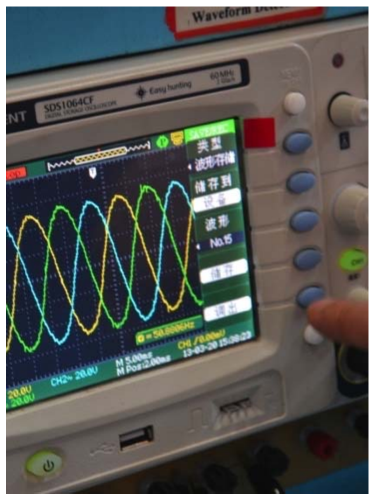
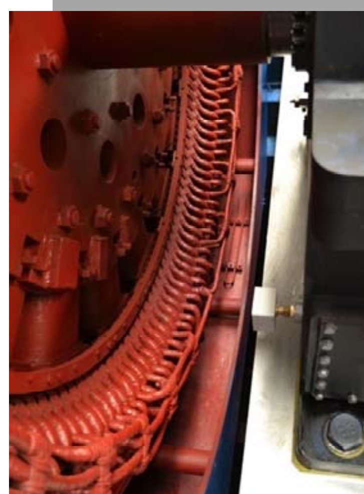
Assessment of Renewable Energy Potential in Alberta

A Pilot Study Prepared by Energy Revolution Services





Energy Revolution Services

Office 8566 | 200-375 Water St.
Vancouver, BC V6B 0M9
+1 604-800-7794
info@energyrevolution.ca

Rev.	Date	Issued For
A	31 May 2016	Preliminary Draft

May 31, 2016

Report Prepared by:

Michael Pullinger, M.Sc., P.Eng.
Senior Engineer | Director

EXECUTIVE SUMMARY

In light of the Alberta government's announced intent to increase renewable energy supplies and transition away from coal power by 2030, Energy Revolution Services has prepared a pilot study of renewable energy potential in the province. This study identifies the economic renewable energy potential for various resources (solar, wind and hydropower) in select regions of Alberta and intends to:

- Provide a benchmark "inventory" of each resource, and the likely cost of incrementally developing each resource. This will help inform energy policy discussions across the industry (see Figure 1).
- Provide a starting point for Independent Power Producers (IPPs) who are looking to develop renewable energy facilities in Alberta and aim to identify and secure the most competitive sites.

It is hoped that this pilot study can be expanded to the entire province with improved methods and addition of biomass and geothermal into the analysis. The study could also be expanded to Saskatchewan, which intends to double renewable energy supply by 2030. Energy Revolution Services are seeking partners interested in supporting this study to its useful conclusion in the next 3-12 months. The final report may be available publically depending on whether public or private partners support the completion of the study.

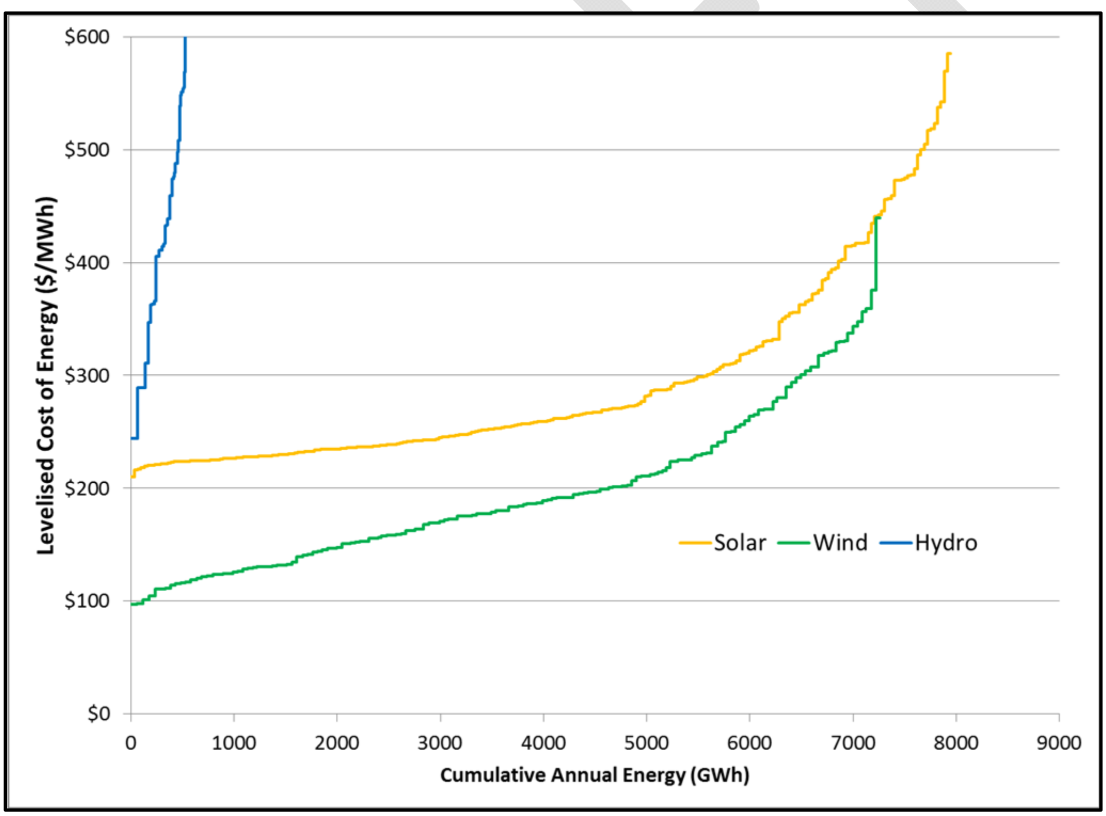


Figure 1: Incremental cost for three renewable resources in the pilot study areas.

The study involved the use of GIS models to determine key parameters for potential renewable energy sites in three study regions in the south of Alberta (Figure 2). Renewable energy resource and distance to transmission were determined for all sites, along with any other site-specific parameters that impact facility cost. These data were exported to a spreadsheet model that calculated capacity factor, annual energy generation and levelised cost of energy (LCOE) for each facility. The calculation of LCOE provided a standard measure to compare the viability of potential projects for different renewable energy resources.

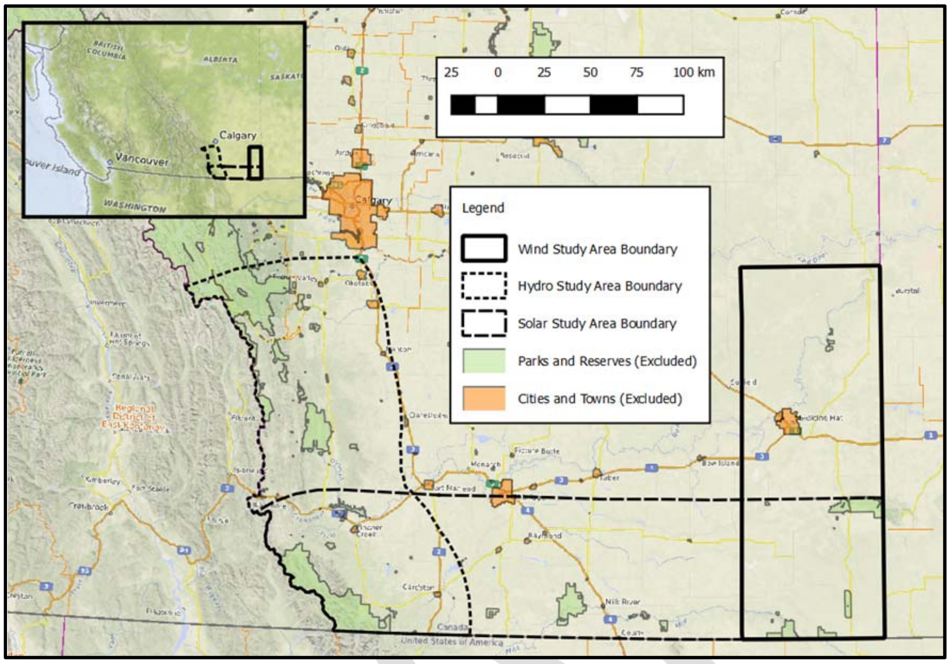


Figure 2: Renewable energy pilot study area in southern Alberta.

The results of the study indicated that wind energy is likely to be the most cost-effective resource within the area investigated, with a minimum LCOE of less than $100/MWh. The most cost effective solar sites are expected to be in the order of approximately $210/MWh, while the best hydro site identified is likely to produce energy at a LCOE of approximately $240/MWh. Both solar and wind have a large potential resource, with a gradual increase in expected costs as the best sites are developed, whereas the resource identified for hydropower is smaller and increases in cost quickly as the better sites are developed. These observations are related to a relatively small portion of the province and may not apply more generally as the study area is expanded and the methodology is improved. In particular, modifying the hydropower screening methodology may identify more sites that are better suited to the low-head nature of the hydroelectric resource in Alberta.

Some considerations for improving the methodology for future iterations of this pilot study include:

- A more detailed assessment of the transmission connection options.
- Assessment of social and environmental issues to screen out sites that have development constraints.
- Increased fidelity cost modelling would allow greater certainty for Alberta specific conditions.
- Assessment of energy production timing against the Alberta electricity market price.
- Sensitivity analysis for all key variables including cost, financial and energy assumptions.

CONTENTS

EXECUTIVE SUMMARY **2**
1 INTRODUCTION **6**
1.1 Purpose **6**
1.2 STATUS **6**
1.3 Publically Available Information **7**
1.4 Disclaimer **7**
2 BACKGROUND **8**
2.1 Alberta's Renewable Energy Market **8**
2.2 Overall Methodology **8**
3 SOLAR PHOTOVOLTAIC POWER **10**
3.1 Solar Photovoltaic – Screening Methodology **10**
3.2 Solar Photovoltaic – Screening Results **11**
3.3 Solar PV - Conclusions **15**
4 WIND POWER **17**
4.1 Wind Energy – Screening Methodology **17**
4.2 Wind Energy – Screening Results **18**
4.3 Wind Energy - Conclusions **22**
5 HYDROPOWER **24**
5.1 Hydropower – Screening Methodology **24**
5.2 Hydropower – Screening Results **27**
5.3 Hydropower - Conclusions **31**
6 CONCLUSIONS **33**
7 REFERENCES **36**

Figure 1: Incremental cost for three renewable resources in the pilot study areas. 2
Figure 2: Renewable energy pilot study area in southern Alberta. 3
Figure 3.1: Solar energy preliminary study area. 10
Figure 3.2: Incremental cost of energy for potential solar PV facilities. 14
Figure 3.3: Cumulative annual energy for solar PV facilities. 15
Figure 3.4: Relationship between transmission distance and energy cost for solar PV. 16
Figure 4.1: Wind energy preliminary study area. 18
Figure 4.2: Incremental cost of energy for potential wind power facilities. 21
Figure 4.3: Cumulative annual energy for wind power facilities. 22
Figure 4.4: Relationship between transmission distance and energy cost for wind facilities. 23
Figure 5.1: Hydropower study area with mean annual unit runoff (MAUR) at Water Survey of Canada sites 24
Figure 5.2: Incremental cost of installed capacity for potential hydropower facilities. 30
Figure 5.3: Cumulative annual energy for hydropower facilities. 31
Figure 5.4: Relationship between transmission distance and energy cost for wind facilities. 32
Figure 6.1: Incremental cost of all renewable technologies by capacity. 33
Figure 6.2: Incremental cost of all renewable technologies by annual energy 34

Table 2.1: Alberta's electricity generation portfolio in 2014. 8
Table 3.1: Inferred costs for potential solar PV facilities. 12
Table 3.2: Technical data for potential solar PV facilities. 13
Table 4.1: Inferred costs for potential wind energy facilities........ 19
Table 4.2: Technical data for potential wind energy facilities. 20
Table 5.1: Water Survey of Canada stream gauges near the study area........ 26
Table 5.2: Inferred costs for potential hydropower facilities........ 28
Table 5.3: Technical data for potential hydropower facilities. 29

1 INTRODUCTION

1.1 PURPOSE

This pilot study has been prepared by Energy Revolution Services for the purpose of identifying some of the most promising renewable energy sites in the province of Alberta. The province currently derives most of its electricity from fossil fuels, generating more than 50% from coal alone. The provincial government has recently announced a policy of transitioning away from the use of coal power generation by 2030. This presents an opportunity for significant renewable energy investment over the next decade and a half. Energy Revolution Services has carried out the current pilot study to independently identify, assess, rank and evaluate the best renewable energy sites in Alberta for the following:

- Solar photovoltaic
- Wind power
- Run-of-river hydropower

It is intended that this study then be expanded to the entire province of Alberta, with the addition of the following renewable energy resources:

- Biomass (solid, liquid, gaseous)
- Geothermal electricity

The intent is that this study will serve two key purposes, filling a gap in the publically available information:

- Inform the public discussion and policy perspectives with regards to renewable energy in the province, by providing a benchmark "inventory" of the approximate quantities of each resource that are available, and the likely cost of incrementally developing each resource.
- Providing a starting point for Independent Power Producers (IPPs) who are looking to develop renewable energy facilities in Alberta and need to determine which sites are the most cost effective.

