Technical Feasibility Analysis of Utility-Scale Solar Farm in Southern Alberta

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Abstract

The project investigates the technical feasibility of a utility scale solar farm in Southern Alberta by considering the current energy market mix, climate and weather data, battery storage, and simulation of the PV system design to determine the optimal and most economical set-up. Elements such as transmission infrastructure, integration capacity and electricity demand are explored to establish the upper limit of the facility at 462 MW and 894 GWh. These results are confirmed by the simulation outputs generated by System Advisor Model (SAM), a powerful performance modeling software developed by National Renewable Energy Laboratory (NREL). The values reported in the technical and market analysis are guided by those reported in the Travers Solar Project in Vulcan County, AB. Parameter such as inverter sizing, module selection, string sizing, row spacing and tracking are also discussed. Preliminary economic values for the levelized cost of energy (LCOE) is reported as 7.97 ¢/kWh, and an LCOE of 6.10 ¢/kWh for 2020 estimates.

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Nomenclature

Term	Description
AB	Alberta
AC	Alternating Current
AESO	The Alberta Electric System Operator
AIES	Alberta Interconnected Electric System
AUC	Alberta Utility Commission
CAPEX	Capital Expenditure
CEC	Clean Energy Council
CWEC	Canadian Weather Year for Energy Calculation
DC	Direct Current
GCR	Ground coverage ratio
GHG	Green-house Gas
GWh	Gigawatt hours
LCOE	Levelized cost of energy
MW	Megawatt
MWac	Megawatts in alternating current
MWh	Megawatt hours
NDP	New Democratic Party
NREL	National Renewable Energy Laboratory
NSRBD	National Solar Radiation Database
POA	Plane of Array
PPA	Power Purchase Agreement
PSM	Physical Solar Model
PV	Photo-voltaic
SAM	System Advisor Model
V	Voltage
Wdc	Watts in direct current

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Introduction

The government of Alberta plans to phase out coal powered generation by 2030 in their Climate Change Legislation (2015) to combat the effects of global warming. To meet this objective and transition away from an economy based on oil and gas, the government must implement forms of sustainable energy generation. The primary objective of the research project is to determine the technical feasibility of the development of a solar farm intended to provide utility scale power to communities in Southern Alberta (AB). This task is completed by first conducting an energy market analysis in the province, which is followed by a case study on the proposed Travers Solar project in Vulcan County, and finally, a detailed technical analysis is conducted to determine the optimal photo-voltaic (PV) solar design conditions.

The market and technical analysis alike are guided by the data associated with the 465 MW Travers Project, utilizing approximately 3,330 acres of land in Vulcan Country, AB and expected to be fully operation by Q4 2022 [1]. The project is spearheaded by Greengate power, a leading renewable energy company operating in Calgary, AB with previous experience in the development of multiple renewable projects such as wind power. Further details on the Travers Project may be found in Case Study: Travers Solar Project.

Investigating the feasibility of harnessing renewable resources in Alberta is crucial to reduce dependency on fossil fuels. Furthermore, it is imperative for economic stability to reduce dependency on technologies volatile to commodity price fluctuations. Diversification of Alberta's energy profile is necessary for economic stability and energy sovereignty. The significance of the project can be outlined as: sustainability, stability, and self-sovereignty.

Methodology

Conventional research techniques such as a case study and model simulation programs are used to accomplish the objective of the report. The project will investigate the technical feasibility of a utility scale solar farm in Southern Alberta by investigating parameters such as ideal plant location, market analysis, and energy demand.

Market Analysis

The objective of the market analysis is to qualitatively determine the potential of integrating renewable energy sources such as solar energy into the current provincial mix. In the past, Alberta's electricity generation has traditionally come from fossil fuel and petroleum-based sources. The market analysis includes an investigation into the Albertan energy mix by source and year, an evaluation on the current and forecasted electricity demand, and a review of the provincial regulations and subsidies encouraging the development of solar energy projects. Information will primarily be derived from Alberta Energy Regulator and Alberta Utilities Commission. The primary resource for the analysis will be the 2019-2020 Alberta Annual Energy Report. An in-depth analysis of the Travers Solar Project in Vulcan County will be conducted. The objective of the case study is to assist in determining the upper limit of a utility scale project in southern Alberta and to identify and overcome barriers involved in determining this value.

Technical Analysis

Design considerations for the ideal PV solar module are investigated by exploring various parameters such as weather data, module selection, and inverter sizing. These variables are integrated into the model simulation that outputs the system power generated throughout the year. A literature review is conducted to identify current PV technologies as it is imperative that the technologies which are investigated can handle utility scale and environmental conditions they will be operating within. The System Advisor Model (SAM) software will be used to model the PV and battery system. SAM allows development of performance and financial models for renewable energy systems. It can also model chemical storage technologies. The primary learning resource for the software tool is the “SAM Photovoltaic Model Technical Reference” by Gilman et al. SAM uses Sandia National Laboratories PV Performance Modeling Collaborative’s methodology. The process can be summarized in 5 main steps: weather, DC module, DC array, DC to AC conversion, and AC system output. Detailed information can be found at: https://pvpmc.sandia.gov/modeling-steps/. With that information, a preliminary cost analysis is conducted in order to determine the levelized cost of energy (a measure of the average net present cost of electricity generation for a plant over its lifetime) and capital cost of the project. To supplement the Travors Project case study, the benefits, drawbacks, and obstacles of implementing grid-scale battery storage will be discussed, supported by the case study of a south Australian 100 MW battery storage system.

Market Analysis

Current Energy Market

In Canada, Alberta is the 3rd largest electricity producer and consumes approximately ~30% more electricity than the national average [2]. The high consumption of electricity in Alberta may be attributed to high demand for in Alberta’s industrial sector, which includes the oil sands. In total, Alberta’s industrial sector consumed ~64% of all electricity produced in 2018[2].

In Alberta's fossil fuel sources including coal, natural gas and petroleum are heavily relied upon to produce the electricity Albertans use every day. Therefore, the energy mix for electricity is dominated by fossil fuels [2]. With Alberta's abundance of fossil fuel resources and having an economy strongly dependent on the oil and gas sector, transition to other forms of energy has been slower when compared to other provinces. As such, Alberta's electricity generators produce more greenhouse gas (GHG) emissions when compared to any other province in Canada and accounts for 60% of all GHG emission in Canada for electricity production [2]. This is mainly attributed to having the largest feet of coal fired generation in Canada with 5,555 MW of total capacity [2]. The breakdown of energy sources for the total electricity generation sources for 2018 is illustrated in Figure 7; as shown, ~91% of electricity was derived from fossil fuels sources [3].

Alberta's energy mix is constantly changing with new projects coming online and policies being implemented to diversify electricity sources. Under the Climate leadership Plan (2015) which was implemented by the New Democratic Party (NDP) government, Alberta's energy mix has begun to diversify through the aid of additional programs and policies to support this change [3]. Most notably, the Renewable Electricity Act and the Renewable Electricity Program [3]. The objectives of the Climate Leadership Plan and additional policies / programs relating to electricity generation are summarized in Table 1 below. Implementation of polices have allowed renewable energy sources to enter the sector and increase the amount of electricity they can generate. Data from the Alberta Utility Commission (AUC) has been compiled from 2013 to 2019 to compare the changes in Alberta's energy mix.

Table 1. Applicable regulations and objectives of various policies in Alberta's energy market

Climate Leadership Plan [4]	Renewable Electricity Act [5]	Interim Targets	Renewable Electricity Program [3]
- Implement a price for greenhouse gas emissions. - Eliminate pollution / GHG emissions from coal-fired generated electricity by 2030. - Increase the amount of renewable energy in Alberta.	- The objective is to have 30% of all electricity in Alberta generated from renewable energy sources by 2030.	15% by 2022 20% by 2025 26% by 2028	-The provincial government of Alberta will provide financing for renewable projects. The objective is to install 5,000 MW of renewable electricity by the end of the program lifetime.

In Table 2 below, the net installed capacity from different energy sources in Alberta is tabulated and a visual representation of the data is provided in Figure 11. Since implementing the Climate Leadership Plan, the installed capacity of coal for electricity generation has decreased. To offset the loss of capacity, other energy sources have increase; most notably natural gas and wind from a total increased amount of MW installed capacity. However, it is important to note that the largest change in year over year installed capacity was in solar energy in year 2017; as this was the first year solar was added to Albert's electricity mix. The percentage change year over year for installed capacity is displayed in Table 3. This table displays the slow transition in installed capacity from coal with natural gas and wind increasing slowly. The change in installed capacity displays the gradual shift in Alberta building the energy infrastructure required to phase out coal-fired powerplants.

Table 2. Alberta electricity net installed capacity (MW) by energy source [6]

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	*Others
2013	6,258.30	5,811.20	900.25	1,113.25	416.65	0.00	97.75
2014	6,258.00	6,160.63	900.25	1,458.90	438.33	0.00	97.75
2015	6,266.80	6,952.96	902.20	1,490.80	423.73	0.00	96.75
2016	6,273.00	7,333.35	916.35	1,490.80	423.66	0.00	96.75
2017	6,273.00	7,465.73	917.15	1,473.80	422.16	15.00	135.00
2018	5,723.00	7,516.27	916.40	1,474.40	419.60	15.00	128.10
2019	5,723.00	7,636.43	916.40	1,675.60	420.60	15.00	128.10

* Other sources include oil, diesel, waste heat

Table 3. Year over year percentage change of energy source for installed capacity [7]

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	*Others
2013	9.98%	2.26%	0.04%	0.00%	0.69%	0.00%	0.00%
2014	0.00%	6.01%	0.00%	31.05%	5.20%	0.00%	0.00%
2015	0.14%	12.86%	0.22%	2.19%	-3.33%	0.00%	-1.02%
2016	0.10%	5.47%	1.57%	0.00%	-0.02%	0.00%	0.00%
2017	0.00%	1.81%	0.09%	-1.14%	-0.35%	1500.00%	39.53%
2018	-8.77%	0.68%	-0.08%	0.04%	-0.61%	0.00%	-5.11%
2019	0.00%	1.60%	0.00%	13.65%	0.24%	0.00%	0.00%

* Others include oil, diesel, waste heat

Due to the intermittency of renewable energy sources like wind and solar the actual generation of electricity can greatly vary. Thus, it is also important to look at actual electricity generation produced from each source. In Table 4, the electricity generation in GWh is displayed for each energy source in Alberta for years 2013 to 2019. For graphical representation of the data, see Appendix A: Market Analysis. The same trend as discussed for installed capacity is apparent in electricity generation. The year over year percentage for electricity generation by source is displayed in Table 5. This table displays which energy source has been growing compared to the previous year. Coal has been decreasing in generation while natural gas, hydro has been increasing steadily. Wind has held steady since 2016, while solar had a large jump in generation change once capacity was added to the Alberta grid.

Table 4. Alberta electricity generation (GWh) by energy source [6]

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	*Others
2013	39,186.4	29,028.3	2,027.8	3,107.4	2,250.1	0.0	404.7
2014	44,442.0	28,136.2	1,861.1	3,471.3	2,065.2	0.0	372.6
2015	41,378.1	32,215.4	1,745.0	3,815.6	2,148.5	0.0	318.1
2016	42,226.9	33,183.7	1,773.0	4,407.5	2,201.2	0.0	339.7
2017	39,323.7	36,821.8	1,937.8	4,406.7	2,062.0	0.1	269.4
2018	30,692.5	44,390.9	1,893.9	4,196.6	2,033.4	22.4	386.0
2019	29,499.7	46,810.8	2,026.7	4,180.4	2,049.8	20.3	303.3

* Others include oil, diesel, waste heat

Table 5: Percentage change of energy source for generation

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	*Others
2013	2.39%	6.57%	-12.55%	17.68%	7.70%	0.00%	12.59%
2014	13.41%	-3.07%	-8.22%	11.71%	-8.22%	0.00%	-7.93%
2015	-6.89%	14.50%	-6.24%	9.92%	4.04%	0.00%	-14.64%
2016	2.05%	3.01%	1.60%	15.51%	2.45%	0.00%	6.80%
2017	-6.88%	10.96%	9.29%	-0.02%	-6.32%	10.00%	-20.70%
2018	-21.95%	20.56%	-2.26%	-4.77%	-1.39%	223%	43.30%
2019	-3.89%	5.45%	7.01%	-0.38%	0.81%	-9.34%	-21.43%

* Others include oil, diesel, waste heat

Current and Future Electricity Demand

In 2019, Alberta had 16,515 MW of installed capacity [7]. The break down form each source is displayed in Table 6 and Figure 1. Alberta's energy mix is predominantly based on fossil fuel sources like natural gas and coal. However, renewable energy capacity has increased by 7.16% compared to the installed capacity in 2018.

Table 6. Alberta electricity net installed capacity (MW) by energy source in 2019 [7]

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	*Others
2019	5,723	7,636	916	1,676	421	15	128
Percentage of Alberta Capacity	35%	46%	6%	10%	3%	0.09%	0.78%

* Others include oil, diesel, waste heat

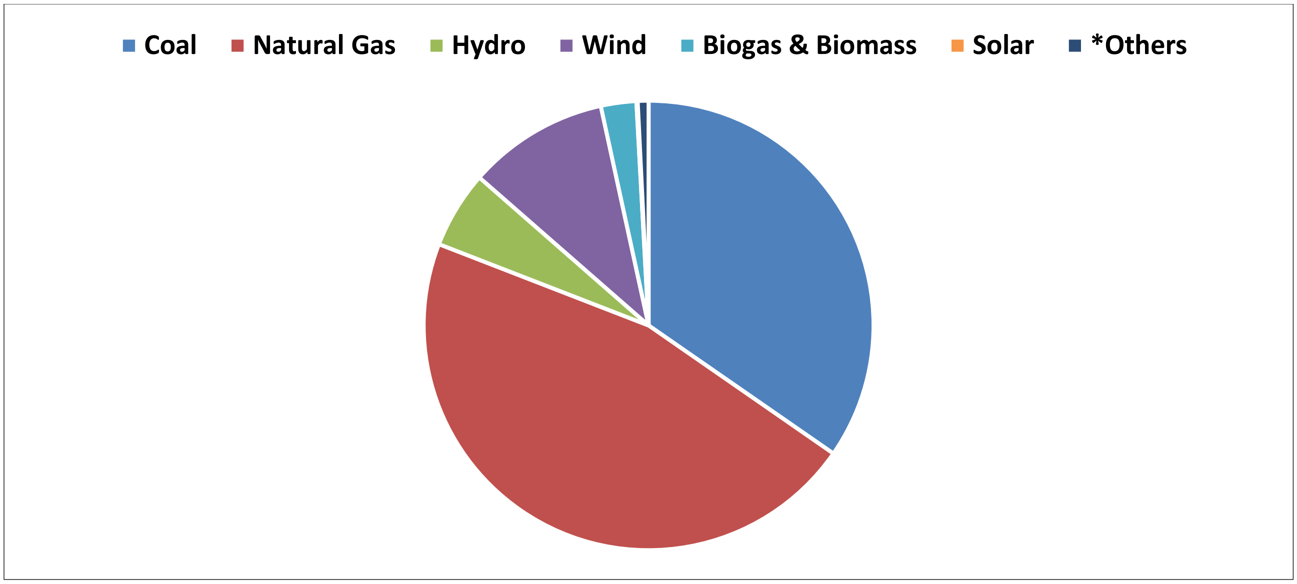

Figure 1. Installed capacity in Alberta by source of energy in 2019 (MW). Majority of production is from fossil fuel sources such as natural gas and coal.

