AGENDA
COUNCIL COMMITTEE MEETING
MUNICIPAL DISTRICT OF PINCHER CREEK
November 10, 2026
11:00 am
Council Chambers

1) Approval of Agenda

2) Delegations:

    a) 11:00 am Massiff Energy - Municipal District of Pincher Creek Community Solar Business Plan

3) Closed Session

    a) Draft Bylaw 1379-26 - ATIA Sec. 29.1
    b) Draft 2027 Operating Budget – ATIA Sec. 29.1

4) Round Table

5) Adjournment

Municipal District of Pincher Creek Community Solar Business Plan

Date	REV.	Status	Description	Drafted	Approved
November 27, 2025	1	For Client Review	-	-	T. Walker
December 29, 2025	2	Final submission	-	-	T.Walker

Executive Summary

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Executive Summary

The Pincher Creek community energy project proposes a 1.5 MWac / 1.95 MWdc installation in southwest Alberta, with the option to include a 1 MW / 4 MWh battery energy storage system (BESS). Several viable brownfield sites have been identified through community engagement, council input, and prior technical studies, ensuring strong local support and minimal land-use impact. Current electricity prices of 7–10 ¢/kWh, combined with carbon credit revenues at roughly $30 per tonne, provide a solid foundation for project economics.

The standalone solar system requires approximately $4.49 million in capital investment and is expected to generate $199,000 annually, resulting in an unlevered IRR of around 8%. Integrating the BESS increases total capital costs to roughly $7.02 million but raises annual revenue to approximately $449,000, improving the project IRR to 13–14% due to additional market and grid-service revenues. Capital costs are reduced by the 30% Federal Investment Tax Credit and a 15% potential Grant from the Green Municipal Fund. Operating costs are estimated at $77,250 per year for solar alone and $148,500 for the solar-plus-storage configuration.

Key risks include regulatory changes in Alberta's electricity market and potential distribution system capacity constraints. However, strong opportunities exist through federal and municipal funding programs, Investment Tax Credits, carbon credit sales, and the growing market for battery services valued at approximately $250,000 per MW. Overall, the project is positioned to deliver meaningful community benefits, create a replicable development model, and enhance local energy resilience.

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Introduction

The Municipal District of Pincher Creek (MD) is located in the southwest corner of Alberta on the North end of Waterton National Park. The MD has made sustainability a priority over the last 4 years, starting with employing a municipal energy manager in partnership with the Town of Pincher Creek, purchasing an electric vehicle as part of their fleet, installing a variety of energy conservation measures and developing the Clean Energy Improvement Program to support residents with their own energy saving projects. With a long history of renewable energy development in the wind sector, the MD is familiar with the benefits of the industry as well as the challenges with these large infrastructure projects. To address these factors, the MD kicked off a process in 2024 to identify how future development can be optimized on community terms.

The project started with an analysis of existing generators within the MD, the historic and projected tax impact of these generators, the transmission capacity within the region, land use preferences, and community sentiment around development. The results of this study highlighted the reliance on renewable projects for the tax base in the MD and expected decrease of these revenues over the next 15 years. While capacity remains for transmission, the community feedback strongly indicates a fatigue with renewable generation and a desire to go smaller, using unproductive land.

Based on this report, an analysis of available brownfield lands was conducted which identified 180 total sites within the MD across orphaned wells, abandoned wells, and gravel pits. It was determined that these locations could host a total of 165 MW of solar generation, however access to distribution and transmission was not available at most sites and therefore total buildable capacity is closer to 60 MW. After reviewing this report, the MD decided to continue pursuing the opportunity and received a grant from the Green Municipal Fund to support the development of a business plan for building out a community owned solar project on a brownfield site.

The following report outlines the business case and key criteria for developing a community owned solar project that will support the tax base while keeping benefits of the project local.

Siting

The siting for the potential community solar project is based on two primary factors; proximity to distribution lines with capacity to host a solar project, and proximity to disturbed or brownfields to reduce the impact of new development. At a Council meeting in June 2025, the MD advised that the preference would be for gravel pit locations, with secondary priority on old well sites so long as the environmental liabilities had been dealt with.

Brownfields

Based on the report provided in 2024 there are a total of 142 sites with visibly disturbed area that could be eligible for brownfield redevelopment. These sites are broken down into Orphaned Wells, Abandoned Wells, and Gravel Pits – with 9, 111, and 22 of each respectively. At the Council meeting in June 2025, the MD council noted additional gravel pits in the region that weren't reported in the original list provided which brings the number up to 64 pits and 184 sites total. Council noted that gravel pits present an excellent opportunity for small scale solar development as the ground remains unproductive for many years after the gravel pit is reclaimed and generally sits under a monitoring program which costs time and resources for both the MD and landowner.