While the current study is focussed on Alberta, the study could easily be expanded to Saskatchewan, where approximately 50% of the province's electricity also comes from coal, and the government has made a commitment to double electricity supply from renewable resources by 2030.

1.2 STATUS

The current pilot study has been undertaken in a select region of southern Alberta with the aim of demonstrating the applicability of the methodology to the province. It is also intended to provide a starting point for discussions to determine the level of interest in the industry, as well as identify potential partners who are interested in working with Energy Revolution Services to progress this investigation. Potential partners could include public agencies and non-profit groups who are interested in increasing the availability of good quality data on the renewable energy in the province to help guide policy decisions. Alternatively, IPPs may be interested in partnering with Energy Revolution Services in confidence to help identify and secure the rights to develop some of the best renewable energy sites in the province. Depending on the mix of partners that Energy Revolution Services is able to secure, completion of these investigations may take anywhere from 3-12 months.

1.3 PUBLICALLY AVAILABLE INFORMATION

Given the uncertainty regarding the next steps for this investigation, certain information has been excluded from this report. This includes the specific site locations identified as the most promising, as well as certain details of the methodology adopted. Depending on whether Energy Revolution Services secures public or private support to further this project, a final report may or may not be made publically available.

Please contact Energy Revolution Services for if you are interested in seeking access to any of the information already prepared, or if you are interested in developing a partnership for completion of the investigation.

1.4 DISCLAIMER

All information in this report is preliminary, and has not yet been subject to independent review. Energy Revolution Services accepts no liability for any decisions made on the basis of any information contained in this report. Please contact Energy Revolution Services if you require any further information.

2 BACKGROUND

2.1 ALBERTA'S RENEWABLE ENERGY MARKET

Alberta's electricity generation portfolio largely consists of fossil fuel based power generation, with coal forming approximately 55% of the generation supply in 2014 (Alberta Energy n.d.) as outlined in Table 2.1. The three main renewable resources currently consist of hydro, wind and biomass, which together constitute approximately 9% of Alberta's total electricity supply. Recently, the Alberta provincial government have announced a policy of transitioning away from coal power by 2030, and have indicated that approximately two thirds of this will come from new renewable energy production facilities (Alberta Government 2015). This implies that approximately 30,000 GWh of new renewable energy will be required in Alberta over a period of approximately 14 years, or approximately 2,100 GWh per year.

Table 2.1: Alberta's electricity generation portfolio in 2014.

Generation	Gigawatt Hours (GWh)	Generation Share by Fuel
Coal	44,442	55%
Natural Gas	28,136	35%
Hydro	1,861	2%
Wind	3,471	4%
Biomass	2,060	3%
Others*	373	0%
Total	**80,343**	**100%**

The Alberta electricity market has been operated using a power pool since 1996, with full deregulation since 2001. The electricity system in Alberta is owned by a mix of investor and municipally owned utilities, with oversight by the Alberta Electric System Operator (AESO) and the Alberta Utilities Commission (AUC). This market-based electricity environment makes it difficult for renewable energy facilities to be competitive enough to secure long-term financing. The Alberta government have announced that they intend to commence a competitive procurement process for renewable energy in late 2016, which will likely provide secure power purchase agreements (PPAs) for the most cost-effective renewable energy facilities bidding into the program. With a secure PPA, it is far more likely that a proposed renewable energy generation facility will be able to secure the long-term financing required to develop a project.

2.2 OVERALL METHODOLOGY

In order to provide a suitable means to compare the cost of energy from alternative renewable resources, the levelised cost of energy (LCOE) was calculated for all potential renewable energy plants identified as part of this study. The LCOE incorporates all costs of developing and constructing a renewable energy facility, and levelises them to the present day in comparison to their annual energy generation potential.

Key considerations adopted in developing the LCOE for each facility include the following:

- Capital costs are estimated as indicated in the relevant chapters for each resource.
- Annual operation and maintenance costs are as indicated in the chapter for each resource.
- Annual generation varies based on the available renewable resource and the specific type of technology adopted to harness each resource.
- The project life determines the period over which the project costs are able to be amortised and is longer for hydropower than for solar or wind.
- The average weighted cost of capital (AWCC) incorporates interest on any debt financing, or required investor return for any equity financing. The assumed AWCC for this study is 6%.
- Interest during construction is neglected for this simplified pilot study.

In identifying suitable project sites, the following exclusions were made:

- No parks (provincial or national parks) or crown reservations are included in the assessment.
- No cities or towns are included in the assessment.
- No environmental or social criteria are incorporated in the screening at this stage.
- No distinction is made between private or public land, all of which is included in the assessment.

For all the renewable resources, a GIS-based model was created using QGIS software to identify and extract key project parameters for each site, including energy resources available, distance to transmission facilities, and additional site-specific parameters for the hydropower facilities (refer to the hydropower chapter for details). These data were then extracted to a spreadsheet model which calculated capacity factor, annual energy production, inferred capital cost and levelised cost of energy for each site.

The methodology for determining the capital costs for the individual projects sites is outlined in the respective chapters for each resource. However, the estimate of transmission costs used a similar methodology for all sites. A pdf map of the Alberta transmission system was obtained from AESO. Since AESO obtain the data from the separate utilities that operate the Alberta transmission system, this map cannot be reproduced in this report. The transmission lines in the study regions were digitised to allow calculation of approximate distance to transmission facilities for each site. No distinction was made in cost for either transmission or interconnection of the facilities at different voltages. In reality, the costs can be dramatically different for higher voltages. This level of detail will be included in future project stages, and the transmission authorities would be approached directly to obtain the higher fidelity GIS data rather than relying on the digitised version of a raster map.

With respect to the capital costs of each facility, these should be considered approximate and subject to variation as more detailed studies are undertaken. They should not be considered a reliable representation of the actual construction costs of the facilities, but are an inferred cost of sufficient detail to provide a relative ranking of the facilities within and across the different energy resources. It is hoped that higher fidelity cost models similar to AACE Class 5 cost estimates can be prepared for the next iteration of this study.

3 SOLAR PHOTOVOLTAIC POWER

3.1 SOLAR PHOTOVOLTAIC – SCREENING METHODOLOGY

3.1.1 SITE IDENTIFICATION

Any location is theoretically suitable for a solar photovoltaic plant, so this pilot study assessed all locations in the study area. The only initial exclusion criterion was for locations within parks, reserves, cities and towns. In order to develop potential solar PV facility locations, the pilot study was restricted to a region covering the southern portion of the province of Alberta (Figure 3.1). The region was segregated into a grid of 10x10 km squares (100 km^2). Of the total 261 squares, 11 were excluded due to being located within cities, towns, parks or reserves, leaving a total of 250 sites that were assessed for their viability.

3.1.2 SOLAR RESOURCE

Solar resource information was obtained from the IRENA Global Atlas for Renewable Energy, which includes a dataset from 3Tier at 3 km grid resolution of annual Global Horizontal Irradiance (GHI) in units of W/m^2. To determine annual variation in solar radiation, monthly data was obtained for Lethbridge, AB using the database included in RETScreen software. This enabled the calculation of an expected annual capacity factor based on pro-rating the solar radiation data to the monthly variation in the data for Lethbridge. Use of a greater number of weather station datasets will enable more accurate assessment of site-specific monthly variation to better reflect local variations for the detailed study.

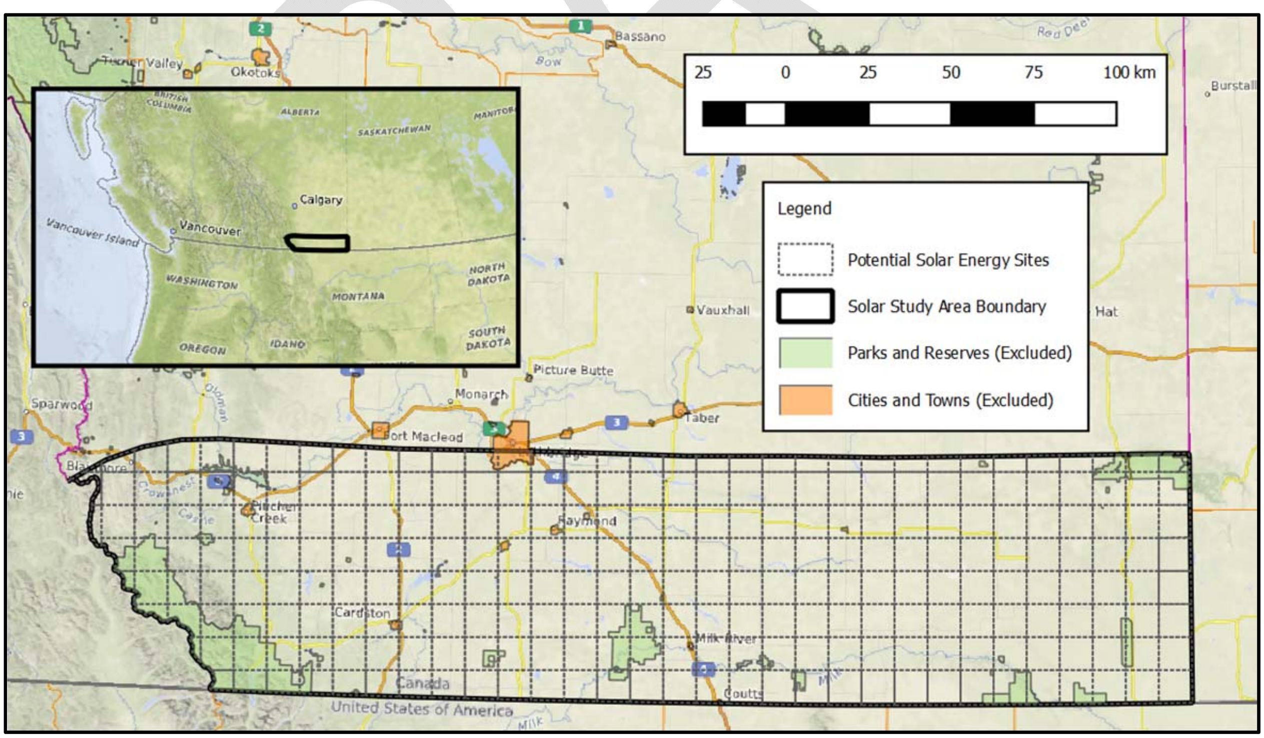


Figure 3.1: Solar energy preliminary study area.

3.1.3 SITE EVALUATION

A project size of 20 MW was assumed, as this matches the 20 MW wind-farm size (chosen as the minimum size for economies of scale) and it also coincides approximately with the largest potential hydroelectric facilities identified in this study. Costs for solar PV facilities were estimated based on recently released industry cost trends from the U.S. Department of Energy (US DoE 2015) and from the National Renewable Energy Laboratory (NREL 2015). Using an assumed installed density of 48 MW/km^2 (NREL 2012), all sites would fit easily within their respective 100 km^2 grids, and it is likely that larger facilities could be constructed at many of the best locations.

Key data including solar resource, distance to transmission line and site slope were extracted from a GIS model developed in QGIS. Using a spreadsheet based model, the inferred cost of construction was determined for each site, combining the single-axis tracking crystalline silicon PV modules, inverters, electrical balance of plant, installation, transmission, interconnection cost and access road cost. An increased construction cost factor was included for sites with a slope greater than 3°. The spreadsheet model also calculates the capacity factor, energy production and levelised cost of energy based on the following additional assumptions specific to the solar PV facilities:

- AC derating factor: 0.8
- Project life: 20 years
- Operations and Maintenance Cost: $35/kW-yr

3.2 SOLAR PHOTOVOLTAIC – SCREENING RESULTS

Inferred costs are shown for the top 30 ranked solar PV sites in Table 3.1, with technical data in Table 3.2.

Table 3.1: Inferred costs for potential solar PV facilities.

