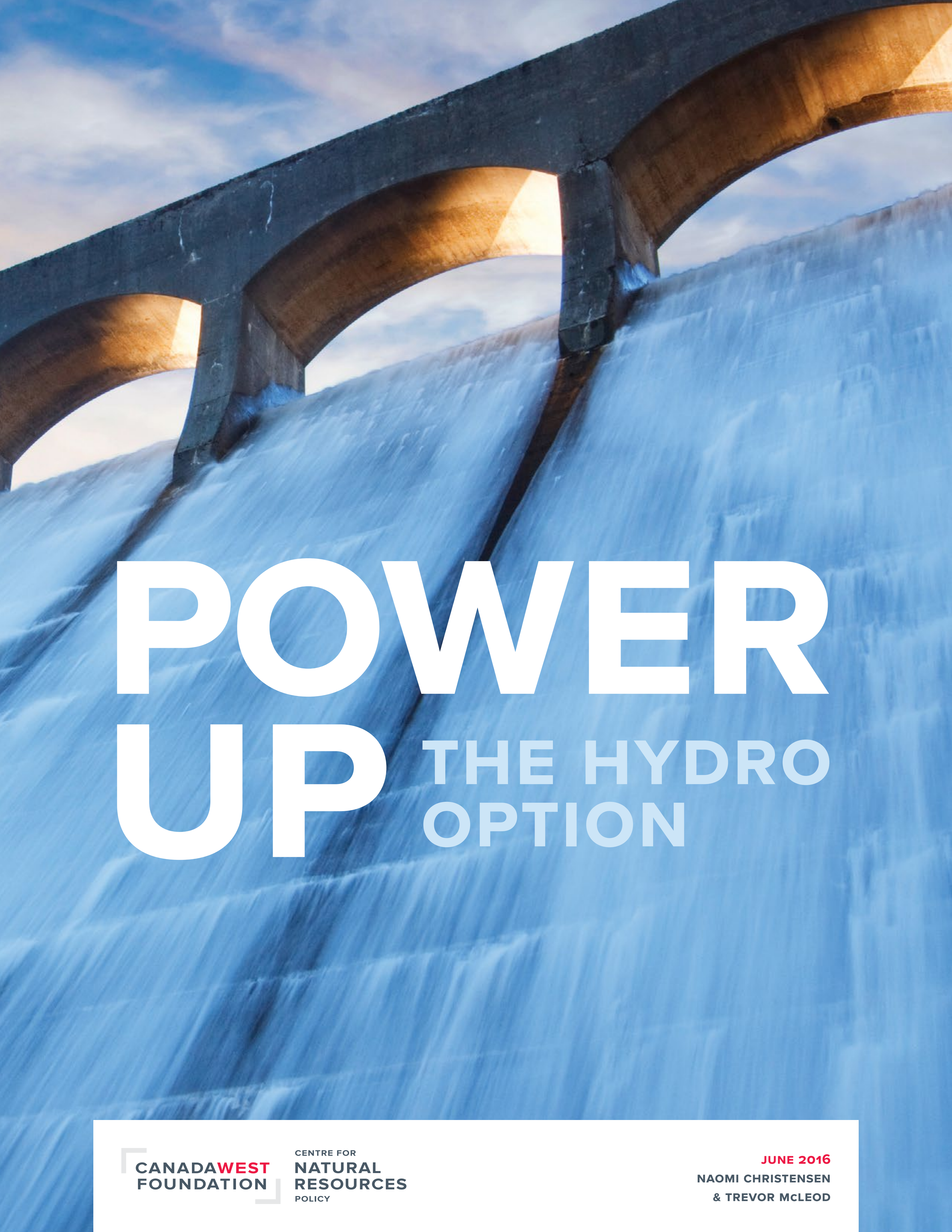

POWER UP
THE HYDRO OPTION

CANADA WEST FOUNDATION

CENTRE FOR NATURAL RESOURCES POLICY

JUNE 2016

NAOMI CHRISTENSEN
& TREVOR McLEOD

CANADA WEST FOUNDATION

cwf.ca

The Canada West Foundation focuses on the policies that shape the West. Through our evidence-based research and commentary, we provide practical solutions to tough public policy challenges. For more than 40 years, we have been a passionate advocate for western Canada.

This report was prepared for the Canada West Foundation's *Centre for Natural Resources Policy* by Naomi Christensen, a policy analyst at the Foundation and Trevor McLeod, the centre's director. The author extends thanks to Floyd Wist, Mike Balfour, BC Hydro and others for providing comments on a draft of the report. The author would also like to acknowledge the dedicated team at the Canada West Foundation who helped enrich the report. Particular thanks is offered to past president Dylan Jones.

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CENTRE FOR NATURAL RESOURCES POLICY

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EXECUTIVE SUMMARY

Alberta and Saskatchewan have ambitious plans to reduce electricity-based greenhouse gas (GHG) emissions. Real action in the electricity sector in Alberta and Saskatchewan would reduce Canadian emissions significantly. Yet, it is important to consider more than just emission reductions when investing in new power generation.

Power generation options come with different costs. Natural gas is the least expensive option. While natural gas should (and will) play a role in both Alberta's and Saskatchewan's strategies, both provinces are emphasizing a move toward technologies with zero emissions. The discussion in both provinces tends to centre on wind power as the lowest-cost, non-emitting solution. While this is understandable, one player has received less than its fair share of attention: hydro.

This analysis reveals that hydro is the lowest cost non-emitting generation option. While hydro has high upfront capital costs and is more expensive to build than natural gas, it has the longest lifespan and the lowest operating costs of all power generation options. Another advantage is that hydro produces reliable baseload electricity, making it a natural substitute for coal-fired generation. If the goal is to replace coal-fired generation with low-cost and reliable substitutes that reduce emissions, then hydro deserves consideration.

For Alberta and Saskatchewan, interprovincial hydro imports may be the most feasible option – in terms of both cost and time – to bring a substantial volume of hydro onto their grids by 2030. Despite the challenges associated with building linear infrastructure in this country, both provinces are well-situated to access hydro imports from B.C. and Manitoba.

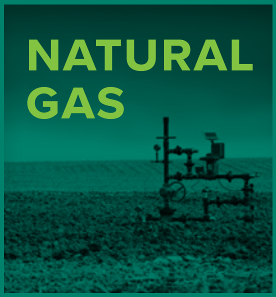
Alberta and Saskatchewan should:

CREATE RULES THAT DO NOT DISADVANTAGE INVESTMENT IN HYDROELECTRICITY.

GET BEHIND THE IDEA OF AN INTEGRATED WESTERN ELECTRICITY GRID.

The federal government should:

FUND INTERPROVINCIAL ELECTRICITY TRANSMISSION LINES IN THE WEST TO FACILITATE INCREASED INTERPROVINCIAL TRADE IN RENEWABLE ELECTRICITY.

 **NATURAL GAS**	Emissions **⅔ LOWER** than coal	**LOWEST** cost option	**BASELOAD** source of power
 **HYDRO**	**ZERO** emissions	**LONGEST** lifespan **LOWEST** operating costs	**BASELOAD** source of power
 **WIND**	**ZERO** emissions	**SHORTEST** lifespan **HIGHER** operating costs than hydro	**INTER-MITTENT** source of power

BASELOAD power sources can generate electricity 24/7, and be dispatched on demand.

INTERMITTENT power sources generate electricity only when weather conditions are favourable. They cannot be dispatched on demand.

EMISSIONS

And plans to reduce them

The nature of the Canadian federation is such that the federal government can and does set goals in areas it has little direct influence over. At the UN Climate Change summit in December, for example, the federal government reaffirmed Canada's commitment to reduce GHGs by 240 megatonnes (MT). This ambitious goal is all the more difficult because emissions are concentrated in specific sectors that are highly vulnerable to international competition. In March, the prime minister and premiers gathered in Vancouver to establish a path toward a Pan-Canadian Climate Strategy that emphasized taking action in the electricity and transportation sectors.

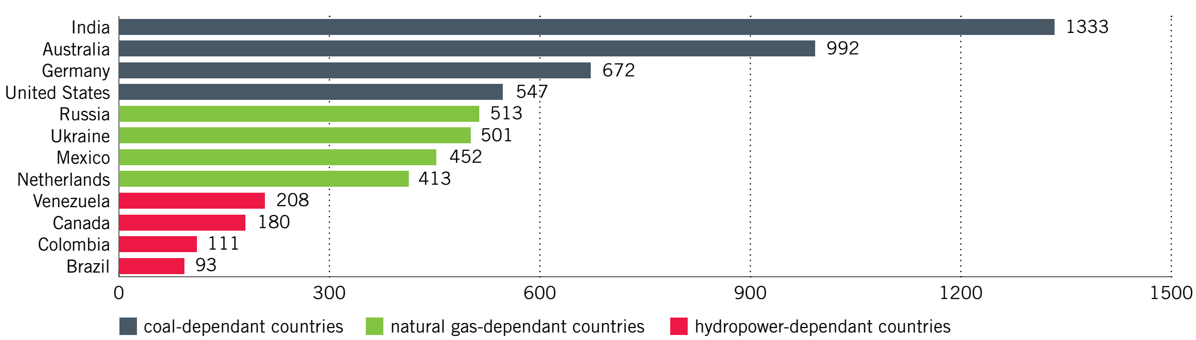
Of all provinces, Alberta and Saskatchewan have the least renewable energy and the most trade-exposed economies. Reducing emissions on their power grids means these provinces can eliminate emissions without directly targeting trade-exposed sectors. The two provinces recently set ambitious targets to increase their renewable electricity by 2030. The question is how to achieve these goals without compromising industry competitiveness and driving up costs for consumers.

Canada's electricity grid is one of the cleanest in the world

Canada's electricity grid is already one of the cleanest in the world. It ranks first in the G7 for renewable electricity generation, and second (behind France) for electricity generated from non-emitting sources.[1] In 2014, more than 80 per cent of the electricity generated in Canada was produced with no emissions. The majority (62 per cent) is from hydro,[2] while nuclear accounts for 16 per cent. Even though wind energy capacity has increased six-fold in Canada in the last decade, wind provides only a small fragment of Canadian electricity.[3]

Figure 1 shows the dominant fuel sources used to provide electricity in various countries and the related carbon emissions. Canada's electricity emissions, like other hydropower consuming countries, rank well below the global energy sector emissions average of 460-500 grams of CO_2 per kilowatt hour (KWh).