Table 7 and Figure 2 illustrate the electricity generated in Alberta from a variety of different energy sources in 2019. Alberta produced 89,842 GWh of electricity in 2019 [6], an increase of 1.11% when compared to 2018 generation data. The AUC forecast electricity demand to continue to grow at an annual compounded growth rate of 0.9% through 2039 [7]. This is ~50% slower than the growth which has been seen in previous years in Alberta. Although capacity from renewable energy sources increased 7.16% from 2018 to 2019 the total generation from renewables only increased by 0.12%. The incremental increase in generation can be attributed to intermittency of wind and solar. For instance, higher winds occur during the night when demand for electricity is low and solar is most predominate doing the afternoon when electricity demand is also low. Battery storage may play a vital role in solving this issue and is discussed further in Battery Analysis.

Table 7. Alberta electricity generation (GWh) by energy source in 2019 [7]

Year	Coal	Natural Gas	Hydro	Wind	Biogas & Biomass	Solar	*Others
2019	34,451	46,811	2,027	4,180	2,050	20	303
Percentage of Alberta Capacity	38%	52%	2%	5%	2%	0.02%	0.34%

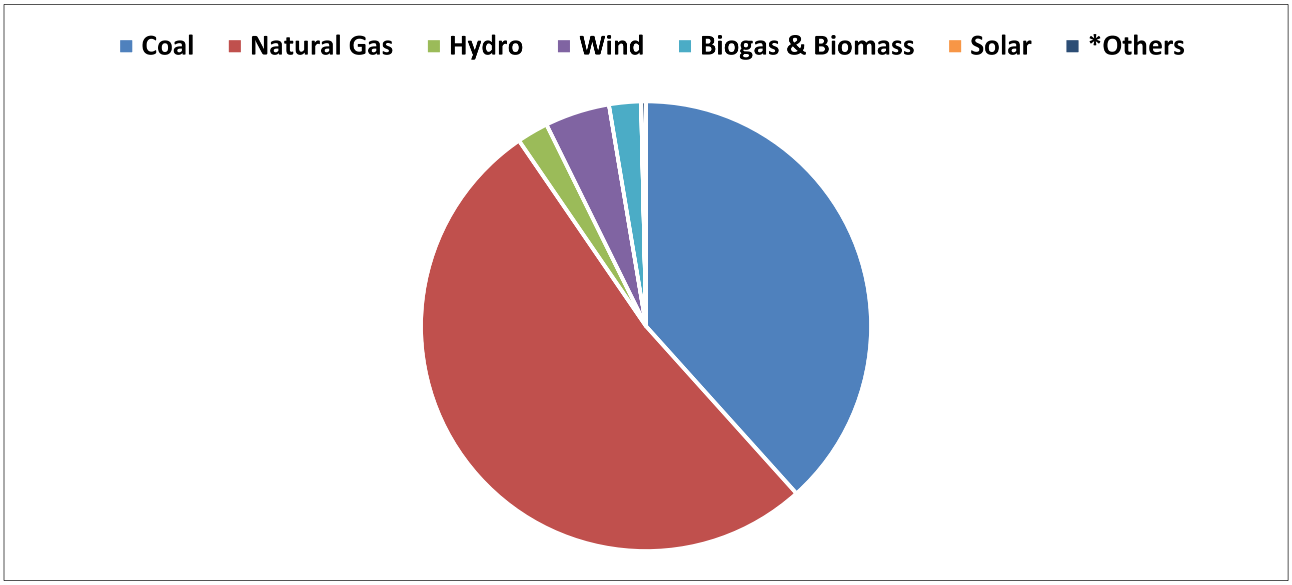

Figure 2. Provincial breakdown of energy source for electricity generation (GWh)

The Alberta Electric System Operator (AESO) has forecasted the peak electricity demand for winter and summer to 2038 based upon the 2017 and 2019 peak loads. The forecasts show a gradual linear increase in demand for electricity, provided in Figure 8 and Figure 9 in the appendices. AESO has also provided a forecast on how the energy mix in Alberta will look like in future years in Figure 3. In the upcoming years, the AESO is expecting that there will be approximately 13 GW of generation capacity will be added by 2039 [8]. Furthermore, the AESO forecast that by 2030, 25% of electricity will come from renewables. By 2039, solar energy is expected to make up 2% of all electricity in Alberta. This forecast displays that these is significant growth in solar as it currently <1% (0.02%).

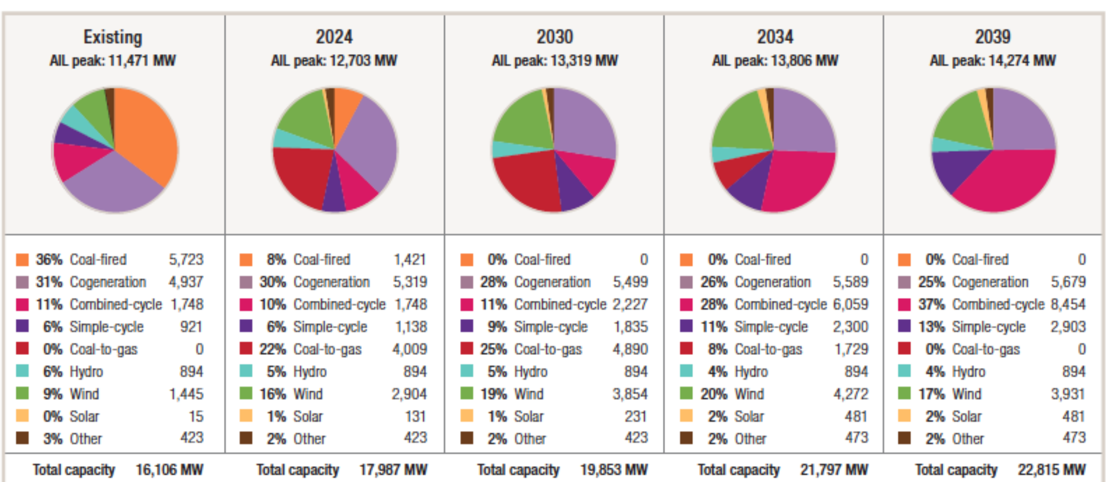

Figure 3. Total peak capacity (MW) in Alberta from various energy sources

Alberta's energy mix is going through a transition. Historically, Alberta has had electricity mainly coming from coal fired generation. However, with the implementation of the Climate Leadership Plan and supporting programs; the energy mix in Alberta has slowly began to shift towards cleaner sources to fill the current demand and future growth. Renewables sources have an opportunity to fill the capacity and generation loss from phasing out coal, with wind and solar projected to increase. Between 2018 and 2019 renewable energy sources increased by 7.16%; however, generation from these sources have only gradually increase by 0.12% in that same timeframe.

Case Study: Travers Solar Project

Greengate Power Corporation (Greengate) is currently constructing the Travers Solar Project which is a 465 MW utility solar plant; located 8 km SW of the Village of Lomond, in Vulcan County [9]. The project will use approximately 4,700 acres of land, where ~2,500,000 bifacial solar PV modules and 153 inverter/transformer stations will be installed and connect to substation which will then connect to the Alberta Interconnected Electric System (AIES) [9][10]. The land use of the project is shown in Figure 15 and Figure 16, found in Appendix A: Market Analysis. The PV modules will use a single-axis tracking system and be mounted with driven steel piles or screw piles. The project is estimated to have a 35-year life expectancy [9]. It is estimated that the project capital expenditure (CAPEX) is $520 million with an additional annual land lease cost of $2.82 million. The Travers Solar Project will also have to absorb the costs to have it connected to the nearby transmission line (represented by the red line in Figure 14). With its advantageous position to this nearby transmission line, the project will only need 40 m new of transmission lines installed; however, it is still estimated to cost ~3.2 million dollars [14]. The Travers Solar Project was used as a gauge because it is currently the largest solar project being built in Canada and is being completed without any government subsidies.

Table 8. Project Summary Economics [11][12][15]

Capacity	465 MW
Land Lease Area	4,700 acres
Number of PV Modules	2,500,000
inverter/transformers	153
CAPEX	$520 M
Annual land lease	$2.80 M
Project Life	35 years

Feasibility

Alberta currently has 11 solar projects under construction, which will add ~999MW of capacity [13]. Furthermore, an additional 8 projects are currently working though the regulatory process and or awaiting approval [14][15]. The projects and costs are supplied in table 8. In Figure 4, the capital costs for proposed, under construction and completed projects have been plotted as a function of their capacity. The costs have been forecasted out, to predict the capital costs required of larger capacity projects. Our proposed project in red, follows this general trend; however, being above the trend this project would be at a premium.

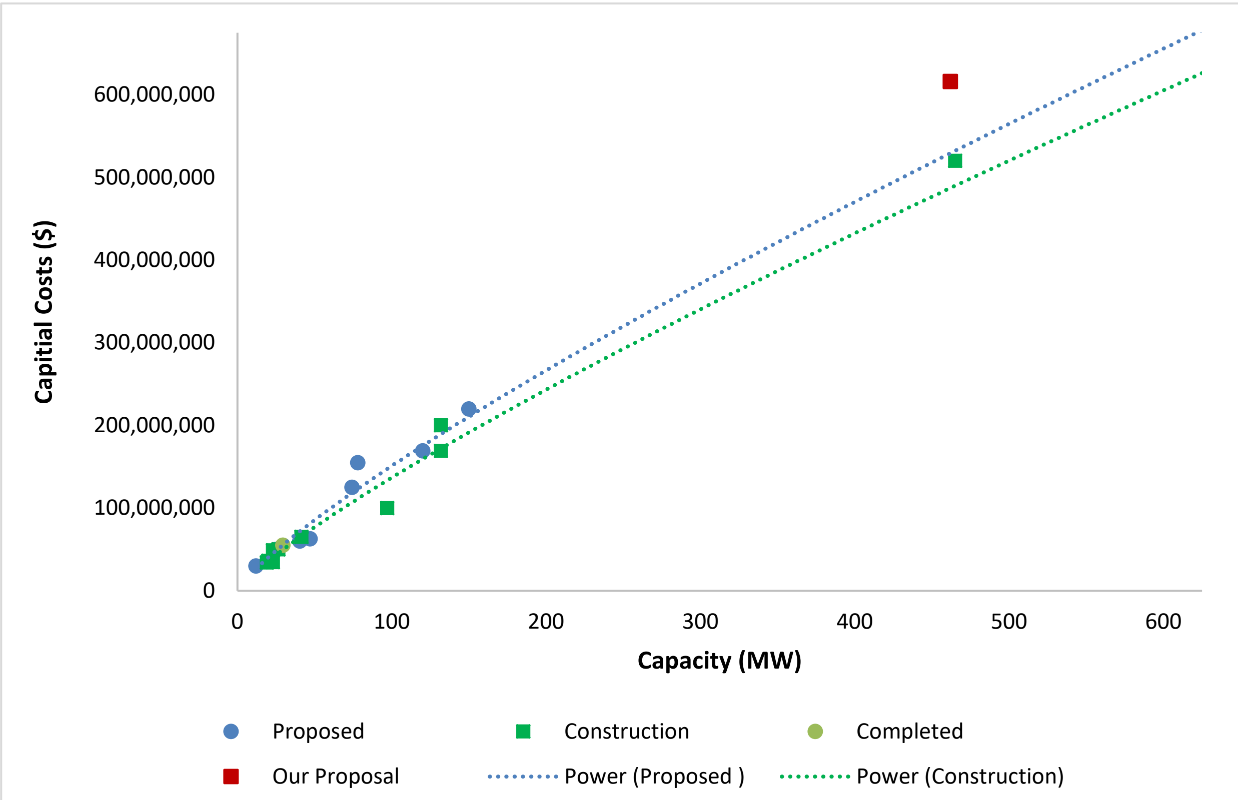

Figure 4. Changes in the capital cost of proposed, constructed, and completed projects at varying plant operating capacities (MW)

In addition to cost, location plays a vital role for solar projects. Alberta's solar irradiance is strongest in Southern Alberta. This is depicted in Figure 12, where irradiance is strongest south of Brooks and between Fort Macleod and Medicine Hat. Although irradiance is an important factor, other location sensitives must be considered, which are listed here as follows: (i) operation must not be within the Solar Exclusion Area in Alberta as displayed as they grey lines in Figure 13**,** (ii) proximity to existing transmission infrastructure operating at the 240kv, a simplified picture of the existing transmission lines for the Southern Alberta Region is displayed in Figure 5 and Figure 14 (the Travers Solar project was able to take advantage of this in their design), and (iii) the system must have integration capability to accept new generation without negatively affecting or constraining the current system [14][15][16][17].

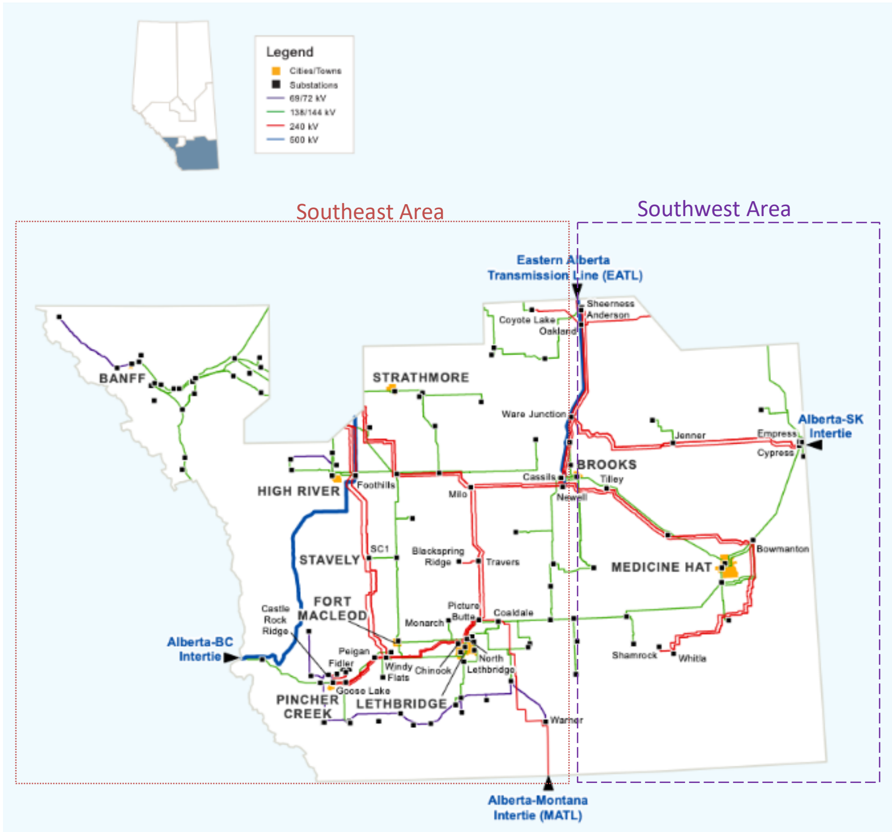

Figure 5. Transmission lines to major towns and municipalities in southern Alberta

AESO has determined that there is currently 470 MW of integration capability in the Southern Alberta Region. It is important to note, that the AESO did not indicate what source could / should be installed; instead, just listed a general nameplate value. Even if the AESO indicated that this capacity should be filled by renewables, the type / source should be stated, as different renewables will have different characteristics. For instance, adding a small-scale hydro project would generate electricity more consistency and not suffer from intermittency like solar. This additional capacity is split between the southwest and southeast areas with 340MW and 130MW respectively [18]. However, if further capacity above this level is installed, then the overall system capability is reduced.