The map shown below in Figure 1 displays all well sites identified throughout the MD using the Alberta Energy Regulator map Viewer [1] and Orphaned well map viewer [2]. More detailed maps are available in the *MD of Pincher Creek Brownfield Solar Analysis* report. Abandoned wells are denoted in green and orphaned wells are in blue. The status of these abandoned wells range from sealed, to reclamation certified or reclamation exempt. The orphaned wells are classified as undergoing decommissioning, closed, or environmentally reclaimed.

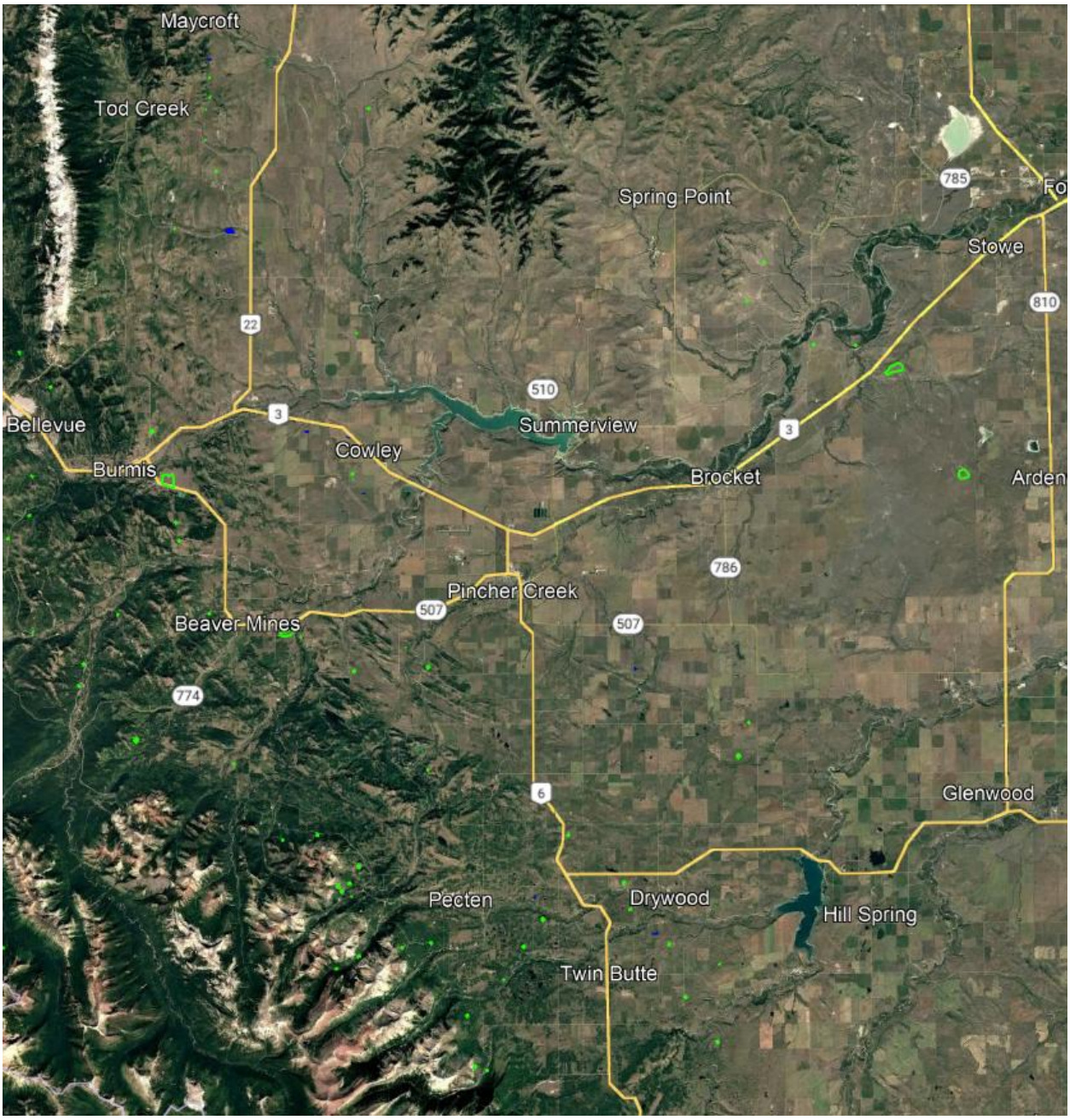


Figure 1: Abandoned and Orphaned wells in the MD of Pincher Creek

The gravel pits shown below in Figure 2 are spread across the MD with concentrations near the Highway 22 and Highway 3 intersection, Summerview, the Highway 6 and Highway 505 intersection, and the intersection of Highway 507 and Highway 3. These pits are colour coordinated with MD stockpiles being white, private stockpiles in green, reclaimed pits in blue, inactive in orange, and historical pits in purple. For the purpose of this study, only the reclaimed,

inactive, and historical pits are considered. The remaining pits present options for future development once the pit is no longer actively being used.