FIGURE 1: ELECTRICITY SECTOR EMISSIONS FOR SELECT COUNTRIES (gCO_2/KWh)



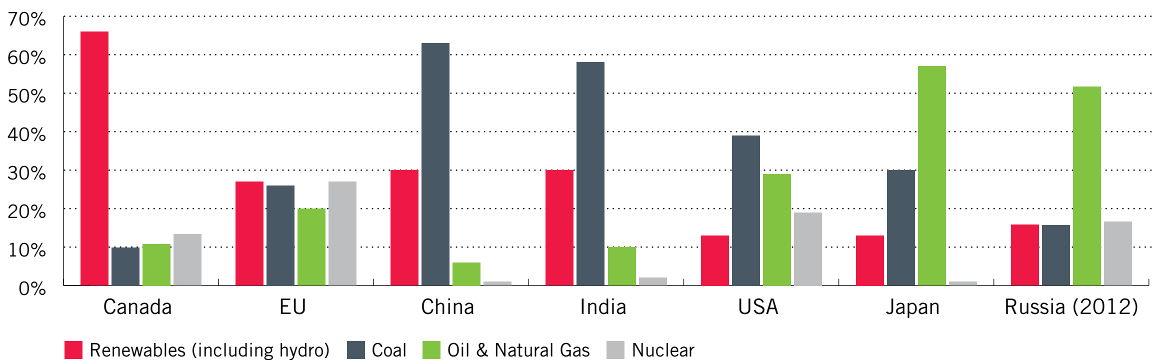
Source: International Energy Agency (2011)

Compared to other major countries, Canada has the largest share of renewable energy generation powering its electricity grid (Figure 2). Given Canada's leadership in clean energy, it is surprising how little international, and even national, attention this receives in discussions of emissions and emission reduction targets.

Renewables fuel electricity generation in the majority of provinces

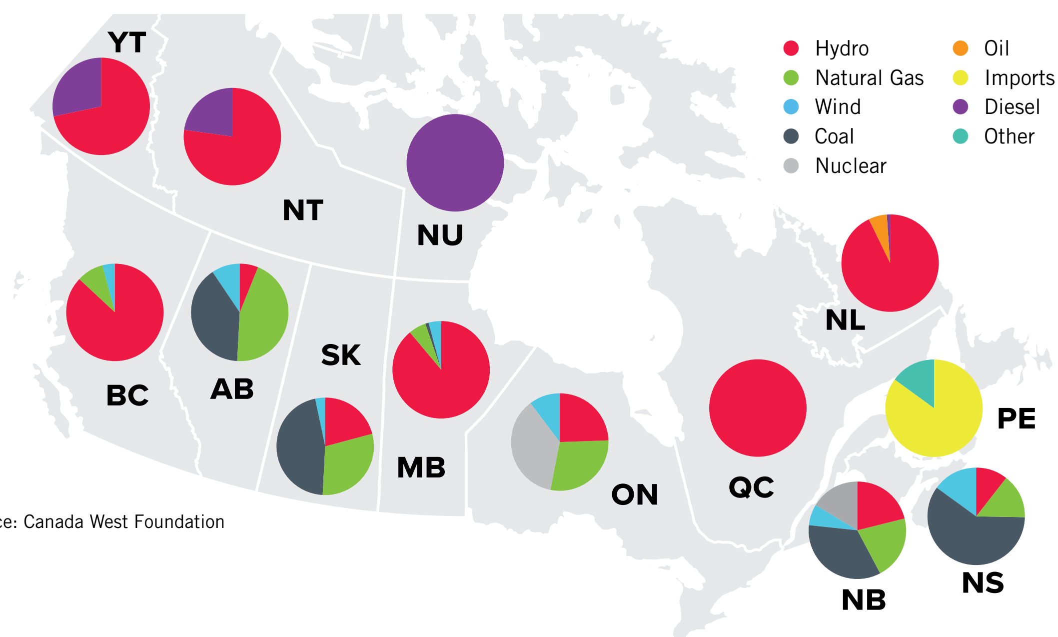
The individual makeup of provincial and territorial electricity grids vary. Many, but not all, provincial grids reflect the national story of being fueled primarily (more than 75 per cent) by renewable energy. In the West, the British Columbia and Manitoba grids are supplied almost entirely by hydroelectricity. Alberta and Saskatchewan are powered primarily by coal and natural gas (as is Nova Scotia).

FIGURE 2: SHARE OF ENERGY GENERATION (2013)



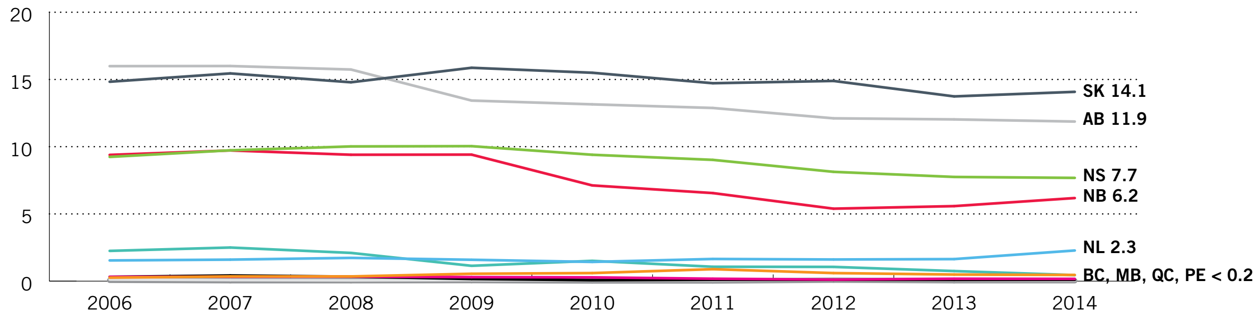
Source: International Energy Agency, Natural Resources Canada, U.S. Energy Information Administration, European Environment Agency, India Central Electricity Authority

FIGURE 3: ELECTRICITY GENERATING CAPACITY BY PROVINCE AND TERRITORY



Source: Canada West Foundation

FIGURE 4: GHG EMISSIONS FROM POWER GENERATION (TONNES PER CAPITA)



Source: SaskWind, Environment Canada National Inventory Report Part 3 (2013), Statistics Canada

In the last decade, the Canadian electricity sector reduced emissions more than any other sector (41 MT from 2004 to 2014).[4] Alberta, Saskatchewan and Nova Scotia together now account for 80 per cent of Canada's emissions from electricity and heat.[5] There is an opportunity to eliminate additional emissions in this sector by changing the electricity mix in these jurisdictions.

The big question is what can replace coal, and whether the alternative will be affordable. Figure 5 provides a snapshot of the GHG intensity of different sources for generating electricity. (The cost of these options are addressed later in this report.)

FIGURE 5: GHG EMISSIONS INTENSITY OF ELECTRICITY SOURCES

TECHNOLOGY	EMISSION INTENSITY (t/MWh)
Conventional Coal	1
Coal with CCS	0.1 – 0.2
High-efficiency Natural Gas*	0.38
Co-generation Natural Gas	0.67
Nuclear	0
Hydro	0
Wind	0
Solar PV	0
Biomass	0

Most global coal-with-CCS (Carbon Capture and Sequestration) projects propose to capture 80 to 90 per cent of emissions. This is reflected in the "Coal with CCS" values. In Canada, Saskatchewan's Boundary Dam Carbon Capture Project is a world leader in using new technology aimed at producing coal-fired energy with zero emissions.

*combined cycle

Source: AESO, U.S. Energy Information Agency

Of all the ways electricity is generated, conventional coal produces the most emissions. In Alberta, 55 per cent of electricity was generated by coal in 2014. In Saskatchewan, conventional coal delivers 32 per cent of provincial generating capacity. Given this reliance on coal, the electricity sectors in Alberta and Saskatchewan have higher emissions than those in other provinces. The electricity sectors account for 17 per cent of Alberta's and 21 per cent of Saskatchewan's total emissions. Displacing any significant amount of high-intensity electricity generation with lower-intensity sources would have a noticeable impact on electricity sector emissions.

Natural gas-fired generation is a relatively clean source of electricity. High-efficiency natural gas plants emit about 40 per cent of the GHG emissions of a conventional coal unit. Natural gas is used in the generation of about 35 per cent of electricity in Alberta, and 40 per cent in Saskatchewan. In Alberta, natural gas is expected to fuel a greater share of electricity generation as the province switches to lower emitting sources of electricity. To the extent that natural gas replaces coal, total emissions in Alberta will decrease.

Electricity generated from nuclear and renewables are emissions free when upstream emissions, such as the manufacture and transport of solar panels and wind turbines, are excluded. The emission intensities in Figure 5 are from generation only, whereas the numbers in Figure 3 reflect capacity.

In 2014, renewables generated nine per cent of the electricity in Alberta. Twenty-five per cent of Saskatchewan's electricity generating capacity (not generation) comes from renewables; 20 per cent is from hydroelectricity. There are no nuclear power plants in western Canada.

THE DIFFERENCE BETWEEN GENERATION AND GENERATION CAPACITY

Electricity generation is the amount of electricity produced on a grid. It is measured in watts/hour. The average Alberta household uses 20KWh of electricity per day. The average hospital uses 62 MWh/day.[6]

Generation Capacity is the amount of electricity the grid is capable of producing if all units were operating at full capacity all day, every day. It is measured in Megawatts (MW). However, "units are rarely used at full capacity over time because of factors such as maintenance requirements, resource limitations and low demand."[7]

Alberta has set a goal of having 30 per cent of electricity generation from renewable sources by 2030. Saskatchewan's target is for 50 per cent of the system's generation capacity to be from renewables in 2030.