With strong solar irradiance, integration capability that is projected to increase as coal-fired generators feeding this area phase out (790MW) and a strong existing network of transmission infrastructure, another utility scale solar project may be a viable option in Southern Alberta [19]. Further costs savings measures could be implemented in the estimate which would bring our proposed project in line with the forecasted costs in Figure 4. In conclusion, the maximum capacity of the project may require further investigation, as it will depend on integration capability available which is re-iterated in the conclusions and future work.

Technical Analysis

Project Location

As discussed in the market analysis, Southern Alberta has the largest solar resource in all of Canada. The weather file utilized is from National Solar Resource Database (NSRBD - ID 273639) from the year 2019. The coordinates for the location are (50.25, -112.74) [20]. The location is Vulcan County which falls between Calgary, Lethbridge, and Medicine Hat. The relevant annual averages calculated from the weather file are as follows: global horizonal solar irradiation is 3.66 kWh/m^2/day, direct normal is 4.57 kWh/m^2/day, diffuse horizontal is 1.31 kWh/m^2/day, average temperature is 4.8^{o}C and average windspeed is 2.8 m/s. It must be noted that the simulation utilizes hourly values for the given parameters and not the yearly averages.

A global irradiance heat map over the year is visualized in Figure 17. As expected, hotspots are concentrated around noon primarily in the summer seasons. Beam, diffuse and global irradiations are graphed in Figure 18. Beam irradiance constantly peaks at 1000 W/m^2 across the entire year but diffuse and global irradiance oscillates between valleys during the winters and troughs during summers. Hourly dry bulb temperatures are also presented in Figure 19. As evident, the summer seasons the temperature can peak at low 30^{o}C and in the summers can fall as low as -27^{o}C. Snow data was not available for download.

A proxy is used to derive sun path information; Calgary's sun path was used to estimate constraints for the tilt and azimuth angle optimization displayed in Figure 20. From the aforementioned data, the constrains for the array tilt would be 15° to 60° and the constraints for the azimuth would be 120° to 240°. These were the ranges used in the SAM parametric study to optimize tilt and azimuth angle. A heat map visualization of the tilt angle and the azimuth angle are presented in Figure 21 and Figure 22 respectively.

System Modeling

Module Selection

Most of the design decisions were informed from the Traver's Solar Project. As discussed in Case Study: Travers Solar Project, the system has 2.5 million modules. With a nameplate capacity of 465MWac and a DC/AC ratio of 1.25 - reverse calculations reveal that the module would have a maximum power of 232 Wdc. The module is selected from the Clean Energy Council's (CEC) approved PV cells database. The closest module discovered was one manufactured by Prism Solar Technologies Inc. the model is B235 with a maximum power of 229.15 Wdc. The module is a Mono-c-Si type with an area of 1.62 m^2, contains 60 cells/module and has a nominal efficiency of 14%.

The module is bi-facial as is the Traver's Project. Additional module specifications are displayed in Figure 23.

Inverter Sizing

Similar to the module selection, invertor selection was reverse calculated. The Traver's Project has 153 inverters for their system. Following suit, a nameplate capacity of 465MWac reveals that each invertor is sized 3.04 MWac. The closest invertor in the CEC database is the Power Electronics: FS2800CU15 [645V]. It has a maximum AC power rating of 3.025 MWac and a CEC weighted efficiency of 97.915%. The inverter as an input voltage range of 913-1200 Vdc. Remaining details can be found in Figure 24. Due to the limitation of the software at its current state, a multiple power point tracking cannot be programmed for the inverter. A single power point tracking could be a reasonable assumption for this study as all the arrays have the similar orientation but practical in real life. This reveals an DC/AC ratio of 1.26 for the system at hand – a 581 MWdc capacity and a 462MWac capacity. The inverter clipping losses will be discussed in System Losses.

System Design

The string design is constrained by the inverter input voltage. As previously discussed, the invertor input voltage range is 913 – 1200 Vdc. The module has an open circuit voltage of 37.8Vdc, this means that the maximum number of modules per string can be 31, resulting in a string open circuit voltage of 1172 Vdc. There are 2,535,800 modules in the system, this would resolve in 81,800 number of strings. Currently the software is limited in allowing maximum of 4 sub-arrays, this would force each array to contain 20,450 strings in parallel and a 633,950 number of modules per sub-array.

The ground coverage ratio (GCR) is set at 0.25 ratio for a single axis system. GCR is a useful parameter that helps calculate self-shading losses, if back tracking would be useful for the system, the total land area requirements, and row spacings. The single axis system has a landscape module orientation with 2 rows and 25 columns. This results in 12679 number of rows with a spacing of 7.83m between them. The total module area is 4,133,354 m^2 and the total land area is 16,533,027m^2, comparable to 16,140,000m^2 for the Trevor's Project.

Tracker System or Tilt Optimization

The main design uses a single-axis tracker system. Secondary studies for fixed-axis and dual-axis tracking are also performed. For the single axis case, thee azimuth angle is fixed, and the tilt angle is free to move within a range of 50°. A parametric study revealed little to no benefit in varying the azimuth angle between 150° to 210°. The half-way point was selected at 180°. Traver's Project utilizes a single tracking system. Utilization of a single axis tracking also allows for “dumping” of the snow which reduces losses.

Financial Parameters

Cost and financial were informed by the U.S. Solar Photovoltaic System Cost Benchmark published in Q1 2018 [33]. The report states that an average installation cost of a single-axis tracker in 2018 was $1.13/W. An average installation cost for a fixed axis was $1.06/W. The fixed operating costs are $14/kW. Data extracted from the benchmark report is presented in Table 13. The analysis period for the financial model is set at 35 years as that is the lifetime of the Trevor’s Project. The effective tax rate is set at 32% as advised from Canada Energy Regulator – Economics of Solar Projects [22].

Results

The simulation outputs an annual energy (year 1) of 894 GWh, capacity factor of 17.6%, energy yield of 1,509 kWh/kW and performance ratio of 0.81. A graph of monthly energy production is presented in Figure 24 and Figure 26. As expected, the production peaks at 1.23 x10^8 kWh in June and falls to 2.42x10^7 kWh in December. The levelized cost of energy is revealed to be 7.97¢/kWh. The Capital cost is $656,619,968 and the fixed operating costs are $11,795,916.

System Losses

There are several losses modeled for the system, some of which are assumed, and others calculated. For example, soiling, snow, module mismatch, AC, DC losses are assumed whereas shading, reflection, module STC, inverter power consumption, inverter power clipping, inverter efficiency, are calculated. As presented in Figure 6, major losses include module deviation from STC at 5.7%, soiling at 5%, shading losses of 2.2% and inverter clipping losses of 0.1%. The system receives 7,687 GWh (plane of array irradiance) energy which reduces to 893 GWh of electricity after accounting for all the losses. A Sankey diagram effectively tells the story and is presented in Figure 27 in Appendix B. A 0.1% inverter clipping loss at DC/AC of 1.26 might indicate that there may be more room to optimize the inverter size. An hourly graph of energy generated is compared with the hourly inverter clipping losses. As evident, and perhaps as expected, clipping losses on exist during the summer months. This accumulates to 1,029 MWh of losses per year. Note: the system generated energy periodically bleeds below zero into the negative section of the graph, this is due to the nighttime inverter energy consumption. The bifacial module produces a 6.6% increase in received solar energy. A detailed cost-benefit analysis could prove this to be a profitable decision.

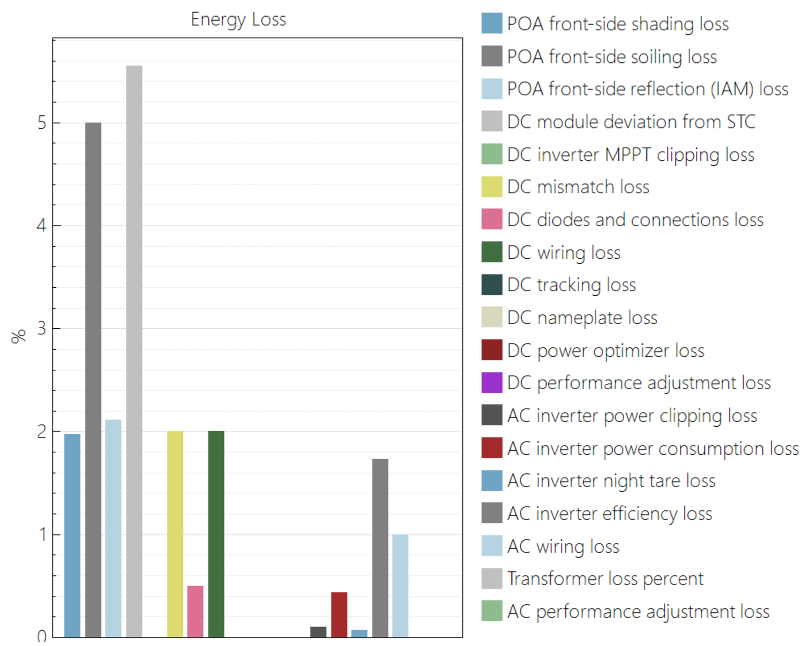

Figure 6. Energy losses throughout the system

A solar resource comparative study is performed between data extracted from Calgary, Medicine Hat, Lethbridge weather station and NSRBD stations. NSRBD is the US National Solar Radiation Database. The database uses a Physical Solar Model (PSM) which is a physics-based modeling approach that provides solar radiation data using geostationary satellites. It has a temporal resolution of 30mins and special resolution of 4x4km. The remaining location uses Canadian Weather Year for Energy Calculation (CWEC) datasets provided by Government of Canada. The purpose of this study is to test the sensitivity of results based on data from nearby locations. The location of the simulated system is in between Calgary, Lethbridge, and Medicine Hat. The results are tabulated as displayed in Table 9. The capacity factor varies from 20.6% from Lethbridge to 17.6 % from Physical Solar Model estimation of Vulcan County. The results seem to indicate a significant underestimation of solar resource. It could be concluded that, once built, the system might experience a larger energy yield, perhaps around 1,700 kWh/kW.

Table 9. Analysis between solar resource sensitivity. Vulcan County Location (273639 NSRBD) is selected for the simulation.

Single-Axis-Bifacial	Vulcan County	Calgary	Lethbridge	Medicine Hat
Site ID	273639 (NSRBD)	C718770 (CWEC)	712430 (CWEC)	718720 (CWEC)
Average Annual Global Horizonal Irradiance (kWh/M^2/day)	3.66	3.79	4.06	3.97
Energy Yield (kWh/kW)	1,538	1,731	1,804	1,759
Capacity Factor (%)	17.6	19.8	20.6	20.1
LCOE (¢/kWh)	7.97	7.08	6.80	6.97

A comparative study between fixed, single axis, and dual axis tracker system is also performed. There are three main differences in the inputs between the tracking system: ground coverage ratio (GCR), capital costs, and fixed operating costs. The GCR for fixed axis is 0.3, for single axis is 0.25, and for dual axis is 0.20. Kiewit suggests a 20% increase in area for implementing a tracker system as a rule of thumb [23]. They also mention that dual-tracking system rarely ever prove economically, as they increase land requirements and increase capital and operating costs. Instead it is preferred to employ more efficient modules. Kiewit also claims that a 15-20% increased overall system costs for tracking system when compared to a fixed tilt system of the same size. Although useful values could be found U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018 for fixed-tilt and single axis system, cost information on the dual axis systems were not available. Therefore, Kiewit's rule of thumb for increased land area and increases costs are used. The capital cost for a fixed axis is reported at $1,060/kW from the benchmark report, and operating costs are $13/kW. The capital costs for the single axis is, from the benchmark report is $1,130/kW and operating costs are $14/kW. The capital costs for the dual axis, from Kiewit rule of thumb is $1,356/kW and operating cost is $16/kW. The land is assumed to be leased, a reverse calculation from the Trevor's Project reveals that the per annum lease cost of the land is $0.17/m^2. The fixed axis requires 13,777,523 m^2 of land, the single axis requires 16,533,027 m^2 land and the dual axis requires 20,666,486 m^2 of land – this amounts to an additional operating cost per annum of $5.21/kW, $6.25/kW, $7.82/kW respectively.

It must be noted, that the LCOE financial selected in SAM as it only performs basic cost calculation using the fixed charge rate (FCR) method. The recommended financial model for a utility scale plant is a Power Purchase Agreement (PPA). Utilization of the PPA model is avoided due time constraints and the model's sheer complexity. The limitation in the LCOE model is that it requires a dollar per kilowatt capital cost value. This neglects the increase in land used by decreasing the GCR to accommodate for tracing systems. This has been remedied with annual lease cost per kilowatt for the land and added to the operating expense. An expert analysis should be performed with a PPA financial model.

The results of the comparative can be summarized in Table 10. The relevant inputs and outputs are tabulated. The fixed-tilt system reveals a capacity factor of 15.9% with a LCOE of 8.01 ¢/kWh, proving to be the most expensive system. The second cheapest is the single axis system with a capacity factor of 17.6% and LCOE of 7.97 ¢/kWh. The optimal system, according to the comparative study, is the dual-axis system with an increased capacity factor of 21.5% and a LCOE of 7.78 ¢/kWh. The study produces an unexpected outcome. Despite accounting for increased capital, operating and land costs, dual axis proves to be the most profitable system. Industry insight, including Kiewit's insight for fixed axis versus tracking system, predicts that a dual axis system is usually not profitable. This unexpected outcome is studied; two hypotheses are proposed, one of which is and the is assumed to most likely the case and the other ultimately rejected with further analysis. The first hypothesis is financial argument and the second offers technical insight. Another hypothesis is offered but not discussed. That is the dual-axis system really is profitable for the given case.

Table 10. Analysis between the tracking systems. Relevant inputs and outputs are tabulated

	Parameter	Fixed-Tilt	Single-Axis	Dual-Axis
Inputs	GCR	0.3	0.25	0.20
	Capital Cost ($/kW)	1,060	1,130	1,356
	Operating and Maintenance Cost ($/kW)	13	14	16
	Land Lease cost ($/kW)	5.21	6.25	7.82
	Total Operating Cost, Annual ($/kW)	18.2	20.3	23.8
Outputs	Capacity Factor (%)	15.9	17.6	21.5
	Energy Generated (GWh)	809	894	1,094
	(POA)Front-side irradiance (kWh/yr)	6.91e+09	7.69e+09	6.89e+09
	(POA)Bifacial Gain (kWh/yr)	6.05e+08	4.60e+08	7.26e+08
	LCOE (¢/kWh)	8.01	7.97	7.78

The first obvious hypothesis to explain the outcome where a dual axis system is more profitable is that the capital cost and annual operating costs are underestimated despite adding a hefty premium compared to fixed-tilt system (28% for capital cost, 23% for operating and maintenance costs, 50% for land lease cost). Land lease cost are most likely to be correct as they are informed by Travers Project. This seems to be the correct explanation as they the inputs were predicated on rules of thumbs, unlike the fixed-tilt and the single axis inputs which uses the NERL Benchmark Report.