Figure 2: MD of Pincher Creek gravel pit map

Distribution Capacity

The distribution lines are owned by Fortis Alberta in the MD. Transmission capacity is not considered within this report due to feedback from the community that the preference is for smaller sites that have less impact on the land. Transmission connected projects are generally much larger in size, taking up multiple quarters of land in order to optimize economies of scale which has been indicated as less desirable by the community.

Fortis Alberta publishes a capacity map for their distribution network which indicates the power hosting capacity of each feeder line [3]. While the capacity on these maps is estimated, it provides a basis for site identification. The main MD distribution network is made up of four distinct feeder circuits identified below in Table 1. The capacity on these circuits ranges from 150 kW on single phase and low capacity three phase lines, up to 19 MW on 396S-117TS close to the Goose Lake Substation.

Table 1: Fortis Alberta distribution feeder lines within the MD of Pincher Creek

Feeder Line
799S-181LE
396S-117TS
396S - 41LE
502S-425LS

Generally, the hosting capacity on these lines is reduced as the line gets further away from the substation interconnection or high load centers like industrial areas and Towns. The capacity is represented visually with colours; green showing the highest capacity, then blue, purple, orange, and finally red being the lowest.

While there are distribution lines across the entire MD, there are certain areas where capacity is consistently higher, an example being the Town of Pincher Creek as shown in Figure 3. While this area has high capacity, it is also in close proximity to the densely populated Town, and it has been indicated that the land in proximity to these lines is valuable for agriculture.



Figure 3: Fortis Alberta distribution line capacity in proximity to the Town of Pincher Creek

The area around the Waterton Gas plant Shown in Figures 4 and 5 has capacity to host projects up to 5.4 MW due to the infrastructure built out to support the extraction activities and pipeline network for the gas plant. There are several abandoned wells in the region, however development in this area is restricted by the Provincial Park and Wildland area boundaries which were established after the wells had been drilled and prevents the construction of any new infrastructure. There are however two possible locations that are outside of these boundaries.

