THE SCHOOL OF PUBLIC POLICY

UNIVERSITY OF CALGARY

MASTER OF PUBLIC POLICY CAPSTONE PROJECT

Keeping the Lights On

Renewable Power in Alberta's Post-Coal Era

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Submitted in fulfillment of the requirements of PPOL 623 and completion of the requirements for the Master of Public Policy degree

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Acknowledgements

I would like to express my deepest gratitude to Dr. Jennifer Winter for her guidance, mentorship, wealth of knowledge, and commitment to rigour, which motivated me to push myself at every stage of this project – from the false starts to the final draft. I would like to acknowledge and thank Dr. Michal Moore, Dr. Ian Brodie and Dr. Jean-Sebastian Rioux, whose teachings and ideas informed many aspects of this work. Thanks to Mark Le Dain, Tom Hansen and Thana Boonlert for their thoughts. Lastly, I would like to thank Brian Frank and Claire McKinnon for their feedback and support, and for demonstrating a work ethic that I strive to emulate.

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Executive Summary

Alberta's Climate Leadership Plan calls for the phase-out of coal-fired electricity in the province by 2030. Renewable power will replace two-thirds of this lost capacity, and 30 per cent of the province's total installed *and* generating capacity will be provided by renewables – also by 2030. As of 2016, coal contributes 39 per cent of Alberta's power by installed capacity and 39 by generation share, while renewables contribute 17 and 10, respectively.[1] To meet the government's stated objectives, the province's installed renewable capacity must grow by almost 150 per cent in just 14 years, while the generation share from renewables must grow by 400 per cent. Wind, solar, biomass (biopower), hydro, and geothermal are the candidates to replace this lost coal capacity. This paper lays out a series of quantitative metrics to test key aspects of each resource's economic, environmental, and social feasibility in Alberta, offering comparative analysis and recommendations.

Based on this analysis, all five renewable power sources could potentially factor into Alberta's future electricity mix. Wind power is the best option for large-scale development, as it offers lower levelized costs and fewer opportunity costs, with manageable environmental impacts and exemption from Alberta's forthcoming carbon tax. However, the intermittent nature of wind makes it incapable of providing baseload power, meaning wind cannot replace coal on its own. Solar is more expensive than wind, but with expected decreases in production costs and technological advances this may not be the case for long. Solar is also viable for small-scale rooftop installations, and perhaps some utility-scale installations on low-grade land. Biopower offers the opportunity to extend the useful lifespan of decommissioned coal facilities, but there is not enough fuel available for the industry to grow in the same way as wind, solar or gas. Small-scale hydropower, particularly run-of-river, is an option for baseload power, which would free up gas-fired plants to better augment peak load requirements. There are a number of geophysical and regulatory obstacles facing geothermal, but Alberta has the ability and expertise to develop geothermal resources. Coal is very socially costly, but also very reliable, and the shift to renewable power has the potential to destabilize Alberta's

[1] Renewables in Alberta currently consist of wind, biomass and hydro.

electricity grid. Policies that emphasize efficiency, diversification and innovation will help ensure consumer demand is met through 2030 and beyond.

1. Introduction

Released in November 2015, Alberta's Climate Leadership Plan calls for the phase-out of coal-fired electricity in the province by 2030. Two-thirds of this lost grid capacity will be replaced with renewables, and 30 per cent of the province's total rated *and* generating capacity will be provided by renewables – also by 2030.[2] Both of these policies have significant implications for Alberta's electricity mix, which is heavily reliant on coal and natural gas. As of 2015, Alberta's electrical generation capacity stood at 16,242 MW. There are, at present, five major contributors to this figure, outlined in Table 1.

Table 1: Alberta's electricity sources by installed capacity and total generation (June 2016)

Source	**Capacity (MW)**	**Share (Percentage)**	**Annual Generation (TWh)**	**Share (Percentage)**
Natural Gas	7,080	43.5	32.22	51
Coal	6,267	38.5	41.38	39
Wind	1,491	9.2	3.82	5
Hydro	902	5.5	1.75	2
Biomass	424	2.6	2.15	3
Other	97	0.6	0.32	0.004
Total	**16,261**	**100**	**81.62 million**	**100**

Source: Alberta Energy, "Electricity Statistics."
Note: Other includes fuel oil, diesel, and waste heat. Figures are rounded.

The Climate Leadership Plan signifies a massive transition that will require incentives and facilitation to meet the policy objectives announced by the government. Given current projections for annual power demand of 119.3 TWh in 2030, the province's installed renewable capacity would have to grow by almost 150 per cent in just 14 years.[3] In terms of actual generation share, total power production from renewables must grow

[2] Government of Alberta, "Climate Leadership Plan."
[3] Alberta Electric System Operator, "AESO 2014 Long-term Outlook," June 2014.

by 400 per cent.[4] The 14-year time horizon presents challenges for both the private sector and the government, particularly since Alberta's electricity generation is deregulated. There are a number of candidate technologies to replace coal, but given the timeline, business climate, market structure, and geographical considerations, some will evidently suit Alberta better than others. Which one(s) is the all-important first question. This paper scrutinizes wind, solar, biomass, hydro and geothermal, and assesses their potential for replacing coal-fired power in Alberta.

Each renewable electricity source will be discussed individually, including a review of the technology, the role (if any) that the technology has played in Alberta to date, environmental and social impacts, and trends and developments in the industry. A series of comparable quantitative metrics are used to test key aspects of each resource's economic, environmental, and social feasibility:

- Existing capacity in Alberta; additional capacity planned or under construction[5]
- Energy Return on Investment (EROI)[6]
- Emissions intensity of electricity generation (kgCO_2e/MWh)
- Lifecycle emissions intensity of the technology (kgCO_2e/MWh)
- Operational power per unit area (MW/m^2)
- Capacity factor[7]
- Cost of energy (levelized[8] and average)
- Capital requirements
- Social cost of carbon (dollars per MWh) and social savings (dollars saved per MWh)

This paper reviews each of the metrics listed above, combined with qualitative and quantitative analysis to round out exactly how, if at all, each renewable source can factor

[4] Ibid.
[5] These figures will reflect the rated capacity, also known as the nameplate capacity.
[6] Also known as the energy-yield ratio or the energy payback period. EROI refers to how much energy a resource is expected to produce over its lifetime, compared to the energy expended making or obtaining it.
[7] A capacity factor refers to how much electricity a source is generating at any point in time when compared to the installed capacity (otherwise known as rated capacity), expressed as a percentage.
[8] Levelized cost of energy standardizes costs for different power sources, including the cost of building, operating and decommissioning a power plant over a set lifecycle on a per-unit power basis, with assumptions made for capital costs, fuel costs, operations and maintenance (O&M) costs, and average capacity factors, among others.

into the future of Alberta's electricity mix. Wind is discussed first, followed by solar, biopower, hydropower and geothermal, respectively. All findings are summarized in Section 8, followed by a discussion of the implications and the future of power generation in Alberta.

2.0 Assumptions Regarding Emissions from Coal and Natural Gas

This section briefly outlines the agencies, publications and literature used to inform this paper. It defines and establishes bounds for the emissions intensities of coal and natural gas. It also defines and bounds the social cost of carbon (SCC).

The qualitative analysis in this paper relies heavily on scientific literature, government documents, working papers, and industry publications. Studies specific to Alberta or Canada were used when available. When unavailable, comparable countries were used – primarily in the U.S. and Europe. Publications and data from the Alberta Electric System Operator (AESO) were used for information on the challenges facing renewable power at the provincial level. Publications from intergovernmental agencies were used where appropriate to provide the global context for these challenges. Emissions intensity, costs of production, EROI, and carbon costs were collected from both academic and government sources. Data from industry supplemented research on capital requirements, EROIs and the cost of energy.

2.1 Combustion and Lifecycle Emissions Estimates

This paper compares the emissions intensities from the five renewable sources of electricity to the sources that currently dominate Alberta's electricity generation: natural gas and coal. Emissions intensity is presented as mass (tonnes) of carbon dioxide and other greenhouse gases (CO_2e) generated in the production of one megawatt-hour (MWh) of electricity. The comparisons are made for both lifecycle emissions[9] and emissions

[9] Lifecycle emissions are defined as the total greenhouse gas emissions (CO_2e) generated during the manufacturing, construction, operation, and decommissioning of a power station, divided by the number of MWh that the power station is expected to produce over its lifetime.

from combustion. As Alberta's carbon tax will apply to all combustion-based emissions, the savings that producers will realize from generating a unit of power from renewables instead of coal or gas can be calculated. The emissions savings, specifically the social costs of those emissions, will be compared on a lifecycle basis. An overview of the data and assumptions used in this analysis is provided below. Additional assumptions are provided for each electricity source in the respective sections.

Combustion emissions refer exclusively to the emissions generated from burning a fuel source. Environment and Climate Change Canada's National Inventory Report (NIR) provides gross emissions for electricity generation from various energy sources along with their emission totals. From this, average combustion emissions intensity from gas and coal-fired electricity. This data is summarized in Table 2.

Table 2: Average emissions intensity for electricity generation

	Natural Gas	Coal
Alberta	583 $kgCO_2e/MWh$	1,016 $kgCO_2e/MWh$
Canada	567 $kgCO_2e/MWh$	1,030 $kgCO_2e/MWh$

Source: Author's calculations, based on Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3."
Note: Canada's figures were taken from 2010-2014. Alberta's data for 2010 and 2011 is unavailable; these figures reflect the last three years for which data are available (2012-2014).

The NIR analyzes facilities that are currently operational; newer facilities that invest in emission-mitigating technologies and adhere to industry best practices for procurement, construction, decommissioning and reclamation will likely have lower emissions intensities. To account for this, this paper utilizes a range of values of emissions intensities for sensitivity analysis.

Lifecycle emissions intensity estimates for gas-fired electricity vary for several reasons, including uncertainty regarding fugitive emissions, venting and flaring rates, the mix of conventional and unconventional natural gas resources, and the combustion technology used (simple cycle, combined cycle or cogeneration). A comprehensive metastudy by Heath et al (2014) estimates lifecycle emissions for coal and natural gas electricity generation.[10] Heath et al is heavily cited in this paper due to its recency, robust methodology, and the number of studies included in its analysis. They find median lifecycle emissions intensity of 450 kgCO_2e/MWh for natural gas (410 to 490 kgCO_2e/MWh in the middle quartiles, full range of 310 to 680 kgCO_2e/MWh).[11] Lifecycle emissions for coal are influenced by the quality of the fuel source, the efficiency with which it is burned, mining practices, and the distance of transport. Heath et al estimate the median emissions intensity of coal-fired electricity generation at 980 kgCO_2e/MWh (940 to 1,050 kgCO_2e/MWh in the middle quartiles, full range 820 to 1,370 kgCO_2e/MWh).

For combustion, the lower bound will be the low-end estimates in Heath et al, which represent a new, highly efficient gas or coal plant. The upper bound is the average NIR calculation for Alberta, which assumes that a new facility is an average emitter at worst. For lifecycle emissions, the lower bound is the average NIR calculation. This assumption is made to accommodate the possibility that a new facility's lifecycle emissions could equal the combustion emissions of an average facility currently operating. The majority of lifecycle emissions from coal and gas come from combustion, so it is conceivable that an older, inefficient facility would have combustion emissions intensity equal or greater to the lifecycle emissions intensity of a new, highly efficient facility.[12] The upper bound for lifecycle emissions will be the high-end estimate provided in Heath et al.

[10] Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation," *Proceedings of the National Academy of Sciences* 111, no. 31 (2014): E3167-E3176.

[11] This study assumes modern combined cycle plants, which explains the discrepancy between these figures and the average emissions intensity of Canadian and Albertan gas plants below.

[12] Heath A. Garvin, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation."; Andrew Burnham, Jeongwoo Han, Corrie E. Clark, Michael Wang, Jennifer B. Dunn, and Ignasi Palou-Rivera, "Life-cycle greenhouse gas emissions of shale gas, natural gas, coal, and petroleum," *Environmental science & technology* 46, no. 2 (2011): 619-627.

Table 3: Bounds for Combustion and Lifecycle Emissions for Natural Gas and Coal

	Natural Gas	Coal
Combustion Lower Bound	310 kgCO_2e/MWh	820 kgCO_2e/MWh
Combustion Upper Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh
Lifecycle Lower Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh
Lifecycle Upper Bound	680 kgCO_2e/MWh	1,370 kgCO_2e/MWh

Sources: Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"; Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3."

Alberta will introduce an economy-wide carbon tax in 2017, starting at \$20/tonne, up to \$30/tonne in 2018, and staying at \$30 per tonne thereafter.[13] Alberta's carbon tax applies to combustion-based emissions, so electricity producers will be taxed based on their operations rather than the lifecycle emissions. Given the stated assumptions regarding combustion emissions, costs from a \$30/tonne carbon tax are detailed in Table 4.

Table 4: Combustion emissions costs for natural gas and coal in Alberta based on a \$30/tonne carbon tax

	Natural Gas	Coal
Lower Bound	\$9.30/MWh (\$9,300/GWh)	\$24.60/MWh (\$24,600/GWh)
Upper Bound	\$17.49/MWh (\$17,490/GWh)	\$41.10/MWh (\$41,100/GWh)

Source: Government of Alberta, "Climate Change Leadership Plan."

2.2 Social Cost of Carbon Estimates

The social cost of carbon (SCC) is a "monetary measure of the global damage expected from climate change from the emissions of an additional tonne of carbon dioxide in the atmosphere in a given year".[14] While subject to a substantial amount of research, the scientific community has yet to achieve consensus on the SCC due to uncertainty regarding the future impacts, costs, and potential benefits of anthropogenic climate change. Moreover, the SCC will differ based on the reference group or jurisdiction

[13] Government of Alberta, "Climate Leadership Plan."
[14] Environment and Climate Change Canada, "Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates," March 2016.

considered. Lower-end estimates are informed by the assumption that climate change will be of some small nuisance or even present net benefits.[15] On the other end of the spectrum, a number of scientific studies suggest that the impacts of climate change are catastrophic and approaching rapidly.[16] For 2016, Environment and Climate Change Canada calculates the aggregated, central tendency for the SCC at $40.70/tonne (2012 dollars). The 95th percentile value of $167/tonne (2012 dollars) is recommended for sensitivity analysis, which represents the social costs associated with extreme shifts in climate.[17] The SCC values rise over time. All references to social costs in this paper are in 2012 Canadian (CDN) dollars.

Table 5: Estimated Social Costs of Carbon through 2030

	Central Tendency (2012 dollars)	95th percentile (2012 dollars)
2015	$40.70/tonne	$167/tonne
2020	$45.10/tonne	$190.70/tonne
2025	$49.80/tonne	$213.30/tonne
2030	$54.50/tonne	$235.80/tonne

Source: Environment and Climate Change Canada, "Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates."

The SCC estimates are discounted at three per cent annually.[18] The central tendency for SCC is poised to grow at a compound annual growth rate of two per cent through 2030 (2.33 per cent for 95th percentile). In this paper, the social costs or savings incurred by switching from coal or natural gas to a renewable electricity source are calculated using the SCC value for 2016 (2012 dollars). This assumption may lead to an understating of future social costs, as most of the renewable projects required to meet Alberta's policy goals will enter service gradually over the next 15 years.

[15] Ibid.
[16] Ker Thang, "Estimated social cost of climate change not accurate, Stanford scientists say," *Stanford News*, January 12, 2015.
[17] Ibid.
[18] Environment and Climate Change Canada, "Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates," March 2016.

Using the bounds provided in Table 3, the lifecycle SCC for coal-fired electricity is between \$41.35/MWh and \$55.76/MWh using the central tendency, and between \$169.67/MWh and \$228.79/MWh using the 95th percentile. The lifecycle social cost of gas-fired electricity is between \$23.73/MWh and \$27.68/MWh using the central tendency, and between \$97.36/MWh and \$113.56/MWh using the 95th percentile.

Finally, this paper relied on sources from a number of agencies that present figures in \$USD. Unless otherwise stated, dollar figures in this paper have been converted to \$CDN and indexed to 2012. Conversions are calculated using the average exchange rate for the year from which the dollar figure was taken (e.g. a paper from 2010 that used \$USD would be converted \$CDN using the 2010 exchange rate) and then indexed to 2012.[19]

3.0 Wind: Established, High-Potential, and Growing Fast

This section will discuss wind power, the state of the technology, its presence in Alberta and potential for expansion, and economic and environmental considerations including social costs. Wind is reviewed first because it is the most established technology in Alberta and will provide greater context for the other technologies examined.

3.1 The Technology

Modern industrial wind turbines capture the kinetic energy contained in moving air and convert it into electrical energy via mechanical energy. Multiple turbines on a single site are referred to as a wind farm. Farms can be built onshore or offshore; both have their advantages and drawbacks.[20] Offshore wind farms deliver higher power per unit area relative to onshore, but also have higher capital costs and issues such as grid connectivity, accessibility and ease of maintenance.[21] As Alberta is landlocked, this discussion will refer exclusively to onshore, commercial wind farms.

[19] Bank of Canada, "Annual Average Exchange Rates."
[20] David J. C. MacKay, *Sustainable Energy--without the Hot Air* (Cambridge, England: UIT, 2009), 263.
[21] Ibid, 264-65.

Most commercial wind turbine models fall within a set range of specifications. Generating capacity is typically between 1.5 and 3.5 MW, though newer models can exceed 7 MW.[22] Typical hub height is between 70 and 100 metres with blades ranging from 35 to 50 metres.[23] Assuming transmission availability, wind power is highly, though not perfectly, scalable.[24] Turbines on a farm must be spaced out at a rate at least five times the blade diameter to avoid significant power loss.[25] Estimates for power output per unit-area on farms range from 2 to 4 MW/hectare. Turbine drag limits production closer to 1 MW/hectare on farms greater than 100km^2 where turbines are placed in rows.[26] Early wind projects in Alberta have averaged one hectare of temporary surface disturbance per windmill during construction, and 0.06 hectares (25 x 25 metres) of surface disturbance per windmill during operation. These figures do not factor in land disturbance for site access and cable trenching for each individual turbine. This figure also assumes that the land immediately surrounding the turbines is arable or otherwise useful.