ID	Inferred Cost ($)	Annual Generation (MWh)	Capacity (MW_{AC})	Cost of Capacity ($/MW)	Cost to Energy Ratio ($/MWh-yr)	Levelised Cost of Energy ($/MWh)
139	$70,800,000	33,500	20	$3,540,000	$2,110	$210
140	$70,800,000	32,600	20	$3,540,000	$2,170	$216
39	$70,400,000	32,300	20	$3,520,000	$2,180	$217
40	$70,300,000	32,100	20	$3,510,000	$2,190	$218
41	$70,300,000	31,900	20	$3,520,000	$2,210	$220
106	$73,100,000	32,900	20	$3,650,000	$2,220	$220
141	$70,600,000	31,900	20	$3,530,000	$2,210	$220
24	$70,600,000	31,900	20	$3,530,000	$2,220	$221
60	$70,600,000	31,800	20	$3,530,000	$2,220	$221
43	$70,500,000	31,700	20	$3,520,000	$2,220	$222
9	$70,300,000	31,600	20	$3,510,000	$2,220	$222
8	$71,000,000	31,700	20	$3,550,000	$2,240	$223
75	$71,600,000	32,000	20	$3,580,000	$2,240	$223
7	$72,300,000	32,100	20	$3,610,000	$2,250	$223
146	$70,700,000	31,500	20	$3,540,000	$2,250	$224
88	$70,800,000	31,500	20	$3,540,000	$2,250	$224
148	$70,400,000	31,300	20	$3,520,000	$2,250	$224
44	$70,800,000	31,500	20	$3,540,000	$2,250	$224
111	$70,800,000	31,400	20	$3,540,000	$2,250	$224
114	$70,500,000	31,300	20	$3,520,000	$2,250	$224
74	$72,300,000	32,000	20	$3,610,000	$2,260	$224
73	$72,900,000	32,200	20	$3,650,000	$2,260	$224
107	$73,200,000	32,300	20	$3,660,000	$2,260	$225
38	$74,200,000	32,700	20	$3,710,000	$2,270	$225
10	$70,700,000	31,300	20	$3,540,000	$2,260	$225
235	$75,800,000	33,200	20	$3,790,000	$2,280	$225
23	$72,100,000	31,800	20	$3,610,000	$2,270	$225
152	$70,800,000	31,200	20	$3,540,000	$2,270	$226
6	$73,600,000	32,300	20	$3,680,000	$2,280	$226
147	$71,100,000	31,300	20	$3,550,000	$2,270	$226

Table 3.2: Technical data for potential solar PV facilities.

Site ID	Capacity Factor (%)	Transmission Line Length (km)	Installed Capacity (MW_{AC})	Annual Energy (MWh)
139	19.1%	0.65	20.0	33,500
140	18.6%	0.66	20.0	32,600
39	18.4%	0.36	20.0	32,300
40	18.3%	0.26	20.0	32,100
41	18.2%	0.29	20.0	31,900
106	18.8%	2.20	20.0	32,900
141	18.2%	0.47	20.0	31,900
24	18.2%	0.51	20.0	31,900
60	18.2%	0.52	20.0	31,800
43	18.1%	0.39	20.0	31,700
9	18.0%	0.26	20.0	31,600
8	18.1%	0.77	20.0	31,700
75	18.2%	1.21	20.0	32,000
7	18.3%	1.65	20.0	32,100
146	17.9%	0.57	20.0	31,500
88	18.0%	0.63	20.0	31,500
148	17.9%	0.33	20.0	31,300
44	17.9%	0.62	20.0	31,500
111	17.9%	0.63	20.0	31,400
114	17.9%	0.40	20.0	31,300
74	18.2%	1.65	20.0	32,000
73	18.4%	2.09	20.0	32,200
107	18.4%	2.30	20.0	32,300
38	18.7%	2.98	20.0	32,700
10	17.9%	0.58	20.0	31,300
235	19.0%	4.09	20.0	33,200
23	18.1%	1.54	20.0	31,800
152	17.8%	0.62	20.0	31,200
6	18.4%	2.58	20.0	32,300
147	17.8%	0.82	20.0	31,300

The incremental cost of solar PV for the study area is shown on Figure 3.2 it indicates that there is a steady increase in solar PV levelised cost from approximately $210/MWh for the most cost-effective site to almost $600/MWh for the least cost-effective site. A total potential installed capacity of 5,000 MW is identified in this study, although the actual potential is much higher, as this study assumes a maximum of 20 MW of installed capacity in each 100 km^2 grid cell, while larger facilities could potentially be built. However, it is unlikely that the entire technical potential would be built due to constraints with other uses of the land.

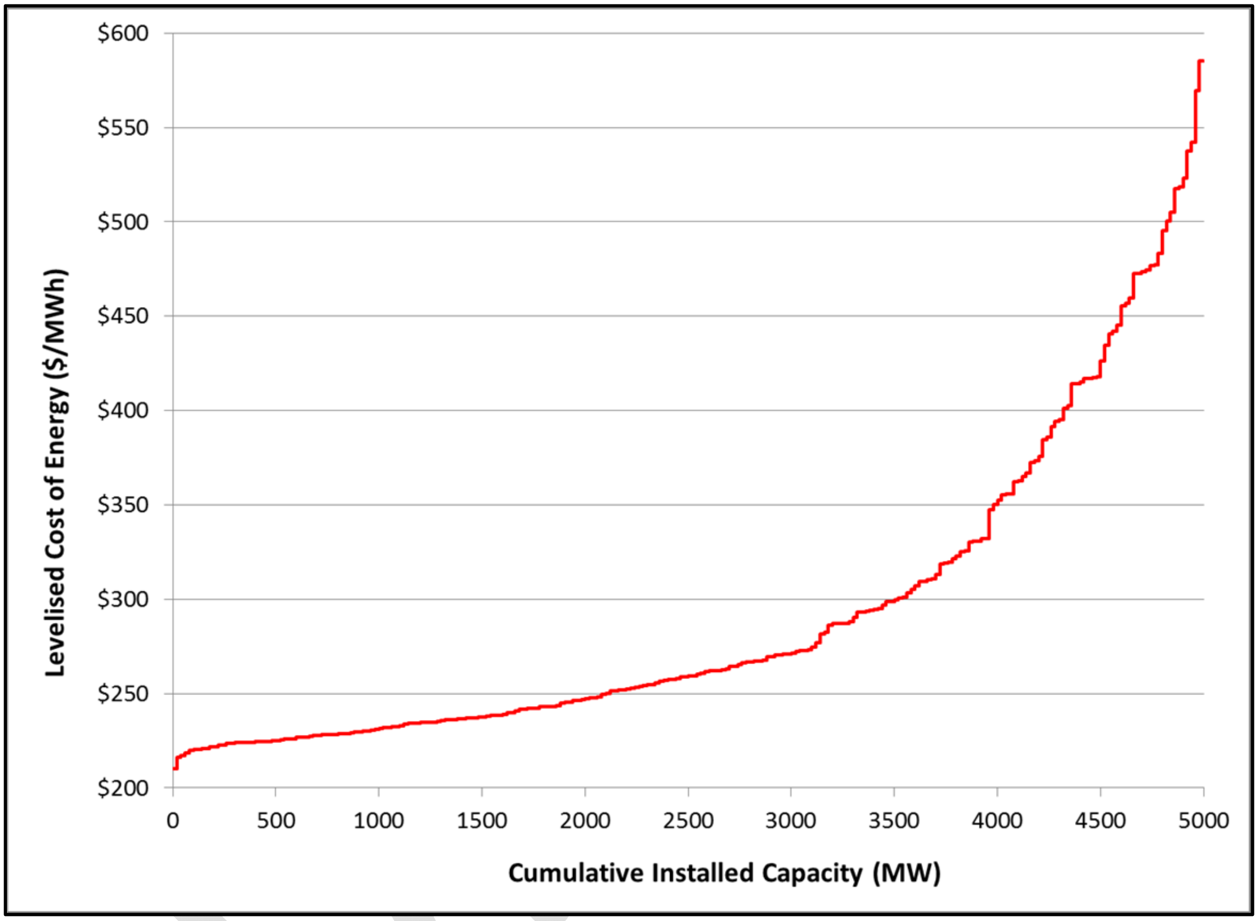


Figure 3.2: Incremental cost of energy for potential solar PV facilities.

The cumulative annual energy provided by the potential solar PV facilities (Figure 3.3) follows a similar trend to the cumulative installed capacity. The total annual hydropower resource identified in this study is over 7000 GWh/yr, although much of that resource is unlikely to be economic in current market conditions.

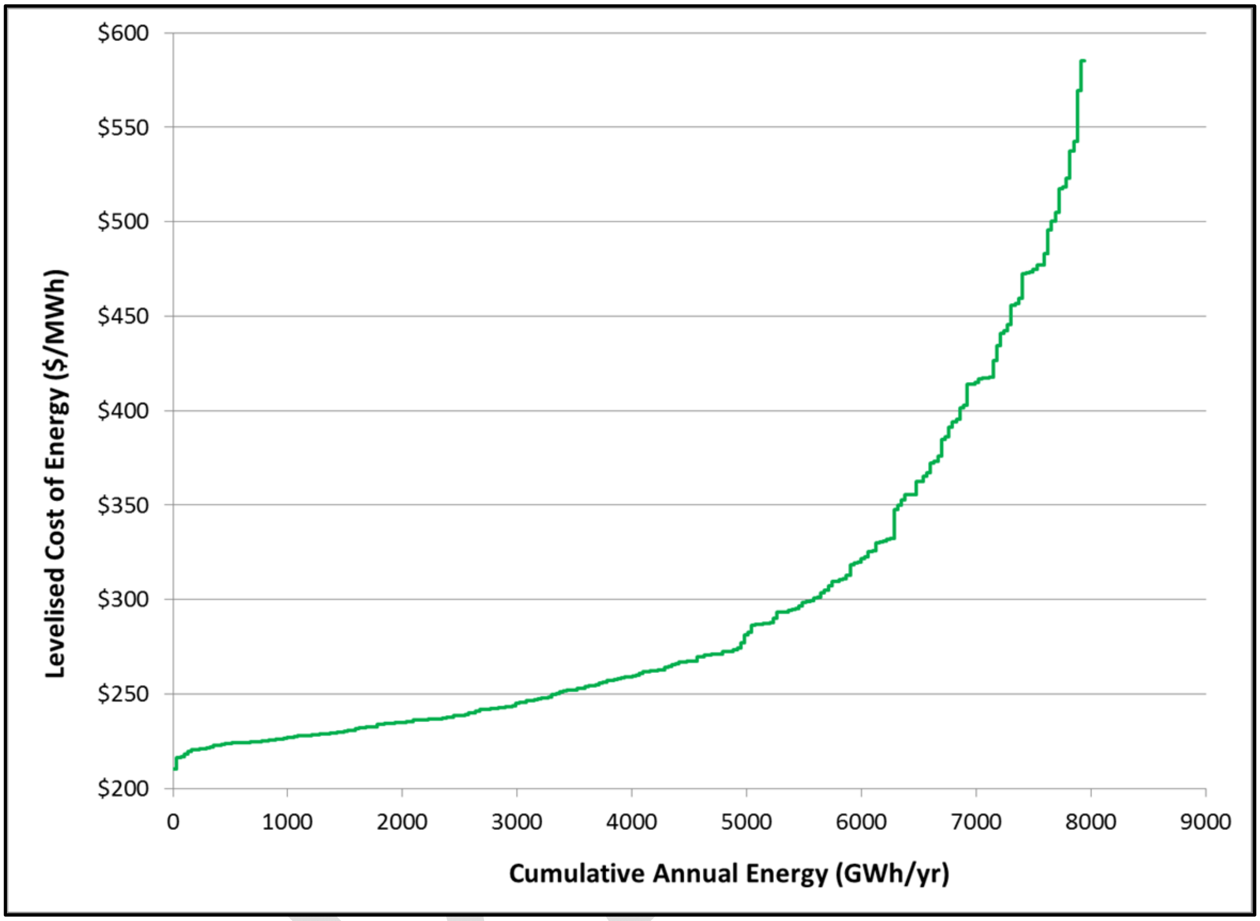


Figure 3.3: Cumulative annual energy for solar PV facilities.

3.3 SOLAR PV - CONCLUSIONS

Within the study region, the key factor determining the economic potential of a site is its proximity to the transmission system. It is likely that this relationship may break down in other regions of the province, since there was only approximately 12% difference in the maximum (19.6%) to the minimum (17.5%) capacity factor between the best and the worst solar resources in the study area. While the solar resource in the study area is somewhat uniform, there is greater variation for the province as a whole. The solar resource is lower further north in the province (approximately 10% lower near Edmonton, and 15% lower near Fort McMurray). Nevertheless, it is apparent that the most cost effective solar PV sites are likely to be located near transmission facilities, and likely in the south of the province where the solar resource is better. The next stage of this study will reduce the calculation burden by limiting to assessment of sites within a certain maximum distance (say 10 km) from existing or soon to be developed transmission facilities.