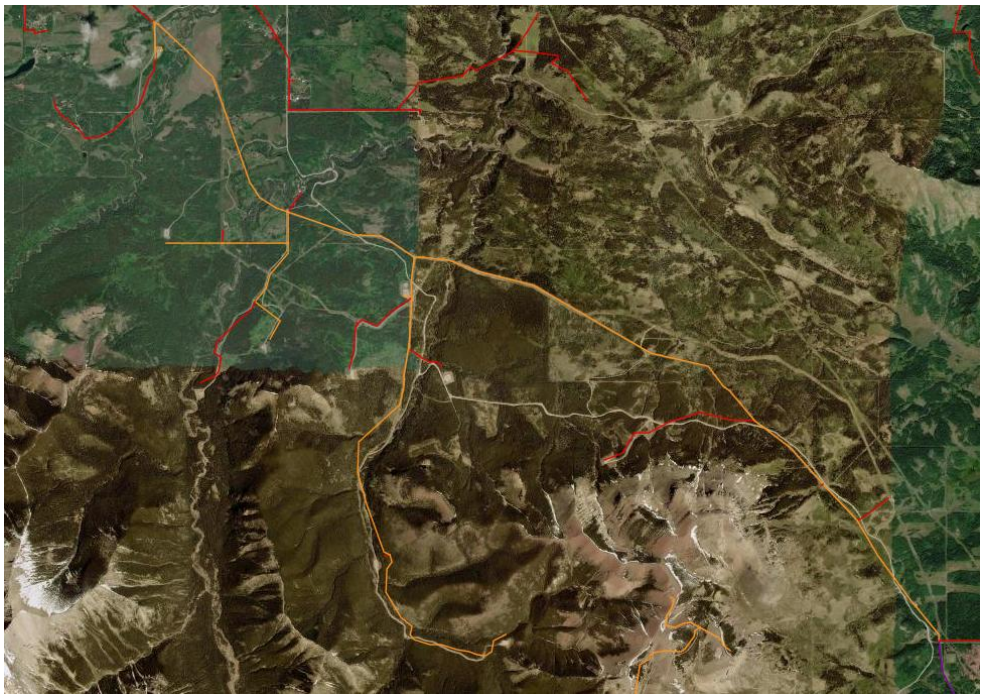


Figure 4: Fortis feeder lines Northwest of the Waterton gas plant

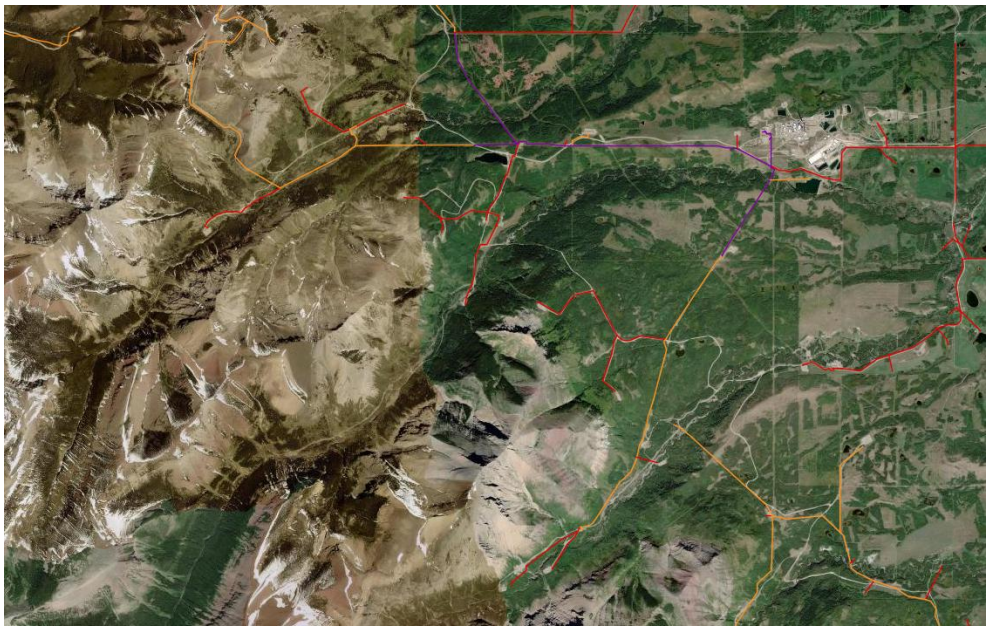


Figure 5: Fortis Feeder Lines West of the Waterton Gas plant

The final region with capacity for a solar project lies along Highway 3 near Lundbreck, and up Highway 22 from shown in Figure 6.



Figure 6: Fortis feeder lines along Highway 3 and Highway 22

Notably, line 396S - 41LE's capacity remains at 150 kW right from the substation which is an anomaly currently being explored with the Fortis team. This line extends along much of the east side of the MD and overlaps many brownfield sites which could be suitable for a project.

Project Locations

The Fortis maps are imported and overlayed with the brownfield map to identify locations that can host potential projects. The imported Fortis line map does not show colour and therefore is manually referenced for capacity. These maps are shown below in Figure 7, with the majority of locations scattered throughout the western side of the MD between the gravel pits near Lundbreck and the gas wells near the Waterton and Drywood plants. There is also a collection of gravel pits near Summerview that have been identified by Council as suitable for development pending an upgrade to the Fortis line as mentioned above. The orphaned wells are shown in yellow, gravel pits in blue, and abandoned wells in green.