The second hypothesis goes as follows: the decreased GCR increases the bifacial gain, which in turn proves the dual-axis system to become more profitable than is common. The increasing bifacial gain is supported by research conducted by Pelaez et al., demonstrating that decreasing the GCR (increasing row spacing) increases the bifacial gain [24]. This occurs as there is more open space for the light to reflect into the rear side of the module. Figure 28 extracted from the paper shows the behavior of bifacial gain for two solar systems in the US is as attached in Appendix B: Technical Analysis. This hypothesis cannot be rejected or accepted right now as comparing the decreasing GCR reveals unexpected change to the bifacial gain. As Figure 28 demonstrates, a 0.3 GCR produces a 6.05e08 kWh/yr gain, a 0.25 GCR produces a 4.60E08 kWh/yr gain, yet a 0.2 GCR produces a 7.26E08 kWh/yr gain. Please note that these gains represent an increase in Plane of Array (POA) Irradiance and *not* the gain in system energy generated, which will be discussed later. The outcome is unexpected: bifacial gain is increases in the case of the dual-axis but decreased in the case of single-axis system. This hypothesis requires further study as the Pelaez et al. have tracking system as a controlled variable in their research. Our comparative study does not control for the tracking system. An explanation offered to explain why bifacial gain is not increasing with decreased GCR is that as the tracking system reorient the module to harness the maximum direct beam irradiance and therefore there is less of that direct beam to reflect off the ground and be received by the rear of the panels. However, this is not the case for the dual axis, which increases in bifacial gain, so the explanation may be taken with skepticism.

As the utility of the bi-facial module and its role in proving the dual-axis system came under question in the discussion above, another study is performed to ascertain the *net* benefit of bifacial module to each system. This time the independent variable in the study is bifaciality of the module. Table 11 provides a side-by-side comparison of the benefit of the bifacial module. As it is evident all system benefits from the upgrade. Fixed tilt increases its capacity factor by 0.9% and reduces the LCOE by 0.47 ¢/kWh. Single axis increases its capacity factor by 0.8% and reduces the LCOE by 0.51 ¢/kWh. Dual axis increases the capacity factor by 0.9% and reduces the LCOE by 0.35 ¢/kWh.

Table 11. Analysis between bifaciality of the modules.

	Parameter	With Bifacial Module	Without Bifacial Module
Fixed Tilt	Capacity Factor (%)	15.9	15.0
	Energy Generated (GWh)	809	764
	LCOE (¢/kWh)	8.01	8.48
Single Axis	Capacity Factor (%)	17.6	16.9
	Energy Generated (GWh)	894	858
	LCOE (¢/kWh)	7.79	8.30
Dual Axis	Capacity Factor (%)	21.5	20.6
	Energy Generated (GWh)	1,094	1,047
	LCOE (¢/kWh)	7.78	8.13

This comparative study allows the acceptance or rejection of the second hypothesis. The hypothesis that “the decreased GCR increases the bifacial gain, which in turn proves the dual-axis system to become more profitable than is common” is false. As evident from the analysis above, the dual axis system accrues the least benefit from the bificaility of the module. In other words, the bifacial module does not make the dual-axis system more profitable than the others. To conclude the analysis in the complication of understanding the unexpected profitability of the dual-axis system, an explanation is offered. There are three conflicting forces of profitability at play for the given scenario: the first is that decreasing the GCR increases the *rear* Plane of Array (POA) Irradiance and thus increases the energy output, the second is that decreasing the GCR increases the Land Lease costs, the third is that increasing the degree of freedom for the tracking system reduces the diffused irradiance for the bifacial modules. Further expert technical and financial analysis will have to parse out the real reason for the unexpected profitability of the dual-axis system.

There are few deficiencies in the cost analysis that must be stated. Although the deficiency does not complicate the discussion above as the nature of error about to be discussed is systematic. In other words, even if this error were resolved the results of the analysis above would be the same in proportion and the conclusions would be the same. The first is the values for the cost analysis are extracted from a 2018 NERL Benchmark Report. The cost reduction from year 2010 to 2018 has been around 80%. Therefore, cost reduction is to be expected for the year 2020. The LCOE for the simulated 462MWac single-axis system is 7.79 ¢/kWh. The projected LCOE for the year 2020 is 6.10 ¢/kWh. The reason for the increased LCOE is the use of 2018 benchmark values, utilization of 2020 cost values may produce a LCOE near 6.10 ¢/kWh. The second deficiency is a matter of factoring the effect of economies of scale. The utilized 2018 benchmark values were informed by a 100MW single-axis solar system. The system simulated is 462MWac. Attached in Appendix B: Technical Analysis, Figure 29 presents the impact of economies of scale, from doubling a 50MW system to 100MW, experiencing a cost reduction from $1.21/W to $1.13 W. Economies of scale is not factored into the cost analysis therefore neglecting benefits from bulk purchasing, labor costs, engineering, procurement, construction overheads and developer costs. These two reasons could explain the 1.69 ¢/kWh increase LCOE when compared to projected 2020 LCOE.

Battery Analysis

Feasibility

A battery storage is a technology that enables energy storage for later use. Batteries power devices and it has been widely used in society through cars, remote controls etc. However, energy storage is a demanding and an emerging technology as there are more needs for bigger and more versatile battery storage. Battery storage offers flexibles, unlocks new business value across the entire energy market. This section will explore the feasibility of a grid-scale battery storage, particularly focusing on its feasibility in the Alberta market when combined with 462MWac Solar Plant.

As mentioned earlier, battery storage is an emerging technology that is continuing to evolve. Initially, a lot of battery storage was dominated using lead acid which allowed use of batteries commercially. There were numerous other battery technologies developed but the most notable development in the recent years have been the lithium batteries. Due to lithium's high electrochemical potential and energy-to-weight ratio, the lithium batteries opened opportunities for many commercial uses. Some of its influence include smart phones, drones, and laptops. In the grid-scale battery storage market, lithium battery technology dominates the market with more than 90% of currently installed grid-scale batteries utilizing lithium battery technology [25]. This has been driven by lithium's high performance and steep price decline of over 70% from 2010-2016 [25]. The lithium battery technology has opportunity to penetrate the energy market, providing system flexibility and enabling higher saturation of renewable energy.

There are multiple factors to consider that makes implementation of battery storage an opportunity for various communities, countries, and markets to take advantage of. These include, but are not limited to:

- **Increase dispatchability and predictability of renewables**: Battery storage can enable renewable energy sources to be effective during times when it cannot produce energy. Furthermore, real-world experience has shown that battery storage improves dispatchability of energy. A system comparison was performed for Hornsdale Battery Reserve and traditional diesel generators and it showed that the fast frequency response time for Hornsdale Battery Reserve was three times faster than traditional diesel generation response time [26][27].

- **Renewable energy curtailment mitigation**: Renewable energy curtailment refers to the deliberate reduction in output below what it could have otherwise been produced [27]. This is in efforts to balance the system and to manage oversupply of energy into the distribution network. This is a loss of renewable energy developers as they are unable to profit from the energy that could have potentially been produced. Battery storage helps mitigate this deliberate reduction by storing the energy and allowing its use later.

- **Maximizing time-of-use rates**: Battery storage can be used to take advantage of demand and supply fundamentals. Through energy storage, the energy can be discharged at a time when it is more profitable [28].

- **Energy System Resilience**: Resilient cities are cities that can absorb, recover, and prepare for future shocks [27][28][30]. This is becoming a mandatory criterion for city developers considering the increase uncertainty due to climate change. With increasing global surface temperatures, there have been more drought and increase intensity of storms [31]. Battery storage help support the resiliency of an energy system as they can act as emergency backup power.

Considering the numerous benefits of implementing a grid-scale battery storage, Alberta has been actively working to implement battery storage in the current energy market. This initiative has been mainly incentivized by the Government of Alberta's target of 30% renewable electrical generation by 2030. AESO has been tasked to assess any potential needs for energy storage as significant intermittent generation is added to the grid to meet the target [32].

Grid-scale battery storage is a very new technology for the Alberta market. Even as recent as 2-3 years ago, there were no grid-scale battery storages present in Alberta. As of July 2020, there are only 10 projects currently on the AESO connection list. This has been largely due to the limitations in the current operation parameters and rules that do not fully contemplate energy storage. However, in a stakeholder engagement session, AESO has found out that there was a general positivity and encouragement for the implementation of a grid-scale battery storage. Some of the key takeaways were that interest in solar energy and battery storage would: (i) give Alberta an opportunity to show global leadership in creating efficient, sustainable, and environmentally responsible energy market, (ii) promote more diverse generation mix which will maximize progress toward Alberta's sustainable energy goals, (iii) achieve provincial and national emissions reduction targets, and (iv) battery storage is a critical component of ensuring grid reliability [32].

However, there are significant barriers for grid-scale batteries to be feasible in Alberta. One of the barriers that have already been mentioned above is Alberta's current operation parameters. While the framework for battery storage is continuously developing in Alberta, it has lagged compared to other cities, states, and countries around the world. An example of such case will be further elaborated later in the report. Furthermore, Alberta's current transmission tariff makes grid-scale battery storage difficult for it to be profitable. The current tariff charges storage as a load when storage is charging which results in relatively high operation costs. Not only are the operation costs high for batteries, but its capital costs remain high when considering AESO's daily pool price spreads. In AESO's 2018 report about battery storage, it was determined that the storage would need more than $60/MWh daily price spread to cover its capital cost. Instead, the daily price spreads only range from $15-30/MWh (this is considering 12 hours of daily “energy arbitrage” which is charging 12 hours at low prices and discharging 12 hours at high prices; $2500/kW capital cost of batteries) [32]. However, battery storage prices have been declining but at an uncertain rate. Considering that AESO has assessed that there are no immediate needs for battery storage, it incentivizes developers to observe, waiting on further decline of battery costs and timing when the Alberta energy market will need flexibility increase [32].

As mentioned previously, there are only 10 grid-scale battery storage projects in Alberta. The market is at an early stage with regards to adoption of battery storage. While current operation reserve market provide storage with high revenues per MW, early market saturation may reduce prices thus reducing the revenue for battery storage owners. Even implementation of a 50MW battery storage can impact the market given its current size. However, higher saturation of renewable energy in the energy market will incentivize the use of battery storages. Over the years, Alberta will continue to see growth in the renewable energy generation which will accelerate the implementation of battery storages. It is an important infrastructure in protecting their network. Currently, South Australia’s network is dependent on the limited interconnection to Victoria. When a major network outage occurred in Victoria, it caused the grid in the state of South Australia to become separate from the rest of the national electricity grid. This reason accelerated the need for a battery storage to support South Australia’s resiliency. Another factor that makes battery storage feasible is the make-up for their renewable energy in the energy market. South Australia has seen rapid growth of renewable energy introduction to the market. The market consists of more 50% renewable energy as portion of total electricity generation which is quite significant when comparing to Alberta’s roughly 10% mark.
Lastly, one of the biggest reasons that South Australia saw successful implementation of battery storage was its changes to the existing regulatory framework. They created a new registered participant category that allows battery storage owners to efficiently participate in the market.

Conclusions

The results of the market analysis indicate that there is a lot of untapped potential in solar energy generation, as production is forecasted to increase by 100 hundred times from present values. The simulation conducted in the technical analysis yielded a total energy generation of approximately 900 GWh and a power capacity of 462 MWac. The preliminary economic analysis reveals that the levelized cost of energy is 7.97¢/kWh, the capital cost is $656.2 million and the fixed operating costs are estimated at $11.8 million per year. The largest barrier that is preventing grid-scale battery storage from being profitable is the regulations and policies governing transmission and market prices.

Recommendations and future work on the project include:

- Economies of scale is not factored into the cost analysis neglecting benefits from bulk purchasing, labor costs, engineering, procurement, construction overheads and developer costs. Including this factor in the economic analysis may help reduce the price of production.

- Due to the limitation of the SAM software at its current state, a multiple power point tracking cannot be programmed for the inverter therefore mismatch losses could not be estimated but were specified. Calculations and results obtained from multiple sources would improve the validity of our results.

- A detailed cost analysis using the most recent data and a PPA financial model is recommended. The values used for the cost analysis are from a 2018 NERL Benchmark Report. The cost reduction from year 2010 to 2018 has been around 80% and is expected to continue.

- Further costs savings measures could be implemented in the estimate for capital cost which would bring our proposed project more in line with the forecasted costs. The influence of subsidies and rebates supplied from the government may reduce the estimated capital costs and need to be researched for an accurate evaluation.

- A deeper study into the current provincial electricity market structure may be conducted to gain a deeper understanding of why utility scale renewables are not particularly attractive by considering factors such as pool price, merit order, intermittency, etc.

- An environmental evaluation on the project may be conducted to determine the influence of the solar farm on the carbon emissions of the province, dependency of fossil fuel resources, and impact of the plant on meeting the government's climate goals.

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Appendix A: Market Analysis

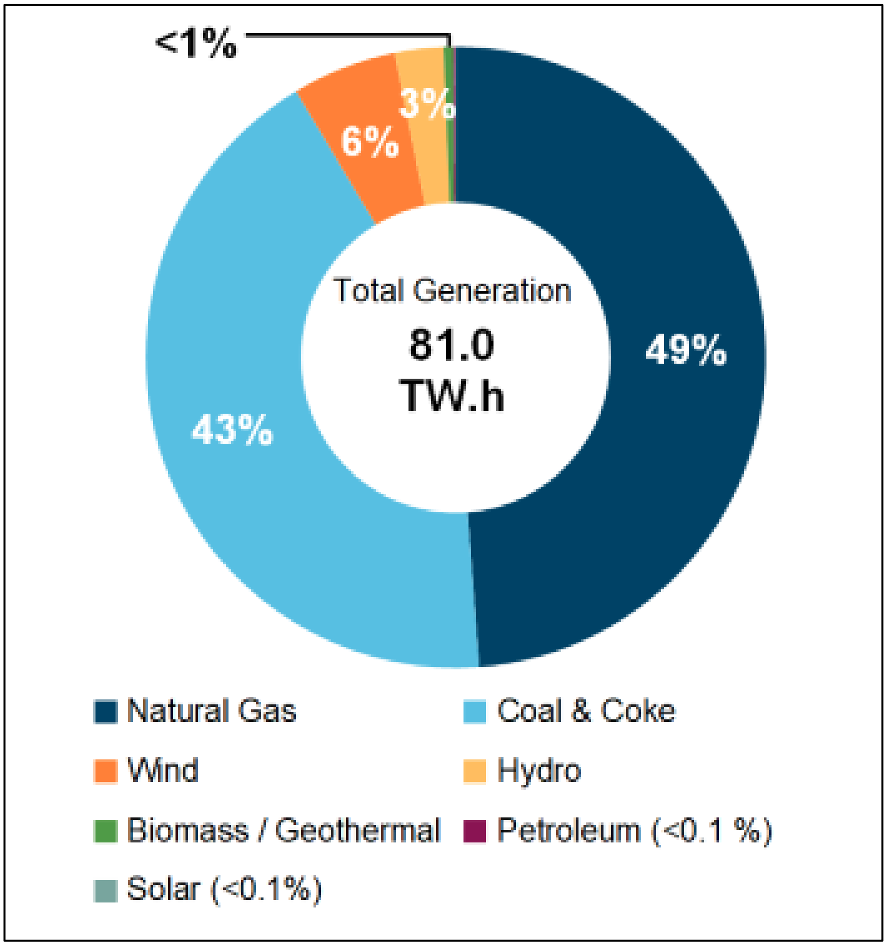

Figure 7. Energy sources used for electricity generation in 2018 [4]