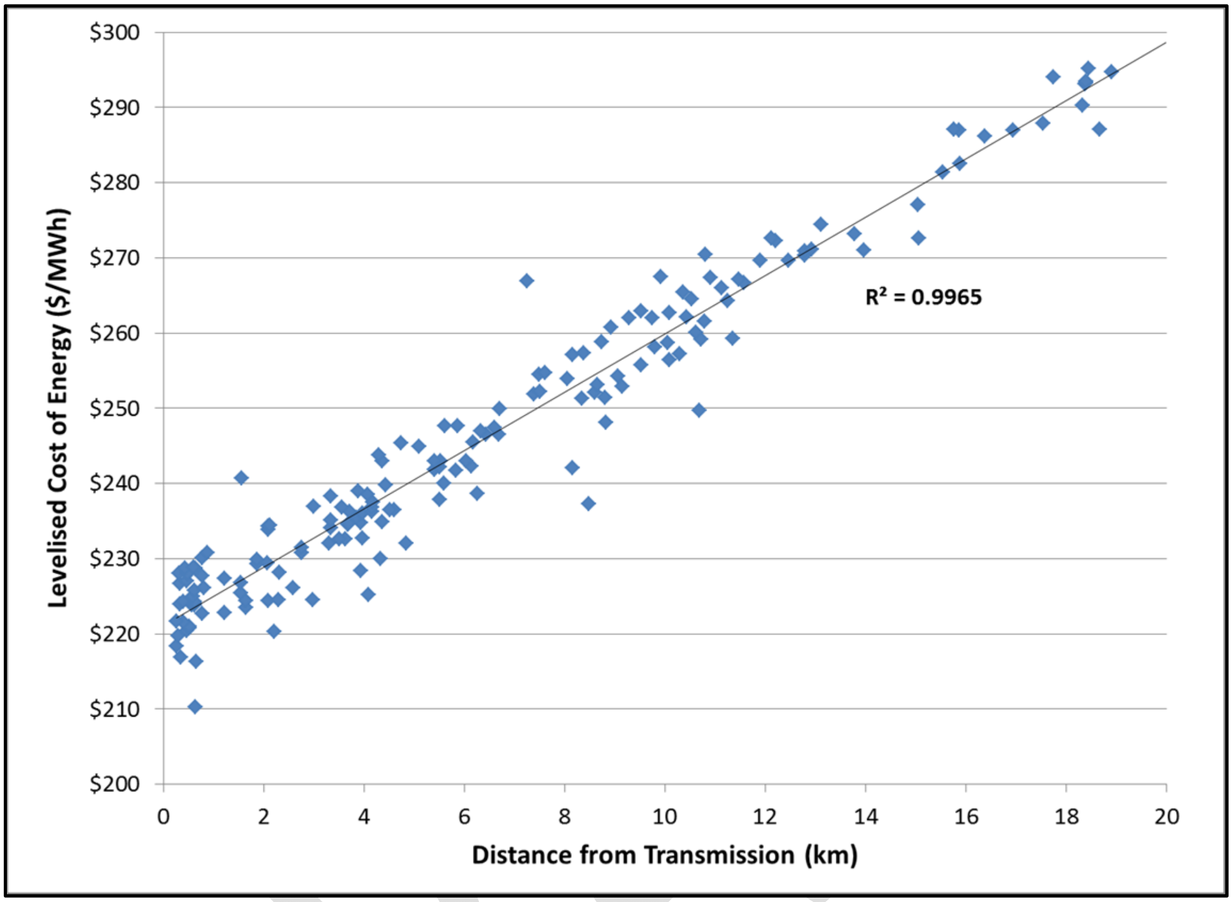


Figure 3.4: Relationship between transmission distance and energy cost for solar PV.

Additional considerations for future iterations of this study specifically relevant to solar PV include:

- Improving the fidelity of the solar PV cost model, for example by obtaining budget quotations from vendors and preparing generic facility layouts to better determine Alberta specific cost scenarios.
- Assessing likely property acquisition scenarios and how this may impact a project's development.
- Sensitivity analysis on projected future cost reduction trends for solar technology.
- Sensitivity analysis on project size to determine economies of scale for commercial scale (<100 kW), community-scale (<1 MW), small utility scale (20 MW) and large utility scale (100 MW) facilities.
- More detailed assessment of solar resource, including month-to-month variation, with a view to determining sites which produce energy at times that coincide with high energy prices.

4 WIND POWER

4.1 WIND ENERGY – SCREENING METHODOLOGY

4.1.1 SITE IDENTIFICATION

Any location is theoretically suitable for a wind energy facility, so this pilot study assessed all locations in the study area. The only initial exclusion criterion was for locations within parks, reserves, cities and towns. In order to develop potential wind energy facility locations, the pilot study was restricted to a region covering the south-eastern portion of the province of Alberta (Figure 4.1). The region was segregated into a grid of 10x10 km squares. Of the total 160 square, no sites were located wholly within a city, town, park or reserve, so no sites were excluded in their entirety.

4.1.2 WIND RESOURCE

Wind resource information was obtained from the Technical University of Denmark (DTU) Global Wind Atlas, which includes a worldwide dataset at 1 km resolution. The top quartile mean annual wind speed for each site at 100 m above ground was extracted from the DTU dataset, and this was used to estimate the wind-speed at an assumed 85 m hub height using a wind shear coefficient of 0.15.

To determine annual variation in wind speed, monthly data was obtained for Medicine Hat, AB using the databased included in RETScreen software. This enabled the calculation of an expected annual capacity factor based on pro-rating the site-specific wind data to the monthly variation in the data for Medicine Hat. Use of a greater number of weather station datasets will enable more accurate assessment of monthly variation for each site to better reflect location variations as part of the detailed study.

Figure 4.1: Wind energy preliminary study area.

4.1.3 SITE EVALUATION

A project size of 20 MW was assumed, as this is identified as the approximate minimum size for a wind farm to exhibit economies of scale (US DoE 2015), and coincides approximately with the largest potential hydroelectric facilities identified in this study. Costs for wind energy facilities were estimated based on recently released industry cost trends from the U.S. Department of Energy (US DoE 2015). Using an assumed installed density of 5 MW/km^2, all sites would fit easily within their respective 10 km^2 grids, although detailed micro-siting within the 100 km^2 grid would likely limit many areas from being suitable.

Key data including wind resource and distance to transmission line were extracted from a GIS model developed in QGIS. Using a spreadsheet based calculation model, the inferred cost of construction was determined for each site, combining the wind turbine and tower cost, electrical balance of plant, civil works, transmission, interconnection and access road cost. The spreadsheet model also calculates the capacity factor, energy production and levelised cost of energy based on the following additional assumptions specific to the wind energy facilities:

- Array and miscellaneous losses: 10%
- Project life: 25 years
- Operations and Maintenance Cost: $45/kW-yr

4.2 WIND ENERGY – SCREENING RESULTS

Inferred costs are shown for the top 30 ranked wind energy sites in Table 4.1, with technical data in Table 4.2.

Table 4.1: Inferred costs for potential wind energy facilities.

ID	Inferred Cost ($)	Annual Generation (MWh)	Capacity (MW)	Cost of Capacity ($/MW)	Cost to Energy Ratio ($/MWh-yr)	Levelised Cost of Energy ($/MWh)
92	$64,000,000	60,600	20	$3,200,000	$1,060	$97
91	$57,800,000	55,300	20	$2,890,000	$1,040	$98
99	$66,600,000	60,400	20	$3,330,000	$1,100	$101
100	$68,800,000	60,100	20	$3,440,000	$1,140	$104
67	$57,800,000	49,000	20	$2,890,000	$1,180	$111
75	$57,900,000	49,000	20	$2,900,000	$1,180	$111
53	$58,200,000	49,000	20	$2,910,000	$1,190	$111
52	$60,000,000	48,800	20	$3,000,000	$1,230	$115
60	$60,400,000	48,800	20	$3,020,000	$1,240	$115
74	$61,100,000	48,800	20	$3,060,000	$1,250	$117
15	$61,300,000	48,700	20	$3,060,000	$1,260	$117
93	$78,500,000	59,100	20	$3,930,000	$1,330	$119
66	$63,400,000	48,600	20	$3,170,000	$1,300	$121
8	$64,000,000	48,500	20	$3,200,000	$1,320	$122
101	$80,500,000	58,900	20	$4,030,000	$1,370	$122
24	$65,000,000	48,400	20	$3,250,000	$1,340	$124
90	$65,000,000	48,400	20	$3,250,000	$1,340	$124
7	$65,400,000	48,400	20	$3,270,000	$1,350	$124
68	$65,600,000	48,400	20	$3,280,000	$1,360	$125
59	$66,200,000	48,300	20	$3,310,000	$1,370	$126
83	$66,600,000	48,300	20	$3,330,000	$1,380	$126
76	$67,800,000	48,200	20	$3,390,000	$1,410	$129
58	$68,200,000	48,200	20	$3,410,000	$1,420	$129
61	$58,700,000	42,300	20	$2,940,000	$1,390	$130
54	$68,800,000	48,100	20	$3,440,000	$1,430	$131
84	$68,800,000	48,100	20	$3,440,000	$1,430	$131
62	$68,900,000	48,100	20	$3,450,000	$1,430	$131
6	$69,000,000	48,100	20	$3,450,000	$1,430	$131
82	$69,400,000	48,100	20	$3,470,000	$1,440	$132
98	$69,400,000	48,100	20	$3,470,000	$1,440	$132

Table 4.2: Technical data for potential wind energy facilities.

Site ID	Capacity Factor (%)	Transmission Line Length (km)	Installed Capacity (MW)	Annual Energy (MWh)
92	35.0%	4.74	20.0	60,635
91	31.6%	0.44	20.0	55,340
99	35.0%	6.50	20.0	60,365
100	35.0%	8.05	20.0	60,128
67	28.0%	0.44	20.0	49,036
75	28.0%	0.53	20.0	49,024
53	28.0%	0.71	20.0	49,003
52	28.0%	1.98	20.0	48,846
60	28.0%	2.27	20.0	48,811
74	28.0%	2.76	20.0	48,751
15	28.0%	2.87	20.0	48,738
93	35.0%	14.77	20.0	59,097
66	28.0%	4.30	20.0	48,562
8	28.0%	4.74	20.0	48,508
101	35.0%	16.14	20.0	58,887
24	28.0%	5.40	20.0	48,427
90	28.0%	5.40	20.0	48,427
7	28.0%	5.72	20.0	48,388
68	28.0%	5.84	20.0	48,373
59	28.0%	6.28	20.0	48,319
83	28.0%	6.50	20.0	48,292
76	28.0%	7.38	20.0	48,183
58	28.0%	7.61	20.0	48,156
61	24.2%	1.10	20.0	42,311
54	28.0%	8.04	20.0	48,102
84	28.0%	8.05	20.0	48,102
62	28.0%	8.12	20.0	48,093
6	28.0%	8.16	20.0	48,089
82	28.0%	8.45	20.0	48,052
98	28.0%	8.45	20.0	48,052

The incremental cost of wind energy is shown on Figure 4.2. It indicates that there is a steady increase in wind levelised cost from under $100/MWh for the most cost-effective site to almost $450/MWh for the least cost-effective site. A total potential installed capacity of 3,200 MW is identified in this study, although many sites may facilitate larger plants than 20 MW within the 100 km² grid. Nevertheless, this technical potential is unlikely to be fully implemented due to the need to use some of the land for other purposes.

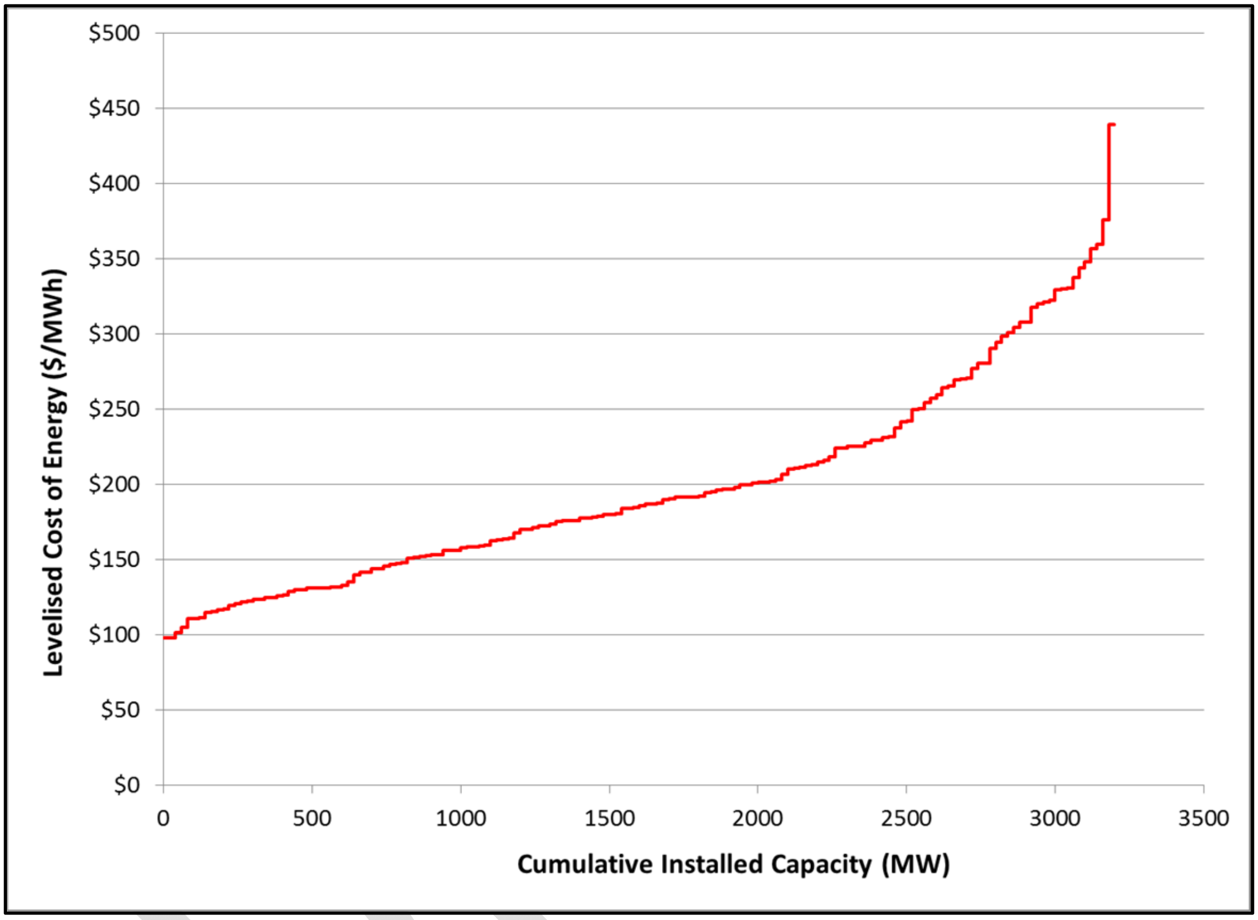


Figure 4.2: Incremental cost of energy for potential wind power facilities.