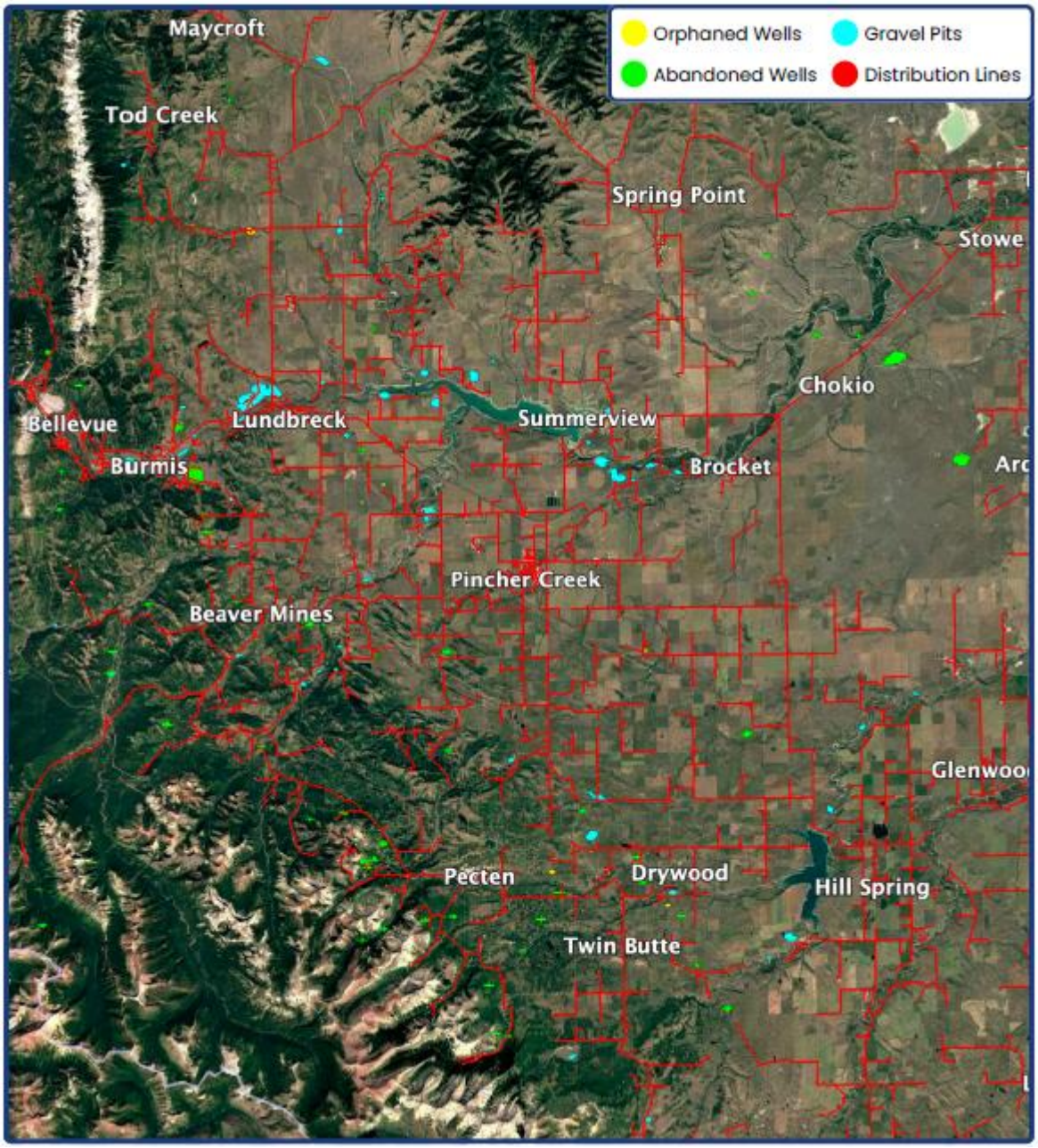


Figure 7: Fortis Feeder Lines overlayed with brownfield sites in the MD of Pincher Creek

Based on the analysis above, locations are sorted based on brownfields with proximity to high capacity distribution lines, and those identified by stakeholder engagement. The top 8 sites are shown below in Table 2. Per the direction of Council, focus was put on gravel pits with one Orphaned Well and one Abandoned well. Several gravel pits have limited capacity however have been identified in a preliminary study request to Fortis for confirmation on the upgrades

required to bring the sites to a shovel ready stage. At the MD Council Meeting on November 12, 2025 their proposed raw water storage site was also identified as a potential location. This is across the road from the OMRD Historical Pit and therefore would use the same distribution line.

Table 2: Brownfields selected for community solar development in the MD of Pincher Creek

Number	Name	Distance (km)	Voltage (kV)	Capacity (kW)	Feeder
1	John Cervo Pit	0.58	25	2035	799S-181LE
2	Orphaned Well: 6	0	25	596	799S-181LE
3	Highway 22 Pit (MD Land)	0	25	1291	799S-181LE
4	Reners Pit (MD Land)	0	14.4	150	799S-181LE
5	Old Smyth Pit	0.37 // 0.31	14.4 // 25	<150	396S-41LE
6	OMRD Historical Pits (Reclaimed)	0.36	8	<150	396S-41LE
7	Summerview Pit (MD Land)	0	14.4	<150	396S-41LE
8	Abandoned Well: 0013351	0	25	1753	502S-425LS

The brownfield locations in the Summerview area are shown in Figure 8, Northwest Region are in Figure 9, and Beaver Mines in Figure 10 for reference.



Figure 8: Brownfields identified in the Summerview Area of the MD of Pincher Creek



Figure 9: Brownfields identified in the Northwest Region of the MD of Pincher Creek



Figure 10: Brownfields identified in the Beaver Mines Area of the MD of Pincher Creek

For the purpose of this analysis, the focus will be on the Abandoned Well: 0013351 shown in Figure 10 which has a favourable landowner and capacity of up to 1.7 MW in addition to road access. The process can be repeated for the other sites identified.