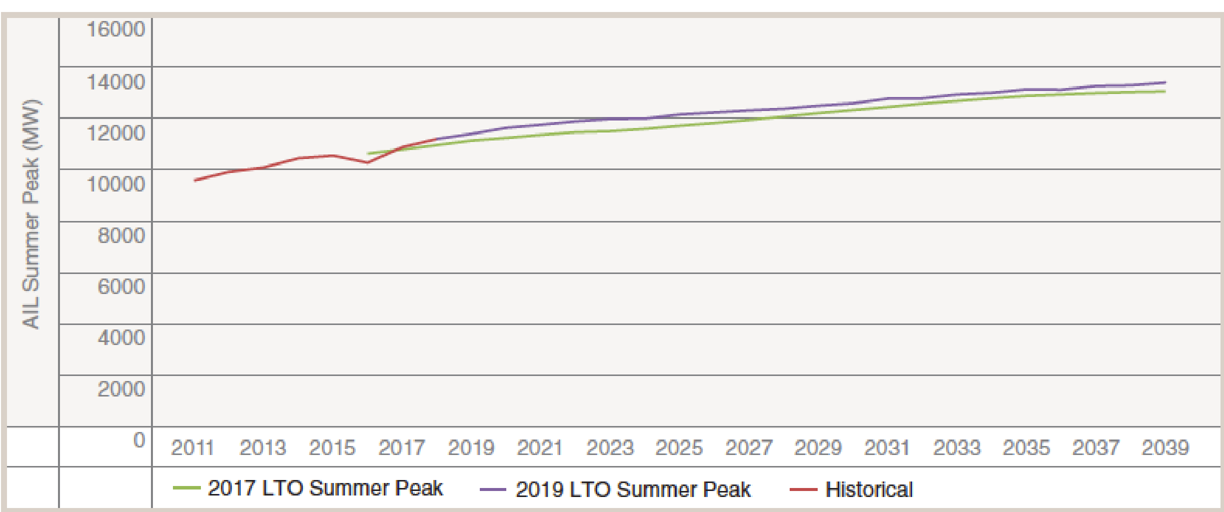

Figure 8. Peak electricity demand forecast in summer from 2011-2039 by AESO [8]

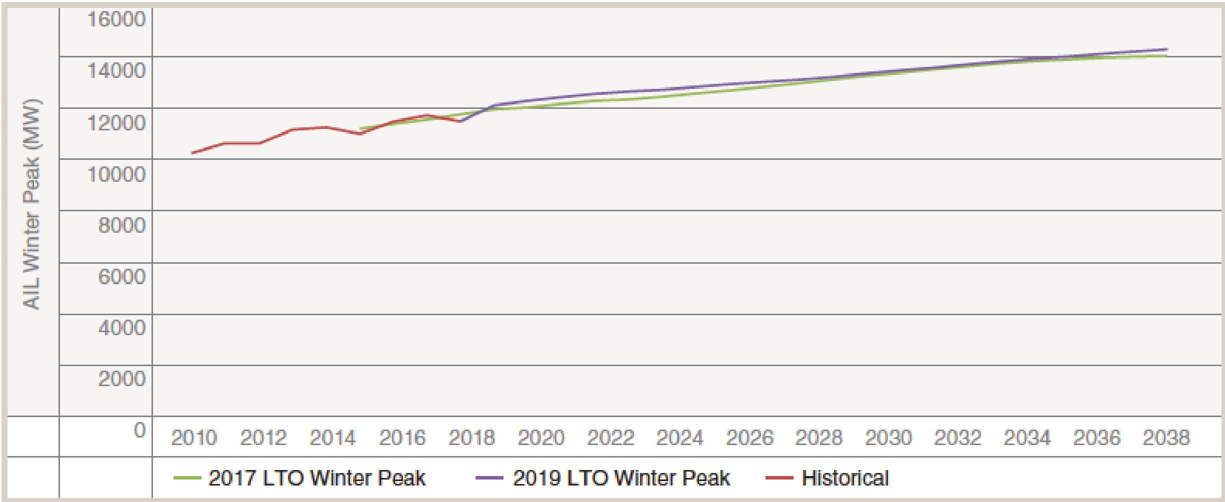

Figure 9. Peak electricity demand forecast in winter from 2010-2038 by AESO [8]

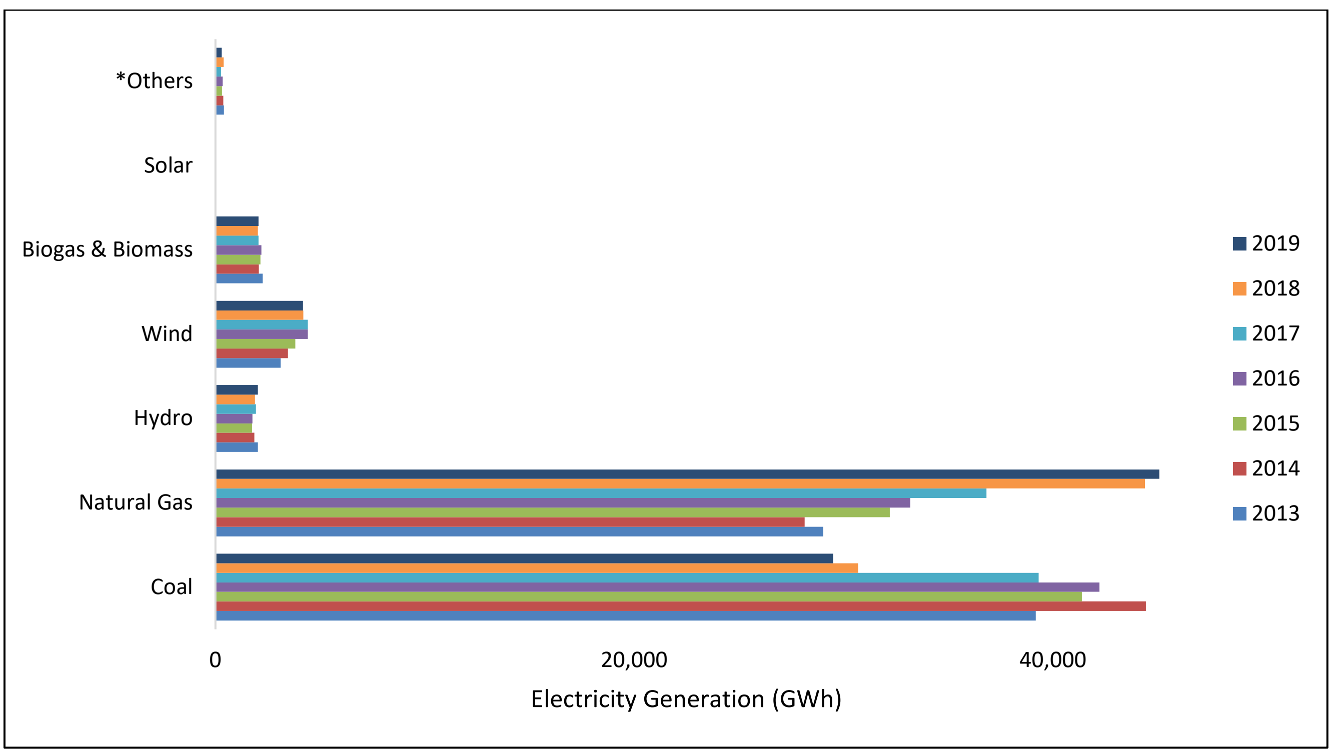

Figure 10. Alberta electricity generation by source of energy (GWh) from 2013-2019 [7]

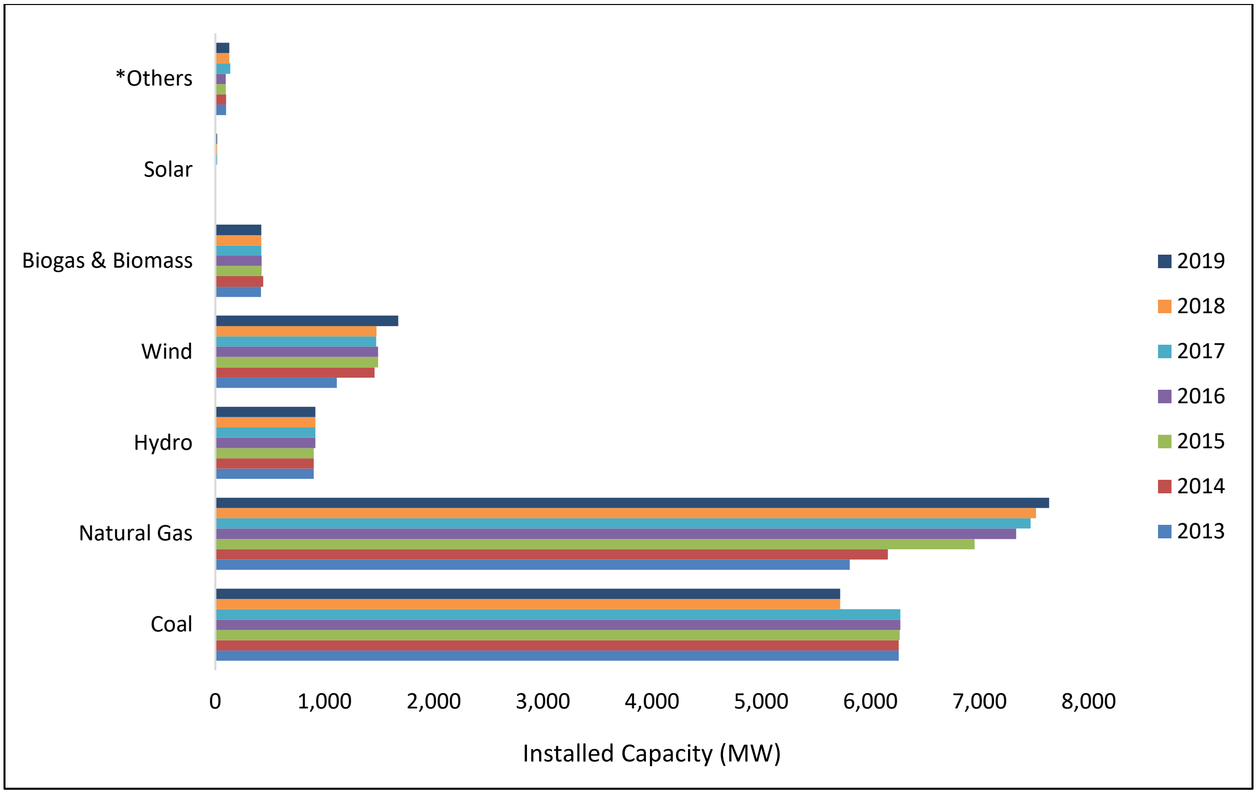

Figure 11. Installed energy capacity from 2013-2019 by power source (MW) [7]

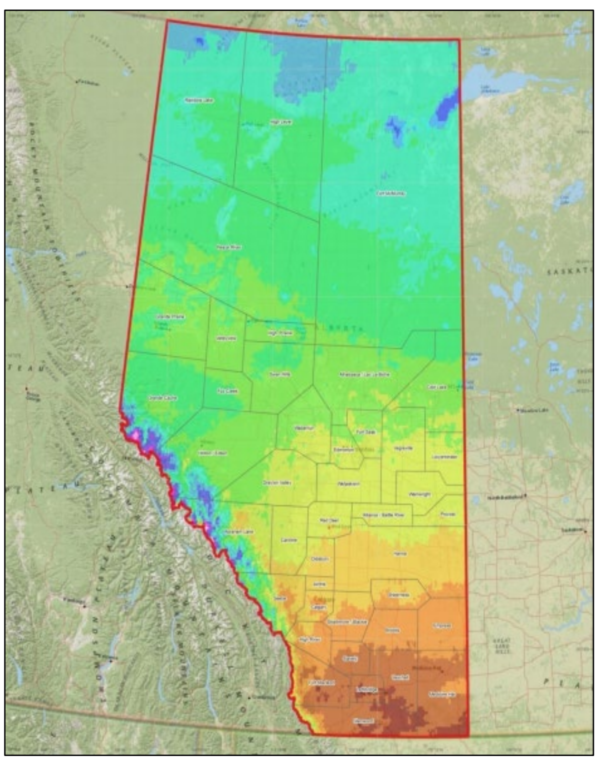

Figure 12. Variance in solar irradiance levels in Alberta [14]

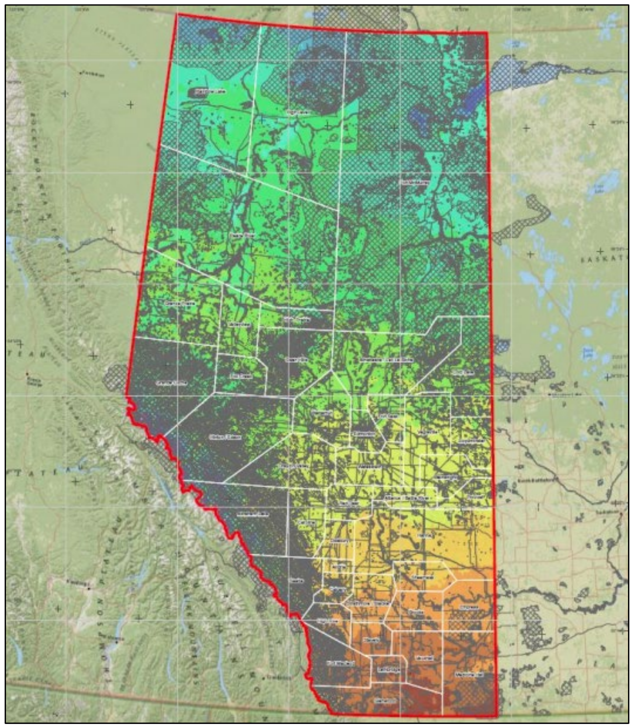

Figure 13. Solar exclusion zones in Alberta [14]

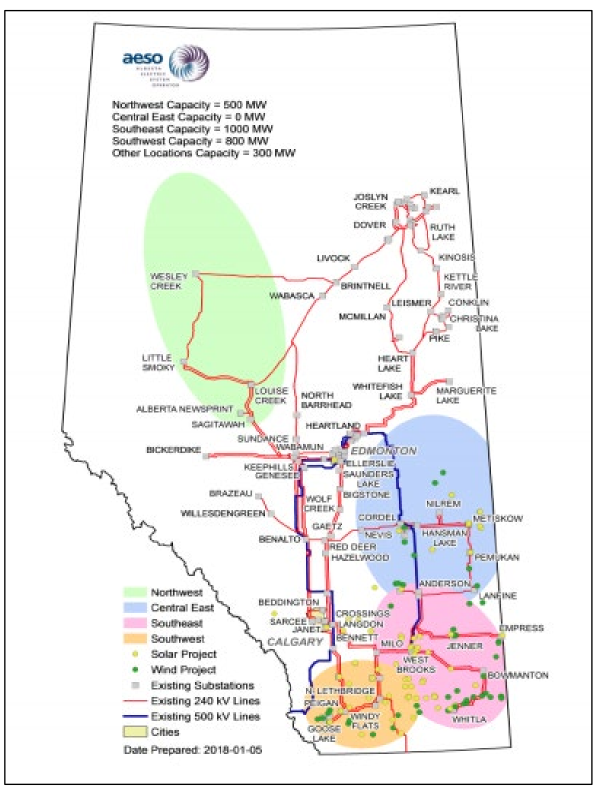

Figure 14. Transmission lines and stations in Alberta [2]