The fuel source for wind power is free and inexhaustible, but there is a ceiling on turbine productivity. The Betz Limit, the theoretical maximum rate at which a windmill can convert kinetic energy into mechanical energy, is 59.3 percent.[27] Factoring in requirements for design and durability, 30 per cent of the wind's total power potential can be converted into usable electricity, at best. Beyond the physical limitations, the fuel source is intermittent. Even on a well-connected and well-dispersed grid, wind power is largely incapable of providing baseload power, and requires backup generation to ensure grid reliability. Erratic wind speeds can further reduce generation levels considerably. Most turbine models produce electricity at optimal levels when wind speed is consistent

[22] GE Power, "GE Wind Turbine Portfolio"; Vestas, "Turbines"; Enercon, "E-126 – Overview of Technical Data."
[23] Ibid.
[24] Amanda S. Adams, and David W. Keith, "Are global wind power resource estimates overstated?," *Environmental Research Letters* 8, no. 1 (2013): 015021.
[25] MacKay, *Sustainable Energy*, 265.
[26] Amanda S. Adams, and David W. Keith, "Are global wind power resource estimates overstated?," *Environmental Research Letters* 8, no. 1 (2013): 015021.
[27] The Royal Academy of Engineering, "Wind Turbine Power Calculations."

and in the range of 11 to 14 m/s.[28] Most modern turbines operate with capacity factors from 30 to 40 percent but remain highly dependent upon the quality of the fuel source.[29]

There has been significant public debate over the human health impacts associated with industrial wind farms. Common complaints include noise in excess of 40 decibels and associated acute health effects such as headaches and sleep disturbance. However, peer-reviewed literature has yet to establish any causal link between proximity to wind turbines, noise pollution, and induced physiological health impacts.[30] Psychological impacts such as insomnia, anxiety and depression have been observed in study groups, though causality is still disputed.[31]

The land impacts of wind power are less controversial, and they can be significant. There are unique challenges posed by the construction, maintenance, decommissioning, and reclamation phases.[32] Identified potential land impacts in Alberta include soil disturbance, compaction and erosion, changes in subsurface hydrology, degradation of wetlands and riparian areas, and direct removal of native vegetation, which can hasten the spread of invasive vegetation.[33] Other, broader environmental risks include impacts on wildlife through habitat fragmentation and land use, and the rotating blades pose unique risks to birds and bats during operation. Fragmentation and wildlife impacts can become more severe if road construction is required.[34] At a regional level, the significance of

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[28] Industrial Wind Energy Opposition, "Size specifications of common industrial wind turbines."
[29] R.H. Crawford, "Life Cycle Energy and Greenhouse Emissions Analysis of Wind Turbines and the Effect of Size on Energy Yield," *Renewable and Sustainable Energy Reviews* 13, no. 9 (2009): 2653-660.
[30] Loren D. Knopper and Christopher A. Ollson, *Health effects and wind turbines: A review of the literature*, Environmental Health, 2011.
[31] Michael A. Nissenbaum, Jeffery J. Aramini, and Christopher D. Hanning, "Effects of industrial wind turbine noise on sleep and health," *Noise and Health* 14, no. 60 (2012): 237; Jesper Hvass Schmidt and Mads Klokker, "Health effects related to wind turbine noise exposure: A systematic review," *PloS one* 9, no. 12 (2014): e114183.
[32] Cheryl Bradley and Marilyn Neville, "Minimizing Surface Disturbance of Alberta's Native Prairie Background to Development of Guidelines for the Wind Energy Industry," Foothills Restoration Forum, (2010).
[33] Ibid.
[34] Canadian Wind Energy Association, "An Introduction to Wind Energy Development in Canada."

impacts related to decommissioning and reclamation are largely unknown at this point since no wind projects in the Canadian Prairies have reached end of life.[35]

3.2 Wind Generation in Alberta

Wind power already has a foothold in Alberta. Total installed, operational capacity is third only to Ontario and Quebec among Canadian provinces.[36] As of June 2016, 20 commercial wind farms are operational with a total installed capacity of 1,491 MW.[37] An additional nine wind projects with a combined capacity of 1,182 MW have received regulatory approval.[38] Another 20 projects combining for 3,432 MW have been announced or are awaiting regulatory approval.[39] Most of these projects have come in the wake of the Climate Leadership Plan, with 2,340 MW of capacity proposed since November 2015. Should they be approved, all of these projects are expected to come online before 2020.[40]

Needless to say, Alberta's wind industry is growing quickly.[41] From the first quarter of 2010 to the first quarter of 2014, capacity in Alberta more than doubled, growing from 600 to over 1,400 MW.[42] Average hourly capacity factors were between 28.2 and 33.8 per cent over that span.[43] Figure 1 shows the growth of wind energy in Alberta. Note that average capacity factors can more than double in the winter months over the summer months.

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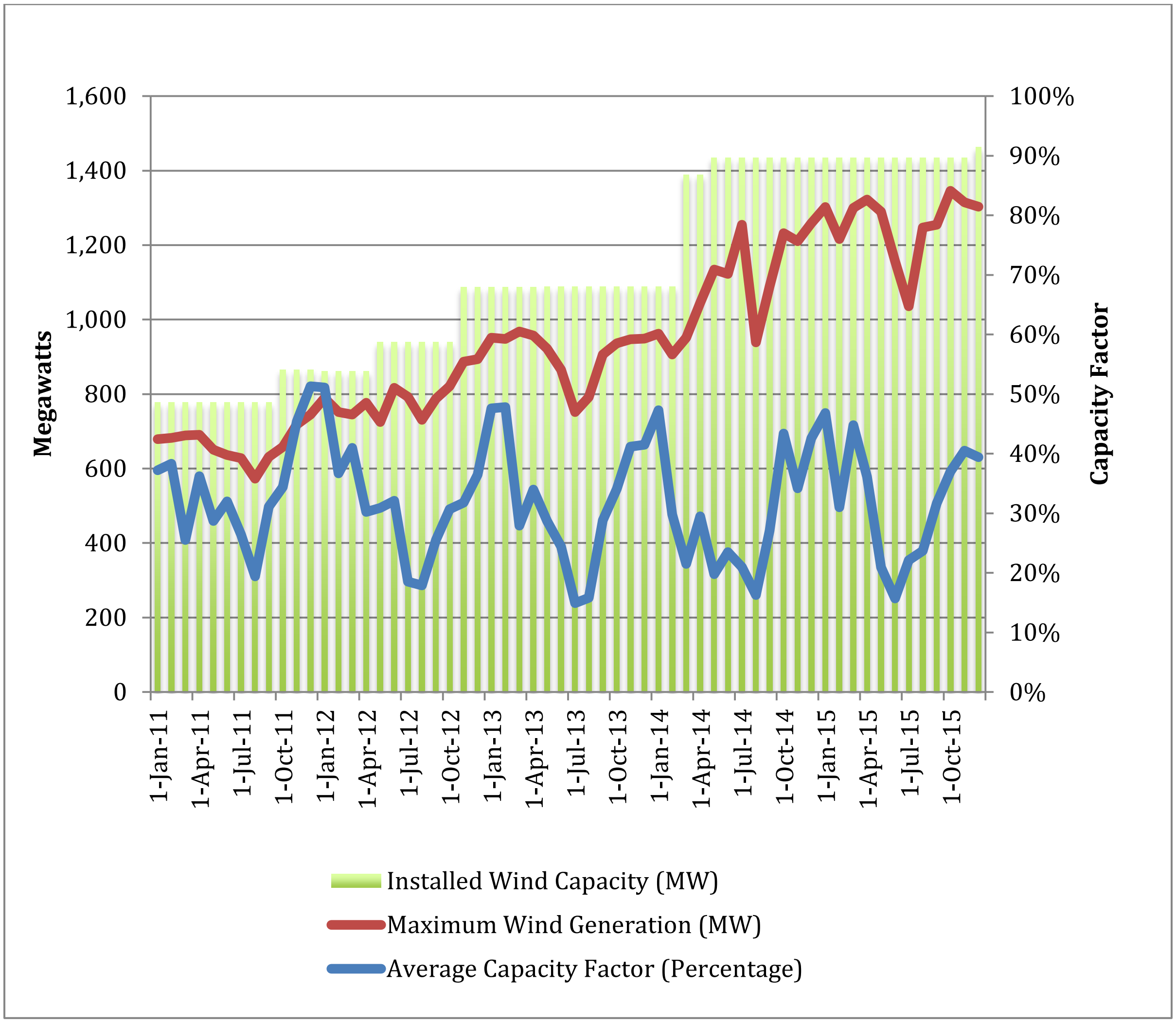
[35] Cheryl Bradley and Marilyn Neville, "Minimizing Surface Disturbance of Alberta's Native Prairie Background to Development of Guidelines for the Wind Energy Industry," (2010).
[36] Canadian Wind Energy Association, "WindVision 2025: A Strategy for Alberta," April 12, 2013.
[37] Alberta Energy, "Electricity Statistics."
[38] Alberta Electric System Operator, "Long Term Adequacy Metrics – May 2016."
[39] Ibid
[40] Ibid.
[41] Ibid.
[42] Alberta Electric System Operator, "2014 Annual Market Statistics," February 2015.
[43] Ibid.

Figure 1: The Growth of Wind Power in Alberta (2011 – 2015)



Source: Alberta Electric System Operator, "2015 Annual Market Statistics."

Eleven of Alberta's wind farms have rated capacities between 50 and 100 MW. The Halkirk Wind Power Facility and the Blackspring Ridge Wind Project are the only two with capacities greater than 100 MW.[44] For comparison, Canada's largest commissioned wind farm is the 350 MW Riviere du Moulin project in Quebec (not yet operational).[45] The largest onshore wind farm commissioned to date in North America is the 1.32 GW AltaWind Energy Center in California.[46] The largest onshore wind farm in Europe is the

[44] Ibid.
[45] Canadian Wind Energy Association, "Wind energy continues rapid growth in Canada in 2015," January 12, 2016.
[46] Power Technology, "AltaWind Energy Center (AWEC)."

600 MW Fântânele-Cogealac in Romania.[47] Details of Alberta's five largest operational wind farms are reported in Table 6.

Table 6: Five Largest Wind Farms Operating in Alberta (2016)

	Blackspring Ridge	Halkirk	Wintering Hills	Ghost Pine	Enmax Taber
Location	Vulcan County, ~60km north of Lethbridge	Paintearth County, 140km E of Red Deer	125km NE of Calgary; 25km SE Drumheller	Kneehill County, 50km east of Olds	Taber, 100km west of Medicine Hat
Total Area	18,200 hectares	6,070 hectares	6,070 hectares	49,000 hectares	24,000 hectares
Turbines	166 X 1.8MW Vestas	83 X 1.8 MW Vestas	55 X 1.6 MW GE	51 X 1.6 MW GE	37 X 2.2 MW Enercon
Capacity	300 MW	150 MW	88 MW	82 MW	81 MW
Power per hectare	0.016 MW/hectare	0.025 MW/hectare	0.0145 MW/hectare	0.0017 MW/hectare	0.0034 MW/hectare
Dispersion Rate	1 turbine per 110 hectares	1 turbine per 73 hectares	1 turbine per 110 hectares	1 turbine per 960 hectares	1 turbine per 650 hectares

Source: Alberta Energy, "Electricity Statistics"; Alberta Electric System Operator, "Market and System Reporting."

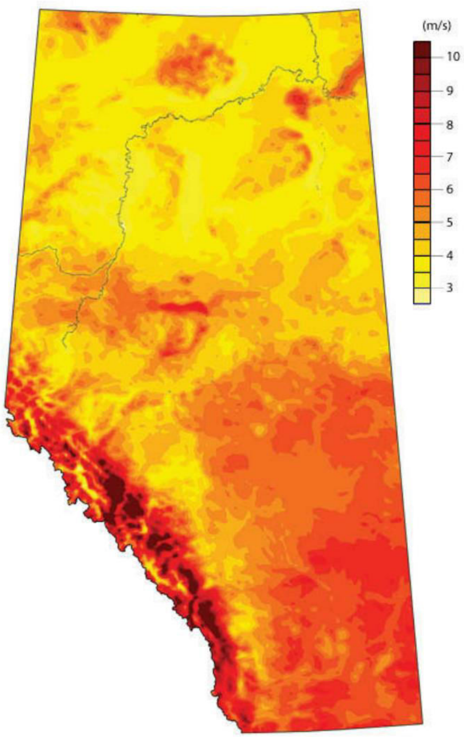
Alberta's five largest operational wind farms occupy 103,340 hectares (1,033 km^2) of land and provide 700 MW of rated capacity. For comparison, Calgary's total area is 82,530 hectares (825.3 km^2); Edmonton's is 68,440 hectares (684.4 km^2). All of these farms are located away from major city centres.

Over 240,000 km^2 (35 per cent) of Alberta's land has been deemed viable for wind projects, with an estimated total available capacity of 150 GW.[48] A study by Alberta Transportation calculated average wind speeds between 13 and 19.4 m/s in much of central and southern Alberta, and as high as 22 to 27 m/s in the Pincher Creek region.[49] As optimal wind speeds for most turbine models are between 11 and 14 m/s, Alberta is

[47] Power Technology, "Fântânele-Cogealac Wind Farm, Romania."
[48] Canadian Wind Energy Association, "WindVision 2025: A Strategy for Alberta."
[49] Alberta Transportation, "Analysis of Alberta Hourly Wind Data."

considered "wind rich" and capable of supporting further development. The best of these wind resources are in the southern half of the province. Figure 2 provides an average wind speed map for Alberta, with more conservative estimates for winds speeds than those from Alberta Transport.

Figure 2: Average Wind Speeds in Alberta



Source: Weis, Tim, Alex Doukas and Kristi Anderson. "Landowners' Guide to Wind Energy in Alberta." *The Pembina Institute*. September 2010.

Much of the land that is wind rich overlays populous areas in the southern half of the province, including Calgary, Edmonton, Lethbridge and Red Deer. Over half of the land in the southern half of Alberta is agricultural, with soils that have moderate to severe limitations on crops or require special conservation practices.[50] This does not necessarily mean that wind projects in this area are not feasible, but these regions may present additional regulatory and environmental requirements. Hundreds of square-kilometers east and southeast of Calgary consist of agricultural land that is potentially viable for wind farms.

[50] Alberta Environment and Parks, "Land Use Planning Maps."

3.3 The Cost of Wind Generation

Thanks to economies of scale and supply chain efficiencies, the costs of generation for wind power are falling rapidly.[51] Every time global wind capacity doubles there is a seven per cent drop in production costs, and similar reductions are expected moving forward.[52] Global cumulative installed capacity rose from 17.4 GW in 2000 to over 432 GW in 2015, a compound annual growth rate of 23.9 per cent.[53] In 2015, over 63 GW of capacity was installed worldwide, which accounts for 14.5 per cent of total global capacity.[54]

Wind speed is the single most important factor for commercial wind projects.[55] The height of the turbines is another important consideration, as the power density of wind resources increases gradually at higher altitudes. Beyond capturing higher wind speeds, the benefits of increasing the size of the blades or the height of the hub are marginal.[56] EROIs[57] are also slightly higher for larger windmills; this will be elaborated upon later in this section.

For any wind project, the turbines themselves are the main cost item, representing anywhere from 60 to 85 percent of the total installed costs.[58] Most other costs represent upfront, fixed capital costs and include civil works for the foundation, grid connection, planning and project management, maintenance buildings, and access roads if required.[59] An average breakdown of costs for onshore wind can be seen below.[60]

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[51] Canadian Wind Energy Association, "WindVision 2025: A Strategy for Alberta."
[52] Ibid.
[53] Global Wind Energy Council, "Global Wind Statistics 2015."
[54] Ibid.
[55] European Wind Energy Association, *Wind energy-the facts: a guide to the technology, economics and future of wind power*, Routledge (2012), 38.
[56] MacKay, *Sustainable Energy,* 60.
[57] A reminder: EROI is the ratio of the amount of energy a particular resource (in this case, a wind turbine) is expected to produce over its lifetime compared to the energy required to make or obtain that resource.
[58] IRENA, "Renewable Energy Technologies: Cost Analysis Series," June 2012.
[59] IRENA, "Renewable Power Generation Costs in 2014," January 2015.
[60] IRENA, "Renewable Energy Technologies: Cost Analysis Series," 43.

Table 7: Cost Breakdown for a Wind Power Project

Component	Share of Costs (Percentage)
Wind turbines	64
Foundation	16
Grid connection	11
Planning & other	9

Source: International Renewable Energy Agency, "Renewable Energy Technologies: Cost Analysis Series – Wind Power," June 2012.

A 2013 study commissioned by the Canadian Wind Energy Association (CANWEA) calculated the levelized cost of wind power in Alberta at $84/MWh.[61] Alberta's average pool price for electricity in 2014 was $49.42/MWh. The AESO calculates the levelized cost of wind power at $89/MWh, compared to $82/MWh for combined cycle gas, $69 to $104/MWh for gas cogeneration, and $110/MWh for simple cycle gas. The levelized cost of coal-fired electricity is around $70/MWh, but jumps to $237/MWh when carbon capture and storage is used.[62] These numbers are heavily influenced by the regulatory regime and will fluctuate. Operations costs (fixed and variable) and maintenance costs for wind usually accounts for 20 to 25 percent of levelized costs, which corresponds to an average supply cost of $16.80 to $22.25/MWh in Alberta.[63]

Alberta is wind rich, but not all of this fuel is equally accessible, and transmission can present significant additional costs in more remote regions. Each turbine requires its own medium voltage collection cable, and every wind farm requires a substation to bring electricity onto a high voltage transmission line. The literature presents a massive range for transmission cost estimates, as high as US$1,500/km ($1,814, 2012 CDN dollars).[64] A 2007 study modeling two wind farms in the Canadian Prairies found total transmission costs to be between $6.70M and $9.98M annually for the life of the projects (2012

[61] Canadian Wind Energy Association, "WindVision 2025."
[62] Alberta Electric System Operator, "AESO 2012 Long-term Outlook."
[63] International Renewable Energy Agency, "Renewable Energy Technologies: Cost Analysis Series."
[64] Andrew D. Mills, "The cost of transmission for wind energy: A review of transmission planning studies," *Lawrence Berkeley National Laboratory* (2009).

dollars).[65] The wind farms were 250 km apart and combined had 480 MW of rated capacity. The range presented accounted for reliability, maintenance, substation and connectivity requirements, and cost recovery and cost sharing scenarios.[66] A 2013 benchmarking study by AESO found the cost of transmission line projects in Alberta varies significantly, depending on the topography, geography, materials and construction, land use, regulatory requirements, and the economic climate.[67] The AESO study found total costs of building 230 or 240kV line facilities, the most common for wind projects, ranged from $744/km for projects on flat, agricultural land, to as much as $3,000/km for projects constructed on multiple terrain types with several water crossings.

Wind turbines offer a favourable energy return on investment (EROI).[68] Assuming a 20-year lifespan, various lifecycle assessments and metastudies have found mean operational EROIs in the range of 18 to 23.[69] Conceptual EROIs under more ideal conditions can be as high as 25.[70] EROIs for larger turbines tend to be higher than smaller turbines (23 to 21).[71] These EROI estimates do not include the costs of any backup generation facilities that may be required to ensure grid reliability. For comparison, coal has an EROI of ranging from anywhere from 30 to 80 depending on where it is mined.[72] In Canada, natural gas has a mean EROI anywhere between 20 and 38.[73] Another study suggests that the EROI for natural gas in Western Canada declined from 38 to 14 between 1993 and 2009.[74]

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[65] Roy Billinton and Wijarn Wangdee, "Reliability-based transmission reinforcement planning associated with large-scale wind farms," *Power Systems, IEEE Transactions on* 22, no. 1 (2007): 34-41.
[66] Ibid.
[67] Alberta Electric System Operator, "Capital Cost Benchmark Study For 240 kV Transmission and Substation Projects," June 2013.
[68] Ida Kubiszewski, Cutler J. Cleveland, and Peter K. Endres, "Meta-analysis of net energy return for wind power systems," *Renewable energy* 35, no. 1 (2010): 218-225.
[69] R.H. Crawford, "Life Cycle Energy and Greenhouse Emissions Analysis of Wind Turbines and the Effect of Size on Energy Yield," 2653-660.
[70] Ajay K. Gupta and Charles AS Hall, "A review of the past and current state of EROI data." *Sustainability* 3, no. 10 (2011): 1796-1809.
[71] R.H. Crawford, "Life Cycle Energy and Greenhouse Emissions Analysis of Wind Turbines and the Effect of Size on Energy Yield," 2653-660.
[72] Charles AS Hall, Jessica G. Lambert, and Stephen B. Balogh, "EROI of different fuels and the implications for society," *Energy Policy* 64 (2014): 141-152.
[73] Ibid.
[74] Jon Friese, "The EROI of conventional Canadian natural gas production,"*Sustainability* 3, no. 11 (2011): 2080-2104.