The cumulative annual energy provided by the potential wind energy facilities (Figure 4.3) follows a similar trend to the cumulative installed capacity. The total annual wind resource identified in this study is over 7000 GWh/yr, although much of that resource is unlikely to be economic in current market conditions.

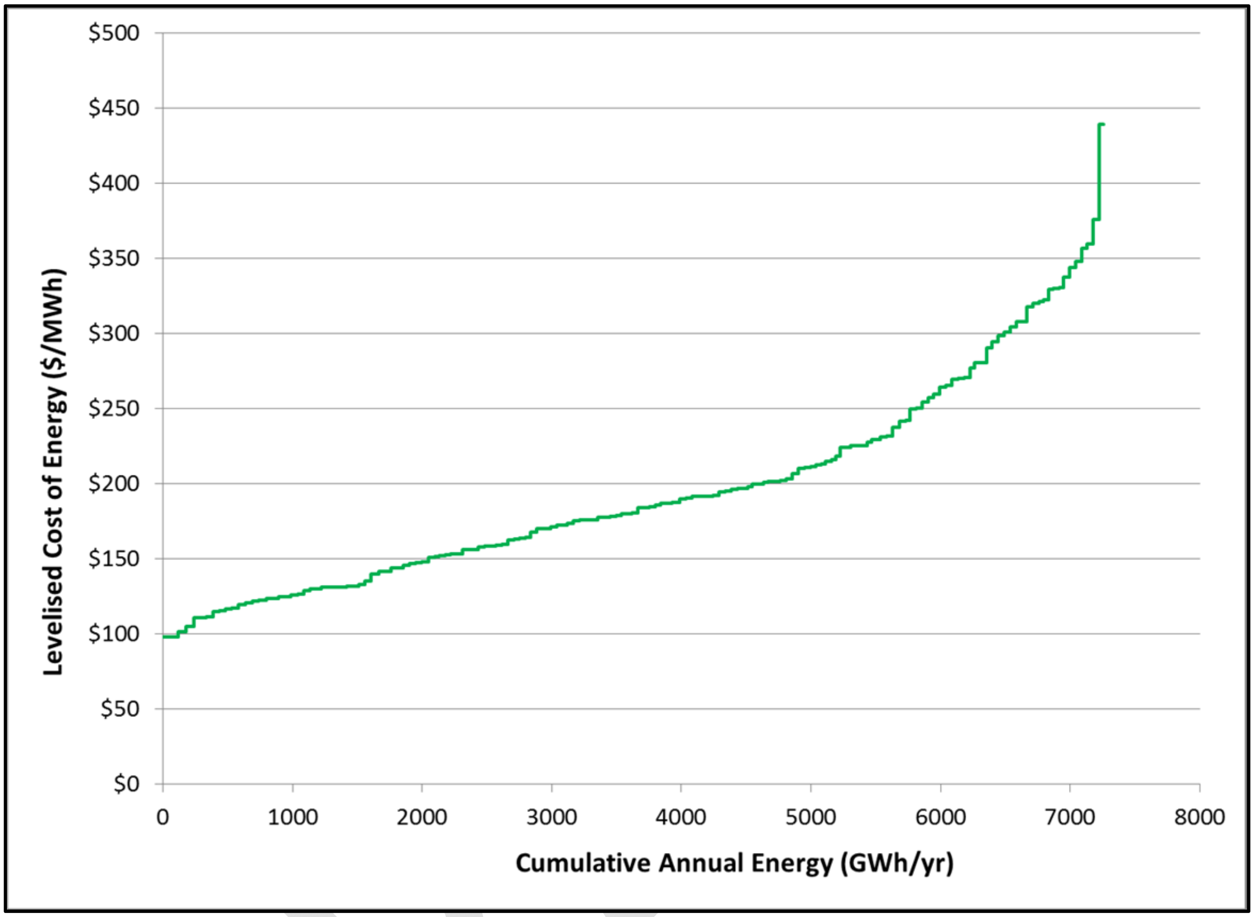


Figure 4.3: Cumulative annual energy for wind power facilities.

4.3 WIND ENERGY - CONCLUSIONS

As for solar PV, a key factor in determining the economic potential of a site is its proximity to the transmission system (Figure 4.4: Relationship between transmission distance and energy cost for wind facilities. However, when compared to solar PV, there is a greater difference between sites with similar transmission distances due to the greater relative difference in wind energy resource across the study area (approximately 35% between the best and worst locations in the study area). The difference in wind resource can be seen by the clustering of sites into four distinct trend lines in Figure 4.4, reflecting the discrete nature of the wind speeds provided in the DTU dataset (6 m/s, 7 m/s, 8 m/s). It is apparent that both a high quality wind resource and proximity to transmission are critical for the most cost effective wind energy sites. The next stage of this study will reduce the calculation burden by limiting to assessment of sites within a certain maximum distance (say 20 km) of existing and proposed transmission facilities, and selection of only sites with a minimum wind-speed of 7 m/s or higher.

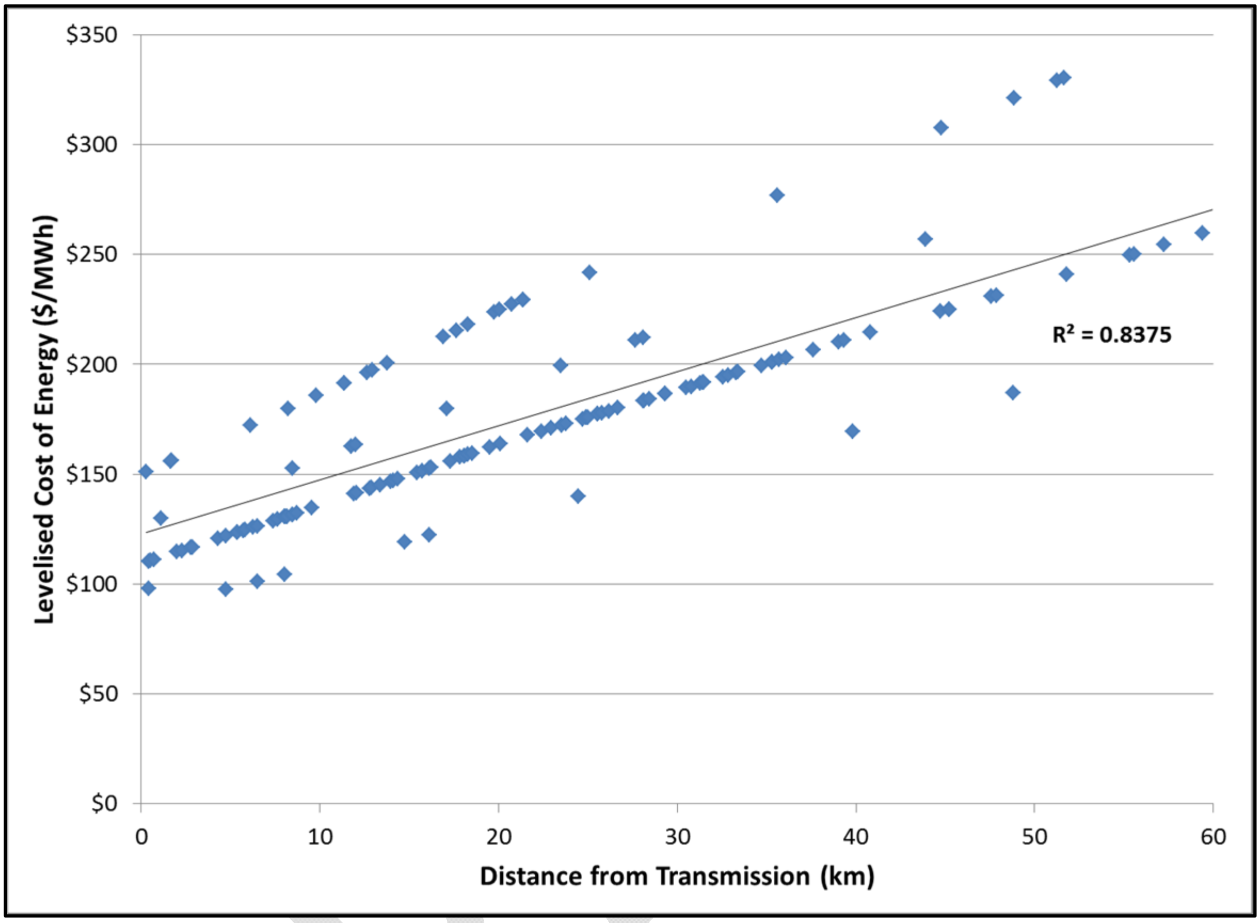


Figure 4.4: Relationship between transmission distance and energy cost for wind facilities.

Additional considerations for future iterations of this study specifically relevant to wind facilities include:

- Improving the fidelity of the wind energy cost model, for example by obtaining budget quotations from vendors and preparing generic facility layouts to better determine Alberta specific costs.
- Assessing likely property acquisition scenarios and how this may impact a project's development.
- Sensitivity analysis on project size to determine economics of scale for community scale (<10 MW), small utility scale (20 MW) and large utility scale (100 MW) facilities.
- More detailed assessment of wind resource factors, including month-to-month variation, with a view to determining sites which frequently produce energy during times of high energy prices.

5 HYDROPOWER

5.1 HYDROPOWER – SCREENING METHODOLOGY

5.1.1 SITE IDENTIFICATION

Hydropower potential is highly site-specific, so a manual screening methodology was required to identify potential locations that may be suited for hydropower development, prior to further analysis of these sites. A GIS model was created for the study region covering the Rocky Mountain foothills in the south-west of the province (Figure 5.1). National Topographic System (NTS) contours were used to identify rivers with sufficient gradient that construction of a diversion style (weir and penstock to powerhouse) run of river hydropower facility may be possible. As well as possible intake/weir locations, penstock routes and powerhouse locations were also identified. A total of 110 potential hydropower facilities locations were identified based on topographic data. Sites within parks, reserves, cities or towns were excluded.

It is apparent that a greater number of potential hydropower facility locations are located in the western portion of the study area, owing to the greater topographic relief compared to the flatter eastern portion of the study area. Nevertheless, the study area has a lower topographic relief than areas of the Rocky Mountains and foothills further to the north, although much of this is located within parks and reserves.