Market Analysis

The energy market in Alberta allows the sale of electricity through the Alberta Electric Systems Operator (AESO) Commercial Generators, Small Scale Generators (SG), or directly through the site owner's retailer as a Microgenerators (MG). For the purposes of this analysis, only SG and MG systems will be analyzed as they fit within the size criteria preferred by the community as noted above. Demand drivers, current power pricing, and the target market are also reviewed.

Small Scale Generator

The Electric Utilities Act Small Scale Generation Regulation establishes SGs to be generators that are connected to the distribution network in Alberta and supply electricity from renewable or alternative sources with emissions lower than 418 kg CO2e per MWh [4]. Based on published emissions averages from the National Research Laboratory, this allows for projects such as wind, solar, hydro, geothermal, nuclear, and biomass to be eligible [5].

According to Fortis Alberta the distribution systems generally have a maximum capacity of 24 MW which sets the upper limit on project size [6]. For SG units under 5 MW dispatch services are not required and energy is sold automatically at pool price, however for SG sites larger than 5 MW, dispatching is required meaning offers must be submitted to the AESO for sale [7].

Micro Generator

The Electric Utilities Act also published a Microgeneration Regulation which outlines the eligibility criteria for a generator to be classified as a MG [8]. This classification is broken down into Small and Large MG, which both use net billing to credit any energy produced and sold against the energy purchased from the grid by the site owner.

In order to be eligible for MG status and thus net billing, the generator must be connected through a meter that is owned by the same entity as the load and paid for under the same retailer. The generator and load can be co-located on the same site, or on different sites, however both generator and load must also be on the same feeder line. There is also allowance to aggregate multiple loads on the same feeder line against one single MG site. The small and large MG classification affects how the energy settlement is completed which is outlined in the following sections. The total annual generation is limited to the total annual consumption so these systems cannot export more than they produce over the course of a year.

Small Microgenerators

Small MG sites are limited to 150 kW of nameplate capacity and are provided a bi-directional meter to settle the energy consumption and production on a monthly basis. An interval meter may be requested but the wires owner is not obligated to install it at no cost to the customer.

For Small MG sites, the energy produced is sold at the same rate as the energy consumed from the grid, therefore creating a one for one offset. The interconnection process for the Small MG sites is done through a basic application to the local distribution owner.

Large Microgenerators

Large MG sites can be up to 5 MW in size and are credited at the wholesale AESO price for any energy exported. This allows for the generators to consume energy directly on site but means they won't be getting direct one for one offset credit values. The interconnection process for these systems is often more in depth due to the size and complexity of the systems.

Power Purchase Agreements

Due to the deregulated nature of the Alberta Energy Market, generators are able to connect to the transmission system without any energy offtake agreements and sell directly through the power pool. The power pool can fluctuate significantly minute to minute, day to day, and year to year, meaning there can be long periods of low or high electricity costs. These periods benefit generators and loads inversely. To hedge against the risk of adverse power pricing loads can enter into power purchase agreements (PPA) with generators to guarantee a price for their consumed energy.

For renewable energy projects, these PPAs have also been used to acquire the sustainability components " Renewable Energy Credits (RECs)" of the power to meet regulatory requirements of the Technology Innovation and Emissions Reduction (TIER) program or voluntary goals.

Demand Drivers

The AESO produces a long-term outlook (LTO) document projecting the demand growth, generation additions and retirements, and the associated policy drivers, risks, and impacts. The 2024 LTO projects significantly stronger electricity demand growth compared to previous forecasts. This outlook reviews three possible scenarios; decarbonization by 2035, alternative decarbonization, and high electrification [9].

The high electrification case shown below in Figure 11 projects faster adoption of EVs, heating, hydrogen, and CCUS, driving demand growth creating sharper ramps that require more flexibility and transmission expansion. The decarbonization by 2035 model aligns with federal Clean Electricity Regulations, constraining unabated gas generation and relying heavily on renewables, storage, and imports, which projects higher adequacy risks, particularly in winter, with expected unserved energy projected to rise significantly in the mid-2030s. The alternative decarbonization case models a more gradual trajectory toward decarbonization, extending the timeline beyond 2035; in this version, more natural gas capacity remains available longer, adequacy risks are reduced compared to the 2035 case, and the system transitions at a less disruptive pace while still increasing reliance on clean resources over time.