3.4 The Emissions Footprint

The lifecycle emissions intensity of wind turbines and wind farms vary significantly depending on the country of manufacture, the materials used, and disposal methods at end of life. One comprehensive metastudy, screening for robust, peer-reviewed studies published within the past ten years, produced a range of 0.4 to 364.8 kgCO_2e/MWh with a mean value of 34.1 kgCO_2e/MWh.[75] Onshore wind turbines with 1 MW of capacity or greater included in the metastudy had emissions intensities of 8 kgCO_2e/MWh at the lower end and 12 kgCO_2e/MWh at the higher end. Wind does not generate any combustion emissions. The same study indicates that manufacturing and fabrication account for 70 per cent of lifecycle emissions, while construction and operational phases are 24 per cent each (these percentages assume that decommissioning functions as a carbon sink due to recycling of materials). Sources of operational emissions include maintenance, turbine replacement parts, and hydraulic oil and oil filters for lubricating the turbines. The only recent peer-reviewed study examining Alberta evaluated a 100 kW turbine and found an emissions intensity of 17.8 kgCO_2e/MWh.[76] A turbine of this size and capacity is small relative to what is installed on a commercial scale in Alberta, but still serves as a reasonable point of reference. In a report compiling research on lifecycle emissions, the Intergovernmental Panel on Climate Change (IPCC) also found a median emissions intensity of 12 kgCO_2e/MWh for onshore wind power.[77] This paper uses a range of 10 to 12 kgCO_2e/MWh.

Given the stated parameters and assumptions for the SCC (central tendency of \$40.70/tonne and 95th percentile estimate of \$167/tonne, 2012 dollars), and the ranges for emissions intensities for electricity generated from wind, natural gas, and coal, the social savings incurred from substituting a MWh of electricity generated from wind for a MWh of electricity generated from coal or gas are displayed in Table 8.

[75] Daniel Nugent and Benjamin K. Sovacool, "Assessing the lifecycle greenhouse gas emissions from solar PV and wind energy: A critical meta-survey," *Energy Policy* 65 (2014): 229-244.
[76] MD Ruhul Kabir Braden Rooke, GD Malinga Dassanayake, and Brian A. Fleck, "Comparative life cycle energy, emission, and economic analysis of 100 kW nameplate wind power generation," *Renewable Energy* 37, no. 1 (2012): 133-141.
[77] Intergovernmental Panel on Climate Change, "IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Summary for Policymakers," (2011): 342.

Table 8: Bounds for Combustion and Lifecycle Emissions for Natural Gas, Coal and Wind

	Natural Gas	Coal	Wind
Combustion Lower Bound	310 kgCO_2e/MWh	820 kgCO_2e/MWh	0 kgCO_2e/MWh
Combustion Upper Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	0 kgCO_2e/MWh
Lifecycle Lower Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	10 kgCO_2e/MWh
Lifecycle Upper Bound	680 kgCO_2e/MWh	1,370 kgCO_2e/MWh	12 kgCO_2e/MWh

Source: Author's calculations, based on Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"; Intergovernmental Panel on Climate Change, "IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Summary for Policymakers," (2011); Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3."

Based on a $30 carbon tax, substituting one MWh of electricity generated from natural gas with one MWh of electricity generated from wind would result in savings between $9.30 and $17.49 ($9,300 and $17,490 per GWh). Substituting one MWh of electricity generated from coal with one MWh of electricity generated from wind would result in savings between $20.40 and $41.10 ($20,400 and $41,100 per GWh). The lifecycle social costs of electricity generated from coal, natural gas and wind in 2016 are shown below, all in 2012 dollars.

Table 9: Social Cost of Electricity Generation for Wind, Natural Gas and Coal (2012 dollars)

	Central Tendency	95th Percentile
Wind Lower Bound	$0.41/MWh	$1.67/MWh
Wind Upper Bound	$0.49/MWh	$2.00/MWh
Natural Gas Lower Bound	$23.73/MWh	$97.36/MWh
Natural Gas Upper Bound	$27.68/MWh	$113.56/MWh
Coal Lower Bound	$33.37/MWh	$136.94/MWh
Coal Upper Bound	$55.76/MWh	$228.79/MWh

Source: Author's calculations, based on Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"; Intergovernmental Panel on Climate Change, "IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Summary for Policymakers," (2011); Environment and Climate Change Canada, "Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates," March 2016.

The upper bound in social benefits resulting from substituting one MWh of electricity generated solely from wind for one MWh of electricity generated from natural gas is $113.15 ($113,150/GWh). The lower bound is $21.73 ($21,730/GWh). The upper bound in social benefits resulting from substituting one MWh of electricity generated from wind for one MWh of electricity generated from coal is $228.38 ($228,380/GWh). The lower bound is $31.37 ($31,370/GWh).

However, these figures assume that no backup generation is required for wind power, which, as discussed previously, is incompatible with a reliable electricity grid. If wind power is to play a larger role in the future of Alberta's electricity market, reliable backup generation will be required. Revised lifecycle costs are reported in Table 10, assuming that wind can provide 35 per cent of any MWh of electricity on the grid relative to its rated capacity, with natural gas making up the difference (lower bound). The worst case (upper bound) assumes 25 per cent from wind, 75 per cent from natural gas.

Table 10: Lifecycle Social Costs for Wind Power when Backstopped by Natural Gas (2012 dollars)

	Central Tendency	95th Percentile
Wind Lower Bound	$15.57/MWh	$63.87/MWh
Wind Upper Bound	$20.88/MWh	$85.67/MWh

Source: Author's calculations, based on Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"; Intergovernmental Panel on Climate Change, "IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Summary for Policymakers," (2011); Environment and Climate Change Canada, "Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates," March 2016.

Under these more realistic conditions, the upper bound in social benefits resulting from substituting one MWh of electricity generated from wind backstopped by natural gas for one MWh of gas-fired electricity is $97.99 ($97,990/GWh). The lower bound is a social loss of $61.94/MWh ($61,940/GWh). In this scenario, the impacts of climate change are so mild that it is socially costlier to replace gas-fired capacity with wind capacity than it is to keep the gas-fired capacity in place. The upper bound in social benefits resulting from substituting one MWh of electricity generated from wind backstopped by natural gas for one MWh of electricity generated from coal is $213.22 ($213,220/GWh). The lower bound is a social loss of $52.30/MWh ($52,300/GWh). These calculations assume generation can switch between wind and gas with perfect efficiency. Ramp rate calculations are not included.

4.0 Solar: Niche and Disadvantaged, but Room for Growth

This section discusses the potential of solar power in Alberta. This will include the state of the technology, presence and potential in Alberta and abroad, economic and environmental considerations including social costs, and the metrics set out in the introduction. Many aspects of this analysis will compare solar and wind directly, as they share many characteristics. Two types of solar technology will be discussed: photovoltaics and thermal solar, with a focus on the former.

4.1 The Technology

Solar power is an umbrella term for any process that captures or harnesses energy from the sun.[78] This section will focus primarily on photovoltaic solar, the most commercially widespread means by which solar energy is converted into electricity. The mechanism for photovoltaic solar is the photovoltaic effect, where light hits semiconductor materials within a solar cell, causing excitation of electrons. The physical structure of the semiconductor manipulates these electrons to generate electricity. Using mirrors or lenses to focus sunlight on smaller surface areas is referred to as concentrated thermal solar.[79] Commercial solar power can be generated on farms or power plants. Any capacity in excess of 1 MW is generally referred to as utility-scale solar.[80] Photovoltaic panels are small enough that they can be installed on rooftops for private use, which is typically referred to as residential-scale.

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[78] MacKay, *Sustainable Energy*, 38.
[79] H. L. Zhang, Jan Baeyens, J. Degrève, and G. Cacères, "Concentrated solar power plants: review and design methodology," *Renewable and Sustainable Energy Reviews* 22 (2013): 466-481.
[80] Patrick Donnelly-Shores, "What Does Utility Scale Solar Really Mean?" Green Tech Media, July 30, 2013, http://www.greentechmedia.com/articles/read/what-does-utility-scale-solar-really-mean.

Solar power is inexhaustible, but unreliable. Electricity from photovoltaics can only be produced during daylight hours, during which periods of cloud cover can further limit generation. If there is no reliable method of storage, solar requires backup generation to ensure a stable base load. Photovoltaics cap out at 45 per cent efficiency with concentration and multiple semi-conductors, but most mass-produced photovoltaic solar panels are between 10 and 20 per cent efficient.[81] Concentrated photovoltaic panels with efficiencies exceeding 40 per cent have been produced on a non-industrial scale.[82]

Solar technology is evolving rapidly, and advances in design and engineering techniques continue to emerge. Most modern residential photovoltaic cells have generating capacities between 150W and 350W, with surfaces areas as large as 2.5 metres.[83] Utility-scale photovoltaic cells are larger and typically ground-mounted. They can be fixed in place or axis-tracking, meaning they follow the sun along one or more dimensions to optimize the sunlight's angle of incidence. The cost-effectiveness of axis-tracking is limited on smaller scales. It is far less common on rooftop panels, for instance.

Photovoltaic panels are modular and therefore highly scalable.[84] However, since high-efficiency panels are much more expensive to produce, less efficient panels (10 to 15 per cent) tend to be used for large-scale projects.[85] Like onshore wind, there is no standard power per-unit area estimate. Any estimate of power per-unit area is highly dependent on latitude, average annual insolation rates,[86] panel efficiency, whether the panels are fixed-axis or not, and whether any concentration techniques are used. Power per unit area for

[81] MacKay, *Sustainable Energy*, 39.
[82] Frank W. Dimroth, Guter, J. Schone, E. Welser, M. Steiner, E. Oliva, A. Wekkeli, G. Siefer, S. P. Philipps, and A. W. Bett, "Metamorphic GaInP/GaInAs/Ge triple-junction solar cells with 41% efficiency," In *Photovoltaic Specialists Conference (PVSC), 2009 34th IEEE*, pp. 001038-001042, IEEE, 2009; Wolfgang Guter, Jan Schöne, Simon P. Philipps, Marc Steiner, Gerald Siefer, Alexander Wekkeli, Elke Welser, Eduard Oliva, Andreas W. Bett, and Frank Dimroth, "Current-matched triple-junction solar cell
[83] Brightstar Solar, "Common Sizes of Solar Panels."
[84] Industrial Energy Applications, "What Type of Commercial Solar Power Should You Choose for Your Business?,"
[85] MacKay, *Sustainable Energy*, 41.
[86] Insolation rates refer to the energy that the Earth receives from the sun per unit area (kW/m^2).

photovoltaics is anywhere from 0.25 to 0.75 MW/hectare.[87] Calculations specific to Alberta will be examined in the next subsection.

The angle of incidence at which sunlight hits the ground determines how much electricity a photovoltaic solar panel can generate. The power density of sunlight is 1.37 kW/m^2 with variation of up to 0.2 per cent at a perfectly perpendicular angle of incidence (90°).[88] As the angle of incidence approaches zero, less energy is received per unit area. High latitude regions present more difficult conditions for solar, specifically during winter months when there is less daylight and the sun is lower in the sky.[89] Alberta's insolation rates will be detailed in subsection 4.2.

Commercial solar farms present a number of environmental challenges. Unlike wind farms, where turbines are highly dispersed over a larger area, solar panels are packed as close to one another as possible, and opportunities for multi-purpose land use are effectively naught. This presents additional risks for habitat loss and fragmentation.[90] Land requirements are significant – far greater than wind for the same power output – and they do not decrease once construction is completed. Trenching, road construction, and grid connections can further increase land requirements for more remote projects. Use of low-quality land with few alternative uses, such as brownfields, that can be situated to minimize disturbance to sensitive species and ecosystems is desirable for solar farms. This is particularly true in regions with agricultural or recreational uses, where the opportunity costs of land use are high.

In addition, solar, and photovoltaics in particular, pose a number of potential risks to human health. The manufacturing process uses a number of hazardous substances, including acids and acetone.[91] The panels themselves contain a number of toxic substances which present risks to soil, groundwater, and human health, including arsenic,

[87] Union of Concerned Scientists, "Environmental Impacts of Solar Power."
[88] Richard C. Willson, S. Gulkis, M. Janssen, H. S. Hudson, and Gaz Chapman, "Observations of solar irradiance variability," *Science* 211, no. 4483 (1981): 700-702.
[89] MacKay, *Sustainable Energy*, 39.
[90] Ibid.
[91] Ibid.

gallium, and cadmium-telluride.[92] While these risks cannot be entirely mitigated, the scarcity of many of the materials used in photovoltaic cells incentivizes cradle-to-grave and cradle-to-cradle management.

A Note on Thermal Solar

As noted earlier, solar is an umbrella term. While photovoltaics are the most established technology, thermal solar has made strides in recent years. Instead of the photoelectric effect, thermal solar uses focused solar radiation to generate steam, which powers a turbine. Concentration methods are much more common with thermal solar than photovoltaic solar. Thermal solar can also be used to directly heat water and buildings instead of generating electricity. This method is unrelated to electricity consumption, though it could certainly play a role in reducing overall energy consumption.

Thermal solar presently offers a few advantages over photovoltaic solar. Most notably, it is making progress with respect to storage, including the use of molten salt baths to retain heat, which can then be released on demand over several hours during nighttime or cloudy periods.[93] In addition, the theoretical maximum efficiency for thermal with perfect concentration is 60 per cent, compared to 45 for photovoltaics.

The biggest drawback of thermal solar is that the technology is simply not as widespread or mature as photovoltaics, though the growth rate is similar. Spearheaded by investment in the U.S. and Spain, thermal capacity more than quadrupled between 2010 and 2014, and now exceeds 5 GW worldwide.[94] However, it is still far behind photovoltaics in a number of respects, and many of its applications are still experimental.[95] Other stumbling blocks include serious risks to wildlife, particularly birds, bats and insects, and significant water requirements for cooling and other industrial processes.[96] Wet-recirculating

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[92] Ibid.

[93] Camila Domonoske, "Morocco Unveils a Massive Solar Power Plant in the Sahara," *NPR*, February 4, 2016.

[94] International Energy Agency, "Technology Roadmap: Solar Thermal Electricity," 2014; International Renewable Energy Agency, “Renewable Power Generation Costs in 2014.”

[95] World Energy Council, "World Energy Perspective: Cost of Energy Technologies," 2013.

[96] Theocharis Tsoutsos, Niki Frantzeskaki, and Vassilis Gekas, "Environmental impacts from the solar energy technologies," *Energy Policy* 33, no. 3 (2005): 289-296.

thermal plants (by far the most common and efficient) require between 2,200 and 2,500 litres of water for every MWh produced.[97] Thermal facilities also have greater spatial requirements, producing 0.15 to 0.66 MW/hectare.[98] Recall that photovoltaics are in the range of 0.25 to 0.75 MW/hectare.

Without further technological breakthroughs, the costs of solar thermal are poised to lag behind photovoltaics for the foreseeable future. Due to these considerations, thermal solar will be excluded from further analysis. The remainder of this section will focus exclusively on photovoltaics.

4.2 Solar in Alberta

Alberta's solar industry is still very much in its infancy. The largest commercial photovoltaic farm (and the largest in Western Canada) currently in operation is Skyfire's 2 MW project in Bassano.[99] One additional 15 MW solar project in Alberta has received regulatory approval, and as of June 2016, another five solar projects totalling 279 MW have been announced or are awaiting regulatory approval.[100] The largest, three separate 80 MW facilities to be operated by Suncor, were all announced in 2016.[101] It is difficult to calculate Alberta's total installed capacity due to the presence of household and micro-generation (less than one MW). As AESO does not factor micro-generation into its figures, Alberta's solar capacity is listed as zero in its 2016 long-term outlook.[102] Estimates from Alberta-based engineering firms are as high as 9 MW spread over roughly 1,300 different locations.[103]

Though it has yet to meaningfully factor into the province's electricity mix, the solar resources in Alberta are among the best in all of Canada – though poor when compared to most countries. For instance, most of the southern U.S. has insolation rates between 200

[97] Union of Concerned Scientists, "Environmental Impacts of Solar Power."
[98] Ibid.
[99] Skyfire Energy, "2 MW Solar Farm; Bassano, Alberta."
[100] Alberta Electric System Operator, "Long Term Adequacy Metrics – May 2016."
[101] Ibid.
[102] Alberta Electric System Operator, "AESO 2016 Long-term Outlook."
[103] Moustafa Youssef, "Imagining Alberta's Solar Future," Neighbour Power, January 2016.

and 220W/m^2 (1800 to 2000 kWh/m^2/year).[104] Tens of thousands of km^2 in southeastern Alberta, including Medicine Hat and Lethbridge, have historic insolation rates of 150W/m^2 (1330 kWh/m^2/year).[105] The majority of Alberta, including Calgary, Edmonton, Red Deer and Fort McMurray, has historic insolation rates of 132 to 150W/m^2 (1160 to 1330 kWh/m^2/year).[106] The insolation levels in southeastern Alberta are the highest of anywhere in Canada, and the insolation levels in central Alberta exceed those of Ontario, Quebec and British Columbia. Based on these figures, a utility-scale, 5 MW solar project with axis tracking and 15 per cent efficiency and a good-quality insolation rate of 150W/m^2 per year could be expected to yield 6.5 GWh/year.[107] Assuming axis-tracking, 20 per cent efficient panels and the range of previously discussed insolation levels, utility scale solar can be expected to yield between 0.26 and 0.3 MW/hectare in Alberta – the low end of the range for spatial requirements described in Section 4.1. If the entire province was covered in utility-scale solar panels under these conditions, it would correspond to 17.2 to 19.9 GW of installed capacity.[108] It is worth noting that Alberta's average insolation rates in December are less than half of what they are in June, and photovoltaics will not produce consistent levels of electricity year-round.

4.3 The Cost of Solar Generation

Long considered a curiosity and too expensive to compete with other sources of electricity, the global growth rate of photovoltaics is now exponential. This trajectory began in earnest in 2008 when the world added 7 GW of capacity, doubling what had been in place just two years earlier.[109] In 2014, 39 GW of photovoltaic capacity was added, bringing the total to 177 GW.[110] Note that these figures account for photovoltaic solar at any scale, and the majority of this capacity is residential.

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[104] SolarGIS, "Global Horizontal Irradiation."
[105] Alberta Agriculture and Forestry, "Agricultural Land Resource Atlas of Alberta - Annual Solar Radiation of Alberta, 1971 to 2000," 2005.
[106] Ibid.
[107] Anticipated Alberta power consumption in 2030 is 125,500 GWh.
[108] Alberta currently has 16.3 GW of nameplate electricity capacity.
[109] Renewable Energy Policy Network for the 21st Century, "Renewables 2015: Global Status Report."
[110] Ibid.