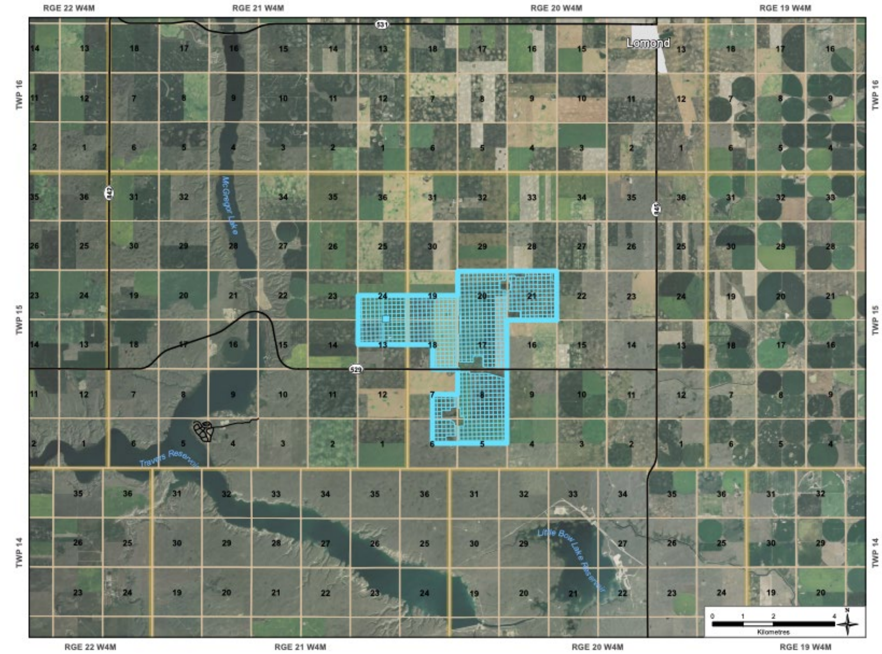

Figure 15. Satellite image overview of land use in Travers Project [11]

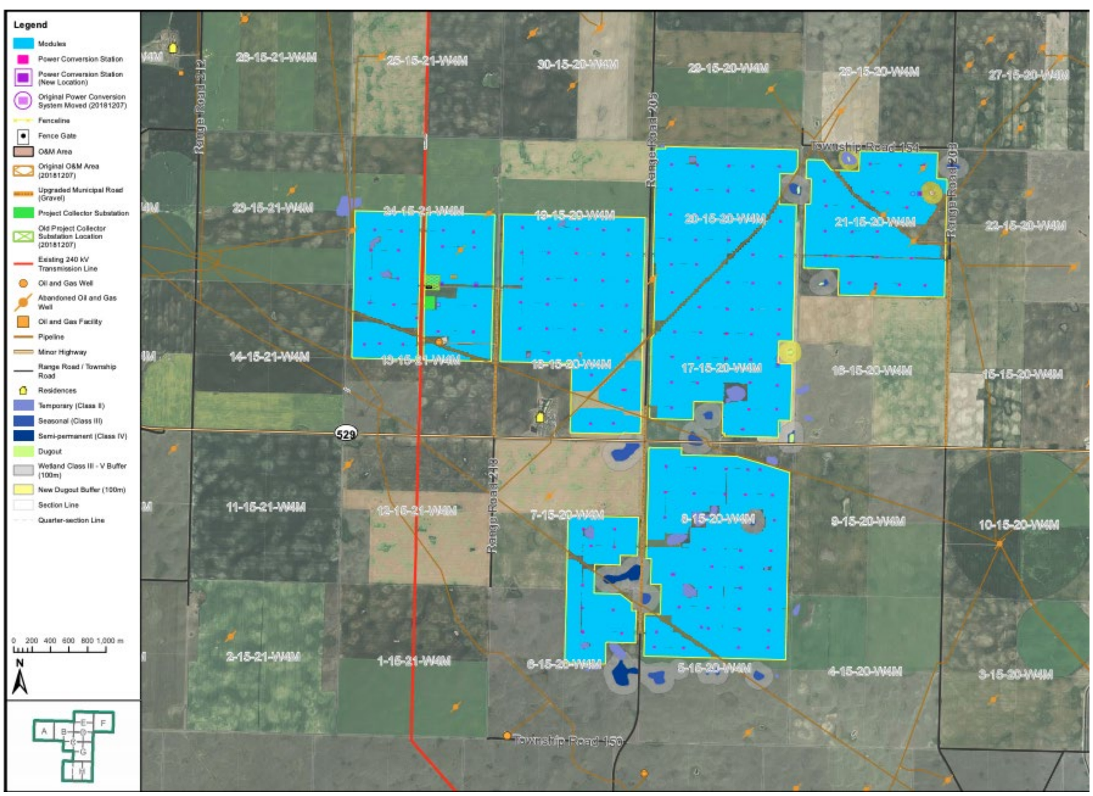

Figure 16. Satellite image showing module distribution and power conversion stations for Travers Project [11]

Table 12. Description of proposed, in construction, and completed solar projects in Alberta

Project Name	Capacity (MWac)	Capital Costs ($ million)
Proposed		
Vulcan Solar Project	78	$155.0
Vauxhall Solar Farm	150	$220.0
Airport City Solar	120	$169.0
Joffre Solar Power Project	47	$62.6
Prairie Sunlight Solar Project Phase 1	74.2	$125.0
Strathmore Solar Farm	40.5	$60.0
South Calgary Solar Farm	25	$50.0
E.L. Smith Solar Farm	12	$30.0
In Construction		
Solar Hays	23	$34.5
Travers Solar Project	465	$520.0
Perimeter Claresholm Solar Project	132	$169.0
Brooks Solar 2 Power Project	26.5	$50.0
Burdett Solar Project	20	$35.9
Wrentham Solar Project	41.4	$65.0
Claresholm Solar Project	132	$ 200.0
Canadian Solar Solutions Solar Plants	97	$100.0
Suffield Solar Project	23	$49.0
Burdett Solar Project	20	$35.9
Yellow Lake Solar Project	19	$34.1
Completed		
Spring Coulee Solar Project	29.5	$55.0
Our Proposal		
462 MW Solar Farm in Vulcan Country	462	$615.9

Appendix B: Technical Analysis

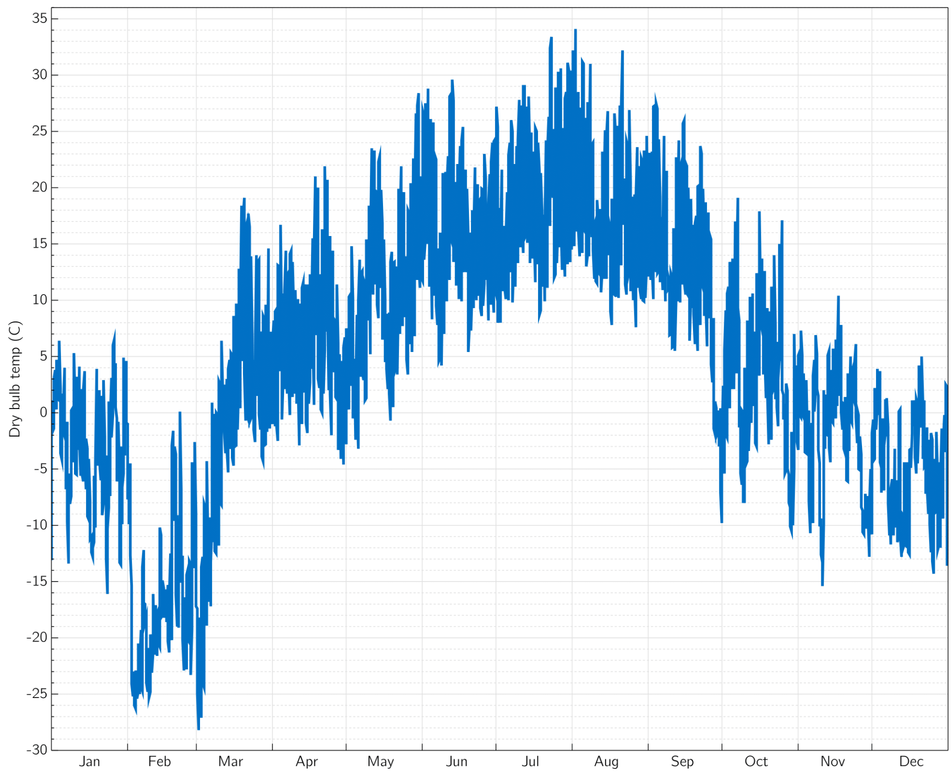

Figure 17. Global Horizontal Irradiance (W/m^2) for Vulcan County

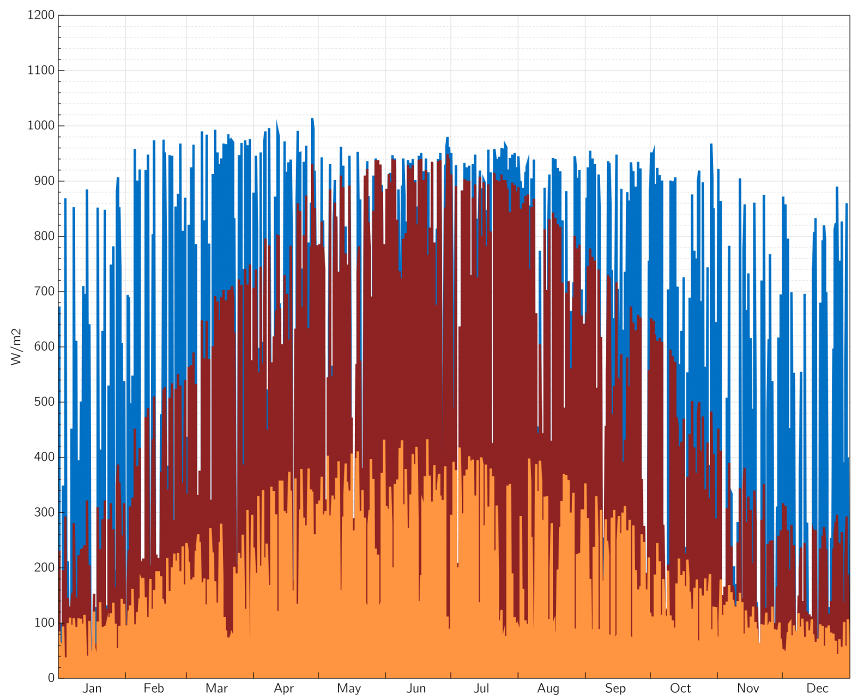

Figure 18. Daily irradiance Values for Vulcan County Location. Beam irradiance is blue, global irradiance is red, diffuse irradiance is orange.

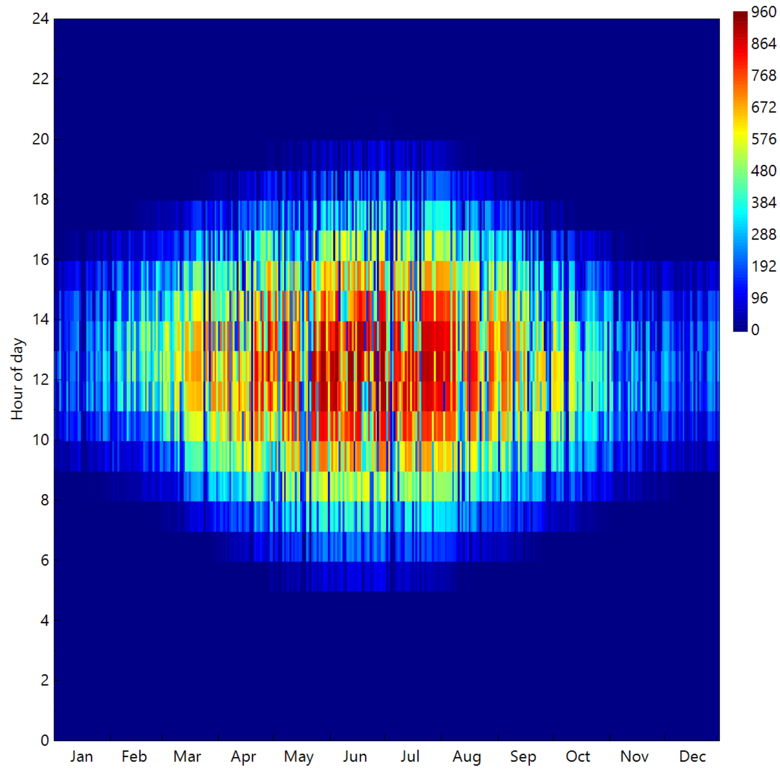

Figure 19. Daily Dry Bulb Temperature - Vulcan County Location (273639 NSRBD) [21]

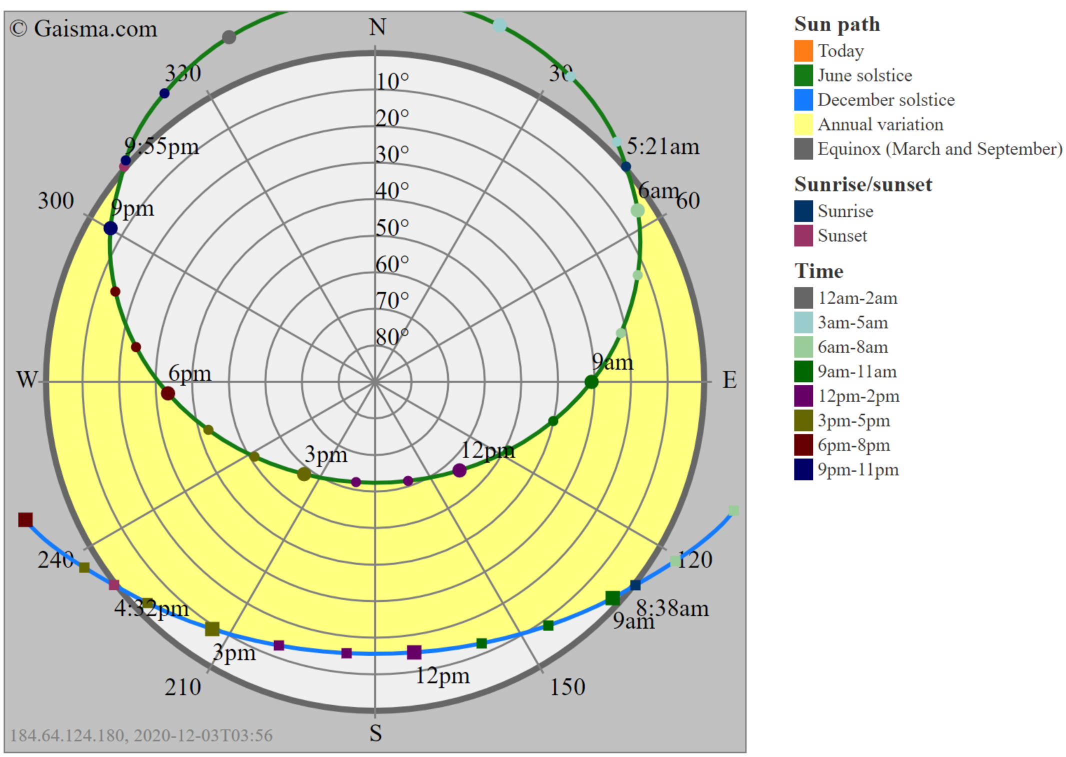

Figure 20. Sun Path Diagram for Calgary [21]