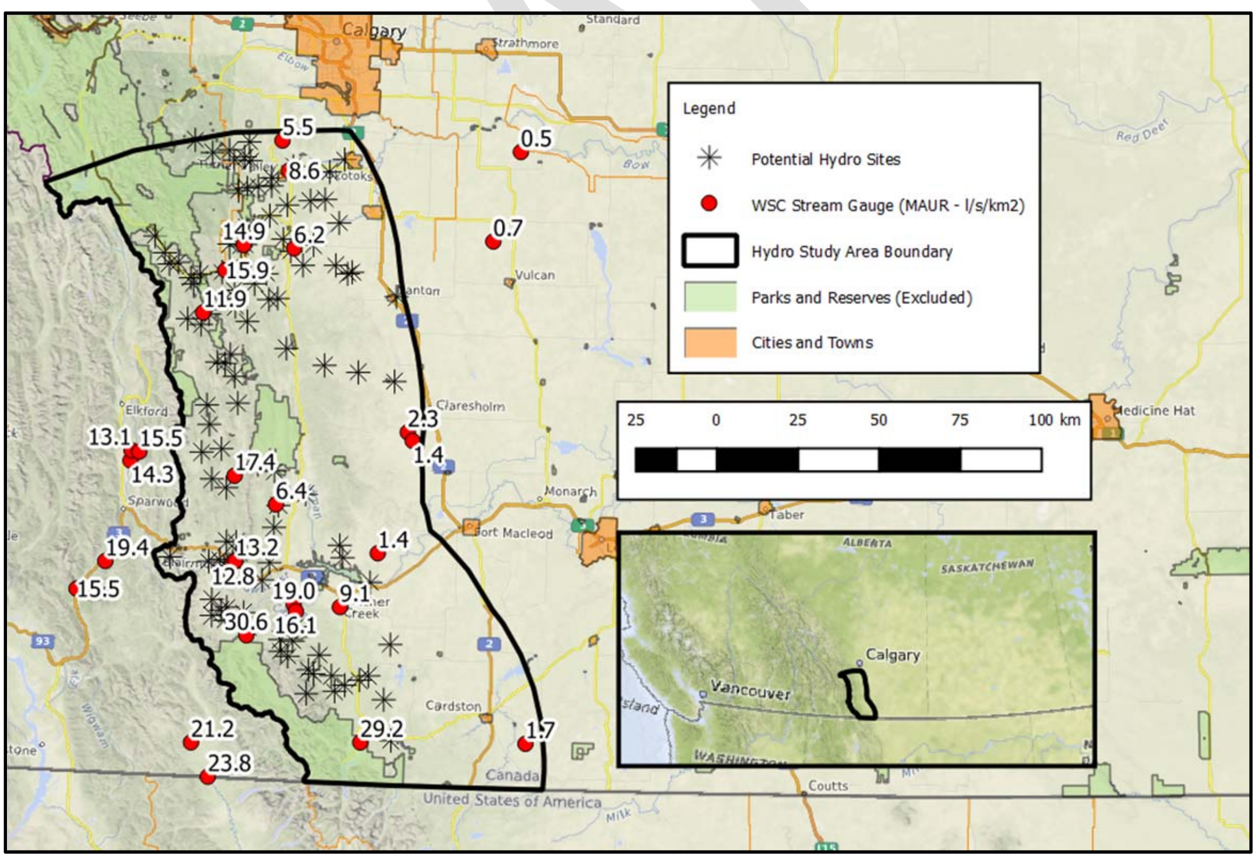


Figure 5.1: Hydropower study area with mean annual unit runoff (MAUR) at Water Survey of Canada sites.

5.1.2 HYDRO RESOURCE

Hydro resource information was obtained from Water Survey of Canada (WSC) stream gauges located within and adjacent to, the study area. Using the long-term daily flow averages and station catchment areas provided in the WSC data, the mean annual discharge (MAD) and the mean annual unit runoff (MAUR) were calculated for each stream gauge site. The data are presented in Table 5.1, and in Figure 5.1. It is apparent that there is a trend of decreasing MAUR moving from the west to the east of the study area, which is to be expected given the rain-shadow that exists to the east of the Rocky Mountains.

For each identified potential hydropower site, the MAUR was determined by interpolating from the nearest WSC gauge(s), considering the likely correlation between the catchment area of the hydropower intake location and the WSC gauge. For example, a hydropower intake which has a significant portion of its catchment lying in the western portion of the study area will have a higher MAUR than a catchment primarily located in the eastern regions of the study area. Note that this technique is necessarily imprecise, and relies on a level of subjective judgement. More reliable estimates of hydropower resource would entail more detailed hydrological studies at specific site locations identified as worthy of further analysis.

Catchment areas for each hydropower intake location were determined by using the hydrological modelling tools within QGIS. A digital elevation from NTS data was used to develop an accumulated catchment raster layer, from which the catchment area at each intake can be extracted. Using the combination of MAUR for each facility, and the intake watershed area, an estimated Mean Annual Discharge (MAD) for each location can be determined. Capacity factor was determined by calculating the flow duration curve for the available WSC stations, as well as assuming a minimum 5% instream flow release (IFR) for environmental requirements. No clear trend was identified in inferred capacity factor for WSC stations based on either increasing catchment area, or increasing MAUR, so the inferred capacity factor was based on the median of all the WSC gauge sites. The inferred capacity factor based on the stream gauge data was 38%, and additional allowance for forced outages, transmission and miscellaneous losses gave a net capacity factor of 34%.

Table 5.1: Water Survey of Canada stream gauges near the study area

ID	Province	Period of Record	Catchment Area (km^2)	Mean Annual Discharge (m^3/s)	Mean Annual Unit Runoff ($l/s/km^2$)
05AB013	AB	1921-2012	255.8	0.359	1.4034
05AA028	AB	1967-2014	375.3	11.5	30.6422
05AA022	AB	1945-2013	820.7	15.6	19.0082
05BL022	AB	1966-2012	165.5	1.97	11.9033
05AA008	AB	1910-2012	402.7	5.16	12.8135
08NK002	BC	1925-2014	3090	47.8	15.4693
08NK016	BC	1950-2015	1840	26.3	14.2935
08NP001	BC	1929-2013	1110	26.4	23.7838
08NK018	BC	1970-2014	621	8.13	13.0918
05BL019	AB	1950-2012	773.6	12.3	15.8997
05AA011	AB	1910-2012	179	2.88	16.0894
05BL023	AB	1967-2014	231.9	1.44	6.2096
05AA004	AB	1910-2013	157.5	1.43	9.0794
05AA027	AB	1966-2013	217.6	3.79	17.4173
05AE005	AB	1911-2012	222.4	0.379	1.7041
05BL014	AB	1909-2012	592.2	5.09	8.5951
05BL013	AB	1909-2014	507.2	2.81	5.5402
05AB005	AB	1908-2013	440.8	0.993	2.2527
05AD003	AB	1908-2012	612.7	17.9	29.2150
05BM014	AB	1965-2013	776.5	0.373	0.4804
08NP004	BC	1977-2014	92.8	1.97	21.2284
05AA030	AB	1975-2014	63.3	0.835	13.1912
08NK026	BC	1981-2014	6.4	0.124	19.3750
08NK022	BC	1971-2014	138	2.14	15.5072
05AB029	AB	1966-2014	130.2	0.184	1.4132
05AA909	AB	1982-2013	74	0.474	6.4054
05BL027	AB	1979-2012	137.4	2.05	14.9199
05BM018	AB	1985-2012	29.5	0.0213	0.7220

5.1.3 SITE EVALUATION

For each of the study sites, the intake and powerhouse elevations, penstock length, catchment area, MAUR and distance to the transmission system were extracted from a spatial model developed in QGIS. Using these data, a design factor (design flow compared to MAD) of 1.5 was used to calculate the design flow for each facility. Coupled with the gross head (intake minus powerhouse elevation) and an installed capacity could be determined based on an assumed penstock head loss of 10% and an assumed electro-mechanical efficiency of 93%. Using the inferred capacity factor of 34% for all sites, the annual energy production can be determined.

A simple spreadsheet cost model was developed based on the author's prior experience and knowledge of the cost of key civil components of hydroelectric facilities (concrete and excavation/backfill). Hydromechanical equipment costs were determined from recent industry data (IRENA 2012). While this methodology is subject to variation based on assumptions, a "top-down" costing approach such as that used for the solar and wind facilities is not suitable for hydropower facilities. Variations in head, flow and penstock length have a significant impact on project costs, and these cannot be determined without site-specific data. The simplified model was tested by using key data (head, flow, capacity) from a recently commissioned facility in BC to compare. Estimated LCOE for that facility using the current cost model came to approximately $105/MWh, within the expected range of energy cost based on BC Hydro's price in their standing offer program.

Using interpolated quantities based on project design flow and capacity, key civil and mechanical cost data could be determined. Note that for facilities less than 5 MW in size, connection to the distribution system (in lieu of the transmission system) was considered acceptable. Since no data was available on the distribution system, the nearest town or village was considered an acceptable interconnection point. A lower cost for the distribution line (as compared to a transmission line) to the point of interconnection was assumed for these facilities. The spreadsheet model combines the expected cost of roads, intake and tailrace, powerhouse, mechanical system, penstock, transmission and interconnection. The energy production and levelised cost of energy are calculated based on the following additional assumptions specific to the hydropower facilities:

- Project life: 50 years
- Operations and Maintenance Cost: 2.5% of capital costs

5.2 HYDROPOWER – SCREENING RESULTS

Inferred costs are shown for the top 30 ranked hydropower sites in Table 4.1, with technical data in Table 4.2.

Table 5.2: Inferred costs for potential hydropower facilities.

ID	Inferred Cost ($)	Annual Generation (MWh)	Capacity (MW)	Cost of Capacity ($/MW)	Cost to Energy Ratio ($/MWh-yr)	Levelised Cost of Energy ($/MWh)
13	$177,000,000	64,329	22	$8,220,000	$2,760	$244
12	$260,000,000	79,487	27	$9,740,000	$3,270	$289
28	$105,000,000	29,939	10	$10,500,000	$3,520	$311
102	$60,700,000	15,474	5	$11,700,000	$3,920	$347
41	$71,500,000	17,438	6	$12,200,000	$4,100	$362
29	$97,500,000	23,730	8	$12,200,000	$4,110	$363
63	$59,800,000	14,455	5	$12,300,000	$4,140	$366
94	$46,000,000	10,028	3	$13,700,000	$4,580	$405
70	$88,400,000	19,279	6	$13,700,000	$4,590	$406
26	$137,000,000	29,566	10	$13,800,000	$4,650	$411
98	$70,700,000	15,102	5	$14,000,000	$4,680	$414
88	$34,700,000	7,376	2	$14,000,000	$4,710	$416
74	$47,900,000	10,148	3	$14,000,000	$4,720	$417
22	$43,400,000	8,873	3	$14,600,000	$4,890	$432
40	$44,500,000	9,090	3	$14,600,000	$4,900	$433
101	$109,000,000	22,005	7	$14,800,000	$4,960	$439
75	$18,700,000	3,691	1	$15,100,000	$5,070	$448
23	$89,300,000	17,186	6	$15,500,000	$5,200	$460
71	$38,500,000	7,231	2	$15,900,000	$5,330	$471
80	$44,700,000	8,345	3	$16,000,000	$5,360	$474
6	$63,600,000	11,802	4	$16,000,000	$5,390	$477
21	$38,700,000	7,148	2	$16,100,000	$5,420	$479
27	$137,000,000	24,804	8	$16,400,000	$5,520	$488
85	$20,900,000	3,712	1	$16,800,000	$5,630	$498
103	$24,300,000	4,227	1	$17,100,000	$5,750	$508
48	$75,000,000	13,053	4	$17,100,000	$5,750	$508
84	$17,900,000	2,933	1	$18,200,000	$6,090	$539
43	$42,700,000	6,889	2	$18,500,000	$6,200	$548
53	$99,400,000	15,957	5	$18,600,000	$6,230	$551
100	$59,600,000	9,510	3	$18,700,000	$6,260	$554

Table 5.3: Technical data for potential hydropower facilities.

Site ID	Elevation (m)		Penstock Length (km)	Catchment Area (km^2)	Power Line Length (km)	Gross Head (m)	Design Flow (m^3/s)	Installed Capacity (MW)	Annual Energy (MWh)
	Intake	Powerhouse							
13	1,320	1,240	11.7	1,370	1.7	80	32.9	21.6	64,300
12	1,235	1,150	17.9	1,699	3.3	85	38.2	26.7	79,500
28	1,345	1,288	4.7	955	11.5	57	21.5	10.1	29,900
102	1,303	1,242	5.4	346	5.2	61	10.4	5.2	15,500
41	1,325	1,270	4.3	288	8.5	55	13.0	5.9	17,400
29	1,264	1,223	4.4	1,127	7.8	41	23.7	8.0	23,700
63	1,668	1,555	8.3	194	20.3	113	5.2	4.9	14,500
94	1,495	1,355	8.0	65	16.4	140	2.9	3.4	10,000
70	1,325	1,280	5.5	383	8.5	45	17.5	6.5	19,300
26	1,442	1,375	8.0	752	22.3	67	18.0	9.9	29,600
98	1,090	1,037	10.4	1,942	0.1	53	11.7	5.1	15,100
88	1,275	1,200	5.3	168	6.7	75	4.0	2.5	7,380
74	1,280	1,230	7.0	432	1.8	50	8.3	3.4	10,100
22	1,650	1,597	3.6	228	12.3	53	6.8	3.0	8,870
40	1,410	1,350	3.3	138	16.1	60	6.2	3.1	9,090
101	1,212	1,178	6.4	882	4.8	34	26.5	7.4	22,000
75	1,400	1,270	4.0	59	1.7	130	1.2	1.2	3,690
23	1,595	1,510	7.5	290	17.2	85	8.3	5.8	17,200
71	1,440	1,355	3.6	77	16.4	85	3.5	2.4	7,230
80	1,242	1,178	8.0	237	6.7	64	5.3	2.8	8,350
6	1,060	1,028	6.1	1,341	1.1	32	15.1	4.0	11,800
21	1,717	1,655	4.3	157	11.7	62	4.7	2.4	7,150
27	1,410	1,355	7.6	768	23.2	55	18.4	8.3	24,800
85	1,480	1,275	7.4	37	1.4	205	0.7	1.2	3,710
103	1,348	1,288	4.3	96	2.1	60	2.9	1.4	4,230
48	1,210	1,138	11.2	618	20.8	72	7.4	4.4	13,100
84	1,445	1,300	4.8	42	1.2	145	0.8	1.0	2,930
43	1,520	1,430	7.1	123	15.3	90	3.1	2.3	6,890
53	1,218	1,181	5.8	1,176	13.2	37	17.6	5.4	16,000
100	1,200	1,160	8.3	540	6.0	40	9.7	3.2	9,510

The incremental cost of hydropower facilities is shown on Figure 5.2. It indicates that there is a steady increase in levelised cost from under $250/MWh for the most cost-effective site to over $2,000/MWh for the least cost-effective sites. A total potential installed capacity of over 200 MW is identified in this study. More installed capacity may be available in the study area, but it is unlikely that any of the sites that have not be identified or examined are as cost effective as those already identified.