Global photovoltaic capacity surpassed 200 GW in 2015, and is expected to hit 300 GW in 2016 and 500 GW in 2019.[111] As a result of this boom, photovoltaic manufacturers have been able to scale up significantly. Production costs dropped by 75 per cent between 2009 and 2014, and total installed costs for utility-scale photovoltaic systems have fallen by 29 to 65 per cent depending on the region.[112] There is good reason to believe these costs will fall further. With US$150 billion in new global investment in 2014 – compared to US$99 billion for wind, US$9 billion for biomass, US$5 billion for small-scale hydro, and US$2.3 billion for geothermal – more money is pouring into solar than any other renewable energy source by a substantial margin.[113]

Annual insolation rates are the single most important considerations for a commercial solar project. Regions that are sunnier also operate more reliably month-to-month. The standard benchmark for solar costs is dollars per watt ($/W) and encompasses all phases of the lifecycle: procurement and assembly, installation, and end-of-life.[114] In 2014, the weighted global average installed costs for utility-scale and residential solar were US$2/W ($2.14, 2012 CDN dollars) and US$2.75/W ($2.94, 2012 CDN dollars), respectively.[115] Average costs for utility-scale photovoltaics vary considerably, and there is little in the way of estimates for Canada. A recent U.S.-based estimate projects that plants entering service in 2020 will have average costs comparable to wind power, in the range of $14 to $16/MWh, which corresponds to approximately 10 per cent of levelized costs (2012 CDN dollars).[116]

Much like average costs, several downward forces are acting upon the levelized cost of photovoltaic electricity. Most estimates suggest the cost has been cut in half since 2010, though this varies by region.[117] Skyfire, the largest residential solar panel installation

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111 Solar Industry Magazine, "Global Solar Capacity to Exceed 310 GW by Year-End: IHS," February 29, 2016, http://solarindustrymag.com/global-solar-pv-capacity-to-exceed-310-gw-by-years-end-ihs.
112 Ibid.
113 Renewable Energy Policy Network for the 21st Century, "Renewables 2015: Global Status Report."
114 International Renewable Energy Agency, “Renewable Power Generation Costs in 2014.”
115 Ibid.
116 U.S. Energy Information Administration, “Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015,” June 2015.
117 World Energy Council, "World Energy Perspective: Cost of Energy Technologies."

company in Western Canada, calculates the levelized cost of electricity for a 5 kW residential system to be between $122 and $204/MWh (2012 dollars), assuming a 25-year lifespan where 50 per cent of electricity generated is sold to the grid. This cost estimate also accounts for variability in installed costs ($3.75/W to $5.75/W), insolation, shading and capacity factors, and interest rates on loans (if any).[118] For utility-scale, the AESO's 2014 long-term outlook prices photovoltaic solar at $174/MWh.[119] To compare, the AESO calculates the levelized cost of wind power at $88.35/MWh, combined cycle gas at $81.40/MWh, gas cogeneration at $68.50 to $103.24/MWh, simple cycle gas at $109.20/MWh, and coal at $235.27/MWh (2012 dollars).[120]

The EROI for photovoltaics is highly dependent upon location, estimated lifespan, and project scale. Raugei et al (2012), assuming conversion factors of 12 to 15 per cent, estimates the EROI for silicon cells at six and between 10 and 12 for higher quality semi-conductors such as ribbon silicon and cadmium-telluride.[121] Recall that EROI for wind is closer to 20. However, Raugei et al assume mean annual insolation rates of 1700 kWh/m^2 per year – too high to be comparable to Alberta. In a more recent study, Bhandari et al (2015) assume insolation rates similar to Alberta's calculated mean EROIs to be between 8.7 and 35 depending on the materials used. Silica, the most common material, occupies the lower end of this range.[122] Interestingly, Bhandari et al calculate higher EROIs across the board when compared to Raugei et al even in less favourable conditions, which speaks to how quickly production costs are falling off.

Due to the small scale at which it can be installed, photovoltaic solar has an advantage over utility-scale power generation with respect to transmission costs and infrastructure costs. For rooftop setups, surplus electricity can be sold into the grid. Recall that estimated installation costs in Alberta are between $3.75 and $5.75 per watt ($3,750 to

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[118] David Kelly, David Vonesch and Tim Schulhauser, "The Economics of Solar in Alberta," white paper, January 2012.
[119] Alberta Electric System Operator, "AESO 2014 Long-term Outlook."
[120] Ibid.
[121] Marco Raugei, Pere Fullana-i-Palmer, and Vasilis Fthenakis, "The energy return on energy investment (EROI) of photovoltaics: Methodology and comparisons with fossil fuel life cycles," *Energy Policy* 45 (2012): 576-582.
[122] Khandendra P. Bhandari, Jennifer M. Collier, Randy J. Ellingson, and Defne S. Apul, "Energy payback time (EPBT) and energy return on energy invested (EROI) of solar photovoltaic systems: A systematic review and meta-analysis," *Renewable and Sustainable Energy Reviews* 47 (2015): 133-141.

$5,750 per kW). Smaller utility-scale solar projects would be also able to connect directly to Alberta's distribution lines to meet local demand, eschewing the need for transmission to other parts of the province.[123]

4.4 The Emissions Footprint

The lifecycle emissions intensity for photovoltaics is dependent upon regional insolation rates and the scale of production and installation. The greater the insolation rate, the more productive the panel is expected to be over its lifetime. Lifecycle emissions intensity considers all aspects of the manufacturing process, as well as installation, operation and decommissioning. One comprehensive metastudy, examining peer-reviewed studies published between 2005 and 2013, produced a range of 1 to 218 $kgCO_2e/MWh$ and a mean value of 49.9 $kgCO_2e/MWh$.[124] Average insolation rates used in the calculation were higher than Alberta's historic insolation rates, but two studies included in this metastudy used insolation rates comparable to Alberta's. Estimates from Nugent and Sovacool (2014) and Liu et al (2015) produced a range of 39 to 92 $kgCO_2e/MWh$ for photovoltaics roof-mounted at a fixed 45-degree angle. Overall, cultivation and fabrication account for 71 per cent of emissions, followed by construction at 19 per cent, and operation at 13 per cent. Decommissioning offers a three per cent sink as a result of reuse and recycling of materials. Solar panels have no combustion emissions. Interestingly, larger solar panels appear to have lower emissions intensities, possibly due to efficiency gains in logistics and transportation.[125] A study focusing solely on utility-scale solar produced a range of 35 to 58 $kgCO_2e/MWh$, though with better insolation conditions than in Alberta.[126] In the analysis below, a lifecycle range of 40 to 90 $kgCO_2e/MWh$ is used.

[123] Canadian Wind Energy Association and Canadian Solar Industry Association, "CanWEA/CanSIA Submission to the Alberta Climate Change Advisory Panel," September 30, 2015.
[124] Daniel Nugent and Benjamin K. Sovacool, "Assessing the lifecycle greenhouse gas emissions from solar PV and wind energy: A critical meta-survey," *Energy Policy* 65 (2014): 229-244.
[125] Ibid.
[126] Xiaowei Liu, S. Kent Hoekman, Curt Robbins, and Peter Ross. "Lifecycle climate impacts and economic performance of commercial-scale solar PV systems: A study of PV systems at Nevada's Desert Research Institute (DRI)." *Solar Energy* 119 (2015): 561-572.

Table 11 outlines the lifecycle and combustion emissions intensity for solar power compared to coal and gas-fired power.

Table 11: Bounds for Combustion and Lifecycle Emissions for Natural Gas, Coal and Solar

	Natural Gas	Coal	Solar
Combustion Lower Bound	310 kgCO_2e/MWh	820 kgCO_2e/MWh	0 kgCO_2e/MWh
Combustion Upper Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	0 kgCO_2e/MWh
Lifecycle Lower Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	40 kgCO_2e/MWh
Lifecycle Upper Bound	680 kgCO_2e/MWh	1,370 kgCO_2e/MWh	90 kgCO_2e/MWh

Source: Author's calculations, based on Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3"; Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"; Daniel Nugent and Benjamin K. Sovacool, "Assessing the lifecycle greenhouse gas emissions from solar PV and wind energy: A critical meta-survey," *Energy Policy* 65 (2014): 229-244.

Based on a $30 per tonne carbon tax, substituting one MWh of electricity generated from natural gas with one MWh of electricity generated from solar would result in savings between $9.30 and $17.49 ($9,300 and $17,490 per GWh). Substituting one MWh of electricity generated from coal with one MWh of electricity generated from solar would result in savings between $20.40 and $41.10 ($20,400 and $41,100 per GWh).

The lifecycle SCC for electricity generated from coal, natural gas and solar in 2016 are shown in Table 12, in 2012 dollars.

Table 12: Social Cost of Electricity Generation for Solar, Natural Gas and Coal (2012 dollars)

	Central Tendency	95th Percentile
Solar Lower Bound	$1.63/MWh	$6.68/MWh
Solar Upper Bound	$3.66/MWh	$15.03/MWh
Natural Gas Lower Bound	$23.73/MWh	$97.36/MWh
Natural Gas Upper Bound	$27.68/MWh	$113.56/MWh
Coal Lower Bound	$33.37/MWh	$136.94/MWh
Coal Upper Bound	$55.76/MWh	$228.79/MWh

Source: Author's calculations, based on Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3"; Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"; Daniel Nugent and Benjamin K. Sovacool, "Assessing the lifecycle greenhouse gas emissions from solar PV and wind energy: A critical meta-survey," *Energy Policy* 65 (2014): 229-244.

The upper bound in social benefits resulting from substituting one MWh of electricity generated from solar for one MWh of electricity generated from natural gas is $111.93 ($111,930/GWh). The lower bound is $8.70/MWh ($8,700/GWh). The upper bound in social benefits resulting from substituting one MWh of electricity generated from solar for one MWh of electricity generated from coal is $227.16 ($227,160/GWh). The lower bound is $18.34 ($18,340/GWh).

However, like wind, these estimates represent ideal conditions that assume that no backup generation is required. Most high-insolation areas in Alberta receive an average of 2,200 to 2,500 hours of sunlight per year, which means that the fuel source for photovoltaics is available between 25 and 28.5 per cent of the time.[127] Revised social cost estimates are reported in Table 13, assuming gas-fired electricity will be used to backstop all photovoltaic capacity. The upper bound assumes 25 per cent solar (90 kgCO_2e/MWh) and 75 per cent natural gas (680 kgCO_2e/MWh); the lower bound assumes 28.5 per cent solar (40 kgCO_2e/MWh) and 71.5 per cent natural gas (583 kgCO_2e/MWh). We are left with an upper bound of 532 kgCO_2e/MWh and a lower bound of 416.85 kgCO_2e/MWh.

Table 12: Social Cost of Solar Generation when Backstopped by Natural Gas

	Central Tendency	95th Percentile
Solar Lower Bound	$16.97/MWh	$69.61/MWh
Solar Upper Bound	$21.65/MWh	$88.84/MWh

Source: Author's calculations, based on Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3"; Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation"; Daniel Nugent and Benjamin K. Sovacool, "Assessing the lifecycle greenhouse gas emissions from solar PV and wind energy: A critical meta-survey," *Energy Policy* 65 (2014): 229-244.

[127] Government of Canada, Climate, "1981-2010 Climate Normals and Averages," September 22, 2015.

Under these more realistic conditions, the upper bound in social benefits resulting from substituting one MWh of electricity generated from photovoltaics backstopped by natural gas for one MWh of pure gas-fired electricity is $96.59 ($96,590/GWh). The lower bound is -$65.11 (a social loss of $65,110/GWh).[128] The upper bound in social benefits resulting from substituting one MWh of electricity generated from photovoltaics backstopped by natural gas for one MWh of electricity generated from coal is $211.82 ($211,820/GWh). The lower bound is -$55.47 (a social loss of $55,470/GWh).

5.0 Biomass: Opportunistic but Approaching its Ceiling

This section analyzes electricity derived from biomass, known as biopower, and its growth potential as a power source in Alberta. This will include an overview of operations, a study of fuel sources suitable for Alberta, the presence and potential of the industry in Alberta, economic and environmental considerations including social costs, and the metrics set out in the introduction. Comparisons will be made to wind and solar where appropriate.

5.1 The Technology

Biomass refers to the mass of any biological substance. The energy content of this mass is in the form of chemical energy, most commonly carbohydrates. This energy can be unlocked through various processes, usually combustion or gasification.[129] Biomass is derived from plants, crops, and organic waste streams, by-products, and residues.[130] Generally speaking, biomass can be divided into two categories. Purpose-grown biomass is anything that grown specifically for fuel; waste-biomass is any repurposed

[128] A reminder: under these conditions, the impacts of climate change are so mild that it is socially costlier to replace gas-fired capacity with solar capacity than it is to keep the gas-fired capacity in place

[129] Peter McKendry, "Energy production from biomass (part 1): overview of biomass," *Bioresource technology* 83, no. 1 (2002): 37-46.

[130] Samir S. Sofer and Oskar R. Zaborsky, *Biomass conversion processes for energy and fuels*, Springer Science & Business Media, 2012.

substance.[131] Energy of any kind derived from biomass is referred to as bioenergy, and electricity generated from biomass is referred to as biopower.

Operationally, combustion-based biopower is similar to coal or gas-fired electricity, creating heat and steam to operate a turbine or other conversion engine. Although it is largely combustion-based like coal and gas, biomass refers to material that was recently living; no mining or drilling is required. The broadness of its definition means that biomass is humanity's oldest energy source. Wood used in a stove, for instance, is bioenergy. Gasification is another method by which the energy content of biomass can be utilized. This process involves heating a substance to very high temperatures in the presence of steam or oxygen; the resulting mixture is then combusted. Biomass can also be co-fired with coal, but that possibility will be excluded from this analysis due to the Government of Alberta's intent to phase coal out by 2030.

Biopower is only a renewable source of energy to the extent that it is managed as such. Unlike wind and solar, it is exhaustible. Moreover, the availability of fuel is a tremendous obstacle to development (discussed in more detail later in this section). Biopower is only sustainable if the fuel source is harvested at a rate equal or lesser to the rate at which it is consumed. Many of the residues and waste streams suitable for biopower are also highly scattered or localized in their distribution, and collection often presents prohibitive cost barriers.[132] Due to the relative scarcity of biofuels compared to fossil fuels, biopower facilities typically have smaller generating capacities than their coal and gas counterparts.

There are significant opportunity costs and environmental impacts associated with purpose-grown biopower. Alternative land use is the largest issue, and alternative uses for the fuel must be considered as well. The growing process is input intensive, particularly with respect to water. This means the environmental footprint of purpose-grown biomass extends far beyond the emissions involved in collection, transport and combustion. Purpose-grown biopower has substantial land requirements. Commercial forestry for

[131] Peter McKendry, "Energy production from biomass (part 1): overview of biomass."
[132] Ibid.

electricity generation generates a meagre 0.25 kW/hectare, at best.[133] Halkirk, the best wind site in Alberta, offers 100 times the power-per-unit area, assuming no alternative use for the land in between turbines. A large-scale solar project would offer 1000 times the power-per-unit area based on average insolation rates for Alberta. Given the challenges associated with purpose-grown biopower, the remainder of this section will focus solely on waste biopower as an alternative electricity source for Alberta.

Waste-biomass presents a more complex array of environmental benefits and consequences. The principle environmental benefit is that the process can divert waste streams from landfills. However, the environmental impacts of road construction, collection and transport of fuels, and operations can be significant, particularly with respect to sensitive habitats and air quality. Biomass combustion also creates ash, which can have high concentrations of toxic substances and metals and must also be disposed of.[134] On a lifecycle basis, biomass is quite emissions-intensive when compared to other renewable energy technologies. Because it is combustion-based, biopower also emits a number of pollutants beyond CO_2, including NO_x, SO_x, carbon monoxide, polycyclic aromatic hydrocarbons, and particulate matter (soot).[135]

5.2 Biomass in Alberta

Biomass has a minor presence in Alberta, and its installed capacity is the smallest of the "big five" power sources listed in the introduction. For the purposes of its supply and demand reports, the AESO includes biopower projects with "other" power plants, namely waste heat.[136] At present, Alberta has nine biomass facilities – all of which combust forestry or pulp and paper-related fuels. They combine for 370 MW of installed capacity.[137] Of these nine facilities, five have generating capacities of 25 MW or less. The largest, Alberta Pacific Forest Industry's 131 MW facility in Athabasca, is vertically

133 MacKay, *Sustainable Energy*, 41.
134 U.S. Energy Information Administration, "Biomass and the Environment."
135 Thomas Nussbaumer, "Combustion and co-combustion of biomass: fundamentals, technologies, and primary measures for emission reduction," *Energy & fuels* 17, no. 6 (2003): 1510-1521.
136 Alberta Electric System Operator, "Current Supply Demand Report."
137 Ibid.

integrated with its pulping operations.[138] One additional plant, a 41 MW wood waste facility, is expected to commence operations in early 2017.[139] The fact that all of the biomass capacity in Alberta is based on residues from forestry and pulp and paper suggests that the capital costs of biopower from municipal waste and agricultural waste are currently prohibitive.

Any number of materials can be used for biopower, but the energy content, efficiencies, ease of collection, and emissions factors vary significantly. In addition, transport costs limit how far biomass can travel from its place of origin before the fuel becomes too costly to use. This section will discuss four fuel sources that are potentially viable in Alberta based on availability, ease of collection and return on investment. The fuels are:

- Agricultural fuels, namely straw
- Forest harvest fuels, including waste from sawmills
- Black liquor, a by-product of the pulp and paper industry
- Municipal waste

These combustible materials can be directly compared to one another via a number of properties; these are summarized in Table 13. Black liquor can be combusted, but it is better suited to gasification due to its high levels of inorganic content. The analysis of forest harvest residues below is confined to pine, birch and fir, which are abundant in Alberta. Agricultural residues are limited to straw from wheat and barley, commonly used fuel sources that could be sourced within Alberta.

[138] Alberta-Pacific Forest Industries, "Products."
[139] Alberta Electric System Operator, "Long Term Adequacy Metrics – May 2016."

Table 13: Various Metrics for Biopower Fuel Sources

	Agricultural residues (1)	Forest harvest residue (1)	Municipal wastewater (2)	Black liquor (3)
Energy Content (MJ/kg)	17.3 for wheat, 16.1 for barley	20 to 22 for purpose-grown wood; 16 for residues	12.4 to 15.9	12.3 to 14.5
Intrinsic moisture content (% H_2O)	16 for wheat, 30 for barley	20	Highly variable	Variable; 70 to 80 in modern pulp mills
Ash (% of total weight after combustion)	4 for wheat, 6 for barley	1 to 2	Highly variable	As high as 40, but dependent on moisture content
Fixed carbon content (% total mass)	21 for wheat, 18 for barley	17 to 19	Highly variable	35

Sources: (1) Peter McKendry, "Energy production from biomass (part 1): overview of biomass," *Bioresource technology* 83, no. 1 (2002): 37-46. (2) Ioannis Shizas and David M. Bagley, "Experimental determination of energy content of unknown organics in municipal wastewater streams," *Journal of Energy Engineering* 130, no. 2 (2004): 45-53. (3) IEA Bioenergy, "Black Liquor Gasification: Summary and Conclusions from the IEA Bioenergy ExCo54 Workshop."