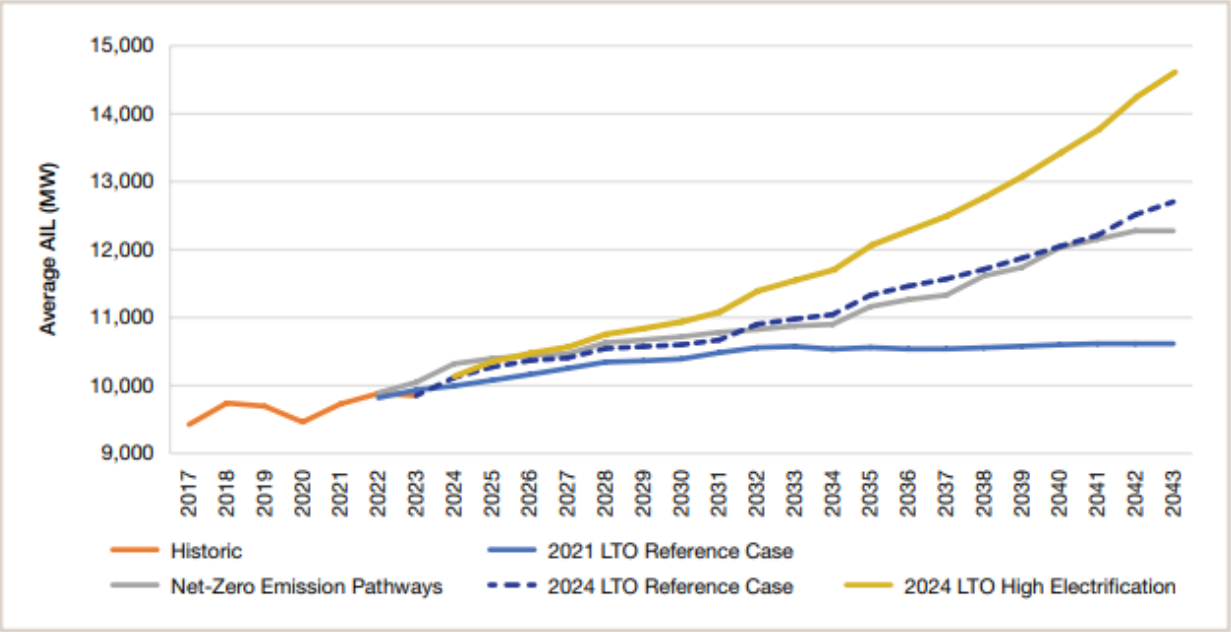


Figure 11: High electrification case from the 2024 AESO LTO [9]

In the reference case shown below in Figure 12, provincial load increases at an average rate of approximately 1.2 percent per year reaching an average internal load of about 12,000 MW by 2040, while in the high electrification case the growth rate rises to about 1.9 percent per year reaching 13,500 MW by 2040.

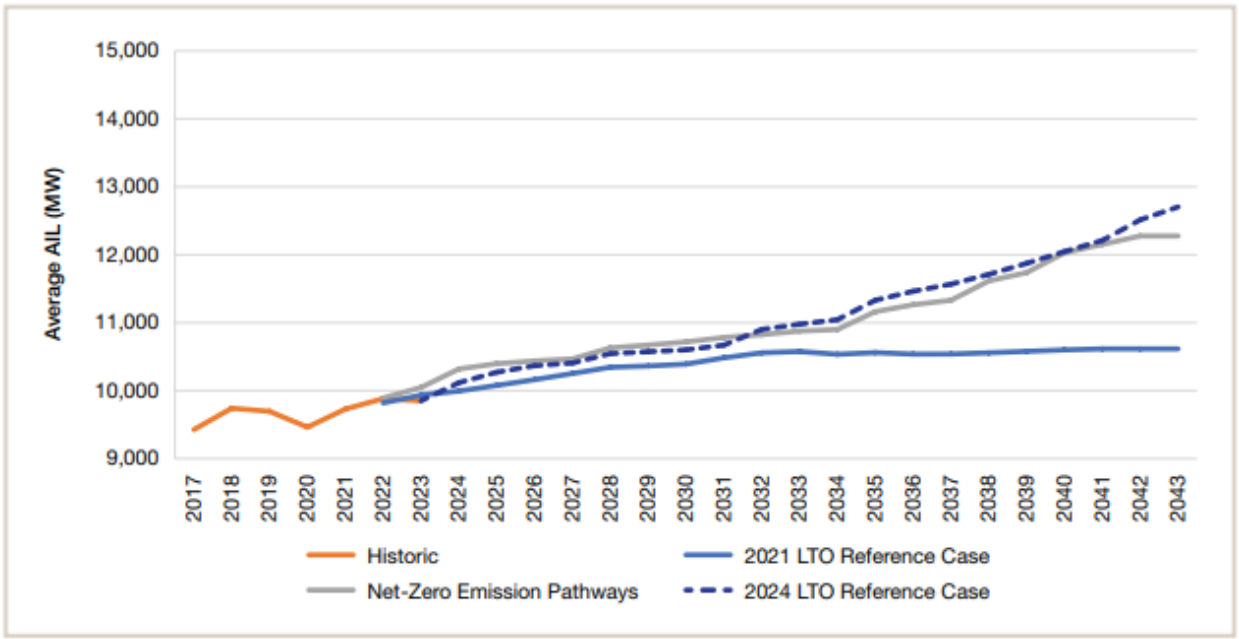


Figure 12: Reference Case from 2024 AESO LTO [9]