ELECTRICITY SECTOR REDUCTIONS ELIMINATE GLOBAL EMISSIONS

Of all Canadian jurisdictions, Alberta and Saskatchewan are the most trade-exposed. Nearly 20 per cent of both provinces' GDP is generated from sectors that compete with firms operating outside the country.[8]

Measures aimed at reducing emissions in trade-exposed industries (like mining, refining, pulp and paper and cement) often result in the transfer of activity – and related emissions – to another jurisdiction. When emissions shift from one country to another, global emissions are not reduced but economies are impacted.

Emission reductions from the electricity and transportation sectors are real reductions in the sense that, as they are reduced, emissions are eliminated rather than moved elsewhere. Focusing action in these sectors will eliminate global emissions, whereas targeting trade-exposed industries merely moves emissions elsewhere while damaging western competitiveness.

Alberta and Saskatchewan emission goals rely on electricity sector reductions[9]

Alberta and Saskatchewan recently set renewable energy targets for 2030. Achieving the targets in both provinces is contingent on adding significant amounts of low-emitting electricity generation.

If Alberta and Saskatchewan meet their goals, approximately 47 MT of emissions will be eliminated.[10] This would amount to a 60 per cent reduction in national *electricity* emissions (as compared to 2014 levels). Put another way, if Alberta and Saskatchewan meet these targets, Canada would be 20 per cent of the way to meeting the goal it set at the UN Climate Summit (30 per cent total emission reductions below 2005 levels by 2030, equivalent to 240 MT).

ALBERTA'S PLAN

Goals are ambitious – even more so than projected

Alberta's *Climate Leadership Plan* aims to reduce provincial emissions by 50 MT by 2030 – with 40 MT coming from the electricity sector.[11] The plan provides two separate benchmarks. First, coal plant operations will be phased out by 2030, and two-thirds of coal-generated electricity will be replaced by renewables. Second, renewables will provide up to 30 per cent of the province's electricity production by 2030.

The *Climate Plan* goals clearly set minimums for renewable electricity *production* by 2030. Achieving this will require more than the 4,200 MW of additional wind capacity the Alberta Electric System Operator (AESO) recently forecast.[12] Discussions with Alberta Energy indicate it is basing the amount of renewable capacity that needs to be added to the grid by 2030 to meet the *Climate Plan* goals on AESO's 4,200 MW number.

The 4,200 MW figure is exactly two-thirds of Alberta's current coal generating capacity. 4,200 MW plus the current 2,800 MW of renewable capacity in the province makes up exactly 30 per cent of AESO's forecast of installed capacity in 2030.

As noted in the text box on Page 8, there is a distinct difference between capacity and generation. For example, in 2014, 17 per cent of Alberta's electricity capacity came from renewables, but only nine per cent of the electricity generated was from renewables. Likewise, nine per cent of Alberta's total capacity is from wind, but wind generated four per cent of the province's electricity in 2014.

The government should clarify whether its goal is to have 30 per cent of the province's electricity *production* or *capacity* to be supplied by renewables in 2030.

Forecasts of electricity demand tell a different story than simply looking at capacity. Analysis indicates Alberta will need between 22,200 GWh and 35,000 GWh of new renewable electricity generation by 2030 to achieve the *Climate Plan* benchmarks (see Appendix 1). To put this in perspective, the minimum requirement is almost 6.5 times more than the amount of wind power and 12 times more than the amount of hydropower generated in the province in 2014. The maximum requirement is 10 times more than the amount of wind power and 18.5 times more than existing hydropower generated in the province in 2014.

Here's the catch – adding 4,200 MW of renewables to the grid by 2030 will only get Alberta to 30 per cent renewable electricity production if the capacity factor[13] of the renewable technology used is close to 100 per cent. The problem is that capacity factors are never 100 per cent, and renewables have lower capacity factors than conventional sources. Figure 6 tells the story.

FIGURE 6: FEASIBILITY OF RENEWABLE OPTIONS TO MEET ALBERTA CLIMATE PLAN GOALS

TECHNOLOGY	CURRENT CAPACITY (MW)	MAXIMUM CAPACITY, 2030 SCENARIO (MW)	CAPACITY FACTOR (%)	ACTUAL ANNUAL PRODUCTION, 2030 (GWh)	SHARE OF 2030 PRODUCTION (%)
Wind	1,459	5,659	30	14,870	13
Large hydro	900	5,100	60	26,805	23
Solar PV	N/A	4,200	15	5,520	5
Biomass	447	4,647	74	30,125	26
Nuclear*	0	4,200	80	29,435	26

*Candu reactor

Source: Canada West Foundation

Wind, for example, has a capacity factor of about 30 per cent. If we add 4,200 MW of wind at a 30 per cent capacity factor, the maximum electricity produced annually by wind in 2030 would be less than half the province's 30 per cent renewable electricity goal.

Both biomass and nuclear have high enough capacity factors that they could individually supply two-thirds of current coal-generated electricity (assuming 4,200 MW is added). However, the high costs of biomass and low public support for nuclear in western Canada make large additions of either source unlikely by 2030.

Renewables will be subsidized

Unlike the other western provinces, Alberta does not own a public utility company. The provincial government is reliant on private utilities, investors and related industries to bring enough new renewable generation online to meet its climate goals.

The Alberta government intends to incent utility companies to bring new renewable capacity online by providing some form of subsidy. The renewables sector indicates that capital intensive projects require revenue certainty to proceed; in response, it is expected the government will introduce a renewable energy credit (REC) program to subsidize upfront costs. AESO has been tasked with recommending to the government an incentive program for renewable energy projects. The government has not mandated what type(s) of renewables should be deployed to meet its renewable targets. It has, however, intimated that wind could be the primary source.

The *Climate Leadership Implementation Act* provides few details on how the *Climate Plan* affects the electricity sector. It is expected the government will provide more details on a potential REC program after cabinet reviews AESO's report.

Mandated, subsidized entry of renewables is a major shift from the design of Alberta's deregulated electricity market where investors determine the timing and type of new generation additions. In the current system, all fuels compete on energy generation costs. Under the deregulated system, more than 6,000 MW of generating capacity has been added to Alberta's grid since 2004, with no government debt incurred.[14] Subsidized renewables would mean that the cost of capacity increases would fall on taxpayers rather than users – keeping users competitive but reducing the incentives to be efficient.

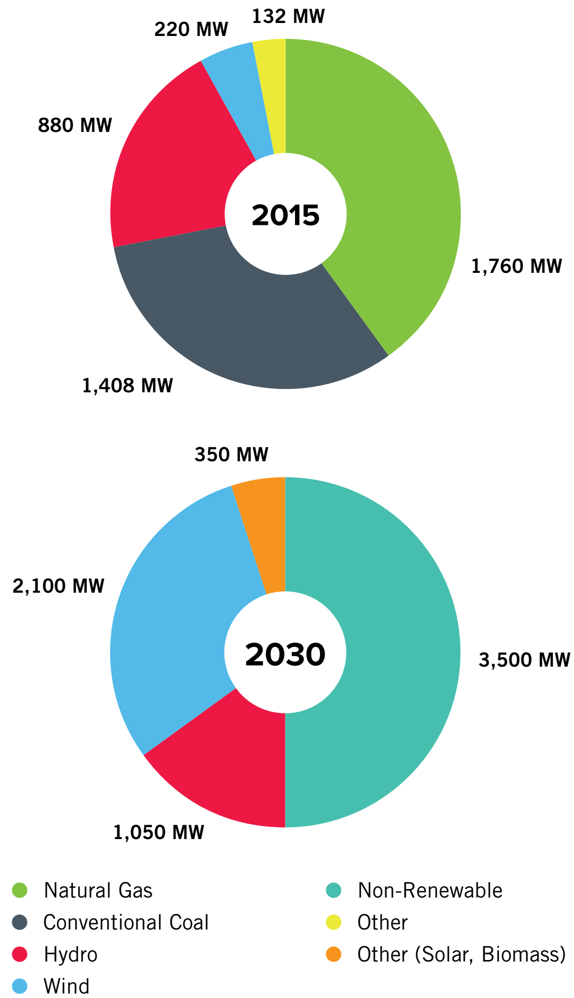
SASKATCHEWAN'S PLAN

In November 2015, SaskPower[15] announced a target of doubling its renewable electricity capacity by 2030, from 25 per cent to 50. This change is expected to reduce emissions by about 7 MT.[16]

Doubling the amount of renewable electricity capacity will require adding 2,288 MW by 2030 – more than coal provides. Saskatchewan plans to achieve this primarily by increasing the use of wind power – from 220 MW today to 2,100 MW in 2030 (a total addition of 1,880 MW). This would raise wind's contribution to the provincial grid from five per cent to 30. The largest share of electricity that wind provides in a Canadian jurisdiction is 14 per cent in Nova Scotia.

While a small hydropower capacity addition is planned – 170 MW – hydro's contribution to the grid is forecast to decrease from 20 per cent to 15 per cent.

FIGURE 7: SASKPOWER ELECTRIC GENERATION CAPACITY MIX



Source: SaskPower

RELIABILITY

Why wind isn't enough

The industries in Alberta and Saskatchewan require large amounts of baseload electricity that can reliably run 24 hours a day, seven days a week. Both provinces' renewable electricity targets need to maintain enough baseload capacity to meet baseload demand in 2030. Wind, however, is intermittent and difficult to predict with certainty. Therefore, hydro should not be dismissed from consideration as a baseload source that can provide consistent electricity production with zero emissions.

Alberta and Saskatchewan require large amounts of baseload power

A large portion of the Alberta and Saskatchewan economies rely on consistent, reliable power. While residential electricity consumers typically have little demand for electricity during the night, industrial users – such as oil fields, mines and processing facilities – run day and night and need baseload power to maintain 24/7 operations.

BASELOAD VS. INTERMITTENT POWER

Baseload power can be thought of as electricity that is available at any time over 24 hours. Sources that can generate electricity 24/7, such as coal and nuclear, are baseload providers. It is costly and time consuming to power these plants up and down; it is more efficient to run them consistently.