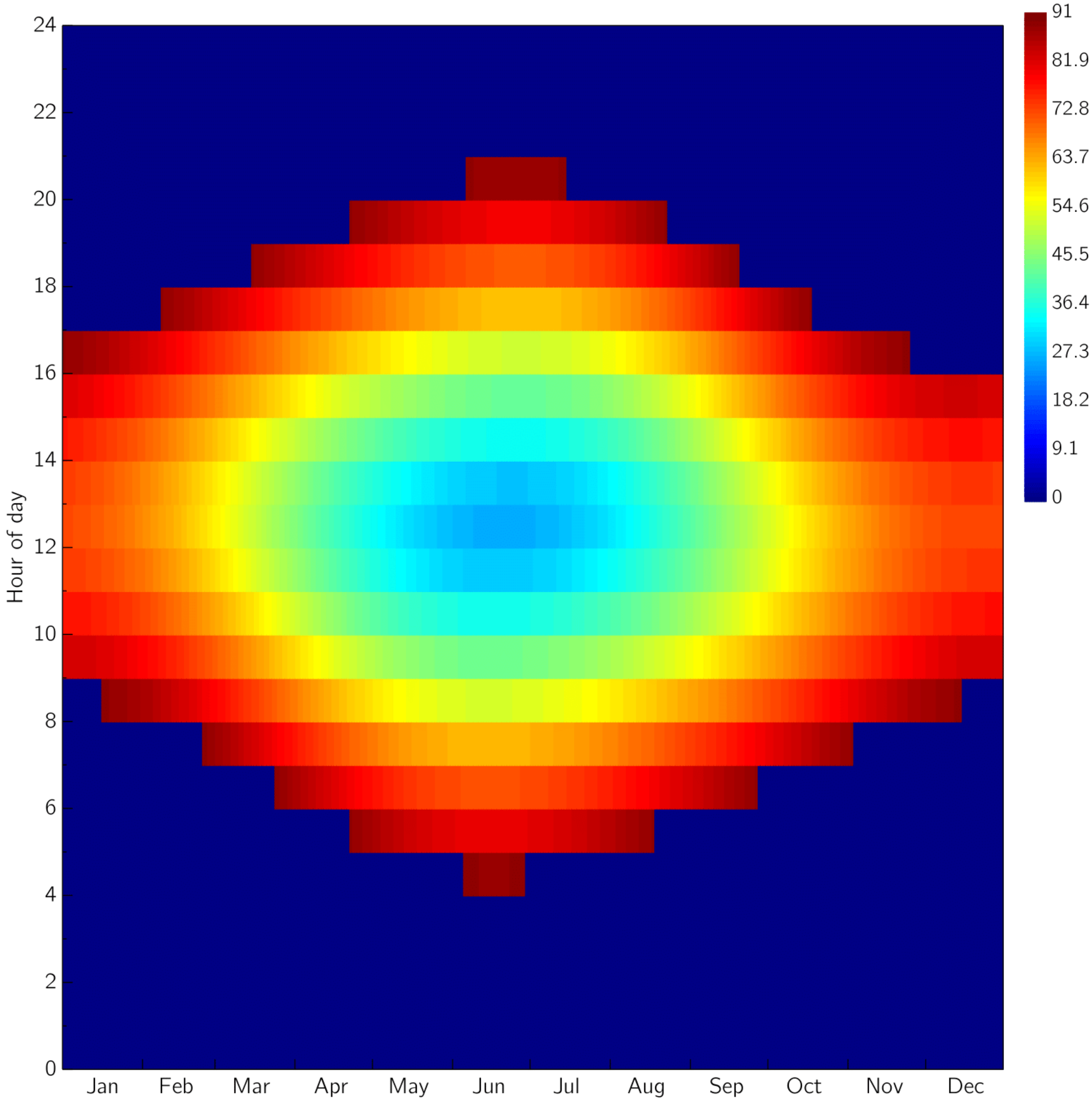

Figure 21. Visualization of tilt angle over the year. Heat spot aligns with 36 degrees.

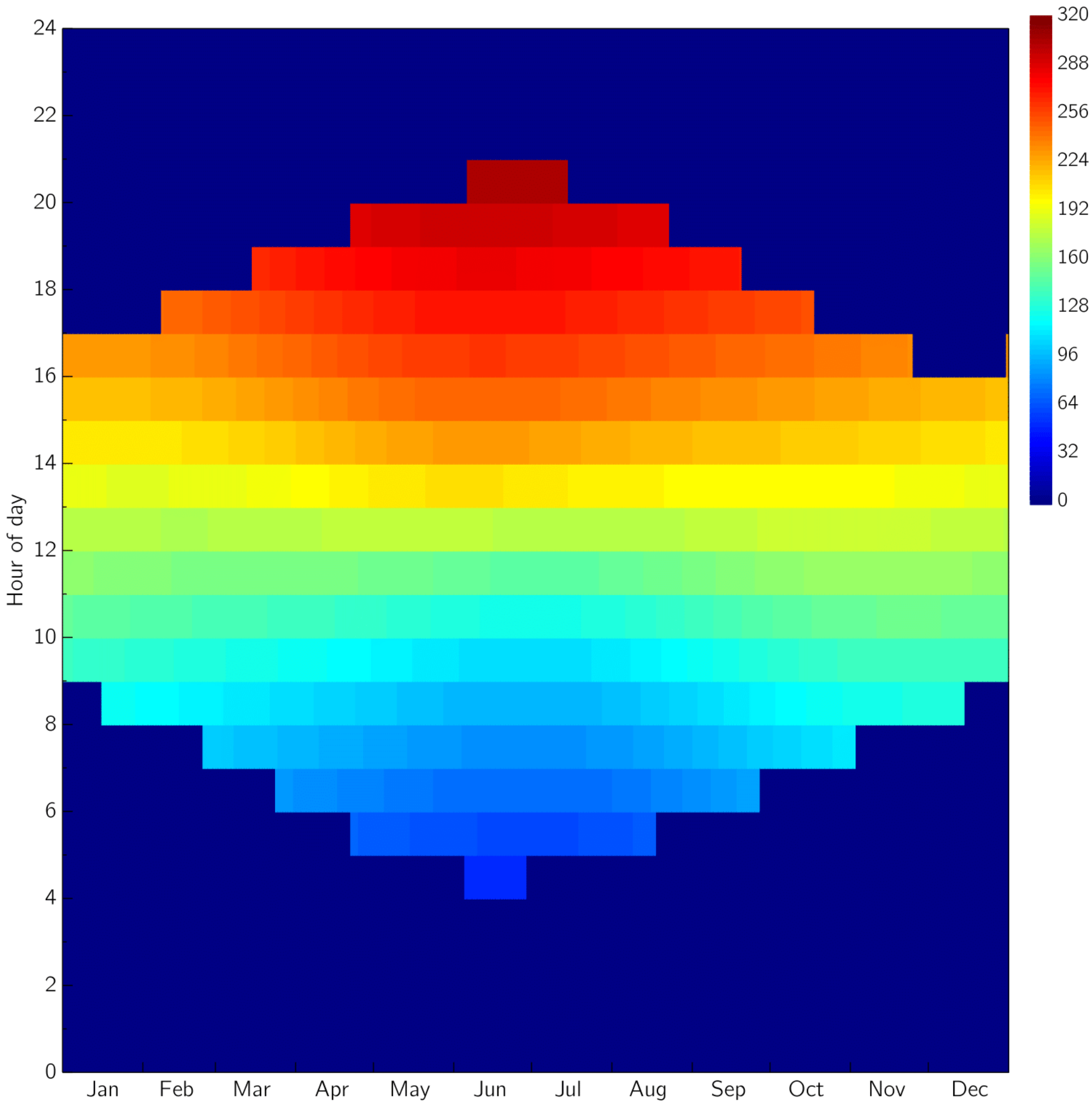

Figure 22. Visualization of azimuth angle

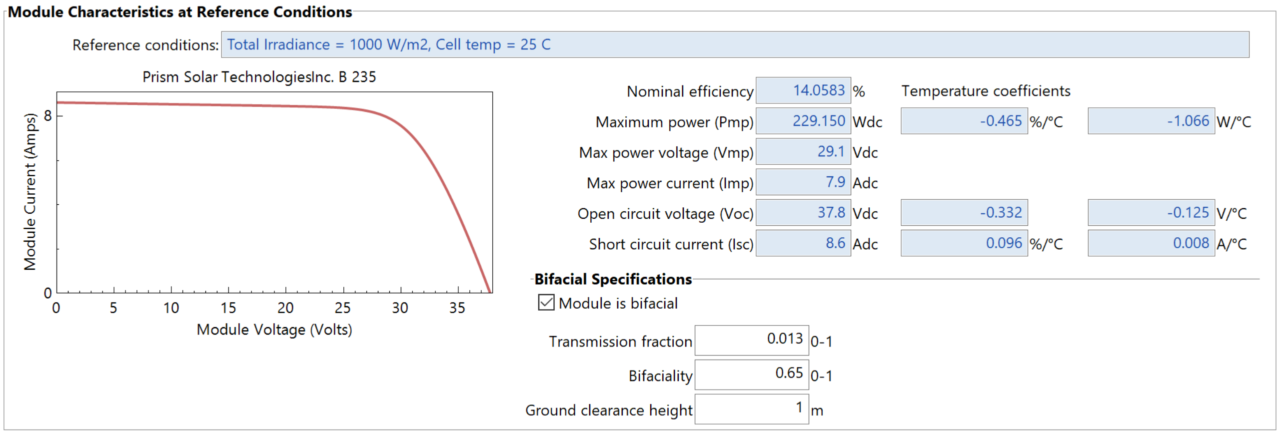

Figure 23. Module specification for Prism Solar Technology B235 at Reference conditions. Extracted from CEC database.

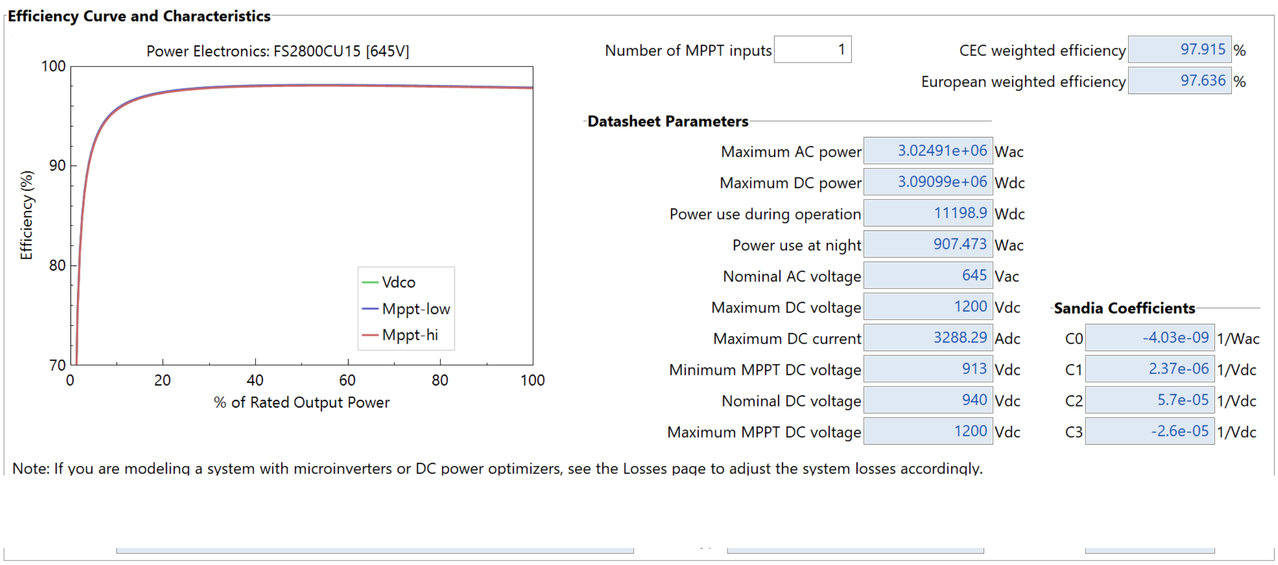

Figure 24. Inverter specifications for Power Electronics: FS2800CU15. Extracted from the CEC database.

Table 13. One-axis tracker and fixed-tile utility scale, LCOE Assumptions [22]. Table extracted from U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018 report.

2018 USD per Watt DC	2010	2011	2012	2013	2014	2015	2016	2017	2018
One-Axis Tracker									
Installed cost ($/W)	5.52	4.65	3.20	2.43	2.18	2.00	1.56	1.12	1.13
Annual degradation (%)	1.00%	0.95%	0.90%	0.85%	0.80%	0.75%	0.75%	0.75%	0.70%
O&M expenses ($/kW-yr)	28	27	25	24	23	22	21	20	14
Pre-inverter derate (%)	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%
Inverter efficiency (%)	96.0%	96.4%	96.8%	97.2%	97.6%	98.0%	98.0%	98.0%	98.0%
Inverter loading ratio	1.10	1.12	1.13	1.15	1.17	1.18	1.20	1.30	1.30
Equity discount rate (real)	7.4%	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%	6.3%	6.3%
Inflation rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%	4.5%	4.5%
Debt fraction	34.2%	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%	40.0%	40.0%
Fixed-Tilt									
Installed cost ($/W)	4.63	3.97	2.70	2.07	1.91	1.85	1.47	1.04	1.06
Annual degradation (%)	1.00%	0.95%	0.90%	0.85%	0.80%	0.75%	0.75%	0.75%	0.70%
O&M expenses ($/kW-yr)	28	26	24	22	20	18	18	17	13
Pre-inverter derate (%)	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%	90.5%
Inverter efficiency (%)	96.0%	96.4%	96.8%	97.2%	97.6%	98.0%	98.0%	98.0%	98.0%
Inverter loading ratio	1.10	1.15	1.20	1.25	1.30	1.35	1.40	1.30	1.36
Equity discount rate (real)	7.4%	7.2%	7.0%	6.9%	6.7%	6.5%	6.3%	6.3%	6.3%
Inflation rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Debt interest rate	5.5%	5.3%	5.2%	5.0%	4.8%	4.7%	4.5%	4.5%	4.5%
Debt fraction	34.2%	35.2%	36.1%	37.1%	38.1%	39.0%	40.0%	40.0%	40.0%

All 2010–2017 data are from Fu et al. (2017), adjusted for inflation. The inverter replacement line-item in Fu et al. (2017) is incorporated into O&M expenses in this edition to be consistent with the 2018 O&M benchmark. Other important assumptions: utility-scale PV system LCOEs assume a 1) system lifetime of 30 years; 2) federal tax rate of 35% from 2010–2017, changing to 21% in 2018; 3) state tax rate of 7%; 4) MACRS depreciation schedule; 5) no state or local subsidies; 6) a working capital and debt service reserve account for 6 months of operating costs and debt payments (earning interest of 1.75%); 7) a 6-month construction loan with an interest rate of 4% and a fee of 1% of the cost of the system; 8) a system size of 100 MW; 9) an inverter lifetime of 15 years; 10) debt with a term of 18 years; and 11) $1.1 million of upfront financial transaction costs.