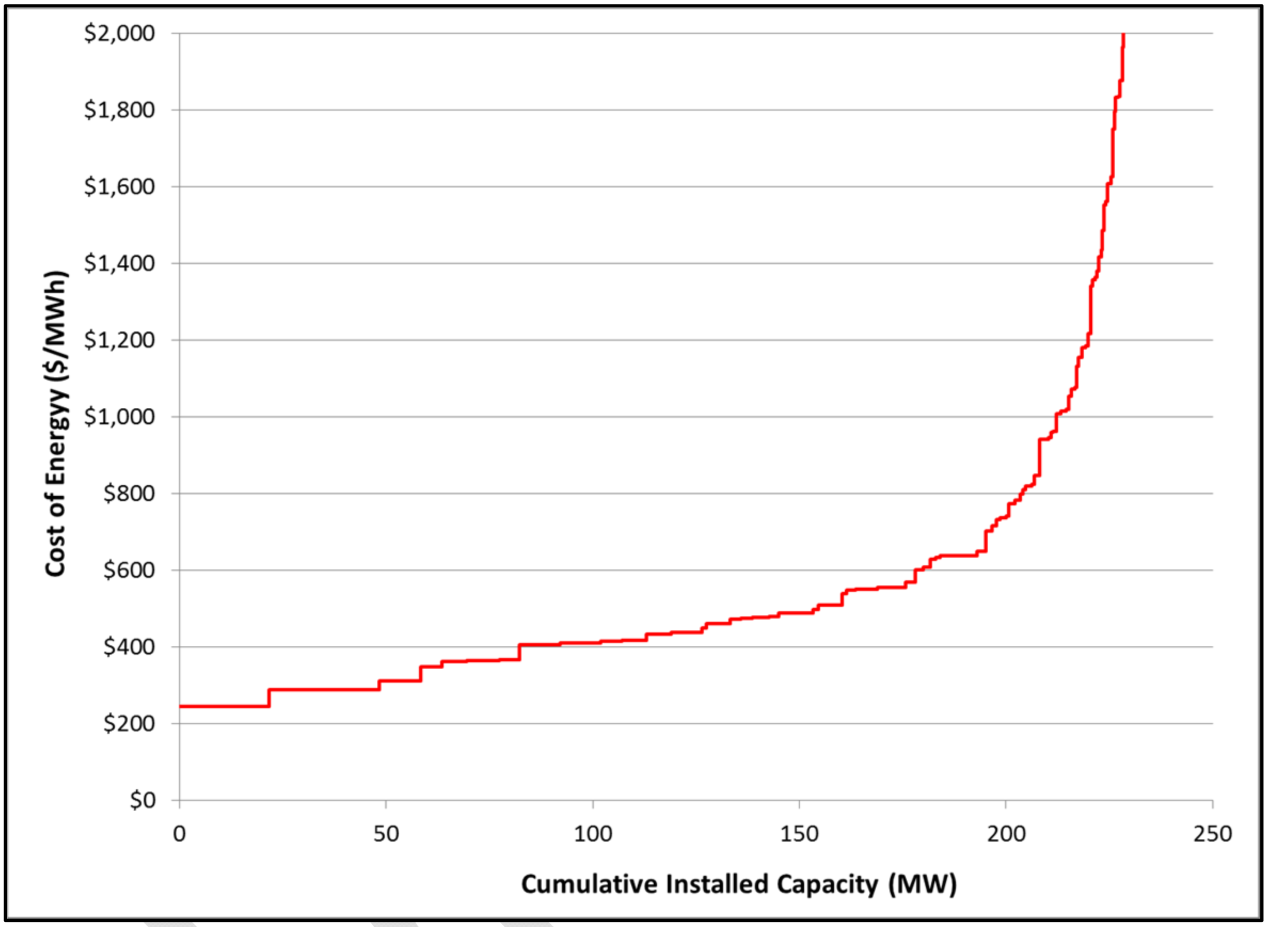


Figure 5.2: Incremental cost of installed capacity for potential hydropower facilities.

The cumulative annual energy provided by the potential hydropower facilities (Figure 5.3) follows a similar trend to the cumulative installed capacity. The total annual hydropower resource identified in this study is approximately 700 GWh/yr, although much of that resource is unlikely to be economic in current market conditions.

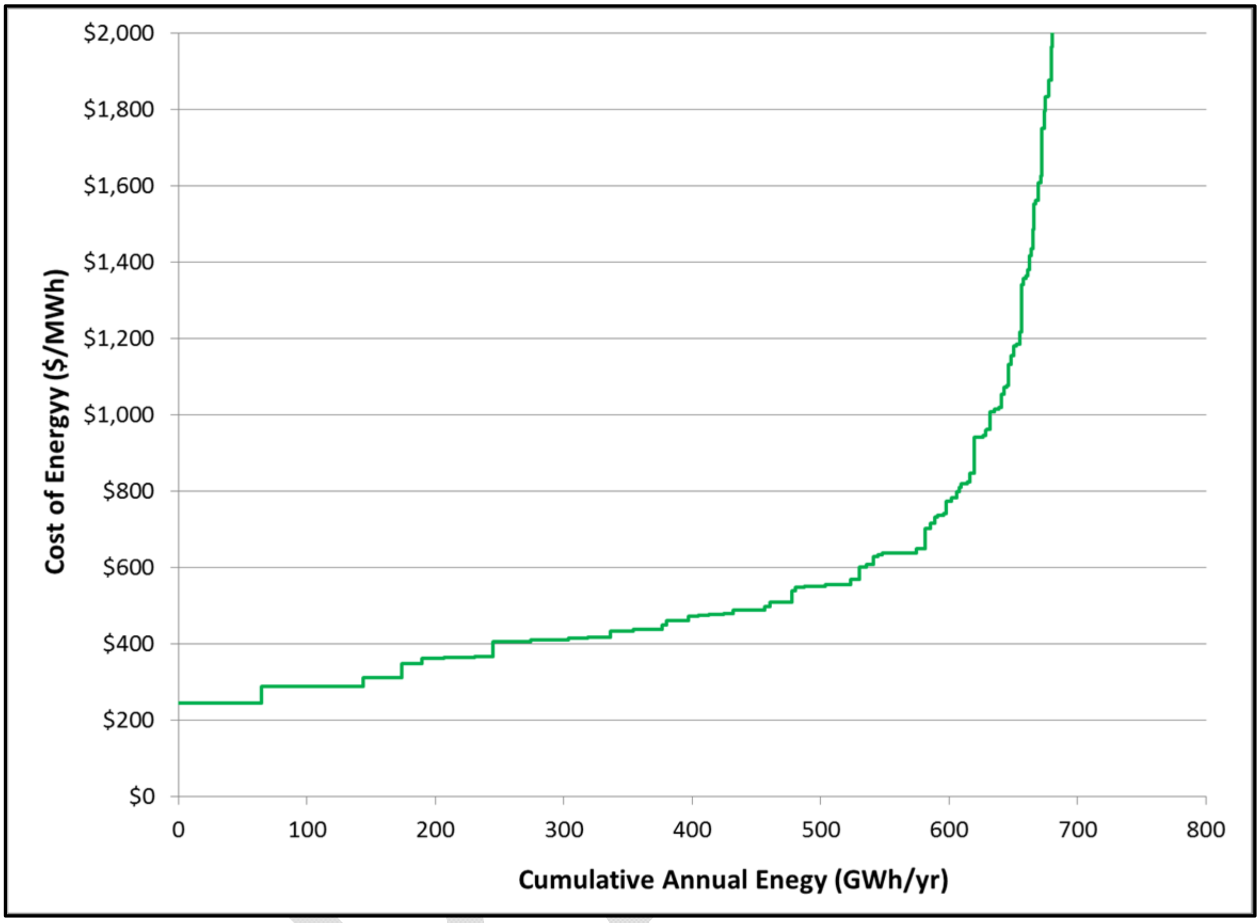


Figure 5.3: Cumulative annual energy for hydropower facilities.

5.3 HYDROPOWER - CONCLUSIONS

Unlike the solar and wind energy facilities, it appears that the most important factor in determining the cost of a hydropower facility is installed capacity (Figure 5.4), with a dramatic increase in costs for facilities below 1 MW. It is likely that this effect is likely to be exacerbated by considering that the cost model has been developed based on 'rule-of-thumb' relationships for medium scale (15-50 MW) hydro facilities in BC. In reality, smaller hydro facilities utilise cost-saving measures that are not captured by the cost model and their estimated cost may be exaggerated. Nevertheless, the effect of transmission cost is notable for smaller facilities and additional analysis would better define this relationship. Future variations of this study would benefit from excluding sites smaller than 1 MW which are further than 5 km from the distribution system, as this study indicates that such sites are unlikely to be viable. The conclusion that the most economically attractive facilities are those with the largest capacity suggests confining the search to larger rivers where a sufficient topographic relief is available. While a few larger rivers exist in the study area, the best locations for hydro facilities on these rivers have already been developed, and the remaining stretches of those rivers do not have sufficient relief to create useful diversion style hydropower facilities.

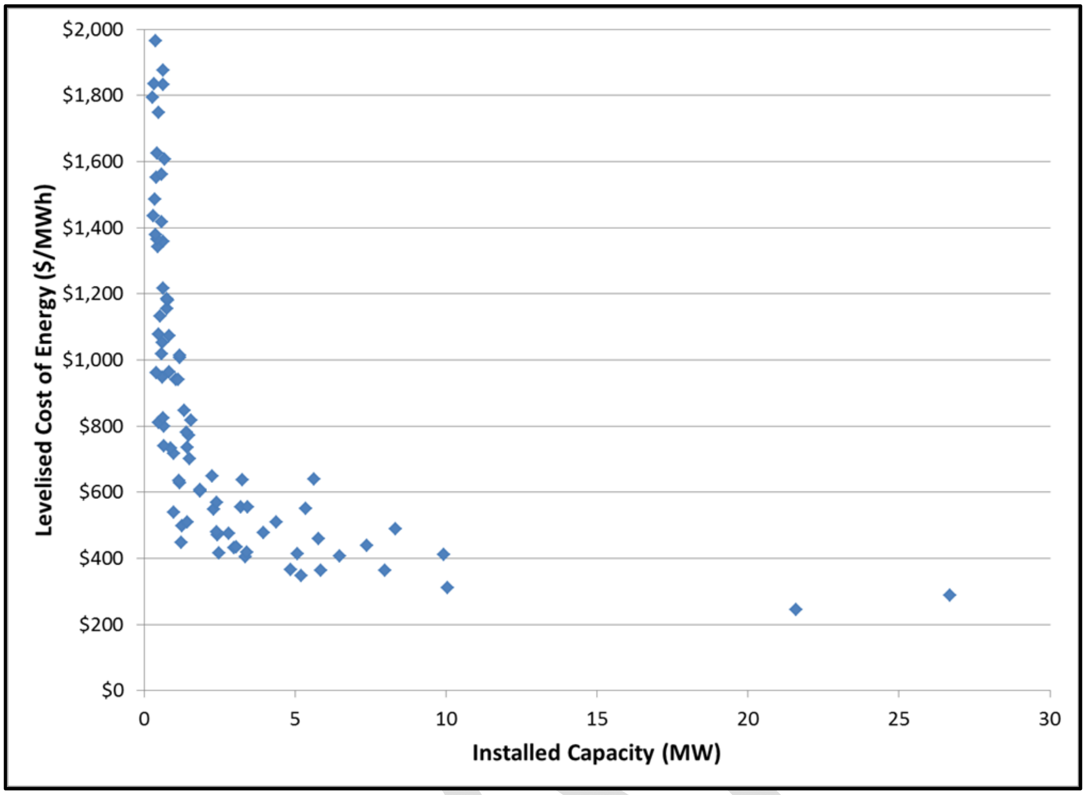


Figure 5.4: Relationship between transmission distance and energy cost for wind facilities.

While this study assumed that all hydropower facilities would be diversion type run of river facilities, it is possible that additional hydropower potential may be identified by also considering low-head barrage style run of river facilities, as well as storage facilities. Such projects have a larger environmental footprint but may be more appropriate to the regions of Alberta with lower topographic relief.