Natural gas and hydro are also baseload power sources that can operate 24/7. Both are easier to ramp up or down than coal and nuclear. Because of this, natural gas and hydro complement intermittent sources because they can be dispatched on demand when an intermittent source is not available.

Electricity from **intermittent** power sources, like wind and solar, cannot be dispatched on demand because they will only generate power when weather conditions are favourable. Harnessing renewables like wind and solar to produce electricity is a matter of putting the infrastructure in place to do so; the challenge is not only their economic feasibility, but also the costs of a backup power source.

In Saskatchewan, more than 56 per cent of electricity sales in 2015 went to customers requiring baseload electricity. Under Saskatchewan's plan, more than 65 per cent of the province's electricity generating capacity in 2030 will be from baseload sources – non-renewables, hydro and biomass. Despite being the second largest global producer of uranium, Saskatchewan has no immediate plans to introduce nuclear energy to its electricity mix.

In Alberta, about 95 per cent of electricity is generated from baseload sources, primarily coal and natural gas.[17] In 2015, average baseload demand accounted for about 56 per cent of provincial generating capacity, while the peak reached 69 per cent.[18] If AESO's forecast of average baseload growth is accurate, in 2030, about 60 per cent of capacity will be required to meet average baseload demand. If peak demand in 2030 is 13 per cent higher than the average – as was the case in 2015 – the maximum baseload demand would be about 73 per cent. If all renewable capacity additions come from wind, Alberta's baseload capacity would be about 75 per cent in 2030. This is enough to cover the expected average baseload demand of 60 per cent, but uncomfortably close to the 2030 peak demand requirement.[19]

Intermittent sources are less predictable than baseload sources

Investments in intermittent sources are riskier than investments in baseload, because you cannot be assured of production volumes. The volume of electricity that baseload sources generate can be controlled. When you build a baseload facility, you can determine how much electricity it will generate and sell. (While this is more complex in Alberta's energy-only market, it is still doable. In Alberta, the pool price is set every hour; prices are also set in contracts between buyers and sellers.) With intermittent sources, like wind and solar, you can model how much electricity you expect to generate based on location, but you cannot control when power is produced. Weather conditions may not meet expectations.

COST

The major driver of choices

Adding new infrastructure for the generation and transmission of renewable electricity will increase the cost of producing electricity. To minimize the costs placed on taxpayers, Alberta and Saskatchewan should look for the most cost-effective options to meet their 2030 targets. Scrutinizing costs with accurate assumptions for each type of technology suggests high-efficiency natural gas is the most cost-effective way of lowering electricity sector emissions, and hydro is the most cost-effective option with zero emissions.

The cost of electricity will rise

It is important to differentiate between cost and price. The costs of generation and transmission rise for many reasons. For example, in both Alberta and Saskatchewan, reducing electricity sector emissions by adding new renewable capacity will require the addition of new infrastructure. It's not certain the market price of electricity will actually rise in an electricity sector where renewables are subsidized (as Alberta plans to do) and dispatched first at minimal variable cost. However, one way or another, citizens will pay. The cost increase could be hidden with tax-funded subsidies. Or, consumers could see an increase on their monthly bills. Generation and transmission costs make up about 65 to 70 per cent of an electricity bill;[20] adding new generation and transmission infrastructure could impact how much residential and industrial users are charged. This is especially evident in Alberta, where the government is eliminating the cheapest source of power (coal), which makes up the majority of electricity generation.

While electricity prices are lowest in hydro-generating provinces (B.C., Manitoba and Quebec), this is largely because the infrastructure has been in place for decades and much of the capital cost is paid.[21]

Western provinces can look east to see the possible effects of a government-imposed shift to renewables. Ontario's *Green Energy Act* created a feed-in-tariff (FIT) program to incent renewable energy production. Through the FIT, the province signed 20-year contracts to buy renewable power at fixed prices well above market prices – about two times the U.S. market price for wind, and 3.5 times the price for solar. Ontario's auditor general recently estimated that over the span of these contracts, consumers will pay more than $9 billion extra for electricity. Further, because the contracts are fixed, Ontario will not benefit from the decreasing prices of wind and solar that are expected as technology improves. While the amount of wind generation in Ontario nearly quadrupled since 2009, it contributed only six per cent of the province's electricity last year. Solar only began generating enough electricity to be calculated in a stand-alone category in 2014, and contributes less than one per cent to the provincial grid.[22]

Alberta and Saskatchewan can learn critical lessons from Ontario's experience. As these provinces move to reduce electricity sector emissions, they should look for the most cost-effective way of doing so, including whether renewable sources are available for import, reducing the need to build all the new capacity within the two provinces.

Cost comparisons

Alberta's and Saskatchewan's renewable energy goals have a tight timeline that leaves less than 14 years to plan, permit and build new generation facilities and associated transmission lines. The governments of both Alberta and Saskatchewan appear to favour the use of wind power to lower electricity sector emissions. However, the cost and emissions reduction potential of all options should be considered.

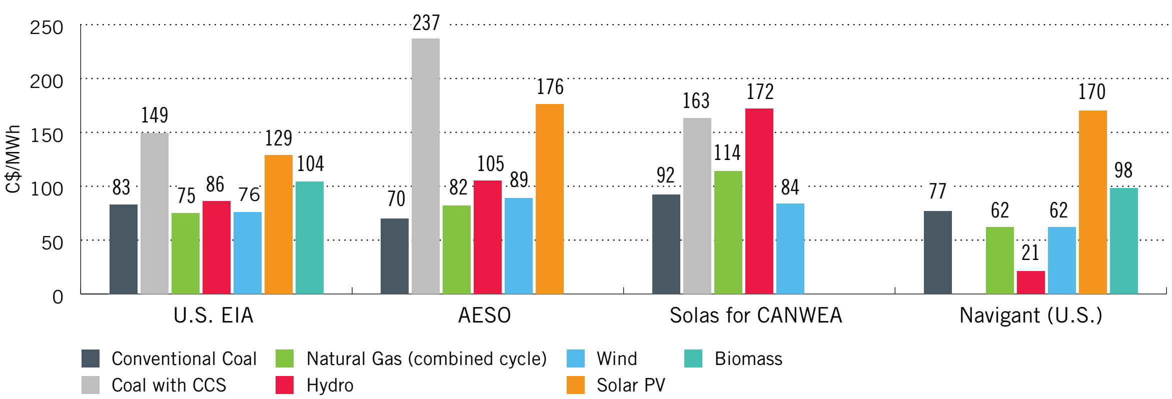
Since different generating technologies have distinct costs and lifespans, the levelized cost of electricity (LCOE),[23] which takes all these factors into account, is often used to compare costs of different options. LCOE's original purpose was to compare baseload technologies, which have similar characteristics. There is debate over whether the application of LCOE to compare intermittent technologies is accurate – particularly in comparison to baseload sources. However, LCOE data is still most often used to make cost comparisons between both types of technologies.

Figure 8 below shows how levelized cost estimates can differ significantly. The assumptions behind LCOE numbers, particularly about operating lifetime and capacity factors, explains the variation.

The biggest difference in the LCOE values in Figure 8 are between hydro and wind. Both the AESO and U.S. government portray wind as having lower levelized costs than hydro. However, their assumptions do not take the different operating lifespans of wind and hydro facilities into account. Wind's lifespan is about 20 to 25 years, whereas a hydro facility can operate from 60 to 100 years. When real operating lifespans are considered, hydro has similar or lower levelized costs than wind. The Navigant Consulting estimates in Figure 8 reflect the longer lifespan of hydro.

The data available to base investment decisions on are clearly imperfect, and must be carefully scrutinized. Relying only on AESO data without examining the assumptions behind it may lead to a conclusion that wind is the most cost-effective renewable option. In fact, hydro, because of its long life span and baseload characteristics, could be a better option.

FIGURE 8: COMPARISON OF LEVELIZED COSTS OF ELECTRICITY



Source: AESO, U.S. Energy Information Agency, Solas Energy Consulting, Navigant Consulting

Figure 9 shows levelized costs that are based on realistic operating lifespans. This provides a more accurate picture to compare the cost of different technologies to generate low-emitting electricity in western Canada. (The levelized costs in Figure 9 are taken from multiple sources. Sources and assumptions can be found in Appendix 2.)

Even when data takes into account more accurate lifespans for technologies, comparing LCOE numbers is not a true apples-to-apples comparison. For example, "electricity that can be supplied by a wind generator at a levelized cost of 6¢/KWh is not 'cheap' if the output is available primarily at night when the market value of electricity is only 2.5¢/KWh. Similarly, a combustion turbine with a low expected capacity factor and a levelized cost of 25¢/KWh is not necessarily 'expensive' if it can be called on reliably to supply electricity during all hours when the market price is greater than 25¢/KWh."[24]

It is unclear how much new transmission infrastructure Alberta and Saskatchewan will need to transmit new renewable energy generation onto their grids; LCOE accounts only for costs of generating facilities and does not include associated transmission costs. Decision-makers will need to take transmission costs into account as new generating options are assessed. For example, new wind farms in Saskatchewan may need a new transmission line to connect to the grid. So would hydro development in north-eastern Alberta, where transmission lines are scarce.

FIGURE 9: COST AND EMISSIONS OF ELECTRICITY OPTIONS

TECHNOLOGY	OPERATING LIFE (YEARS)	LEVELIZED COST ($/MWh)	EMISSIONS (MWh)	COST/TONNE REDUCED ($)
Conventional Coal	45	70	1	
SK Coal with CCS*	30	70	0.33	
Co-generation Natural Gas	30	106	0.67	
High-efficiency Natural Gas** (reference case)	30	82	0.38	
Nuclear	60	98	0	42
Hydro	80	97	0	39
Wind	20	120	0	100
Solar PV	30	129	0	124
Biomass	30	104	0	57

* Estimates of a $1.5 B (2015 actual) 30-year planned forecast life for a 120 MW (Net) first of a kind post-combustion carbon capture coal power plant operating at 90 per cent of capacity (946,080 MWh net) with an operating capture rate of 800,000 tonnes CO2 annually from 1,111,000 gross CO2 emissions

** combined cycle natural gas

Source: AESO, U.S. Energy Information Agency, International Renewable Energy Agency, Saskatchewan Ministry of Economy

If coal plants are repurposed into natural gas plants, existing transmission infrastructure could be used, lowering costs. The cost of transmission lines depend on multiple factors, including length of the line, conductor type (AC or DC) and structure type.