Many of the properties of these four fuels are similar. Purpose-grown biomass discounted, wheat has the highest energy content (17.3 MJ/kg), followed by barley (16.1 MJ/kg) and wood (16 MJ/kg). All are inferior to hydrocarbons. The energy content of coal is 20 to 28 MJ/kg depending on the type, 55 MJ/kg for natural gas, and 42 to 46 for crude oil.[140] Municipal wastewater has comparatively poor energy content, and isolating for components of the waste stream that can be combusted or gasified requires significant energy, time and infrastructure.[141] Given Alberta's relatively robust forestry, pulp and

[140] Bradley E Layton, "A comparison of energy densities of prevalent energy sources in units of joules per cubic meter," *International Journal of Green Energy* 5, no. 6 (2008): 438-455.
[141] I. Rawat, R. Ranjith Kumar, T. Mutanda, and F. Bux, "Dual role of microalgae: phycoremediation of domestic wastewater and biomass production for sustainable biofuels production," *Applied Energy* 88, no.

paper, and agricultural sectors, municipal wastewater will be excluded from further analysis. Forest harvest residues and agricultural resides have superior dry-weight energy content. Black liquor has the edge for fixed carbon content, which means it is more energy dense. But its ash content, which generates particulate matter and must be disposed of, is up to ten times higher than forest or agricultural residues if combusted, which speaks to the merits of gasification. Black liquor and sawmill residues are more centralized than agricultural residues or forestry residues, and have an advantage with respect to ease of collection.

Another option for Alberta is landfill methane capture. Beyond installation and maintenance of on-site infrastructure, this method requires no additional steps in the waste disposal process. Alberta has specific protocols under the Specified Gas Emitters Regulation for the capture and combustion of landfill methane.[142] The Clover Bar Landfill in Edmonton is the only landfill in Alberta currently capturing methane for the purposes of electricity generation. On-site facilities have a generating capacity of 5 MW.[143] Given that this contribution to the electric grid is relatively minor, coupled with the fact that AESO does not consider Clover Bar to be biopower but rather simple-cycle gas,[144] landfill methane capture will be considered out of scope for the purposes of this analysis.

5.3 The Cost of Biopower

Biopower is experiencing slower global growth than wind or solar. An overwhelming majority of electricity derived from biomass is waste-based, and as such there is a natural cap on what it can contribute to the global electricity mix, and the electricity mix in Alberta.[145] From 2004 to 2014, biopower capacity grew from 36 to 93 GW worldwide, a

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10 (2011): 3411-3424; Diego Rosso, Michael K. Stenstrom, and Lory E. Larson, "Aeration of large-scale municipal wastewater treatment plants: state of the art," *Water Science & Technology* 57, no. 7 (2008).

[142] Alberta Environment and Parks, "Quantification Protocol for Landfill Gas Capture and Combustion: Specified Gas Emitters Regulation," September 2015.

[143] The City of Edmonton, "Landfill Gas Recovery."

[144] Alberta Electric System Operator, "Current Supply Demand Report."

[145] Renewable Energy Policy Network for the 21st Century, "Renewables 2015: Global Status Report."

compound annual growth rate of 9.96 per cent.[146] In 2014, 75 per cent of worldwide biopower generation was sourced from solid waste, including forestry products and by-products, black liquor, and animal waste. Seventeen per cent was sourced from biogas, seven per cent from municipal solid waste, and one per cent from biofuels. Wood pellets are the predominant fuel source; the world produced 24 million tonnes in 2014.

Capital requirements for biopower can be quite intensive for new facilities. Cost per MWh of installed capacity in Western Canada is up to 20 percent higher for agricultural residues than forest harvest residues when adjusted for scope and size.[147] This explains the latter's dominant presence in Alberta. Kumar et al examined capital costs for various biomass facilities in Alberta and determined that the ideal size for a forest harvest residue facility is 137 MW, and requires residues harvested over a projected 764,000 km^2 (115 per cent of Alberta's total area), assuming 0.247 tonnes of dry-weight residues per hectare, at a cost of $12.06 per dry tonne of fuel. The cost of generation would be at least $104/MWh (2012 dollars).[148] Ideal size in this context considers increasing capital economies of scale and the limits imposed by transportation costs.[149] Kumar et al also found that the ideal size for a facility using agricultural residues is 450 MW, which would require 61,000 km^2 of land (9.2 per cent of Alberta's total area), assuming a yield of 0.416 tonnes of fuel per hectare, and has a cost of $6.60 per dry tonne of fuel. The cost of power from a facility with agricultural residues as its fuel source would be at least $83.25/MWh (2012 dollars). Under these conditions, overnight capital costs (i.e. the cost of building a plant overnight), for wood and straw are $1,855 and $2,100/kW, respectively (2012 dollars).[150]

The greatest challenges with biopower are a stable and secure supply of fuel, and the low energy content when compared to hydrocarbons. The required energy expenditure for collection and transport also means that biomass is more capital intensive than coal or

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[146] Ibid.
[147] Amit Kumar, Jay B. Cameron, and Peter C. Flynn, "Biomass power cost and optimum plant size in western Canada," *Biomass and Bioenergy* 24, no. 6 (2003): 445-464.
[148] Ibid.
[149] Ibid.
[150] Ibid.

gas. Biomass cannot be transported by pipeline; in Alberta it must be shipped via rail, road or river. There are long-term supply issues associated with fuel sources that are by-products of other processes, such as sawdust or black liquor, so long-term supply contracts like those found in oil and gas do not exist. A company (such as a sawmill) would be taking on an unusual risk by committing itself to a contract for one of its by-products when demand for its primary product is erratic or in decline. As such, large biomass facilities generally require a decade or more before a positive return on investment is realized.[151] The risk aversion of by-product suppliers is a serious obstacle for which there is no simple policy or business solution, and puts a natural ceiling on biopower output in Alberta and other jurisdictions. The lack of price certainty and long-term contracts makes it very difficult to sink capital into a biopower facility when alternatives like natural gas can offer far greater stability.

However, generating biopower does not necessarily require that a new facility be built. Over the past decade, several coal facilities across Canada have been repurposed for wood-based biomass.[152] Wood pellets are ideal, as the furnace system does not need to be altered to accommodate the change in fuel.[153] No new transmission infrastructure is required for repurposed facilities either. For waste-biomass, operational power per unit area is limited by the size and design of the facility, as well as any additional infrastructure required to deliver the fuel source.

Biopower has the ability to operate at close to 100 per cent capacity if there is adequate fuel. Alberta's biopower facilities currently operate at anywhere from 18 to 100 percent of their nameplate capacity.[154] However, the conversion efficiency of the fuel source is much lower, usually in the range of 20 to 25 per cent for electricity generation.[155]

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[151] Georgia Forestry Commission, "Developing Forest Resource and Biomass Markets in the South – Volume II: Methods for Securing Long-Term Forest Biomass Supply," March 2012.
[152] Heather Ledger, "Biomass Power."
[153] Ibid.
[154] Alberta Electric System Operator, "Current Supply Demand Report."
[155] Biomass Energy Resource Center, "Biomass Energy: Efficiency, Scale and Sustainability."

There is no consensus in the literature on the EROI for biopower, as a number of assumptions have to be made regarding collection and distance of transport.[156] The EROI of woodchips and other forestry residues generally falls between six and 20, depending on transport distance and assumptions around generation and collection of the by-products. Estimates for biopower from straw range from around eight to 10.[157] Low end EROIs for both forestry and agricultural residues are inferior to wind (20), solar (10 to 35), coal (30) and natural gas (14). On the high end, EROIs for woodchips and other residues are comparable to wind and higher efficiency solar and superior to natural gas. Biopower's EROI upside is limited as there is no downward driver on technology costs like there is for wind and solar. Biopower EROIs will vary from facility to facility based on the boiler design, heat recovery system, methods used in collection, and distance of fuel transportation.

The levelized cost of electricity for combustion-based biomass varies depending on the cost of capital and fuel availability. A study by IRENA produced a substantial range estimate of $62 to $210/MWh for fuels that are generally abundant, like forestry products and residues (2012 CDN dollars).[158] Estimates from an Ontario-specific study fall right in the middle of this range – $151 to $182/MWh (2012 dollars).[159] Average operational costs for biomass facilities are comparable to those of coal.[160] Operation and management costs generally range from one to six per cent of initial capital expenditure costs per year.[161] Variable costs range from $3.80 to $4.70 per MWh (2012 CDN dollars).[162]

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[156] D Weißbacha, G. Ruprechta, A. Hukea, K. Czerskia, S. Gottlieba, and A. Husseina, "Energy intensities, EROIs, and energy payback times of electricity generating power plants"; Natasha Nikodinoska, Elvira Buonocore, Alessandro Paletto, and Pier Paolo Franzese, "Wood-based bioenergy value chain in mountain urban districts: An integrated environmental accounting framework," *Applied Energy* (2016); Kevork P. Hacatoglu, James McLellan, and David B. Layzell, "Feasibility study of a Great Lakes bioenergy system," *Bioresource technology* 102, no. 2 (2011): 108.
[157] Oludunsin Arodudu, Alexey Voinov, and Iris van Duren, "Assessing bioenergy potential in rural areas–a NEG-EROEI approach," *Biomass and Bioenergy* 58 (2013): 350-364.
[158] International Renewable Energy Agency, "Renewable Energy Technologies: Cost Analysis Series – Biomass For Power Generation," June 2012.
[159] Kevork P. Hacatoglu, James McLellan, and David B. Layzell, "Feasibility study of a Great Lakes bioenergy system."
[160] Ibid.
[161] International Renewable Energy Agency, "Renewable Energy Technologies: Cost Analysis Series – Biomass For Power Generation."
[162] Ibid.

5.4 The Emissions Footprint

Because all of Alberta's biopower facilities use wood-based fuels, which are the most likely source for future biopower development in Alberta, the calculation of emissions intensity are based on wood-based biopower. However, many of the issues discussed in this section are relevant for other biopower fuels as well.

Because biopower is both renewable and combustion-based, there are arguments to be made for and against its exemption from a carbon tax. There is debate amongst scientists, governments and industry groups as to whether biopower is actually carbon neutral.[163] The crux of the argument for carbon neutrality is that emissions from biopower can be offset on relatively short timescales through reforestation, and any material that is not collected and combusted would decompose and generate atmospheric emissions regardless.[164] However, decomposing biomass releases greenhouse gases into the atmosphere much slower than combusting biomass does. The time horizon is of consequence when considering the emissions intensities and other externalities, positive and negative, of biopower.

While it can certainly be considered carbon neutral from a policy perspective, biomass combustion does release significant amounts of greenhouse gases. On a lifecycle basis, which includes production, transport and decommissioning and reclamation, forest residues will emit 75 $kgCO_2e/MWh$ with an optimum plant size of 137 MW.[165] Straw's lifecycle emissions are lower, in the range of 49 $kgCO_2e/MWh$ with an ideal plant size.[166] For forest residues, comparable emissions values were found by a study analyzing Ontario.[167] However, both studies assumed that the combustion process is carbon neutral.

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163 Warren Cornwall, "Proposal to Define Wood-burning as 'carbon Neutral' Fuels Debate," Science, March 04, 2016.
164 Environment Canada, "Forest Bioenergy."
165 Amit Kumar, Jay B. Cameron, and Peter C. Flynn, "Biomass power cost and optimum plant size in western Canada," *Biomass and Bioenergy* 24, no. 6 (2003): 445-464.
166 Ibid.
167 Yimin Zhang, Jon McKechnie, Denis Cormier, Robert Lyng, Warren Mabee, Akifumi Ogino, and Heather L. Maclean, "Life cycle emissions and cost of producing electricity from coal, natural gas, and wood pellets in Ontario, Canada," *Environmental science & technology* 44, no. 1 (2009): 538-544.

The lifecycle calculations in this section will not assume carbon neutrality.[168] One recent metastudy that does not assume carbon neutrality showed just how significantly the supply chain influences lifecycle emissions for biopower. When adjusting for a range of variables for forest and sawmill residues, including drying, storage and price fluctuations, Röder et al calculated an upper bound lifecycle emissions as high as 1,330 $kgCO_2e/MWh$, with a lower bound of 132 $kgCO_2e/MWh$.[169] Storage is of particular importance, as raw fuel held for several months can emit large volumes of methane.[170]

Environment and Climate Change Canada estimates industrial-scale emissions from wood and fuel waste at 852 $kgCO_2e$/tonne of fuel.[171] Assuming energy content of 4.44 KWh/kg (16 MJ/kg) and an efficiency rate of 22 to 25 per cent, combustion emission intensities fall between 768 and 883 $kgCO_2e/MWh$. The combustion emission calculations will use 700 to 900 $kgCO_2e/MWh$ to encompass this range.

Lifecycle emissions for biopower are calculated using a range of 50 to 1,300 $kgCO_2e/MWh$. A scenario involving the lower bound for lifecycle emissions would entail a well-designed supply chain that operates under a regulatory framework where forests are treated as a carbon sink.[172] The upper bound represents a comparatively inefficient supply chain that does not combust on-site and requires storage on an order of months. Table 15 outlines the lifecycle and combustion-emissions intensity for natural gas, coal and biomass.

[168] Lifecycle emissions for a biopower project could approach zero if offsets are included.
[169] Miriam Röder, Carly Whittaker, and Patricia Thornley, "How certain are greenhouse gas reductions from bioenergy? Life cycle assessment and uncertainty analysis of wood pellet-to-electricity supply chains from forest residues," *Biomass and Bioenergy* 79 (2015): 50-63.
[170] Ibid.
[171] Environment and Climate Change Canada, "Biomass Combustion."
[172] One such example in Canada is British Columbia's Climate Change Investment Branch in the Ministry of Environment, which replaced the now-defunct Pacific Carbon Trust

Table 14: Bounds for Combustion and Lifecycle Emissions for Natural Gas, Coal and Wood-Based Biomass

	Natural Gas	Coal	Biomass
Combustion Lower Bound	310 $kgCO_2e$/MWh	820 $kgCO_2e$/MWh	700 $kgCO_2e$/MWh
Combustion Upper Bound	583 $kgCO_2e$/MWh	1,016 $kgCO_2e$/MWh	900 $kgCO_2e$/MWh
Lifecycle Lower Bound	583 $kgCO_2e$/MWh	1,016 $kgCO_2e$/MWh	50 $kgCO_2e$/MWh
Lifecycle Upper Bound	680 $kgCO_2e$/MWh	1,370 $kgCO_2e$/MWh	1,300 $kgCO_2e$/MWh

Source: Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3"; Miriam Röder, Carly Whittaker, and Patricia Thornley, "How certain are greenhouse gas reductions from bioenergy? Life cycle assessment and uncertainty analysis of wood pellet-to-electricity supply chains from forest residues," *Biomass and Bioenergy* 79 (2015): 50-63.

Based on a $30 carbon tax, given the aforementioned assumptions, substituting one MWh of electricity generated from natural gas with one MWh of electricity generated from wood-based biomass results in a cost to producers between $3.51/MWh and $17.70/MWh ($3,510 GWh and $17,700 GWh), meaning biomass can be more emissions intensive than coal. Substituting one MWh of electricity generated from coal with one MWh of electricity generated from wood-based biomass results in savings up to $9.48/MWh ($9,480/GWh) or costs of up to $2.40/MWh ($2,400/GWh). If Alberta were to consider biopower carbon neutral, exempt from the carbon tax, or both, then substituting one MWh of electricity generated from natural gas with one MWh of electricity generated from wood-based biomass would yield savings between $9.30 and $17.49 ($9,300 and $17,490 per GWh). Substituting one MWh of electricity generated from coal with one MWh of electricity generated from wood-based biomass results in savings between $20.40 and $41.10 ($20,400 and $41,100 per GWh). Needless to say, how the Alberta government chooses to treat biopower under the carbon tax will have significant implications for the future of the industry in the province.

The lifecycle SCC for electricity generated from coal, natural gas and biopower in 2016 are shown in Table 15, all in 2012 dollars.

Table 15: Social Cost of Electricity Generation for Biopower, Natural Gas and Coal (2012 dollars)

	Central Tendency	95th Percentile
Biopower Lower Bound	\$2.04/MWh	\$8.35/MWh
Biopower Upper Bound	\$52.91/MWh	\$217.10/MWh
Natural Gas Lower Bound	\$23.73/MWh	\$97.36/MWh
Natural Gas Upper Bound	\$27.68/MWh	\$113.56/MWh
Coal Lower Bound	\$33.37/MWh	\$136.94/MWh
Coal Upper Bound	\$55.76/MWh	\$228.79/MWh

Source: Author's calculations, based on Environment and Climate Change Canada, "National Inventory Report 1990-2014: Greenhouse Gas Sources and Sinks in Canada – Part 3."

The upper bound in social benefits resulting from substituting one MWh of electricity generated from biomass for one MWh of electricity generated from natural gas is \$111.52 (\$111,520/GWh). The lower bound is a social loss of \$193.37 (193,370/GWh). The upper bound in social benefits resulting from substituting one MWh of electricity generated from biomass for one MWh of electricity generated from coal is \$226.75/MWh (\$226,750/GWh). The lower bound is a social loss of \$183.73 (\$183.73/GWh). Given the ranges involved in the calculations, any regulatory regime that treats biopower as carbon neutral could be drastically underestimating its social costs.

6.0 Hydropower: High-Potential and High-Impact

This section will analyze hydroelectricity, including an overview of the technology, the presence and potential of the energy source in Alberta, environmental impacts and social costs, and the metrics set out in the introduction. Comparisons will be made to previously discussed electricity sources where appropriate.

6.1 The Technology

Hydroelectricity, or hydropower, is the process by which the potential and kinetic energy contained in running and falling water is used to turn a turbine and generate electricity. Falling water has greater potential energy and is therefore more desirable for prospective projects. Hydropower projects are categorized both by scale and the method by which the water's energy is harnessed.[173] There is no agreed upon standard for scale; project size varies by region in Canada and abroad. Scale can also refer to the extent of a project's environmental impacts. Approximate bounds are provided in Table 16.

Table 16: Hydropower projects by scale

Scale Descriptor	Power Capabilities
Mega	>1 GW
Large-scale	>50 MW
Small or medium-scale	2 to 50 MW
Mini	1 MW
Micro	≤100 kW

Source: Dominique Egré and Joseph C. Milewski, "The diversity of hydropower projects," *Energy Policy* 30, no. 14 (2002): 1225-1230.
Note: The largest mega-scale dam (and power station) in the world is China's Three Gorges Dam, with 22,500 MW (22.5 GW) of installed capacity.

Broadly speaking, there are four major categories of hydropower. The first and perhaps best-known method involves the use of dams. These structures halt the flow of a river, trapping and storing water upstream, thereby creating an artificial lake or reservoir.[174] When the water is released downstream it passes through several channels that contain turbines. Reservoirs can store potential energy for years and release it as needed to supplement peak loads, provide baseload power, or some combination thereof.[175]

The second method is run-of-river, which does not use storage.[176] It instead diverts a portion of a running body of water for the purposes of turning one or more turbines. The water is then returned to the river downstream of the plant. Because there is no storage method, run-of-river cannot help with peak load requirements. Power output is also affected by seasonal fluctuations in flow rates (higher in the spring, lower in the fall), and

[173] Dominique Egré and Joseph C. Milewski, "The diversity of hydropower projects," *Energy Policy* 30, no. 14 (2002): 1225-1230.
[174] Ibid.
[175] International Renewable Energy Agency, "Renewable Power Generation Costs in 2014," January 2015.
[176] Renewable Energy Policy Network for the 21st Century, "Renewables 2015: Global Status Report."

climatic or extreme weather events such drought and flood. Run-of-river can generally provide baseload power, but it may only be capable of providing a small fraction of its nameplate capacity.

