporation of America in the Matter of the Petition of Magnesium Corporation of America to Require PacifiCorp to Purchase Power from MagCorp and to Establish Avoided Cost Rates, Docket No. 02-035-02
April 11, 2002	Testimony before the U.S. Senate Committee on Commerce, Science and Transportation, Washington DC
February 13, 2002	Testimony before the U.S. House of Representatives Subcommittee on Energy and Air Quality, Washington DC
January 29, 2002	Testimony before the U.S. Senate Committee on Energy and Natural Resources, Washington DC
August 30, 2001	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10
August 16, 2001	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10
June 12, 2001	Rebuttal Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
April 17, 2001	Before the Public Utility Commission of the State of Oregon, Direct Testimony on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002

March 17, 2000	Rebuttal Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10
February 1, 2000	Direct Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10

Presentations

January 23-24, 2017	"Are Electric Markets Obsolete?", Buying & Selling Electric Power Conference, Seattle, Washington
December 3, 2015	"Ozymandias: Seventeen years of administered markets, high costs, and poor eligibility", Utility Markets Today, Rockville, Maryland
May 6, 2014	"Economic Analysis of the Columbia Generating Station", Energy Northwest, Boise, Idaho
April 30, 2014	"Economic Analysis of the Columbia Generating Station", Portland State University, Portland, Oregon
April 22, 2014	"Economic Analysis of the Columbia Generating Station", Clark County, Vancouver, Washington
January 9, 2014	"Economic Analysis of the Columbia Generating Station", Northwest Power & Conservation Council, Portland, Oregon
January 1, 2014	"Economic Analysis of the Columbia Generating Station", Bonneville Power Administration, Portland, Oregon
December 2, 2013	"Economic Analysis of the Columbia Generating Station", Skamania, Carson, Washington
December 1, 2013	"Peak Peddling: Has Portland Bicycling Reached the Top of the Logistic Curve?" Oregon Transportation Research and Education Consortium, Portland, Oregon

July 12, 2013	"Economic Analysis of the Columbia Generating Station", Tacoma, Washington
June 21, 2013	"Economic Analysis of the Columbia Generating Station", Seattle City Light, Seattle, Washington
January 29, 2013	"J.D. Ross (Who)", Portland Rotary Club, Portland, Oregon.
January 13, 2011	"Estimating the Consumer's Burden from Administered Markets", American Public Power Association conference, Washington, DC
October 15, 2009	"The Mysterious New York Market", EPIS, Tucson, Arizona
October 14, 2009	"Do ISO Bidding Processes Result in Just and Reasonable Rates?", legal seminar, American Public Power Association, Savannah, Georgia
June 22, 2009	"Pickens' Peak Redux: Fundamentals, Speculation, or Market Structure", International Association for Energy Economics
June 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas", Presentation at Texas Legislature
May 8, 2009	"Pickens' Peak", Economics Department, Portland State University
April 7, 2009	"Pickens' Peak: Speculators, Fundamentals, or Market Structure", 2009 EIA energy conference, Washington, DC
February 4, 2009	"Why We Need a Connecticut Power Authority", presentation to the Energy and Technology Committee, Connecticut General Assembly
October 28, 2008	"The Impact of a Volatile Economy on Energy Markets", NAESCO annual meeting, Santa Monica, California
April 1, 2008	"Connecticut Energy Policy: Critical Times…Critical Decisions", House Energy and Technology Committee, the Connecticut General Assembly

May 23, 2007	"Past Efforts and Future Prospects for Electricity Industry Restructuring: Why Is Competition So Expensive?", Portland State University
February 26, 2007	"Trust, But Verify", Take Back the Power Conference, National Press Club, Washington, DC
May 18, 2006	"Developing a Power Purchase/Fuel Supply Portfolio"
February 12, 2005	"Northwest Job Impacts of BPA Market Rates"
January 5, 2005	"Why Has the Enron Crisis Taken So Long to Solve?", Public Power Council, Portland, Oregon
September 20, 2004	"Project Stanley and the Texas Market", Gulf Coast Energy Association, Austin, Texas
September 9, 2004	"Back to the New Market Basics", EPIS, White Salmon, Washington
June 8, 2004	"Caveat Emptor", ELCON West Coast Meeting, Oakland, California
June 9, 2004	"Enron Discovery in EL03-137/180"
March 31, 2004	"Governance and Performance", Public Power Council, Portland, Oregon
January 23, 2004	"Resource Choice", Law Seminars International, Seattle, Washington
January 17, 2003	"California Energy Price Spikes: The Factual Evidence", Law Seminars International Seattle, Washington
January 16, 2003	"The Purloined Agenda: Pursuing Competition in an Era of Secrecy, Guile, and Incompetence"
September 17, 2002	"Three Crisis Days", California Senate Select Committee, Sacramento, California
June 10, 2002	"Enron Schemes", California Senate Select Committee Sacramento, California