The last column in Figure 9 illustrates the cost of reducing emissions for non-emitting sources in relation to high-efficiency natural gas (the reference case). It indicates Alberta's $30 carbon tax will not make any non-emitting source of electricity cost-competitive with high-efficiency natural gas in terms of the cost of reducing emissions. (Again, the costs of transmission or backup for intermittent sources is not reflected in the abatement costs.)

Wind is not the only option; natural gas and hydro deserve consideration

In both Alberta and Saskatchewan, discussion about the 2030 targets is centered on bringing enough wind energy onto the grid to fulfill virtually the entire renewables requirements. Analysis of Figure 9 indicates high-efficiency natural gas and hydro have the potential to help achieve Alberta and Saskatchewan's 2030 goals at the lowest cost.

NATURAL GAS IS THE LEAST EXPENSIVE OPTION

If the goal is to lower electricity sector emissions at the lowest cost to electricity consumers and the public treasury, high-efficiency natural gas is the most attractive option for doing so. Thanks in part to new technology, natural gas plants built today emit less than half as many emissions as coal; their increased use would reduce overall electricity sector emissions at the lowest cost. High-efficiency plants – a term usually used in reference to combined cycle technology when talking about natural gas – produce more electricity than older plants, while burning less fuel and creating fewer emissions.

Natural gas plants also have lower capital and levelized costs than any other generating technology. Fuel costs are expected to remain low; although the National Energy Board forecasts the price of natural gas to increase by 60 per cent by 2035, these price projections are still well below natural gas prices during the 2002-2010 period. Natural gas is readily available in Alberta and Saskatchewan; 79 per cent of Canadian natural gas resources are located in the West.[25]

Alberta's *Climate Plan*, however, is not driven only by cost. Of the coal capacity that will need to be replaced, it caps natural gas at replacing one-third. This leaves two-thirds of the amount of electricity supplied by coal to be supplied by other – renewable – sources. Natural gas is necessary to maintain reliable baseload and provide a backup to intermittent sources. As renewables increase, the amount of gas that needs to be dispatched will decrease. This will make the investment climate for natural gas in Alberta challenging.

"A **combined-cycle** power plant uses both a gas and a steam turbine together to produce up to 50 per cent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power."[26]

In Alberta, 11 per cent of the province's electricity capacity comes from combined-cycle natural gas, 28 per cent comes from co-generation natural gas, and six per cent comes from simple-cycle natural gas. In Saskatchewan, close to half the natural gas capacity is supplied by combined-cycle technology.

HYDRO

Hydro has been widely accepted in western Canada. The West accounts for 27 per cent of Canada's installed hydropower capacity. Hydro generates more than 90 per cent of the electricity in B.C. and 97 per cent in Manitoba.

Hydro's levelized cost is higher than high-efficiency natural gas and conventional coal, but not excessively so. When hydro's full lifespan is taken into account, as it is in Figure 9, it has a lower levelized cost than all the other renewable options. The cost of carbon abatement is also lower for hydro than for any non-emitting option. Operating costs of hydro generation facilities are the lowest of all options. However, capital costs are high and site-sensitive.[27] A barrier to private investment in hydro is the high upfront costs.

Alberta's hydro potential

Specific cases can be looked at to get a clearer sense of the costs associated with hydro projects. A recent study by the Canadian Energy Research Institute (CERI) estimates capital costs for both the generation and transmission infrastructure that would be required to bring large volumes of hydroelectricity onto Alberta's grid. CERI's study examined individual hydro sites that could provide large-scale (at least 500 MW) hydroelectricity to Alberta.[28] These parameters rule out most of the potential hydro sites within Alberta, except for the Slave River. (See Appendix 3 for internal hydro development potential in Alberta.) Although CERI notes the Northwest Territories is reported to have significant hydropower potential, it was not considered as a source of hydro imports for Alberta "due to the unavailability of reliable resource data and potentially longer transmission distances."[29]

The options CERI looked at with potential to provide more than 500 MW of hydropower to Alberta are:

- Site C, B.C.'s hydro development under construction on the Peace River.
- Reinforcing the existing intertie between B.C. and Alberta to fully utilize the capacity of the line and increase hydro imports by Alberta.
- Manitoba's Conawapa hydro facility on the Nelson River north of Lake Winnipeg.

The cost of hydroelectricity is dominated by the capital costs of hydro facilities.[30] The last proposal to develop a hydroelectricity project on the Slave River[31] through a partnership between TransCanada and ATCO was estimated by the companies to require an investment of $5 billion to $7 billion over 10 years.[32] CERI's more recent estimate of developing a similar project today is more than $10 billion.

Figure 10 shows that the estimated capital costs of generation and transmission infrastructure for increasing hydropower on the Alberta grid are significant. CERI's data show transmission infrastructure accounts for 17 to 27 per cent of the total cost of the potential projects it examined.

FIGURE 10: COST, CAPACITY, AND COAL REPLACEMENT POTENTIAL OF LARGE SCALE HYDRO ADDITIONS TO THE ALBERTA GRID

CAPITAL COST (BILLION $)	SITE C (DC)	SITE C (AC)	CONAWAPA (DC)	SLAVE RIVER (DC)	SLAVE RIVER (AC)	B.C. INTERTIE
Generation	8.4	8.4	9.5	8.8	8.8	N/A
Transmission	2	3.1	3.1	1.8	2.6	0.28
TOTAL	10.4	11.5	12.6	10.6	11.4	0.28
Operating & Maintenance Cost* (Million/year)						
Generation	16	16	16	17	17	N/A
Transmission	10	15	16	9	15	93
TOTAL	26	31	32	26	32	93
		SITE C	CONAWAPA		SLAVE RIVER	B.C. INTERTIE
Rated Capacity (MW)		1100	1485		1100	500
Alberta coal generation capacity replacement potential		18%	24%		18%	8%

* In addition to operating and maintenance costs, transmission tariff charges would need to be factored into the price of energy – and therefore paid by the recipient of the energy. This could be particularly significant for a transmission line from Manitoba to Alberta, where tariff charges would need to be paid in Saskatchewan.

Source: Canadian Energy Research Institute, Alberta Energy, Canada West Foundation

The rated capacity of the projects in Figure 10 is not necessarily the capacity Alberta would have access to. With 1,100 MW of capacity, Site C will produce about 5,100 GWh of electricity annually. While some of this power will be surplus to B.C.'s electricity demand, it is expected to be gradually used to meet increasing load growth. BC Hydro estimates the province will need the full capacity of Site C by 2030. It is possible Alberta could access the total capacity of Conawapa. Although the project is approved, it was put on hold in 2014 until export sales can be confirmed.[33] The B.C.-Alberta intertie exists to export B.C. hydropower sales to Alberta. If it were reinforced to utilize its full capacity, Alberta would benefit from an increase of 500 MW of hydroelectric accessibility.

AC & DC DISTINCTION

In alternating current (AC) systems, the electric current changes direction. In direct current (DC) systems, the current flows one way. DC lines are typically used for long-distance transmission because they have higher efficiency and flexibility and a lower physical footprint than AC lines.

Alberta's hydropower potential – defined as the amount of long-term hydroelectric energy that could be extracted from the province's river basins under favourable economic conditions – is 53,000 GWh. As of 2011, about four per cent has been developed.[34] It appears technically feasible that if Alberta decided to meet its renewable generation targets with hydro alone, there is sufficient capacity within the province to do so. It would take 42 per cent of Alberta's total hydro potential to meet the *Climate Plan's* minimum generation volume (22,200 GWh), and 65 per cent to meet the maximum (34,470 GWh).

It is unlikely this volume of hydroelectric generating capacity could be developed within the province by 2030. In 2010, it was estimated only 20 per cent of Alberta's hydro potential – 10,610 GWh – could be developed feasibly by 2040.[35] It is also more cost-efficient to develop one or two large hydro sites, rather than multiple small sites. "[D]ue to the amount of transmission requirements, if sufficient demand is available, developing larger sites with high capacity factors leads to lower overall costs than developing several smaller sites."[36]

Hydro imports would be more cost & time effective

If hydro is to play a part in meeting Alberta's renewable target, it may be more feasible from a cost and time perspective for the province to import hydro rather than develop large scale hydro within the province by 2030. As luck would have it, western neighbours (B.C. and Manitoba) are hydro exporters. In 2014-15, Manitoba exported 30 per cent of the electricity it generated.[37] Manitoba Hydro has sales agreements with utility providers in Minnesota, Wisconsin, and Saskatchewan. This year, Alberta and Manitoba signed a memorandum of understanding that includes improved electrical grid integration as one of its six priorities. (It is unclear whether the recent change in government in Manitoba will affect this MOU.) British Columbia exports hydropower to the U.S. and Alberta. In 2010, the province passed legislation to make exports easier by allowing BC Hydro to sign long-term contracts.[38]

While Alberta has interties with B.C., Saskatchewan and Montana, it is "one of the least interconnected jurisdictions in North America."[39] The existing Alberta-B.C. intertie may be the most logical place to look to for hydro imports to Alberta. It is the least expensive of CERI's options because the transmission infrastructure exists. If it were fully utilized, it could replace close to 10 per cent of the electricity currently generated from coal. CERI estimates it could be fully utilized within two to five years – well before 2030.

Hydro potential in Saskatchewan

Hydropower makes up 20 per cent of Saskatchewan's electricity capacity. SaskPower estimates there is potential to add 3,240 MW of hydropower within the province – about 3.5 times its current capacity. (See Appendix 3 for details.)