The third hydropower technology is pumped storage. A series of engines draw electricity from the grid during periods of low demand to pump water uphill and store it, usually within a geological formation.[177] The water is then held and released downhill during peak hours when power costs are higher. Pumped storage is a net energy consumer (only 65 to 75 percent of the power used is recovered) but is a helpful technology for augmenting peak loads and is generally viewed as one of the best commercially available energy storage technologies. Pumped storage projects have very specific geophysical and engineering requirements, so they are limited in terms of where they can be located.

There is also tidal or ocean power, which can be built anywhere that the Earth's tides influence water levels, including oceans, estuaries and large rivers. Because tidal power relies on a diurnal process, it is very predictable, though erratic hour-to-hour.[178] As a landlocked province, Alberta does not have the ability to use tidal power, and this category will not be discussed further.

Hydropower projects present a number of environmental issues that vary by location.[179] Run-of-river is low impact with respect to disturbance of the river, but it can affect adjacent land use. As only part of the river's flow is diverted for the purposes of electricity generation, the ecological and wildlife risks can largely be mitigated. Dams, on the other hand, can be highly disruptive and often have serious effects upstream and downstream, including thermal stratification, poor nutrient cycling, and sediment deposition.[180] Thermal stratification is unavoidable in reservoirs, and releases downstream can create temperature gradients, which are harmful to fish and especially

[177] Dominique Egré and Joseph C. Milewski, "The diversity of hydropower projects," *Energy Policy* 30, no. 14 (2002): 1225-1230.
[178] MacKay, *Sustainable Energy*, 82.
[179] Dominique Egré and Joseph C. Milewski, "The diversity of hydropower projects."
[180] Matthew McCartney, "Living with dams: managing the environmental impacts," *Water Policy* 11, no. S1 (2009): 121-139.

fish embryos.[181] Warmer water also holds less oxygen. Poor nutrient cycling and irregular sediment deposition are a result of stagnant water in the reservoir that would otherwise be flowing and turbulent. This affects plant species and microorganisms, which can in turn affect higher levels of the ecosystem's food chain.[182] These disruptive effects can also be cumulative. For instance, a release of water with high nutrient content but poor oxygen could drive up chemical oxygen demand at lower levels of the ecosystem, which can be disastrous for fish, amphibians and other aquatic species.

Dams also present unique social challenges and opportunities. When a dam is constructed, the flooded area precludes the use of the land for other activities, including any previous uses. In Alberta this could include impacts to agriculture, recreation, and traditional usage by Aboriginal-Canadians. Flooded areas may also contain known or unknown natural and historic resources. Any existing economic activity could also be impacted or destroyed.[183] Dams can also offer benefits beyond power generation, including storage, flood control, irrigation, and recreation.[184]

There is debate as to whether large and mega-scale hydropower, which requires dams, is truly renewable or sustainable. Policies around the world seem to favour small-scale hydro. For instance, many states in the U.S. exempt hydro that is 30 MW or greater from renewable portfolio standards.[185] A recent study has shown that on a megawatt basis, hydro dams less than 50 MW may actually have greater potential for adverse environmental impacts than large-scale projects, including length of the river channel affected, impacts on land where biodiversity is a priority, modification of hydrological regimes, and water quality.[186] While the optics of large and mega-hydro projects appear to be a stumbling block from a policy perspective, many of the world's mega-dams

[181] J.R Brett, "Temperature and fish," *Chesapeake Science* 10, no. 3-4 (1969): 275-276.
[182] Gabriela Friedl, and Alfred Wüest, "Disrupting biogeochemical cycles-Consequences of damming," *Aquatic Sciences* 64, no. 1 (2002): 55-65.
[183] Ibid.
[184] Ibid.
[185] Jeff Opperman, "Sustainable Hydropower: Are Small Dams Really Better for the Environment?" Cool Green Science. March 17, 2014.
[186] Kelly M. Kibler, and Desiree D. Tullos, "Cumulative biophysical impact of small and large hydropower development in Nu River, China," *Water Resources Research* 49, no. 6 (2013): 3104-3118.

currently in operation have no planned dates for decommissioning, and are intended to last forever.[187] Another issue with mega-hydro is the limited number of sites in the world that can support such large projects.

6.2 Hydropower in Alberta

Hydropower is well established in Alberta, and has been for some time. In the 1950s, half of the province's installed generation capacity was hydropower.[188] The AESO currently lists nine separate facilities with total installed capacity of 902 MW, though other mini and micro projects exist.[189] TransAlta alone has 24 hydro projects listed on its website, many are as small as two or three MW.[190] TransAlta also built and currently operates the three largest facilities in Alberta, all reservoirs. Table 17 summarizes all of the hydropower facilities included in the AESO's Current Supply Demand Report.

Table 17: Major hydropower facilities in Alberta

Name	River	Location	Capacity (MW)	Year of Completion
Bearspaw Dam (1)	Bow	Calgary	120	1954
Bighorn Dam (1)	North Saskatchewan	Clearwater County	320	1972
Brazeau Reservoir (1)	Brazeau, North Saskatchewan Basin	Drayton Valley	350	1965
CUPC Oldman (Run-of-river) (2)	Oldman	Pincher Creek	32	2003
Chin Chute (irrigation canal diversion) (3)	St. Mary Main Canal	Taber	15	1994
Dickson Dam (4)	Red Deer	Innisfail	15	1992

[187] Dominique Egré and Joseph C. Milewski, "The diversity of hydropower projects," *Energy Policy* 30, no. 14 (2002): 1225-1230.
[188] Alberta Culture & Tourism, "Hydroelectricity in Alberta Today."
[189] Alberta Electric System Operator, "Current Supply Demand Report," June 3, 2016; Alberta Energy, "Electricity Statistics."
[190] TransAlta, "Plants in Operation."

Irrican Hydro (irrigation canal diversion) (3)	St. Mary Main Canal	Lethbridge	7	2004
Raymond Reservoir (3)	St. Mary Main Canal	Lethbridge	18	1994
Taylor Hydro (irrigation canal diversion) (1)	Taylor Coulee Chute	Magrath	14	2000

Sources: TransAlta, "Plants in Operation."
1) ATCO Power, "Oldman River Hydroelectric Plant," http://www.atcopower.com/Our-Facilities/Our-Power-Technologies/Hydroelectric/Oldman_River.
2) St. Mary River Irrigation District, "Irrican Power General Overview," http://www.smrid.ab.ca/Irrican%20Power%20General%20Information.pdf.
3) Algonquin Power, "Dickson Dam," http://algonquinpowercompany.com/assets/dickson-dam/.

Many of the best locations for hydro in Alberta have already been developed, as evidenced by the vintage of the larger facilities. The other six facilities listed in Table 18 are considered small hydro.[191] One additional 330 MW run-of-river project, to be situated on the Peace River, has been referred to an independent review panel.[192] If approved, it is expected to enter service in 2023.

A 2010 report commissioned by the Alberta Utilities Commission presents a comprehensive overview of the potential for additional hydropower capacity in Alberta.[193] There are five river basins that offer serious potential for electricity generation: Athabasca, Peace, Slave, and North and South Saskatchewan. The ultimate generation potential of these rivers is estimated at 53,000 GWh per year. In a best-case scenario, with the right combination of larger projects in the northern basins and small-scale projects in the southern basins, anywhere from 10 to 20 percent of this potential could be realized before 2040. The report further states that, given the right economic climate, there is a "reasonable possibility" that significant development of Alberta's hydro resources occurs after 2020.

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[191] Alberta Culture & Tourism, "Hydroelectricity in Alberta Today."
[192] Alberta Electric System Operator, "Long Term Adequacy Metrics – May 2016."
[193] Alberta Utilities Commission, "Update on Alberta's Hydroelectric Resources - Final Report."

According to the Canadian Hydro Association, Alberta could economically develop an additional 11,500 MW of hydropower capacity on top of what is already installed.[194] This assumes that the social and environmental impacts of any project are justified and that consent is obtainable. However, the majority of this capacity resides in the northern and sparsely populated regions of the province where there is less electricity infrastructure. Due to these geographical considerations, it is unlikely that many of these potential large-scale projects will be developed.

6.3 The Cost of Hydropower

As a result of its technological maturity, scalability, and low emissions intensity, hydropower is a prominent electricity source around the world. In 2014, 37 GW of generating capacity was commissioned worldwide, bringing the total to 1,055 GW.[195] Most of this growth occurred in China, with further additions from Canada, India, Turkey, Russia and Brazil.[196] Cumulative installed capacity grew by 20 per cent worldwide between 2010 and 2014.[197]

Hydropower is inexpensive to produce on a marginal basis when compared to other renewable sources. The levelized cost of hydropower is as low as $25/MWh at excellent sites and $190/MWh at poor sites, and averages $60 to $70/MWh.[198] Excellent sites have a quality water resource for generating power, existing infrastructure including grids and roads, high regional demand, and fewer environmental impacts. Civil works and equipment costs are by far the largest capital cost for hydropower – anywhere from 75 to 90 per cent.[199] Total installed costs, including materials, infrastructure, civil works and construction, operation, decommissioning and reclamation, run from $550 to more than $5000/kW of capacity. The lower bound reflects installing generating capacity into an existing dam built for other purposes; the latter assumes a remote project and no existing

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[194] Ibid.
[195] Renewable Energy Policy Network for the 21st Century, "Renewables 2015: Global Status Report."
[196] Ibid.
[197] International Renewable Energy Agency, "Renewable Power Generation Costs in 2014," January 2015.
[198] Ibid.
[199] Ibid.

infrastructure or grid connectivity. For hydro projects greater than 10 MW, operations and maintenance costs fall in the range of $5.36/MWh to $21.43/MWh (2012 CDN dollars).[200] Projects with installed capacities of 10 MW or less can be as high as $45/MWh (2012 CDN dollars).[201]

The EROI for hydro is by far the best among renewable resources. One recent, comprehensive metastudy calculated an EROI of 84 for a variety of small and large-scale projects.[202] Another provided a sensitivity analysis of projects in Quebec, yielding an EROI of 205 for large-scale dams up to 2.6 GW, and 267 for run-of-river projects over a period of 100 years.[203] While the range varies significantly, the low-end estimate is still far superior the other electricity sources discussed. Recall that the upper limit EROIs for solar panels, wind turbines and woodchips top out at 35, 20 and 20, respectively. In addition to offering a superior EROI, hydro can operate at a high capacity factor. The weighted average capacity factor generally hovers around 50 per cent for both small and large projects, but many projects regularly operate as high as 80 per cent.[204]

6.4 The Emissions Footprint

The operational emissions footprint of hydropower is effectively zero. Its emissions footprint encompasses materials, construction, operation, and decommissioning of the facility. As such, the emissions intensities for hydropower projects are quite low. In a comprehensive screening of hydropower facilities in the U.S., the National Renewable Energy Laboratory calculated a range of four to 14 kgCO_2e/MWh for small-scale projects and most large-scale projects over a range of lifespans. Some large-scale outliers were as high as 150 kgCO_2e/MWh.[205] Flooded land created by dams introduced significant uncertainty. Another study that accounted for emissions from the land flooded by

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[200] International Energy Agency, "Renewable Energy Essentials: Hydropower."
[201] Ibid.
[202] Charles AS Hall, Jessica G. Lambert, and Stephen B. Balogh, "EROI of different fuels and the implications for society," *Energy Policy* 64 (2014): 141-152.
[203] Luc Gagnon, Camille Belanger, and Yohji Uchiyama, "Life-cycle assessment of electricity generation options: the status of research in year 2001," *Energy policy* 30, no. 14 (2002): 1267-1278.
[204] International Renewable Energy Agency, "Renewable Power Generation Costs in 2014," January 2015.
[205] National Renewable Energy Laboratory, "Hydropower Results – Lifecycle Assessment Review."

reservoirs produced a range of 0.2 kgCO_2e/MWh to 152 kgCO_2e/MWh, with a standard deviation of 54.5 kgCO_2e/MWh.[206] Lifecycle emissions for reservoir hydro and run-of-river were calculated at 21 kgCO_2e/MWh and 12 kgCO_2e/MWh, respectively.[207] As most of Alberta's future hydropower projects are poised to be small-scale with minimal flooded land, an emissions intensity range of 4 to 14 kgCO_2e/MWh will be used.

Table 18: Emissions Bounds for Small-Scale Hydropower Compared to Natural Gas and Coal

	Natural Gas	Coal	Hydro
Combustion Lower Bound	310 kgCO_2e/MWh	820 kgCO_2e/MWh	0 kgCO_2e/MWh
Combustion Upper Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	0 kgCO_2e/MWh
Lifecycle Lower Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	4 kgCO_2e/MWh
Lifecycle Upper Bound	680 kgCO_2e/MWh	1,370 kgCO_2e/MWh	14 kgCO_2e/MWh

Source: Hanne Lerche Raadaal, Luc Gagnon, Ingunn Saur Modahl, and Ole Jørgen Hanssen, "Life cycle greenhouse gas (GHG) emissions from the generation of wind and hydro power," *Renewable and Sustainable Energy Reviews* 15, no. 7 (2011): 3417-3422; Garvin A. Heath, Patrick O'Donoughue, Douglas J. Arent, and Morgan Bazilian, "Harmonization of initial estimates of shale gas life cycle greenhouse gas emissions for electric power generation."

Based on a $30/tonne carbon tax, substituting one MWh of electricity generated from natural gas with one MWh of electricity generated from hydro results in savings between $9.30 and $17.49 ($9,300 and $17,490 per GWh). Substituting one MWh of electricity generated from coal with one MWh of electricity generated from hydro results in savings between $20.40 and $41.10 ($20,400 and $41,100 per GWh). Seasonal variation in flow rates can prevent hydropower, particularly run-of-river from providing a steady baseload year round. Instead, a "floor" can be assumed based on flow rates during winter months to remove the need for backup generation.

Given the stated parameters and assumptions for the SCC (central tendency of $40.70/tonne and 95th percentile estimate of $167/tonne, 2012 dollars), and the ranges for emissions intensities for electricity generated from hydropower, natural gas, and coal, the social savings incurred from substituting one MWh of electricity generated from hydro

[206] Hanne Lerche Raadaal, Luc Gagnon, Ingunn Saur Modahl, and Ole Jørgen Hanssen, "Life cycle greenhouse gas (GHG) emissions from the generation of wind and hydro power," *Renewable and Sustainable Energy Reviews* 15, no. 7 (2011): 3417-3422.
[207] Ibid.

for one MWh of electricity generated from coal or gas are calculated. The lifecycle SCC for electricity generated from coal, natural gas and hydro in 2016 are shown in Table 19.

Table 19: Social Cost of Electricity Generation for Small-Scale Hydro, Natural Gas and Coal

	Central Tendency	95th Percentile
Hydro Lower Bound	$0.16/MWh	$0.69/MWh
Hydro Upper Bound	$0.57/MWh	$2.34/MWh
Natural Gas Lower Bound	$23.73/MWh	$97.36/MWh
Natural Gas Upper Bound	$27.68/MWh	$113.56/MWh
Coal Lower Bound	$33.37/MWh	$136.94/MWh
Coal Upper Bound	$55.76/MWh	$228.79/MWh

Source: Authors calculations based on Environment and Climate Change Canada, "Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates," March 2016.

Under these conditions, the upper bound in social benefits resulting from substituting one MWh of electricity generated from hydro for one MWh of gas-fired electricity is $113.40 ($113,400/GWh). The lower bound is $21.39 ($21,390/GWh). The upper bound in social benefits resulting from substituting one MWh of electricity generated from hydro for one MWh of electricity generated from coal is $228.63 ($228,630/GWh). The lower bound is $31.03 ($31,030/GWh).

7.0 Geothermal: Nascent and Falling Further Behind

This section analyzes geothermal electricity generation, including an overview of the technology, the industry's potential in Alberta and barriers to development, environmental impacts, social costs, and the metrics set out in the introduction. Comparisons to other renewables are made to give greater context to the analysis where appropriate.

7.1 The Technology

Geothermal uses heat energy from the Earth's interior. This energy has multiple sources, including radioactive decay in the crust, heat energy radiating outward from the mantle, and pockets of steam and superheated water within the crust.[208] To generate electricity, a fluid consisting mostly of water is pumped far enough underground to create a heat gradient. This heated water is then returned to the surface where it either powers a low-pressure turbine directly, or heats a different fluid that is used to power the turbine.[209] Pockets of water in the crust can also be drilled for and pumped to the surface to power a turbine. Geothermal can be used for direct heating or cooling, or a mix of heating, cooling and power generation. This section will refer mostly to power generation. Four different methods can be used to extract this heat energy: hydrothermal, hot dry rock (HDR), magma and geopressure. The latter two are still in the experimental stages with no commercial developments at present. Given the timelines for Alberta's renewable power generation targets, only hydrothermal and HDR will be considered in the analysis presented below.

The concept of geothermal energy has been around for over a century. It was first used to generate electricity in 1904.[210] Despite the technology's age, very little installed geothermal capacity exists, and most of it is in concentrated in areas with natural hotspots.[211] At present, the vast majority of commercial geothermal operations are hydrothermal, which is an umbrella term for a few different methods of heat extraction. Drilling for pockets of water that exist at depth and piping them to the surface is called dry steam. Water can also be sent down, heated, and returned to the surface to power a turbine (flash steam), or sent down, heated, and then used to heat different liquid with a lower heat capacity that powers a turbine (binary cycle).[212] Water can be sent to the surface as liquid, vapour, or an intermediate phase, and can be stored in-situ or circulated continuously. Vapour-dominated systems offer greater energy yield per unit mass of fluid, but liquid-dominated systems are much more common.[213] Hydrothermal can be

[208] MacKay, *Sustainable Energy*, 96.
[209] Annette Evans, Vladimir Strezov, and Tim J. Evans, "Sustainability Assessment of Geothermal Power Generation," *Alternative Energy and Shale Gas Encyclopaedia* (2016): 301-309.
[210] Energy Information Administration, "Geothermal Power Plants."
[211] Geothermal Energy Association, "2016 Annual US & Global Geothermal Power Production Report."
[212] Energy Information Administration, "Geothermal Power Plants."
[213] Darrell L Gallup, "Production engineering in geothermal technology: a review," *Geothermics* 38, no. 3 (2009): 326-334.

accessible just a few hundred metres below the surface; HDR generally ranges from 1.5 to 6.5 kilometers.[214]

HDR is the most abundant source of geothermal energy and is the only other technology moving towards commercial development, with a small number of operational facilities worldwide.[215] This method uses the heat stored in massive rock formations below the Earth's surface that contain minimal or no water. In a process very similar to hydraulic fracturing, an injection of water and other chemicals "stimulates" the rock, creating fissures and increasing accessible surface area. This allows for greater access to the heat contained within. Systems that fracture HDR are also referred to as enhanced geothermal systems.[216]

Heat energy is constantly radiating outward from the Earth's mantle, so any subsurface region used for geothermal power will be replenished at a fixed rate.[217] Geothermal can provide baseload power and is inexhaustible, provided that heat is drawn from the source at a rate equal or lesser to the rate of replenishment. Geothermal can also be "mined" to provide a greater power output over a finite timespan, usually on the order of decades.[218] Beyond its ability to provide baseload power, geothermal also offers superior capacity factors to wind or solar – in the range of 70 to 90 percent – and greater power per unit-area.[219] The heat energy radiating from the Earth averages about 50MW/m^2, but it is low-grade energy at the Earth's surface.[220] To create a useful heat gradient, it is necessary to drill to depths of at least a few hundred meters, and even then only 10 to 20 per cent of the available heat energy is recoverable.[221] Like hydropower, the low-hanging fruit has

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214 Ibid.
215 Annette Evans, Vladimir Strezov, and Tim J. Evans, "Sustainability Assessment of Geothermal Power Generation," *Alternative Energy and Shale Gas Encyclopedia* (2016): 301-309.
216 Mark C. Grubelich, Dennis King, Steve Knudsen, Douglas Blankenship, Sally Bane, and Prashanth Venkatesh, "An overview of a high energy stimulation technique for geothermal applications," In *Proceedings World Geothermal Congress*, pp. 19-25. 2015.
217 MacKay, *Sustainable Energy*, 96.
218 Ibid, 97.
219 Ingvar B. Fridleifsson, "Geothermal energy for the benefit of the people," *Renewable and sustainable energy reviews* 5, no. 3 (2001): 299-312.
220 MacKay, *Sustainable Energy*, 97.
221 Peter Bayer, Ladislaus Rybach, Philipp Blum, and Ralf Brauchler, "Review on life cycle environmental effects of geothermal power generation," *Renewable and Sustainable Energy Reviews* 26 (2013): 446-463.

been picked; the best heat resources (areas with natural hotspots or geysers) have already been developed.