While this study indicates that the hydropower resource is poor compared to the wind and solar resource in the study area, additional potential may be available in other regions of the province. Key targets for further assessment include further north in the Rocky Mountains and foothills (diversion type facilities) or on the larger rivers in the lowland regions (barrage type facilities). Search for potential sites within a certain distance (say 20-30 km) from the Alberta transmission systems, but located within BC (where the topographic relief and hydrological resources are both higher) may also be beneficial.

Additional considerations for future iterations of this study specifically related to hydropower include:

- Improving the fidelity of the hydropower cost model, by breaking down facility components into finer detail and obtaining a range of recent civil construction costs in Alberta.
- Creating alternative construction cost models for different facility sizes, say one for the <1 MW range, one for the 1-10 MW range, and one for the 10 MW range.
- Preparation of alternative construction cost models for different facility configurations, such as diversion style or barrage style facilities.

  Assessment of the energy revenue benefits of alternate hydropower resources, as well as the benefits of potential storage projects that are able to release energy at times of high energy prices.

6 CONCLUSIONS

The combined incremental cost of renewable energy is shown on Figure 6.1. It demonstrates that the most cost effective renewable energy source in the chosen study areas is likely to be wind energy, followed by solar and then hydro. The analysis indicates that the most expensive wind sites are likely be more costly than constructing a similar installed capacity of solar projects, however there are some characteristics of the analysis that will likely not make this hold for the entire province:

- The wind study area (15,000 km^2) was smaller than the solar study area (24,000 km^2) for this pilot study. Random variation means that the best locations will be exhausted more quickly in a smaller region than in a larger one.
- There is a comparatively low density of transmission lines in the south-east of the province where the wind study area is located.

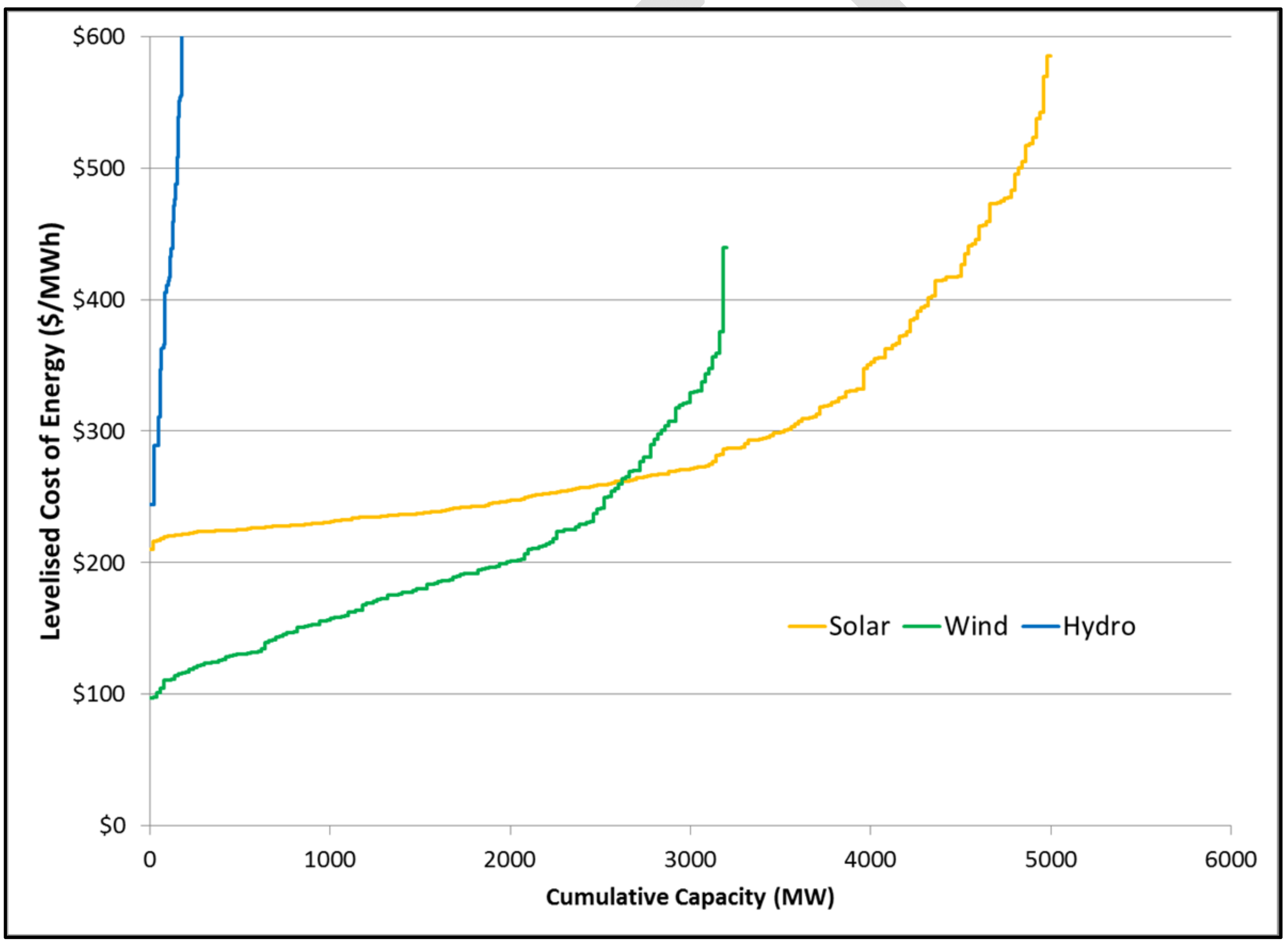


Figure 6.1: Incremental cost of all renewable technologies by capacity.

Comparing the technologies by annual energy (Figure 6.2) presents a different picture. The lower relative capacity factor of the solar energy plants means wind remains competitive against solar for any equivalent annual energy production. Approximately 5,000 GWh of annual wind production appears possible before wind energy becomes more expensive than the least expensive solar facility. Due to the rapid improvement in

PV module costs and efficiencies, this cost gap may reduce in the future. The identified hydropower resource within the assessed study remains uncompetitive with both solar and wind.

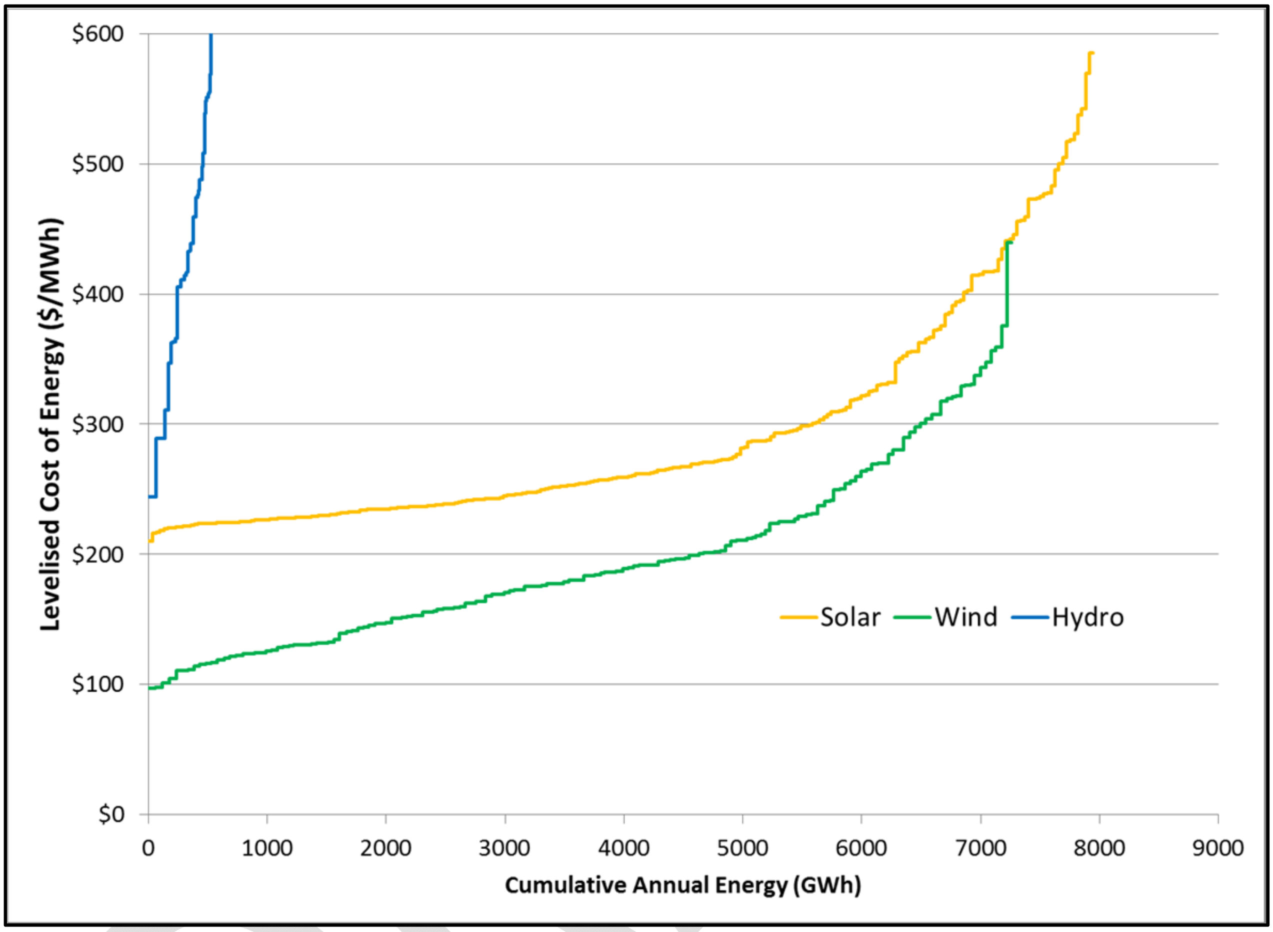


Figure 6.2: Incremental cost of all renewable technologies by annual energy.

There is a relatively poor hydro resource in the study area compared to either wind or solar on both a technical potential capacity and cost of energy basis. However, assessing the variation of hydropower costs and the small sample size for larger (10 MW+) facilities, it is possible that there are hydropower sites in other regions of the province that may be more cost effective than the best solar sites. Despite the hydropower resource being poor on the basis of the current study, this assessment should be extended in an effort to locate these cost-effective hydropower facilities. Furthermore, hydropower facilities may have added benefits if some storage is adopted, as the hydro resource can then be held and dispatched at times of high energy price on the open market. Nevertheless, it is apparent that the total volume of the hydropower resource alone may not be sufficient to fully meet the province's renewable energy goals.

For the individual energy resources, some considerations for improving the methodology for the future, detailed study have already been outlined. The following considerations would apply to all of the facilities:

- A more detailed assessment of the transmission and distribution connection options should be undertaken. This would include breaking down transmission costs by voltage and determining the most cost effective transmission and interconnection option based on the nearest substation(s) and/or transmission lines of various voltages. Interconnection to a lower voltage substation will likely be cheaper, but may require a longer transmission line for some facilities.

- Assessment of social and environmental issues would assist in screening out some otherwise viable sites. Particular considerations worth assessing include land ownership and acquisition constraints and threatened species habitat or other environmental permitting limitations.
- Increased fidelity cost modelling would allow greater certainty regarding the optimum sites and expected energy costs for Alberta specific conditions.
- Assessment of monthly and daily variations in production for various facilities against the Alberta market price may show higher levels of viability for sites that are otherwise less promising if their production can match high energy prices in the market.
- Sensitivity analysis for all key variables including capital cost, financial assumptions and energy production. This should include projected future cost reductions for both wind and solar.
- Future studies should include other potentially promising renewable resources such as biomass (solid, liquid and gas), as well as geothermal electricity resources.

This pilot study has demonstrated the validity of the chosen methods for assessment renewable energy potential in Alberta, as well as identifying some key considerations to improve the fidelity. Enhancing the methodology and expanding to the entire province would provide a good baseline measure of the economic potential of the various renewable energy sources throughout Alberta and may have the following benefits:

- Informing the discussion over the best procurement processes and the likely change in Alberta's renewable energy mix over the coming years.
- Providing a starting point for potential renewable energy developers looking to secure and develop the most promising renewable energy sites.

7 REFERENCES

Alberta Energy. *Electricity Statistics.* n.d. http://www.energy.alberta.ca/electricity/682.asp (accessed April 2016).

Alberta Government. "Climate Leadership Plan Press Release." *Alberta Government.* November 22, 2015. http://www.alberta.ca/release.cfm?xID=38885E74F7B63-A62D-D1D2-E7BCF6A98D616C09 (accessed May 31, 2016).

IRENA. *Renewable Technologies: Cost Analyais Series - Hydropower.* International Renewable Energy Agency, 2012.

NREL. *Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results.* National Renewable Energy Laboratory, 2015.

NREL. *U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial, and Utility-Scale Systems.* National Renewable Energy Laboratory, 2015.

NREL. *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis.* NREL, 2012.

US DoE. *2014 Wind Technologies Market Report.* US Department of Energy, 2015.

US DoE. *Photovoltaic System Pricing Trends.* SunShot - US Department of Energy, 2015.