While hydro expansions make up a small portion of Saskatchewan's renewable plan as articulated (170 MW), SaskPower is examining the potential of hydro projects, including imports from other provinces.[40]

Saskatchewan has interties with Alberta, North Dakota and Manitoba. In 2020, Manitoba Hydro will begin selling a minimum of 100 MW of hydroelectricity to SaskPower – enough to power about 40,000 homes. This will require the construction of an 80-kilometre transmission line, at an estimated cost of $50 million. The two utility providers also have an MOU in place to potentially expand the transmission capacity to allow 500 MW to move from Manitoba to Saskatchewan.[41] The imports from Manitoba will play a big role in adding the 170 MW of hydroelectric capacity planned by 2030.

Saskatchewan may want to consider a larger role for hydro, particularly if Alberta were to import hydro from Conawapa in Manitoba. Doing so would require new transmission infrastructure that crossed Saskatchewan, in which case the province might be able to secure a substation to import a portion of the electricity onto the Saskatchewan grid. The recent Alberta-Manitoba MOU recognizes "that discussions of the expansions of electrical grids through western Canada should include Saskatchewan."[42]

Hydro faces public support challenges

The biggest potential barrier to new hydro developments is a lack of public support for both dams and transmission infrastructure.

While importing hydropower into Alberta and Saskatchewan is technically viable and appears to be more cost effective than building new, capital-intensive hydro facilities within these two provinces, non-financial barriers pose challenges. Site C, for example, faces environmental opposition. First Nations in B.C. have filed lawsuits to stop the project. Many arguments against the project mirror those used to oppose pipeline infrastructure. Further, the difficulty in building linear infrastructure is not a problem borne only by pipelines. The Western Alberta Transmission Line, completed in 2015, ignited opposition from landowners and ratepayers alike (in Alberta, the cost of building transmission lines is borne by consumers; electricity bill fees are used to cover the construction costs). Projects developed primarily to supply out-of-province customers may be viewed differently by provincial stakeholders than projects serving provincial electricity consumers.

WIND

Wind is a fairly well-established generation technology in western Canada. It can provide large scale power generation with zero emissions. Of all Canadian jurisdictions, Alberta ranks third in terms of installed wind capacity and Saskatchewan ranks seventh. Canada's first commercial wind farm was located in southern Alberta. It was recently decommissioned after 23 years of service.

Wind's intermittent nature results in a gap between the amount of installed capacity and the volume of electricity generated. In 2014, the electricity generated by wind in Alberta used about 27 per cent of wind's total installed capacity. In Saskatchewan, 38 per cent of capacity was used. As the wind does not blow 24/7, it is difficult to predict where and when it will blow and for how long. In Ontario, the provincial feed-in-tariff subsidizing wind power installations increased the amount of wind power, but also caused excess capacity during the night when demand is low. This led the provincial government to cancel all its offshore wind projects, embroiling the province in a NAFTA dispute.[43]

Wind is often portrayed as the renewable with the lowest levelized costs. However, as mentioned earlier, this is the outcome when the operating lifespans and capacity factors of all technologies are assumed to be similar. In reality, wind has the shortest lifespan and one of the lowest capacity factors of any of the renewable and conventional options.

Depending on location, the most economic choice for a low-emitting source of electricity could very well be wind with a natural gas backup. However, favouring the use of wind to generate the majority of the renewable electricity province-wide is based on an inaccurate assumption that it is the most cost-effective option. This is not in the best interests of taxpayers or ratepayers. Looking at data – such as from AESO and the EIA – where hydro's long lifespan is not taken into account, wind is portrayed as the lowest cost option. In reality, if a wind farm and hydro facility came online at the same time, during the lifespan of the hydro facility, the wind turbines would need to be replaced about four times. When assumptions more in line with actual operating reality are taken into account, wind has both higher levelized costs and GHG abatement costs than hydro.

In western Canada, wind developments have so far had fewer public support challenges than hydro developments. Wind turbines in Ontario have become a lightning rod for opposition. Complaints centre on landscape and soundscape "pollution" and health and property value concerns. In comparison, wind farms have operated in Alberta and Saskatchewan for decades with comparatively little public opposition. However, public support for infrastructure is never guaranteed.

Nuclear, solar and biomass won't play a major role by 2030

While nuclear, solar and biomass can provide electricity with few emissions, various factors outlined below suggest these technologies will not be feasible, large-scale providers of electricity in the West in time to contribute to achieving the 2030 goals.

NUCLEAR

Nuclear power should not be written off in the long run as a low-GHG baseload source of electricity with a long lifespan and domestic fuel source (Saskatchewan uranium). However, given its unfamiliarity as a power generator in western Canada, it is not a realistic option to supply any large amount of electricity in Alberta or Saskatchewan by 2030.

Alberta's 2008 *Provincial Energy Strategy* identified nuclear power as a potential source of clean, low-emission power and outlined a public consultation approach to determine a policy. The previous government maintained a policy of considering nuclear power on a case-by-case basis. In 2011, after five years of development, Bruce Power cancelled plans to build a nuclear power plant in northern Alberta because community support for the project was low.

In 2009, when the Government of Saskatchewan undertook public consultation on the topic, 85 per cent of respondents were opposed to the use of nuclear to generate power within the province. In 2011, the province committed $30 million over seven years to establish a nuclear research centre at the University of Saskatchewan; one of the four research areas is focusing on improving the safety and engineering of nuclear energy systems. In 2014, SaskPower's CEO at the time stated the company was keeping a close eye on small modular reactors (SMRs), which are capable of supplying 50-300 MW.[44] Last year, the utility provider's CEO made similar comments but also noted SMRs are not yet commercially viable and would not be used in Saskatchewan until the technology is proven.[45]

SOLAR

Photovoltaic (PV) solar panels emit zero emissions when generating electricity, have low operating costs and an average lifespan close to that of a natural gas or coal plant. In Canada, solar panels are typically used for small scale requirements such as powering road signs or residential homes. Because of high capital costs, solar power is more expensive than power generated by wind or hydro. Like wind, it is intermittent and needs to be backed up with a baseload source. Perhaps the biggest barrier to developing large scale PV plants on the prairies is the large land-use requirements.[46] Unlike with wind turbines, land cannot be used concurrently for both solar panels and agriculture.

BIOMASS

Electricity plants account for only four per cent of the global use of biomass energy.[47] Biomass operations in Canada are typically small. Alberta is unique among the western provinces in that it has more installed biomass capacity than hydro capacity. In terms of actual electricity generation, the two sources provide similar amounts. According to Alberta Energy, in 2014 hydro accounted for two per cent of the province's electricity (1,861 GWh) and biomass contributed three per cent (2,060 GWh).

Biomass electricity can be generated from a variety of materials, and is a baseload power source.[48] While it could be an advantage that biomass plants' fuel source is so diverse, it also makes it difficult to pinpoint how much potential biomass capacity could be developed in a province. Biomass plants also have the highest operating costs of all electricity generating facilities and, along with wind, the shortest lifespans. Primarily because of cost, biomass is not considered in this paper to be a viable option to provide large amounts of power by 2030.

To meet their emission reduction goals in the electricity sector by 2030, while maintaining a stable volume of baseload power, Alberta and Saskatchewan will need to use a mix of generating options to replace high-emitting sources, like coal. The most cost-effective options are natural gas and hydro.

IMPACT ON ALBERTA'S ELECTRICITY MARKET

Alberta is the sole energy-only market in Canada, meaning electricity generators in the province "are only paid for the energy they produce, not how much they are capable of producing."[49] This is different from many other Canadian jurisdictions, where generators are paid based on their supply capacity, regardless of how much electricity is produced. In essence, this kind of market prevents the overpayment experienced in Ontario, where the auditor general recently found electricity consumers have paid $37 billion since 2006 for a global adjustment fee charged on electricity bills "to make up the gap between the market price and the higher, non-market prices that most producers actually receive."[50]

The Alberta Climate Advisory Panel recommended the provincial government maintain the competitive market structure while "providing long-term revenue certainty for renewable power" generators. "Investment costs need to be recovered solely through revenue earned in Alberta's energy and ancillary service markets."[51] This can make it difficult to attract investment for renewable energy projects, which are capital intensive, requiring the majority of costs up front. The long-term revenue certainty recommended by the panel is expected to take the form of direct subsidies through a renewable energy credit program.

Increasing the amount of electricity imports could also precipitate changes. In Alberta's commoditized electricity market, "[r]ules have been applied to intra-Alberta government owned entities, but there do not appear to be similar rules to govern imports, including those from regulated markets and from markets with different design […] where cost recovery risk, leverage, debt backstop, or reciprocal access to consumers, is not the same as it is in Alberta."[52]

WHO SHOULD PAY?

The case for federal participation

In addition to meeting environmental goals, achieving a cleaner grid has the potential to reap significant economic benefits. Environmental and economic benefits will be felt not only by Alberta and Saskatchewan as individual provinces, but also by Canada as a whole. Changing the electricity mix will be expensive, and costs stand to be borne primarily by citizens in Alberta and Saskatchewan. As a beneficiary of the potential benefits, however it would not be extraordinary for the federal government to financially support interprovincial transmission infrastructure for renewable electricity.

There are precedents for ad hoc federal investments

The need for a more connected interprovincial electricity grid in western Canada will arise if hydro imports play a role in achieving Alberta and Saskatchewan's renewables targets. The idea of a regional grid connecting British Columbia and Manitoba hydro power to Alberta and Saskatchewan is not new. B.C. Premier Christy Clark has requested $1 billion in federal infrastructure funding to connect Site C hydropower to Alberta's grid. There is a possibility that an arrangement where B.C. provides power from Site C to Alberta to reduce emissions from the oil sands plants may address some of the challenges of getting pipelines to the West Coast built. BC Hydro is spending more than $8 billion to construct Site C. Connecting the dam to Alberta's grid is estimated by CERI to cost $2 billion.

Prime Minister Justin Trudeau's first budget signals a willingness to make significant investments in the electricity sector. It commits $2.5 million over two years to "facilitate regional dialogues and studies that identify the most promising electricity infrastructure projects with the potential to achieve significant greenhouse gas reductions [… to] help shape future investments to maximize economic and environmental benefits."[53] The potential to make significant emission reductions in the electricity sector lies primarily in Alberta, Saskatchewan and Nova Scotia.