The two most prevalent environmental concerns associated with geothermal are water use and induced seismic activity. Geothermal systems can require anywhere from 10 to 300 liters of water per kWh (3,000 L/MWh).[222] Fracturing rocks at depth can induce microseismic or seismic events, though these risks can be partially mitigated with proper site selection.[223] Major seismic events, induced and non-induced, typically originate six to 10 kilometers below the Earth's surface, uncommon depths for existing geothermal power stations.[224] These depths may become more common with the advent of HDR, however, so it is an issue that the industry must address in the future. Other environmental hazards include potential fluid leakage in the subsurface, the impacts of which are poorly studied, and potential emissions of critical toxic substances found in the fluid, such as mercury, boron and arsenic.[225]

Total land disturbance associated with resource development for 30 to 50 MW geothermal facilities varies from 21 to 149 hectares, the greatest uncertainty coming with transmission line installation (10 to 100 hectares) and drilling and field development (2 to 20 hectares).[226] Power per unit-area for existing geothermal plants, most of which are between 30 and 50 MW, ranges from 0.097 to 2.38 MW/hectare when transmission is excluded.[227] A quality geothermal resource situated near developed transmission infrastructure can increase the power per unit-area by a factor of nearly 100. Geothermal power plants take up relatively little surface area, so the inclusion of transmission drops the lower bound to 0.025 MW/hectare if the infrastructure requirements are significant.

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[222] Ernest L. Majer, Roy Baria, Mitch Stark, Stephen Oates, Julian Bommer, Bill Smith, and Hiroshi Asanuma, "Induced seismicity associated with enhanced geothermal systems," *Geothermics* 36, no. 3 (2007): 185-222.
[223] Ibid.
[224] Ibid.
[225] Peter Bayer, Ladislaus Rybach, Philipp Blum, and Ralf Brauchler, "Review on life cycle environmental effects of geothermal power generation," *Renewable and Sustainable Energy Reviews* 26 (2013): 446-463.
[226] Ibid.
[227] Ibid.

7.2 Geothermal in Alberta

There are currently no commercial geothermal power operations in Alberta and no plans for development at present.[228] The AESO does not list any operations in its supply demand report and only mentions it in the context of other renewable energy sources in its 2016 Long-Term Outlook. In addition to the financial barriers, which will be discussed in Section 7.3, project proponents in Alberta have cited a lack of policies and information as preliminary obstacles to development.[229] This lack of regulatory clarity speaks to the nascence of geothermal power in Alberta.

A handful of studies have been published on the potential for geothermal power in Alberta. The general view within the scientific literature is that as a potential source of heat and power, geothermal has been crowded out by abundant and inexpensive natural gas.[230] In addition, Alberta's subsurface heat resources are of poor quality and require drilling depths of several kilometers, which would necessitate using HDR over hydrothermal.[231] Drilling at depths of four to six kilometers is now commonplace in the petroleum industry, and the equipment, labour and technical expertise to do so are readily available in Alberta, but issues with temperature, rock hardness, directional drilling and fluid loss must still be overcome.[232]

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[228] Hannes Hofmann, Simon Weides, Tayfun Babadagli, Günter Zimmermann, Inga Moeck, Jacek Majorowicz, and Martyn Unsworth. "Potential for enhanced geothermal systems in Alberta, Canada," *Energy* 69 (2014): 578-591; Alberta Electric System Operator, "Current Supply Demand Report," May 1, 2016.

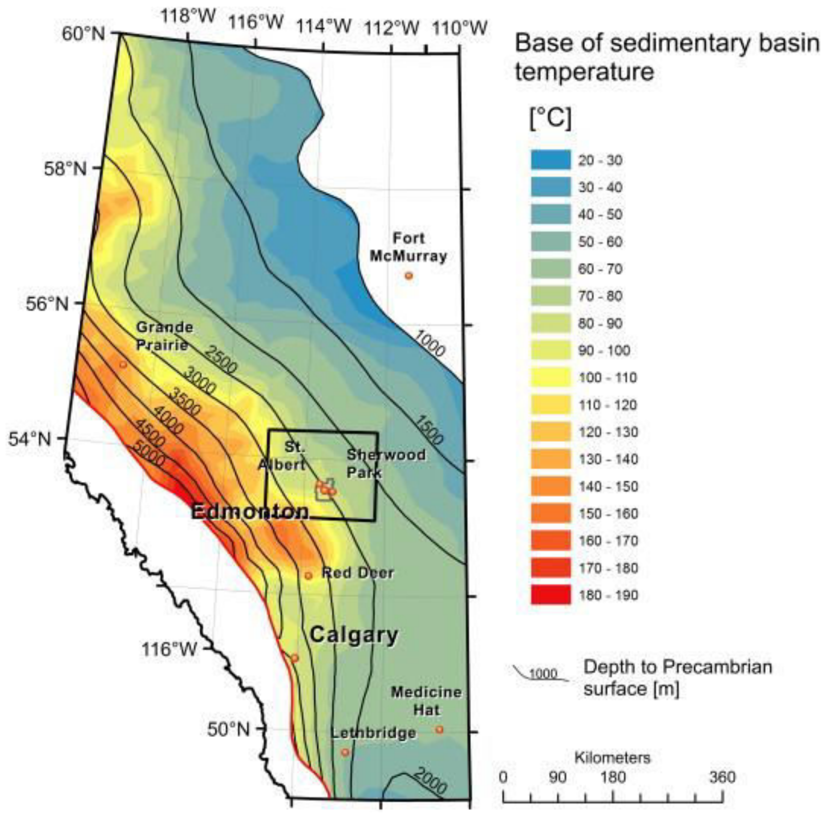
[229] Alberta Electric System Operator, "Renewable Electricity Production Update to Stakeholders."

[230] Jacek Majorowicz and Michal Moore, "The feasibility and potential of geothermal heat in the deep Alberta foreland basin-Canada for CO2 savings," *Renewable Energy* 66 (2014): 541-549.

[231] Ibid.

[232] Ronald DiPippo, *Geothermal power plants: principles, applications, case studies and environmental impact*, Butterworth-Heinemann, 2012: 12-13.

Figure 3: Sedimentary Basin Heat Map in Alberta



Source: Hannes Hofmann, Simon Weides, Tayfun Babadagli, Günter Zimmermann, Inga Moeck, Jacek Majorowicz, and Martyn Unsworth, "Potential for enhanced geothermal systems in Alberta, Canada," *Energy* 69 (2014): 578-591.

Given the low cost of power in Alberta, geothermal sites require high subsurface temperature flow rates and high heat gradients to be competitive with natural gas. This limits where geothermal power can be located in Alberta, but it leaves some options open. Regions with basin temperatures of at least 100 degrees Celsius may be feasible for geothermal power generation, but ideally temperatures should exceed 130 Celsius.[233] In Alberta, temperatures of 130 Celsius are achievable at depths of four kilometers, but depths of five kilometers and temperatures of 150 Celsius are required to make electricity costs competitive with gas-fired electricity.[234] As Figure 3 shows, there are regions that fulfill these criteria in the western regions of the province near major city centres.

[233] Hannes Hofmann, Simon Weides, Tayfun Babadagli, Günter Zimmermann, Inga Moeck, Jacek Majorowicz, and Martyn Unsworth. "Potential for enhanced geothermal systems in Alberta, Canada," *Energy* 69 (2014): 578-591.
[234] Jacek Majorowicz and Michal Moore, "The feasibility and potential of geothermal heat in the deep Alberta foreland basin-Canada for CO2 savings," *Renewable Energy* 66 (2014): 541-549.

7.3 The Cost of Geothermal Power

Geothermal is a minor contributor to renewable power generation worldwide. It is by far the least widespread form of power generation of the five renewable sources discussed. From 2000 to 2016, global nameplate geothermal power capacity grew from 7.97 GW to 13.7 GW, a compound annual growth rate of 3.48 per cent.[235] Thirty GW of capacity by 2030 is possible if all countries that have made commitments to develop geothermal power follow through on their stated targets.[236]

These growth rates bely the potential of geothermal energy. One study summarizing multiple international reports estimated that an astounding 158 TW of recoverable geothermal energy exists at depths of five kilometres or less. This exceeds the study's combined estimates for the accessible capacity of solar (49.9 TW), wind (20.3 TW), and hydro (1.6 TW).[237] It is estimated that 5 GW of total recoverable geothermal energy exists in Western Canada, which includes both power and heat generation.[238]

The main reason that geothermal has yet to take hold in Alberta, or Canada in general, is the high upfront costs.[239] According to IPCC estimates, they range from $2,475 to $7,150/kW depending on the depth of drilling, heat flow rate and cost of capital (2012 CDN dollars).[240] Drilling can account for up to 50 per cent of total project costs, so the depth of the heat resource can present prohibitive barriers.[241] Recall that utility-scale solar, which is less financially competitive than wind, has an upfront capital cost in Alberta on the order of $2,000/kW (2012 dollars). Geothermal still has significant ground

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[235] Ruggero Bertani, "Geothermal power generation in the world 2010–2014 update report," *Geothermics* 60 (2016): 31-43.

[236] Geothermal Energy Association, "2016 Annual US & Global Geothermal Power Production Report."

[237] Kewen Li, Huiyuan Bian, Changwei Liu, Danfeng Zhang, and Yanan Yang, "Comparison of geothermal with solar and wind power generation systems," *Renewable and Sustainable Energy Reviews* 42 (2015): 1464-1474.

[238] Natural Resources Canada, "Opportunities for Canadian energy technologies in global markets."

[239] Alberta Electric System Operator, "Renewable Electricity Production Update to Stakeholders."

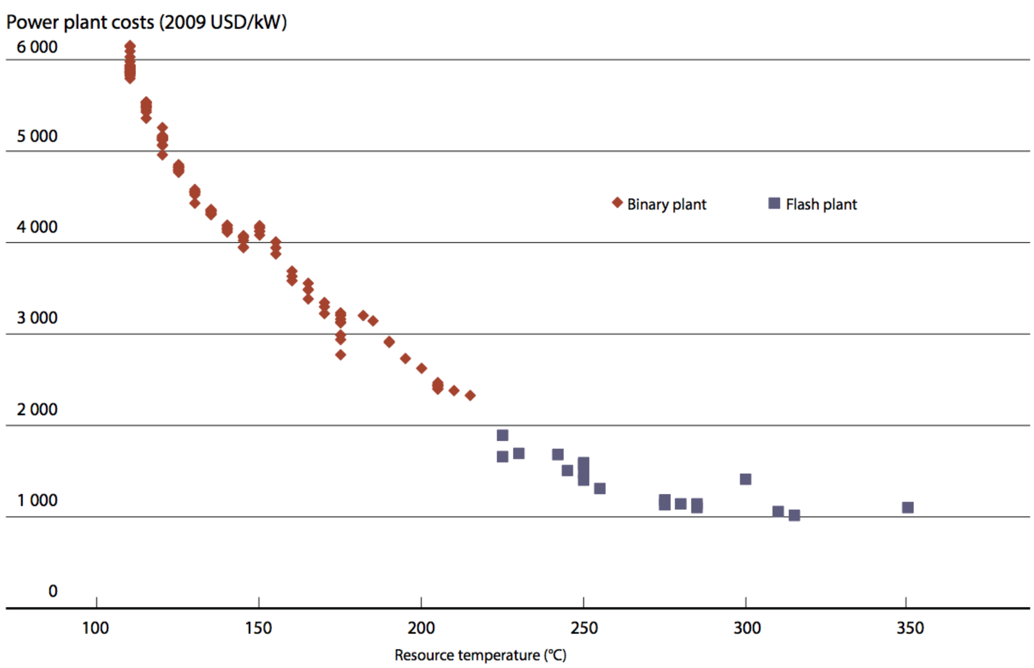
[240] B. Goldstein, G. Hiriart, R. Bertani, C. Bromley, L. Gutiérrez-Negrín, E. Huenges, H. Muraoka, A. Ragnarsson, J. Tester, V. Zui, *Geothermal Energy. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*, 2011, 410.

[241] Kewen Li, Huiyuan Bian, Changwei Liu, Danfeng Zhang, and Yanan Yang, "Comparison of geothermal with solar and wind power generation systems," *Renewable and Sustainable Energy Reviews* 42 (2015): 1464-1474.

to make up as an attractive investment. Furthermore, geothermal drilling has a success rate of 60 to 90 per cent. At least one in 10 projects will fail, and exploratory costs are high.[242]

High-quality geothermal reserves offer advantages with respect to levelized cost of electricity and fuel availability. The same IPCC report referenced above determined the levelized cost of geothermal power generally falls between \$67/MWh and \$127/MWh, though it can reach as high as \$235/MWh (2012 CDN dollars).[243] As can be seen in Figure 4, levelized costs are highly correlated to the temperature of the heat resource.

Figure 4: Powerplant costs for geothermal projects by reservoir temperature



Source: International Renewable Energy Agency, "Renewable Power Generation Costs in 2014," January 2015.

Estimates specific to Alberta suggest that at temperatures of 150 degrees Celsius and depths of five km, the levelized cost of electricity can be as low as \$72/MWh.[244] Average costs range between \$2.70 and \$3.29/MWh, no more than five per cent of levelized costs

[242] Ibid.
[243] Ibid.
[244] Jacek Majorowicz and Michal Moore, "The feasibility and potential of geothermal heat in the deep Alberta foreland basin-Canada for CO2 savings," *Renewable Energy* 66 (2014): 541-549.

(2012 CDN dollars).[245] It is worth nothing that levelized costs for geothermal heating are much lower than geothermal power generation. Geothermal has a number of hurdles to overcome before it meaningfully factors into Alberta's electricity mix. Much like solar thermal, its potential applications for heating could help reduce the province's reliance on using natural gas for heat.

The EROI for geothermal is quite favourable when compared to other renewable power sources. Assuming a facility is operational five years or more, geothermal power yields an EROI between 28 and 33.[246] Recall that the upper bounds for wind, solar, woodchips and hydro are 20, 35, 20, and 267, respectively. Supply stability and fuel availability also mean that geothermal offers more certainty when compared to wind, solar, or biomass, which make it a viable option for baseload and long-term supply contracts.

7.4 The Emissions Footprint

In most cases, geothermal is more emissions intensive than wind, solar or hydro but superior to both coal and natural gas. Lifecycle emissions intensity estimates for industrial scale projects vary in the literature, due in large part to geographical and geological considerations. Multiple studies suggest an industry average of 170 $kgCO_2e/MWh$.[247] The most heavily cited global survey provides a range of 4 to 750 $kgCO_2/MWh$ with a weighted average of 122 $kgCO_2/MWh$.[248] The emissions estimates from the International Geothermal Association are significantly higher than estimates provided by the U.S. National Renewable Energy Laboratory, which estimates 50 kg CO_2e/MWh for flash steam geothermal and less than 80 CO_2e/MWh for projected EGS

[245] B. Goldstein, G. Hiriart, R. Bertani, C. Bromley, L. Gutiérrez-Negrín, E. Huenges, H. Muraoka, A. Ragnarsson, J. Tester, V. Zui, *Geothermal Energy. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*, 2011, 410.
[246] Reynir Atlason and Runar Unnthorsson,"Ideal EROI (energy return on investment) deepens the understanding of energy systems," *Energy* 67 (2014): 241-245.
[247] Kewen Li, Huiyuan Bian, Changwei Liu, Danfeng Zhang, and Yanan Yang, "Comparison of geothermal with solar and wind power generation systems," *Renewable and Sustainable Energy Reviews* 42 (2015): 1464-1474.
[248] Peter Bayer, Ladislaus Rybach, Philipp Blum, and Ralf Brauchler, "Review on life cycle environmental effects of geothermal power generation," *Renewable and Sustainable Energy Reviews* 26 (2013): 446-463; Ruggero Bertani and Ian Thain, "Geothermal power generating plant CO2 emission survey," *IGA news* 49 (2002): 1-3.

power plants.[249] Non-binary geothermal systems are considered preferable from an emissions perspective, as they do not generate steam – a potent greenhouse gas.[250]

Assumptions made with regards to land use and fugitive emissions estimates explain these discrepancies. Whether or not a geothermal system is truly closed loop has a significant impact on fugitive emissions. Non-closed loop systems result in subsurface leakages, which can be difficult to measure. Emissions are very case-specific and reported data is limited.[251] This paper will use a range of 50 to 200 kgCO_2e/MWh, for which the weighted average of 122 kgCO_2/MWh approximates a midpoint.

Table 20: Emissions Bounds for Geothermal Compared to Natural Gas and Coal Power

	Natural Gas	Coal	Geothermal
Combustion Lower Bound	310 kgCO_2e/MWh	820 kgCO_2e/MWh	0 kgCO_2e/MWh
Combustion Upper Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	0 kgCO_2e/MWh
Lifecycle Lower Bound	583 kgCO_2e/MWh	1,016 kgCO_2e/MWh	50 kgCO_2e/MWh
Lifecycle Upper Bound	680 kgCO_2e/MWh	1,370 kgCO_2e/MWh	200 kgCO_2e/MWh

Source: National Renewable Energy Laboratory, "Geothermal Results – Lifecycle Assessment Review."

Based on a $30/tonne carbon tax, substituting one MWh of electricity generated from natural gas with one MWh of electricity generated from geothermal yields savings between $9.30 and $17.49 ($9,300 and $17,490 per GWh). Substituting one MWh of electricity generated from coal with one MWh of electricity generated from geothermal would result in savings between $20.40 and $41.10 ($20,400 and $41,100 per GWh).

Given the stated parameters and assumptions for Canada's SCC (central tendency of $40.70/tonne and 95th percentile estimate of $167/tonne), and the ranges for emissions intensities for electricity generated from geothermal, natural gas, and coal, the social savings incurred from substituting one MWh of electricity generated from geothermal for one MWh of electricity generated from coal or gas can be calculated. The lifecycle SCC

[249] National Renewable Energy Laboratory, "Geothermal Results – Lifecycle Assessment Review."
[250] Peter Bayer, Ladislaus Rybach, Philipp Blum, and Ralf Brauchler, "Review on life cycle environmental effects of geothermal power generation," *Renewable and Sustainable Energy Reviews* 26 (2013): 446-463.
[251] Ibid.

for electricity generated from coal, natural gas and geothermal in 2016 are shown in Table 21.