May 2, 2002	"One Hundred Years of Solitude"
March 21, 2002	"Enron's International Ventures", Oregon Bar International Law Committee, Portland, Oregon
March 19, 2002	"Coordinating West Coast Power Markets", GasMart, Reno, Nevada
March 19, 2002	"Sauron's Ring", GasMart, Reno, Nevada
January 25, 2002	"Deconstructing Enron's Collapse: Buying and Selling Electricity on The West Coast", Seattle, Washington
January 18, 2002	"Deconstructing Enron's Collapse", Economics Seminar, Portland State University
November 12, 2001	"Artifice or Reality", EPIS Energy Forecast Symposium, Skamania, Washington
October 24, 2001	"The Case of the Missing Crisis" Kennewick Rotary Club, Kennewick, Washington
August 18, 2001	"Preparing for the Next Decade"
June 26, 2001	"Examining the Outlook on Deregulation"
June 25, 2001	Presentation, Energy Purchasing Institute for International Research (IIR), Dallas, Texas
June 6, 2001	"New Horizons: Solutions for the 21st Century", Federal Energy Management-U.S. Department of Energy, Kansas City, Kansas
May 24, 2001	"Five Years"
May 10, 2001	"A Year in Purgatory", Utah Industrial Customers Symposium-Utah Association of Energy Users, Salt Lake City, Utah
May 1, 2001	"What to Expect in the Western Power Markets this Summer", Western Power Market Seminar, Denver, Colorado
April 23, 2001	"Emerging Markets for Natural Gas", West Coast Gas Conference, Portland, Oregon

April 18, 2001	"Demystifying the Influence of Regulatory Mandates on the Energy Economy" Marcus Evans Seminar, Denver, Colorado
April 4, 2001	"Perfect Storm", Regulatory Accounting Conference, Las Vegas, Nevada
March 21, 2001	"After the Storm 2001", Public Utility Seminar, Reno, Nevada
February 21, 2001	"Future Imperfect", Pacific Northwest Steel Association, Portland, Oregon
February 12, 2001	"Power Prices in 2000 through 2005", Northwest Agricultural Chillers, Bellingham, Washington
February 6, 2001	Presentation, Boise Cascade Management, Boise, Idaho
January 19, 2001	"Wholesale Pricing and Location of New Generation Buying and Selling Power in the Pacific Northwest", Seattle, Washington
October 26, 2000	"Tsunami: Market Prices since May 22nd", International Association of Refrigerated Warehouses, Los Vegas, California
October 11, 2000	"Tsunami: Market Prices since May 22nd", Price Spikes Symposium, Portland, Oregon
August 14, 2000	"Anatomy of a Corrupted Market", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 30, 2000	"Northwest Market Power", Governor Locke of Washington, Seattle, Washington
June 10, 2000	"Northwest Market Power", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 5, 2000	"Northwest Market Power", Georgia Pacific Management
May 10, 2000	"Magnesium Corporation Developments", Utah Public Utilities Commission
May 5, 2000	"Northwest Power Developments", Georgia Pacific Management

January 12, 2000	"Northwest Reliability Issues", Oregon Public Utility Commission

Volunteer Positions

2015-Present	Board member, Portland State University Master in Public Policy Advisory Committee
2016-2017	Eastmoreland Neighborhood Association, Treasurer
2013-2016	Eastmoreland Neighborhood Association, President
2013-2016	Southeast Uplift Neighborhood Coalition, President
2013-Present	City of Portland Office of Management and Finance Advisory Committee
1990-Present	Chairman, Portland State University Economics Department Advisory Committee

Respectfully Submitted,

Robert McCullough