Moving beyond studies to direct financial support for linear infrastructure would not be unprecedented. A few years ago, the federal government provided a $6.4-billion loan guarantee for the Lower Churchill Falls hydro development. Located in Newfoundland and Labrador, the hydro facility will also provide electricity to Nova Scotia. About $1.3 billion of the loan guarantee covers the construction of a transmission line to link the two provinces.[54] The bridge being constructed between Detroit and Windsor provides another example of federal funding for infrastructure that provides both regional and national benefits. The federal government expects to spend about $5 billion on the bridge – the most important trucking route between Canada and the U.S.

The brand advantage of being a low-emitting oil producer is worth billions

The federal government receives about $3 billion in oil and gas royalties each year.[55] The total amount of revenue the federal government receives from this sector is much higher. Revenue is received from royalties, corporate and personal income tax, sales and payroll taxes and land sales. On average, the oil and gas sectors pay $17 billion in federal and provincial taxes annually.[56] Western Canada is responsible for about 95 per cent of Canadian oil production,[57] which provides benefits to all Canadians as a major employer and contributor to the manufacturing supply chain.

The revenue the federal government enjoys from this sector is at risk. The global dynamics of the oil and gas market are far from stable, as current low prices illustrate. Climate change policies can threaten competitiveness if the trade-exposed nature of the sector is not taken into account. Western Canadian oil and gas faces loud criticism internationally and at home.

Despite already having one of the most aggressive carbon pricing systems of any oil producing region in the world, Alberta (and by extension, Canada) is vilified by the environmental movement for producing "dirty" oil. The oil sands' reputation has a real impact on the ability to increase pipeline (i.e. export) capacity. Yet the emissions difference between oil sands and the U.S. crude supply is actually quite small – about six per cent on a well-to-wheels basis.[58] CERI calculates that using hydro to power oil sands production could reduce its emissions by 13 to 16 per cent,[59] making it cleaner than competing crudes. The ability to say, with authority, that western Canadian oil is cleaner than alternatives could be a turning point in the pipeline debate.[60]

A $2-billion investment from the federal government for transmission infrastructure (for example, the cost of a transmission line from Site C to Alberta) is less than a year's worth of taxes paid by the oil and gas sector to the federal government. It would help western Canada achieve a cleaner electricity grid and improve Canada's reputation as an oil producer. This brand advantage would ensure western Canada's oil sector continues to contribute billions to both the private and public sectors, and provide employment in multiple regions of the country.

Electricity reductions will lower emissions from transportation

The transportation sector is Canada's second largest source of emissions after oil and gas production – and therefore a big prize in terms of emission reductions. In 2014, the sector accounted for 170 MT (23 per cent) of national emissions. In comparison, the electricity sector contributed 85 MT (12 per cent of national emissions).[61]

As shown in Figure 11, road transportation (personal vehicles), contributes the majority of transportation sector emissions in Manitoba, B.C., and Alberta, as well as Canada as a whole. They are also significant in Saskatchewan.

FIGURE 11: TRANSPORTATION SECTOR EMISSIONS IN CANADA AND THE WESTERN PROVINCES, 2013 (KT CO_2 EQ.)

SOURCE OF EMISSIONS	CANADA	B.C.	ALBERTA	SASKATCHEWAN	MANITOBA
Transport	204,000	24,800	44,200	16,600	8,220
Road transportation	137,000	15,900	23,700	7,770	5,720
Road transportation's contribution to transport emissions	67%	64%	54%	47%	70%

Source: Environment Canada 1990-2013 National Inventory Report, Part 3

The federal government recently committed to "advance the electrification of vehicle transportation, in collaboration with provinces and territories."[62] In the last election, the Liberal Party promised it would add "electricity storage technologies and electrical car charging stations to the list of investments that are eligible for accelerated capital cost allowance" and work with provinces and companies to attract clean technology companies and investment.[63]

An increased use of electric vehicles would drive up the demand for electricity. If the electricity used to charge these vehicles also comes from non-emitting or low-emitting sources, EVs would mean substantial emission reductions.

While electric vehicles could dramatically reduce Canada's GHG emissions, the widespread adoption of EVs is likely to be a lengthy, and costly, transition. Last year, 6,933 EVs were sold in Canada,[64] accounting for less than 0.4 per cent of the nearly 1.9 million new vehicles sales.[65] In Canada, the average age of vehicles on the road is about 10 years; the majority of Canadians today are buying gasoline-fueled cars, and will continue to drive them for the next decade. This is particularly true in the prairie provinces, where the EV fleet totaled 585 at the end of 2015. Ninety-six per cent of the EV fleet in Canada exists in Quebec, Ontario and B.C. – all provinces with subsidies for both the purchase of electric vehicles and personal charging stations.[66] Ontario plans to spend $20 million on public charging stations, but has not indicated how many stations this funding will generate.

If the vision of a clean Canadian electricity grid, coupled with mass adoption of electric vehicle technology were realized, emission reductions would be significant. These nearly 120 MT of emission reductions[67] would get Canada almost halfway to the emission reduction targets reaffirmed at the UN Climate Summit.

BOTTOM LINE

Hydro has a role to play

Provincial and federal governments are operating on similarly tight timelines to reach their GHG reduction goals. Alberta and Saskatchewan are relying primarily on reductions in the electricity sector to do the heavy lifting, and Ottawa is also giving the sector priority. Action in this sector can reduce real emissions without compromising the competitiveness of western Canada's trade-exposed industries, like oil and gas, which contribute billions to federal government revenue.

To meet their 2030 goals, Alberta and Saskatchewan plan to add significant volumes of low-emission electricity generation in less than 14 years. Natural gas is the least expensive option, and replacing coal with natural gas will decrease total emissions. The strategies of Alberta and Saskatchewan involve adding large amounts of renewable electricity that emit zero emissions, with plans heavily reliant on wind. This analysis demonstrates that hydro, not wind, is the most cost-effective sources of emissions-free electricity.

Hydro is an attractive option to meet at least a portion of the 2030 goals. It produces reliable baseload electricity with zero emissions at a cost higher than natural gas but lower than other options. It has the longest operating lifespan and lowest operating costs of all technologies. For Alberta and Saskatchewan, importing hydro from B.C. and/or Manitoba may be the most cost- and time-effective way to bring any substantial volume of new hydropower onto their grids by 2030. For example, Saskatchewan's MOU with Manitoba could allow it to expand its imports of hydro more than its 2030 plan sets out.

Increasing imports and exports of hydro among the western provinces would require substantial new transmission infrastructure. While the long-term operating costs of hydroelectricity are minimal, building linear infrastructure is an expensive endeavour. Given the precedent for federal investment in exactly this type of infrastructure, Ottawa should consider the return on investment (both economic and environmental) it would receive on supporting such a project financially; either directly or indirectly through a loan guarantee. To assist with the very real challenge of public support for linear infrastructure in Canada, the federal government could show leadership by designating transmission lines that carry renewable electricity as critical, green infrastructure.

A cleaner western Canadian electricity grid has the potential to reap huge economic benefits for Canada while helping to meet both provincial and federal GHG reduction targets.

RECOMMENDATIONS

Alberta & Saskatchewan should:

CREATE RULES THAT DO NOT DISADVANTAGE INVESTMENT IN HYDROELECTRICITY

Alberta and Saskatchewan are committed to reducing electricity emissions. The prevailing wisdom in both provinces suggests that a combination of natural gas and wind power makes the most sense. Hydroelectricity does not receive as much attention. Our analysis shows that hydro is more cost-effective than wind. Hydro also provides baseload power over a long lifespan and at low operating costs.

GET BEHIND THE IDEA OF AN INTEGRATED WESTERN ELECTRICITY GRID

Both Alberta and Saskatchewan have the internal capacity to develop hydroelectricity projects, but are operating on tight timelines to make large scale additions of renewable electricity to their grids. Being situated next to two major producers of hydroelectricity provides an opportunity for Alberta and Saskatchewan to import hydroelectricity. B.C. and Manitoba have large-scale hydro projects in development, or approved. Importing from these projects to Alberta and Saskatchewan would bring hydro online in a shorter time period than developing internal capacity. Transmission costs, while significant, are lower than developing internal capacity. The idea warrants real consideration.

The federal government should:

FUND INTERPROVINCIAL ELECTRICITY TRANSMISSION LINES IN THE WEST

To the extent that the federal government is going to financially support GHG emission reductions, it should fund electricity emission reductions in the West; cleaner electricity grids in Alberta and Saskatchewan will go a long way to reducing Canada's total emissions. As this analysis shows, further integrating pan-western hydropower trade is a cost-effective, reliable and timely solution to helping Alberta and Saskatchewan transition to more renewable electricity.

The primary challenges include funding and gaining public support for long linear infrastructure projects. Federal leadership in designating, and funding, interprovincial transmission lines that move renewable electricity as green infrastructure could go a long way to increasing hydroelectricity use throughout western Canada.

APPENDIX 1

Alberta Climate Leadership Plan: capacity and generation calculations

FIGURE A1: ACTUAL AND FORECAST ELECTRICITY CAPACITY AND GENERATION IN ALBERTA

	2014 TOTAL (ACTUAL)	2030 TOTAL (FORECAST)
Capacity (MW)	16,242	23,422
30% of capacity		7000
Generation (GWh)	80,343	114,900
30% of generation		34,470

Source: Alberta Energy, Alberta Electric System Operator, Canada West Foundation

Figure A1 assumes the same capacity factor for total generation in 2030 as occurred in 2014 (56 per cent).

Phasing out Coal

In 2014, coal generated 44,442 GWh of electricity in Alberta. The *Climate Plan* mandates that by 2030, one-third of coal-fired electricity generation can be replaced with natural gas (14,665 GWh), and two-thirds must be replaced with renewables (about 29,770 GWh). Even if the 7,392 GWh of renewable electricity generated in 2014 applied, Alberta will need a minimum of 22,237 GWh of new renewable generation to replace two-thirds of coal-fired generation.

30 per cent renewables

The AESO forecast of adding 4,200 MW of wind generation to the grid by 2030 would mean renewables provide 30 per cent of electric *capacity*. However, when capacity factors are taken into account, a 4,200 MW addition of any renewable source would not be able to provide 30 per cent of renewable electricity *production*.