Table 21: Social Cost of Electricity Generation for Geothermal, Natural Gas and Coal

	Central Tendency	95th Percentile
Geothermal Lower Bound	$2.04/MWh	$8.35/MWh
Geothermal Upper Bound	$10/MWh	$33.40/MWh
Natural Gas Lower Bound	$23.73/MWh	$97.36/MWh
Natural Gas Upper Bound	$27.68/MWh	$113.56/MWh
Coal Lower Bound	$33.37/MWh	$136.94/MWh
Coal Upper Bound	$55.76/MWh	$228.79/MWh

Author's calculation based on Environment and Climate Change Canada, "Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates," March 2016.

Under these conditions, the upper bound in social benefits resulting from substituting one MWh of electricity generated from geothermal for one MWh of pure gas-fired electricity is $111.52 ($111,520/GWh). The lower bound is a social loss of $9.67 ($9,670/GWh). The upper bound in social benefits resulting from substituting one MWh of electricity generated from geothermal for one MWh of electricity generated from coal is $226.75 ($226,750/GWh). The lower bound is $0.03 ($3.00/GWh).

8.0 Discussion

This section of the paper will summarize the information collected and analyzed above. The merits and drawbacks of each renewable electricity source are discussed, as well as each's suitability for meeting Alberta's future electricity needs. Recommendations will take into consideration all metrics examined in previous sections.

8.1 Overview of Key Metrics

As Table 22 shows, each renewable power source discussed has its advantages and drawbacks. While they all offer benefits over fossil fuels, each introduces new challenges and obstacles that are not encountered with coal and natural gas. Generally speaking, renewable power is more expensive with higher levelized costs, lower capacity factors and less reliability. Assuming that the consequences of climate change will be moderate or severe, however, renewable power is less socially costly in the long run.

Table 22: Summary of Key Metrics

	Wind	Solar	Biomass	Hydro	Geothermal	Coal	Natural Gas
Capacity in Alberta (MW)	1,491	~9; includes residential	424	902	0	6,267	7,080
% Share of Alberta's Renewable Mix by Capacity	53.2	0.33; includes residential	13.6	32.9	0	N/A	N/A
Planned or Proposed Capacity (MW)	4,614	294	41	330	0	0	6,566
Minimum EROI, average lifespan	20	10; 15 for thin film	Wood 6; straw 8	84	30	30	14
Baseload Capability	No	No	Yes	Yes	Yes	Yes	Yes
Peak Load Capability	No	No	Yes	Case-by-case	Yes	Yes	Yes
Lifecycle Emissions ($kgCO_2e$/ MWh)	383 to 513 (back-stopped)	417 to 532 (back-stopped)	50 to 1,300	4 to 150	50 to 200	1,016 to 1,370	583 to 680
Combustion Emissions ($kgCO_2e$/ MWh)	0	0	700 to 900	0	0	820 to 1,016	310 to 583
Power/unit-area (MW/ hectare)	10 to 40	0.25 to 0.3	1.09 to 1.95	Case-by-case	0.025 to 2.4	Case-by-case	Case-by-case
Average Capacity Factor	30 to 40	10 to 20	18 to 100	50	70 to 90	As high as 100	30
Average Cost ($/MWh)	$15.78 to $19.72	$17 to $18	$3.80 to $4.70	$5.36 to $21.43 (>10 MW)	$2.70 to $3.30	Case-by-case	Case-by-case
Levelized Cost ($/MWh)	$84 to $89	$122 to $204	$100 to $120	$60 to $70	$67 to $235	$70 to $237	$69 to $110
Social Savings Upper Bound ($/MWh)	$85.67	$88.84	$217	$0.69	$33.40	$228.79	$113.56
Social Savings Lower Bound ($/MWh)	15.57	$16.97	$2.04	$0.16	$2.04	$33.37	$23.73

8.2 Analysis and Recommendations

Wind has become the dominant renewable power source in Alberta, a trend that will continue over the next 10 years. Driven by fuel quality, availability of multi-use land, and cost competitiveness, it is positioned to lead the charge as Alberta moves its grid towards green options. The wind speeds in much of the southern half of the province present favourable conditions for development, as evidenced by the quantity of wind projects queued up in the regulatory process. Furthermore, wind offers a competitive levelized cost of electricity ($84/MWh) when compared to combined cycle gas ($82/MWh), cogeneration ($69 to $104/MWh), simple cycle gas ($110/MWh), and coal ($70/MWh; $237/MWh with carbon capture and storage), and is exempt from Alberta's carbon tax.[252]

The environmental impacts of wind power can be mitigated through site selection that emphasizes protection of sensitive ecosystems and wildlife, particularly birds and bats, and minimizes habitat fragmentation. Other regional issues, such as impacts to human health, hydrology, and soil, must be evaluated on a case-by-case basis. In terms of grid compatibility, the biggest issues with wind power are its inability to supplement during peak load times or provide baseload power. If coal is no longer an option, increasing reliance on wind power necessitates increasing reliance on natural gas, which would impose additional costs on the system via greater ramp rate and reserve requirements.[253] Wind's combustion emissions are nonexistent and its lifecycle emissions are minimal, but the fact that wind power must be backstopped reduces many of its social and environmental benefits.

Solar has only begun to realize its potential as a power source globally, but it is disadvantaged in Alberta and Canada in general due to comparatively poor insolation and more extreme seasonal variation in daylight hours. In terms of costs, land requirements, reliability, EROI, capacity factor and technological maturity, commercial solar is inferior

[252] Alberta Electric System Operator, "AESO 2014 Long-term Outlook."
[253] National Renewable Energy Laboratory, "Fundamental Drivers of the Cost and Price of Operating Reserves."

to wind, its main competition.[254] The advantage that solar power holds over wind is the level to which it can be scaled down. Rooftop generation makes use of unused space, presents no land use opportunity cost and could supplement residential and commercial electricity requirements. Alberta could have as much as 300 MW of commercial solar capacity by 2020, but solar also has potential as a consumer-driven initiative. The challenge here is installation costs, which continue to fall but still range from $3.75 to $5.75/W in Alberta. It is conceivable that $2/W for photovoltaic panels could come to fruition before 2030, which would put it on par with wind's current installation costs (2012 dollars).

Solar and wind power are exempt from Alberta's carbon tax, but neither is capable of providing baseload power or augmenting peak load requirements. In other words, they cannot do it alone. Hydro, geothermal and biomass are all capable of providing baseload power and one or more can be developed further to ease the burden on Alberta's gas plants, which will be relied upon for baseload and ramping during times of high demand. For addressing peak load requirements, large-scale hydro and biopower are likely the best options. Since it operates at such a high capacity factor, geothermal is well suited for baseload, but ill-suited for peak load.

In contrast to wind and solar, biopower seems to have plateaued in Alberta, and its potential for growth is limited by fuel availability. In an industry where certainty is desirable and readily attainable, the erratic nature of biopower's fuel supply chain (that is, the collection, transport and distribution of biomass) is a key hurdle to developing major projects. There is no readily evident policy solution for these limitations. The picture is further obscured by biopower's high emissions intensity, and uncertainty over how exactly it should be captured, if at all, by Alberta's carbon tax. There is potential to inexpensively repurpose one or more of Alberta's decommissioned coal-fired facilities into biopower facilities but the lack of reliability and supply, coupled with the abundance of natural gas, means that any increases in biopower's contribution to Alberta's electricity mix will likely be negligible moving forward.

[254] Alberta Electric System Operator, "Renewable Electricity Production Update to Stakeholders."

The potential for large-scale hydro in Alberta is limited by a lack of suitable sites near populated regions. Though small-scale hydro has significant potential, several dozen projects are required for it to contribute meaningfully to the growth of renewable power in Alberta over the next 14 years. If renewables are to supply 30 per cent of Alberta's electricity needs by 2030 by generation share, a combination of numerous small-scale hydro projects and a handful of larger hydro projects (ideally run-of-river) appear to be the best option to ensure that the province is not entirely reliant on natural gas for baseload. Further, regulatory uncertainty, including possible public opposition, Aboriginal concerns and environmental impacts could be obstacles preventing hydropower capacity from being developed before 2030.[255]

No geothermal projects have been developed in Canada to date, and projections for global growth are slow. Without regulatory clarity and facilitation, high upfront costs will likely encumber the development of any significant geothermal power capacity in Alberta before 2030. Geothermal does not receive the same level of support as other renewables, and suffers from a lack of regulatory clarity, permitting systems and access to transmission.[256] Geothermal presents more potential for heat generation than power generation, and renewable heat has yet to be granted the same regulatory standing as renewable power in Alberta or Canada. This is preventing geothermal projects of any kind from getting off of the ground.[257] Moreover, given the estimated accessible geothermal reserves in Western Canada (5 GW), it seems unlikely that geothermal will ever become more than a modest contributor to Alberta's electricity mix.

8.3 Scenarios for Installed Capacity and Generation

As of 2015, coal and natural gas make up 38.5 and 43.6 per cent of Alberta's fuel share by capacity and 55 and 35 per cent of its generation share, respectively. All sources of renewable power (wind, hydro and biomass) combined comprise 16.7 percent of

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[255] Alberta Electric System Operator, "Renewable Electricity Production Update to Stakeholders."
[256] Canadian Geothermal Energy Association, "An open letter to Canada's geothermal community," October 11, 2013.
[257] Ibid.

capacity, but just nine per cent by generation share.[258] A summary of the AESO's projections for Alberta's current and future generation needs are reported in Table 23. Alberta's installed capacity is projected to grow faster than its peak load requirements through 2030 – compound growth rates of 2.66 to 2.20 per cent annually, respectively.[259] Given that renewable power is generally less reliable than coal or gas-fired power, this is a favourable trend.

Table 23: Anticipated Growth of Alberta's Electricity Market

	2016	2030	Percentage Change	Equivalent CAGR
Installed Capacity (MW)	16,228	23,442	44.45%	2.66%
Peak Load (MW)	11,229	15,230	35.53%	2.20%

Source: AESO, 2016 Long-term Outlook, May 2016.

If the Government of Alberta's goal is 30 per cent renewable power by installed capacity in 2030, then a minimum of 7,033 MW is needed based on the AESO's long-term projections (30 per cent of 23,442 MW).[260] Alberta currently has 2,718 MW of installed renewable capacity, so an additional 4,227 MW would be required to meet the 30 per cent target.

If all proposed renewable projects in Alberta were approved and built, the province would have a total of 6,059 MW of installed wind capacity (75.8 per cent of all renewable capacity), 303 MW of solar (3.8 per cent), 465 MW of biomass (5.1 per cent), and 1,232 MW of hydro (15.3 per cent). Table 24 breaks down all of the installed, planned, and proposed capacity for the four renewable sources. Table 24 also shows the minimum installed capacity requirements for each renewable source under the 70/30 scenario, assuming each source's share in the renewable energy mix holds steady.

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[258] Alberta Energy, "Electricity Statistics."
[259] Alberta Electric System Operator, "AESO 2016 Long-term Outlook."
[260] Alberta Electric System Operator, "AESO 2014 Long-term Outlook."

Table 24: Anticipated Growth of Alberta's Renewable Electricity Mix

	Wind	Solar	Biomass	Hydro
Existing Capacity	1,491 MW	9 MW	424 MW	902 MW
Planned or Proposed Capacity	4,614 MW	294 MW	41 MW	330 MW
All Existing, Planned & Proposed Capacity	6,059 MW	303 MW	465 MW	1,232 MW
Current, Planned & Proposed Capacity as a Percentage Share of All Renewables	75.8	3.8	5.1	15.3
Required Capacity to Meet 30 Per Cent Mandate Assuming Percentage Shares for Wind, Solar, Biomass and Hydro Hold Steady	5,331 MW	267 MW	359 MW	1,076 MW

Source: AESO, "Long-Term Adequacy Metrics," May 2016.

As Table 24 shows, every renewable source (excluding geothermal) is currently on pace to exceed the required installed capacity by 2030 under the 70/30 scenario. Alberta currently has 4,614 MW of proposed and approved but yet-to-be-constructed wind capacity, which on its own is enough to meet the minimum requirements. It is not reasonable to assume that every proposed project will be approved, but given the time horizon, a business-as-usual approach appears sufficient to hit 30 per cent installed renewable capacity by 2030.

The majority of Alberta's installed renewable capacity is and will continue to be wind power. As discussed previous sections, wind is incapable of providing baseload power or augmenting peak load requirements, both of which are problems for grid stability. Table 25 shows the average capacity factors that Alberta's renewable and gas-fired power facilities would need to operate at during peak load times given a 70/30 gas-to-renewables mix. All of the figures in Table 25 are based on the AESO's projected power requirements for 2030.

Table 25: Required Capacity Factor for Gas-Fired Electricity in 2030 Assuming a 70/30 Gas-to-Renewables Mix

Renewable Capacity Factor	Online Gas-Fired Capacity (MW)	Required Capacity Factor for Gas Plants	Spare Capacity for Gas Plants (MW)
0	15,230	92.8 per cent	1,179
0.05	14,469	88.2 per cent	1,940
0.1	13,707	83.5 per cent	2,702
0.15	12,945	78.9 per cent	3,464
0.2	12,184	74.3 per cent	4,225
0.25	11,423	69.6 per cent	4,986
0.3	10,661	65.0 per cent	5,748
0.35	9,900	60.3 per cent	6,509
0.4	9,138	55.7 per cent	7,271

Source: Alberta Electric System Operator, "AESO 2016 Long-term Outlook," May 2016.

The worst-case scenario, where intermittent renewable sources comprise 30 per cent of installed capacity but are generating zero power at peak hours, would leave Alberta's gas-fired facilities with just 1,179 MW of spare generating capacity. This means that all gas-fired facilities would need to operate at a capacity factor of 93 per cent during peak hours. At the other extreme, gas facilities would have to operate at a reasonable 56 percent capacity if renewables were capable of operating at a 40 percent capacity factor during peak load times. A middle-of-the-road scenario, where all of Alberta's renewable power facilities operate at an average capacity factor of 30, the province's natural gas power plants would need a capacity factor of 65 per cent to satisfy demand.[261] In any of these scenarios, gas-fired plants would also need to be able to ramp up quickly in the event that conditions for renewable generation suddenly became unfavourable during peak hours. Depending on the level of connectivity in the grid and the ramping ability of gas facilities, the 30 per cent renewable generation goal may require additional installed capacity beyond the AESO's forecast 23.4 GW to satisfy peak load requirements and ensure system reliability.

[261] Alberta Energy, "Electricity Statistics"; Alberta Electric System Operator, "AESO 2015 Annual Market Statistics."

If the Government of Alberta pursues 30 per cent renewable power by generation share, the picture changes dramatically for installed capacity requirements. The AESO projects Alberta's total power consumption at 125,500 GWh/year by 2030.[262] Thirty per cent by of this figure is 37,650 GWh/year. Given the minimum 7,033 MW of installed renewable capacity, all renewable power in Alberta would have to operate at a factor of 61.1 per cent to generate this amount of power in a year. These calculations are shown in Table 26.

Table 26: Renewable Power Requirements by Generation Share in 2030 with 30 Per Cent Installed Renewable Capacity

Maximum Generation Given 30 Per Cent Renewables by Installed Capacity	7,033 MW * 8760 hours/year **61,609 GWh/year**
Required Capacity Factor For a 30 Per Cent Generation Share, Given 30 Per Cent Installed Renewable Capacity	37,650 GWh/year ÷ 61,609 GWh/year **0.611**

Source: Author's calculations, based on Alberta Electric System Operator, "AESO 2016 Long-term Outlook," May 2016.

To underline the importance of differentiating between capacity and generation share, consider the 70/30 scenario. Given that wind power generally operates at a capacity factor closer to 30 per cent, 7,033 MW of installed capacity would be woefully inadequate to supply 30 per cent of the province's power by generation share. If an average capacity factor of 30 per cent is assumed for all of Alberta's renewables, installed capacity would have to effectively double from the minimum required 7,033 MW to supply the required 37,650 GWh/year. Table 27 shows a breakdown of the required percentage share of renewables at various capacity factors based on the AESO's projections for electricity demand through 2030.

262 Alberta Electric System Operator, "AESO 2014 Long-term Outlook."

Table 27: Capacity Factors for Renewable Power and their Influence on Installed Capacity Requirements in Alberta

Capacity Factor	Installed Capacity Required to Generate 30 Per Cent (37.65 GWh) of Forecasted Annual Power Demand (125.5 GWh)	As a Percentage of Total Forecast Installed Capacity for 2030 (125.5 GW)
0.2	21,490 MW	91.7%
0.25	17,192 MW	73.3%
0.3	14,327 MW	61.1%
0.35	12,280 MW	52.4%
0.4	10,745 MW	45.8%
0.45	9,551 MW	40.7%
0.5	8,596 MW	36.7%

Source: Author's calculations, based on forecasts from AESO, "2016 Long-Term Outlook."

If 30 per cent by generation share is indeed the goal, then Alberta's renewable energy mix must become more reliant on hydro, biopower and possibly geothermal to ensure baseload and peak load requirements are satisfied without introducing exorbitant costs to the system. In this case, additional installed capacity beyond the forecast 23.4 GW for both gas and renewables would almost certainly be required.

In a May 2016 update to stakeholders, AESO cited resource-specific timelines for development, regulatory approval and construction for anticipated renewable projects.[263]

- Wind: 4 to 6 years
- Solar: 1.5 to 3 years
- Biomass: 2 to 3 years
- Geothermal: 3 to 7 years
- Large Hydro: 10 to 14 years

There is adequate time for any of the five renewable power resources to be developed, but the lack of regulatory clarity for hydro and geothermal, which provide baseload power, must be remedied if grid reliability is to be maintained.

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[263] Ibid.

9.0 Conclusion

All five renewable power sources have a potential role to play in the future of Alberta's electricity mix. Based on the metrics employed in this paper, wind power is the best option for large-scale development. It offers lower levelized costs, fewer opportunity costs, with manageable environmental impacts and exemption from Alberta's carbon tax. It is also more productive in the winter when electricity demand is generally higher. With that said, wind has far too many limitations to be able to meet the Government of Alberta's renewable power goals on its own. Solar is more expensive than wind on an installed and levelized cost basis, but its production and levelized costs are decreasing faster than wind's. The advent of high-efficiency panels and axis tracking make solar a viable option for small-scale rooftop installations, and perhaps some utility-scale installations on low-grade land. Biopower offers the opportunity to extend the useful lifespan of decommissioned coal facilities, but there is not enough fuel available for the industry to grow in the same way as wind or solar. Small-scale hydropower (particularly run-of-river) is a better option for baseload power, which would free up gas-fired plants to better augment peak load requirements. Without regulatory clarification, geothermal will make little progress over the next 14 years, but Alberta has the ability and expertise to develop geothermal resources if it so chooses.

Developing renewable power can address social costs associated with fossil-fuel-based electricity while meeting the government's policy goals, but it has the potential to compromise the reliability of the grid. The findings in this paper emphasize the need to maintain balance within Alberta's electricity grid, limiting social costs to the extent possible while maintaining a mix capable of supplying baseload power and meeting peak demand. Further diversifying Alberta's renewable power mix and emphasizing efficiency for gas-fired plants will help to achieve these objectives and meet the demands of consumers through 2030 and beyond.

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