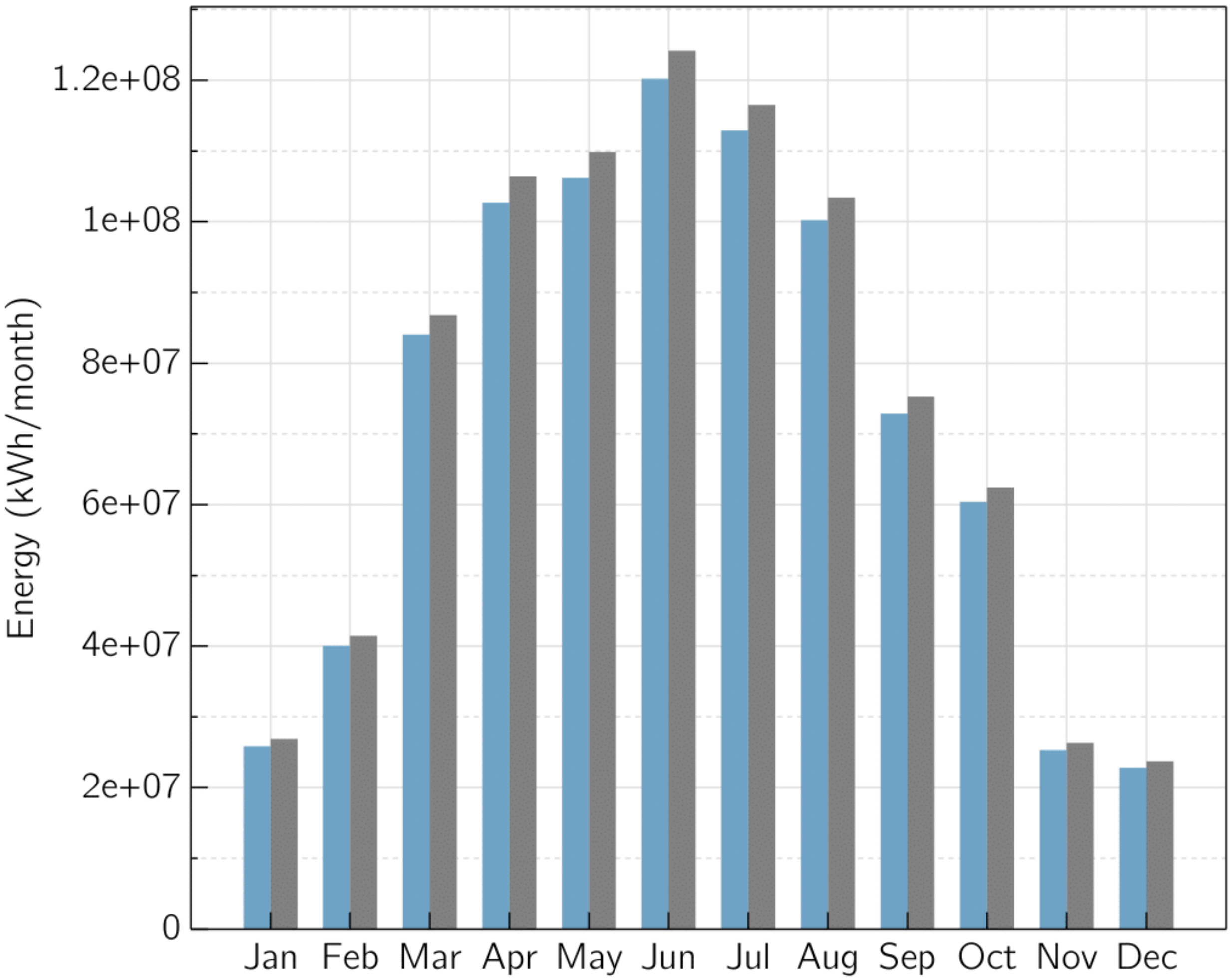

Figure 25. Monthly system energy production (grey bar is ac output, blue bar is dc)

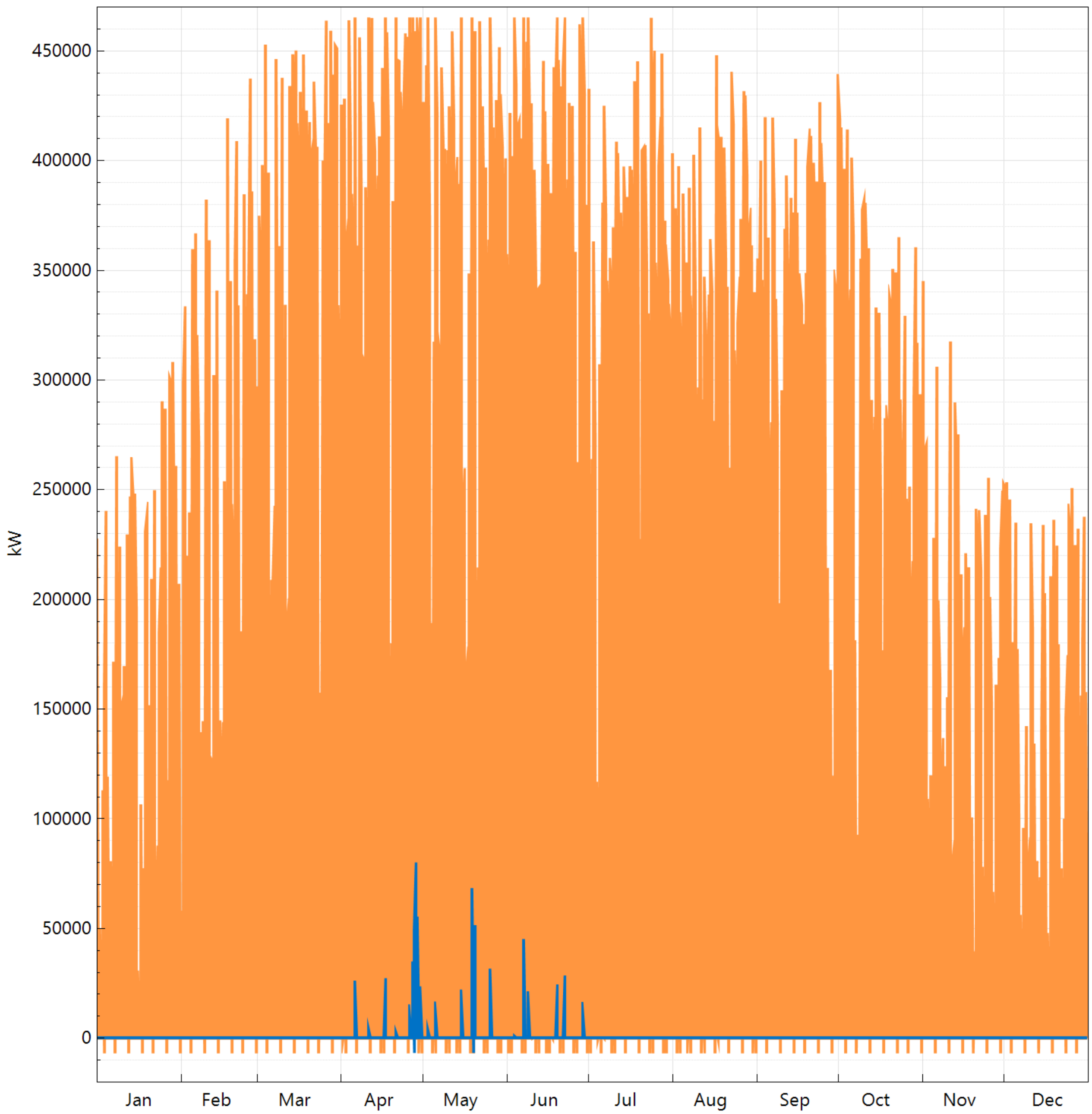

Figure 26. System power (kW) generated in orange, in comparison to the inverter clipping losses in blue over the course of the year.

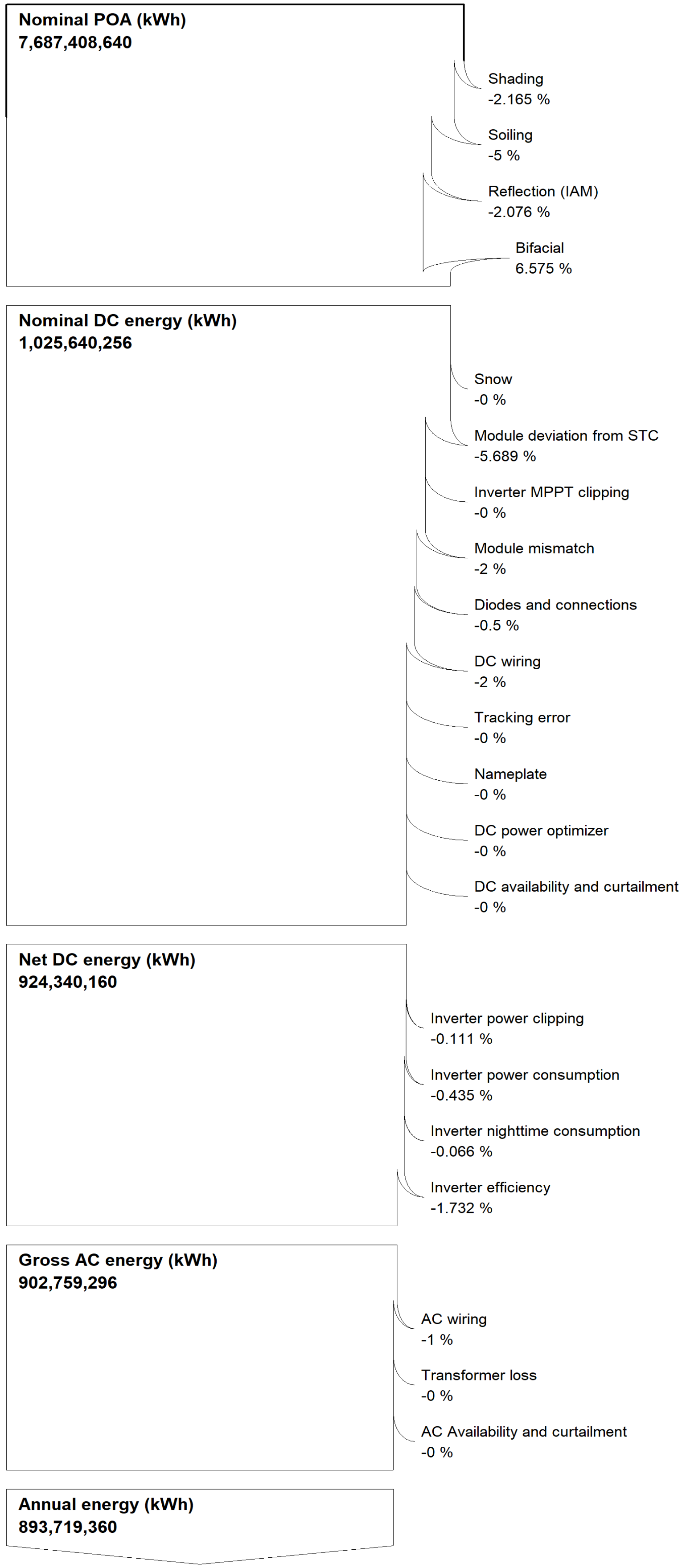

Figure 27. Sankey diagram of total losses experienced by PV module annually, with bifacial gain.

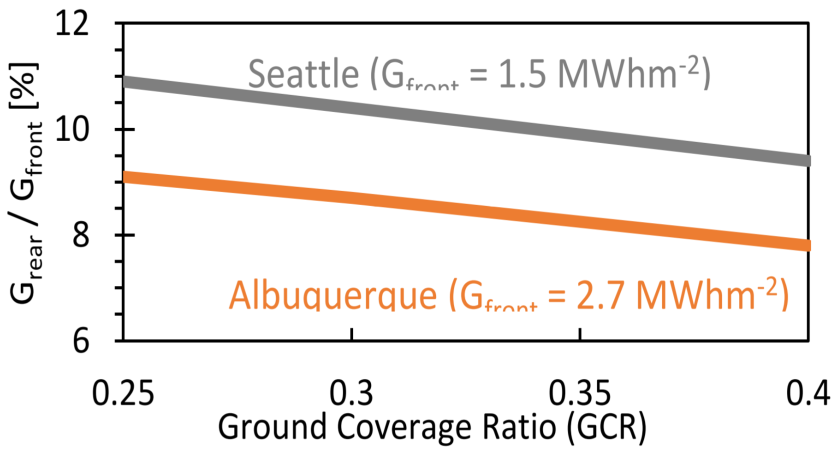

Figure 28. Yearly cumulative G_{rear}/G_{front} irradiance modeled for two locations. As evident, high GCR reduces bifacial gain. Graph extracted from research performed by Pelaez et al [22].

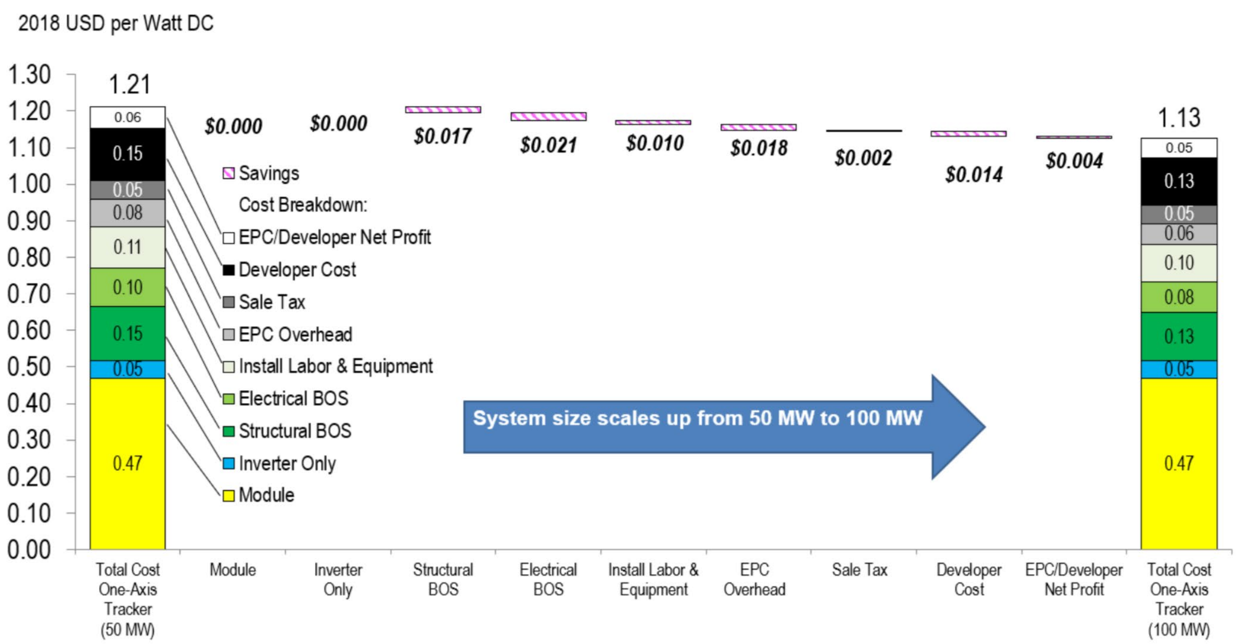

Figure 29. Cost reduction from economies of scale effect for one-axis tracking. The system size doubles from 50MW. Graph is extracted from U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018 report.