The maximum capacity 2030 scenario in the figure below is the sum of the existing installed capacity for each renewable technology in Alberta in 2014 and the addition of 4,200 MW.

FIGURE A2: DATA USED FOR FIGURE 6 – FEASIBILITY OF RENEWABLE OPTIONS TO MEET ALBERTA CLIMATE PLAN GOALS

TECHNOLOGY	AESO FORECAST OF ADDITIONAL RENEWABLE CAPACITY (MW)	CURRENT CAPACITY (MW)	MAXIMUM CAPACITY 2030 SCENARIO (MW)	CAPACITY FACTOR (%)	ACTUAL ANNUAL PRODUCTION, 2030 (GWh)	SHARE OF 2030 PRODUCTION (%)
Wind	4,200	1,459	5,659	30	14,870	13
Large hydro	4,200	900	5,100	60	26,805	23
Solar PV	4,200	N/A	4,200	15	5,520	5
Biomass	4,200	447	4,647	74	30,125	26
Nuclear	4,200	0	4,200	80	29,435	26

Source: Canada West Foundation

APPENDIX 2

Capital and operating costs of electricity generation by technology

This figure provides estimates of capital and operating costs for new electricity generating facilities coming online in the United States in 2020. The U.S. values were converted into Canadian dollars using the Bank of Canada's average annual exchange rate for 2013.

FIGURE A3: ESTIMATED CAPITAL AND OPERATING COSTS OF NEW GENERATING FACILITIES

TECHNOLOGY	CAPITAL COSTS ($/MWh)	OPERATING & MAINTENANCE COSTS ($/MWh)
Coal with CCS*	100	10
High-efficiency Natural Gas**	15	2
Nuclear	72	12
Hydro	73	4
Wind	59	13
Solar PV	113	12
Biomass	49	39

*single unit, advanced pulverized coal **combined cycle
Source: U.S. Energy Information Administration, Bank of Canada, Canada West Foundation

FIGURE A4: ASSUMPTIONS IN FIGURE 9 – COST AND EMISSIONS OF ELECTRICITY OPTIONS

TECHNOLOGY	OPERATING LIFE (YEARS)	CAPACITY FACTOR (%)	EMISSIONS INTENSITY (t/MWh)	CAPITAL COST	ASSUMPTION SOURCES
Conventional Coal	45	92	0.9	3850 (2011 C$/kW)	AESO 2012 Long-term Outlook
U.S. Coal with CCS	30	85	0.89	97.3 (2013 US$/MWh)	U.S. EIA, 2015
SK Coal with CCS	30	90	0.33	$1.5B (2015 actual)	Saskatchewan Ministry of Economy
Co-generation Natural Gas	30	90	0.67	1850 (2011 C$/kW)	AESO 2012 and 2014 Long-Term Outlooks
High-efficiency Natural Gas	30	75	0.38	1625 (2011 C$/kW)	AESO 2012 and 2014 Long-Term Outlooks
Nuclear*	30	90	0	70.1 (2013 US$/MWh)	U.S. EIA, 2015
Hydro	80	45	10	3,000 (US$/kW)	International Renewable Energy Agency, 2012
Wind	20	30	0	1,950 (US$/kW)	International Renewable Energy Agency, 2012
Solar PV	30	25	0	47.1 (2013 US$/MWh)	U.S. EIA, 2015
Biomass	30	83	0	191.6 (2013 US$/MWh)	U.S. EIA, 2015

*US EIA uses a 30 year lifespan, which is about half an actual lifespan of a nuclear plant. However, because the U.S. nuclear associations use the EIA data and Canadian-specifc LCOE data could not be found, the EIA data is used Figure 9.

APPENDIX 3

Hydroelectric development potential in Alberta and Saskatchewan

Hydropower plants require large sources of flowing water and the West has significant hydro capacity – certainly enough to meet provincial renewable electricity targets.

Alberta

The figure below shows the estimated hydropower potential of Alberta's rivers. The annual energy estimates are for the river as a whole; more than one site may be needed to harness the total energy available.

FIGURE A5: HYDROELECTRIC ENERGY DEVELOPMENT POTENTIAL OF ALBERTA RIVERS

RIVER BASIN	ANNUAL ENERGY (GWh)
Athabasca	13,050
Churchill	0
Hay	100
Milk	0
North Saskatchewan	8,270
Peace	19,720
Red Deer	340
Slave	7,640
South Saskatchewan	3,930
Total	**53,050**

Source: HATCH Report to the Alberta Utilities Commission, 2010

Saskatchewan

As shown in the figure below, SaskPower estimates there is the potential to develop a further 3,240 MW of hydropower within the province.

FIGURE A6: HYDROELECTRIC ENERGY DEVELOPMENT POTENTIAL IN SASKATCHEWAN

RIVER BASIN	ENERGY POTENTIAL (MW)
Saskatchewan	2,053
Churchill	734
Athabasca	453
Total	**3,240**

Source: SaskPower

ENDNOTES

1. Natural Resources Canada, "Energy Markets Fact Book – 2014-215," p. 81.
2. Canadian Electricity Association, "The North American Grid: Powering Cooperation on Clean Energy & the Environment," 2016, p.10.
3. Wind power capacity in Canada increased from 1455.7 MW in 2006 to 10425.3 MW in 2015.
4. Environment Canada, "Greenhouse gas emissions by economic sector, Canada, 1990 to 2014," last modified 2016-04-14, www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=F60DB708-1.
5. Environment Canada, "National Inventory Report 1990-2013, Part 3," 2015.
6. Alberta Energy, http://www.energy.alberta.ca/Electricity/684.asp, accessed June 2016.
7. Natural Resources Canada, "Energy Markets Fact Book – 2014-2015," p. 94.
8. Canada West Foundation, "Look Out: Toward a Climate Strategy that Reduces Global Emissions," May 2016, p. 14.
9. The focus of this paper is on a western Canadian clean electricity grid, therefore the Nova Scotia electricity system is not examined.
10. 40 MT from Alberta and 7 MT from Saskatchewan.
11. 40 MT represents 15 per cent of Alberta's 2013 GHG emissions. Reducing Alberta's electricity sector emissions by 40 MT would reduce the sector's share of provincial emissions from 17 to 9 per cent.
12. Alberta Electric System Operator, "AESO 2016 Long-term Outlook," May 2016, p. 17.
13. A power plant's capacity factor is the ratio of its actual energy output over a period of time (in this case, annually), to its potential output if it were to operate continuously over the same period of time.
14. TransCanada, www.transcanadapoweralberta.com/powering-alberta-business/deregulation-in-alberta/, accessed April 2016.
15. As a Crown corporation, SaskPower is the province's public utility company.
16. SaskPower's renewables goal is expected to reduce SaskPower's emissions 40 per cent below 2005 levels by 2030. Achieving this would reduce emissions by 6.6 MT.
17. Coal, natural gas, hydro and biomass contributed 95 per cent of the electricity generated in Alberta in 2014 (Alberta Energy).
18. In 2015, AESO reported an Alberta Internal Load average demand of 9,162 MW (56 per cent of total provincial generating capacity). The maximum AIL was 11,229 MW. According to the Alberta Market Surveillance Administrator, "Alberta Internal Load (AIL) is the most commonly used measure to gauge the [electricity] demand of the province." AIL conveys the amount of energy demanded in the province per hour by taking into account both the system load and on-site generating systems, like those used for industrial purposes.
19. The *AESO 2016 Long-term Outlook* forecasts the average AIL up to 2020 (10,711 MW); the average growth in this forecast an addition of about 300 MW/year. Assuming the rate of growth stays about the same up to 2030, the AIL average demand in 2030 would be about 13,809 MW – 59 per cent of the forecast capacity in 2030.
20. Altalink, "Alberta's Electricity System," www.altalink.ca/albertas-electricity-system/transmission.cfm, accessed April 19, 2016. SaskPower, www.flickr.com/photos/saskpower/16314660180/in/album-72157645573382962/.
21. National Energy Board, "Canada's Energy Future 2013" 2013, p.22.
22. Independent Electricity System Operator, http://www.ieso.ca/Pages/Power-Data/Supply.aspx, accessed May 2016.

23. The Levelized Cost of Electricity "represents the present value of the total cost (overnight capital cost, fuel cost, fixed and variable operation and maintenance costs, and financing costs) of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments, given an assumed utilisation, and expressed in terms of real money to remove inflation" (International Energy Agency, "Technology Roadmap, Solar Photovoltaic Energy," 2014).

24. Paul L. Joskow, "Comparing the costs of intermittent and dispatchable electricity generating technologies," Alfred P. Sloan Foundation and MIT, September 2010, p.3.

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26. GE, powergen.gepower.com/resources/knowledge-base/combined-cycle-power-plant-how-it-works.html, accessed May 2016.

27. CERI, "An assessment of hydroelectric power options to satisfy oil sands electricity demand," January 2016, p.10.

28. CERI selected a 500 MW minimum potential because it was examining sites with sufficient capacity to power oil sands operations.

29. CERI, "An assessment of hydroelectric power options to satisfy oil sands electricity demand," January 2016, p.16.

30. Ibid, p.10.

31. Proposed in 2008 and abandoned in 2013.

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33. Government of Manitoba, "Province Releases Public Utilities Board Report on Manitoba Hydro's Preferred Development Plan," July 2, 2014, news.gov.mb.ca/news/index.html?item=31611.

34. HATCH Ltd., "Update on Alberta's Hydroelectric Energy Resources," Final Report for Alberta Utilities Commissions, February 2010.

35. Ibid.

36. CERI, "An assessment of hydroelectric power options to satisfy oil sands electricity demand," January 2016, p.10.

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38. BC Hydro, www.bchydro.com/content/dam/hydro/medialib/internet/documents/news/press_releases/clean_energy_act/background_cea_export_policy.pdf, accessed April 2016.

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67. 47 MT from the electricity sectors in Alberta and Saskatchewan, and 70 MT from the transportation sector.

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