The primary drivers of this change are associated with electrification, industrial development, and new forms of load. Electrification of transportation and buildings, including the increasing adoption of electric vehicles and electric heating, is expected to have the largest long-term impact. These changes are not only expected to raise total demand but will likely also reshape the hourly load profile, introducing sharper morning and evening ramps and reinforcing Alberta's position as a winter-peaking jurisdiction.

Industrial activity remains an important near-term and medium-term source of demand. Oil sands operations, new hydrogen production facilities, and carbon capture, utilization, and storage (CCUS) projects are all expected to contribute to future load growth. These projects typically add demand in large, discrete increments, and because they are often geographically concentrated, they can create localized stress on the transmission system in addition to increases in overall provincial demand. In Alberta, many of these sites produce their own electricity as self generators and therefore can be expected to offset some of the impacts introduced. Currently, some of the largest generators in Alberta are cogeneration or combined heat and power systems tied to Oil sands production such as the Scotford baseplant or CNRL horizon station [10].

Another potential driver identified in the LTO is the growth of data centres and high-performance computing facilities. The scale and speed of these connections introduce additional uncertainty into provincial load forecasting and transmission planning.

The report also identifies some risks associated with Alberta's electricity demand peaks during the wintertime. The electrification of heating will further amplify demand during periods of extreme cold. The AESO identifies the year 2038 as particularly critical in multiple scenarios. By that time, the retirement of coal-to-gas converted units will reduce available firm capacity, coinciding with ongoing load growth. This combination raises the risk of unserved energy. Under more stringent decarbonization scenarios, such as the federal target of net-zero electricity by 2035, the risk is projected to be even greater, with expected unserved energy concentrated in winter periods when adequacy margins are already thin.

These developments have several implications for system planning and resource development. The AESO notes that flexible, dispatchable generation will remain a central requirement for maintaining reliability. Combined-cycle natural gas, CCUS-retrofitted units, and hydrogen-capable facilities are all identified as options to provide firm capacity and flexibility to manage winter peaks and sharper ramps. Energy storage, while increasingly important, is limited in

duration and is unlikely to fully cover extended winter peak conditions on its own. Demand-side flexibility, including managed EV charging and demand response programs, is expected to play a growing role in reducing system stress, while aggregated DERs can provide additional localized support. Transmission planning must also account for the uneven distribution of load growth across the province, particularly in regions where large industrial projects and data centres may connect.

Current Power Contract Costs

In Alberta, consumers can chose to be on a variable or fixed rate electricity contract which is provided by retailers. Current electricity contracts are being sold to consumers between 6.890¢/kWh for a one-year contract up to 11.290¢/kWh for a five-year contract based on UCA helps data as of November 2025. These values act as a benchmark for the sale price from the solar project as end users will be unlikely to pay higher rates than what is offered in the market.

Carbon Markets

The carbon markets offer an opportunity to earn additional income from the project's sustainability credits associated with the generation of clean energy on the Alberta grid which has set an offset value of 0.31 $tCO2_e$/MWh generated. The carbon value is estimated at \$31/$tCO2_e$ based on current market rates [11], [12]. The \$31/$tC02_e$ is based on current trading activity, however the price has upside to \$95/$tC02_e$ based on current carbon pricing caps [11] These credits can be traded on the Alberta TIER compliance market or through international voluntary markets.

Target Market

The target market will differ for a solar project with and without batteries. Solar will focus more on the energy market directly, while batteries have opportunities to bid into markets like Ancillary services or Fast Frequency response (FFR). Ancillary services are broken up into Regulating, Spinning, and Supplemental Reserves, each of which has different criteria for bidding and also separate payout structures.

The solar and battery opportunities are broken down in the following sections.

Solar Energy Only

The average electricity pool price fluctuates year to year as shown in Figure 13 below with data referenced from the AESO 2024 market Report [13]. As observed, power prices saw a trough in 2015-2017, and then a large spike in 2021-2023. Power prices have now decreased again in

2024 and 2025 due to the increase of wind and solar bidding at $0/MWh, however it can be expected that these swings will continue as more load is brought on.

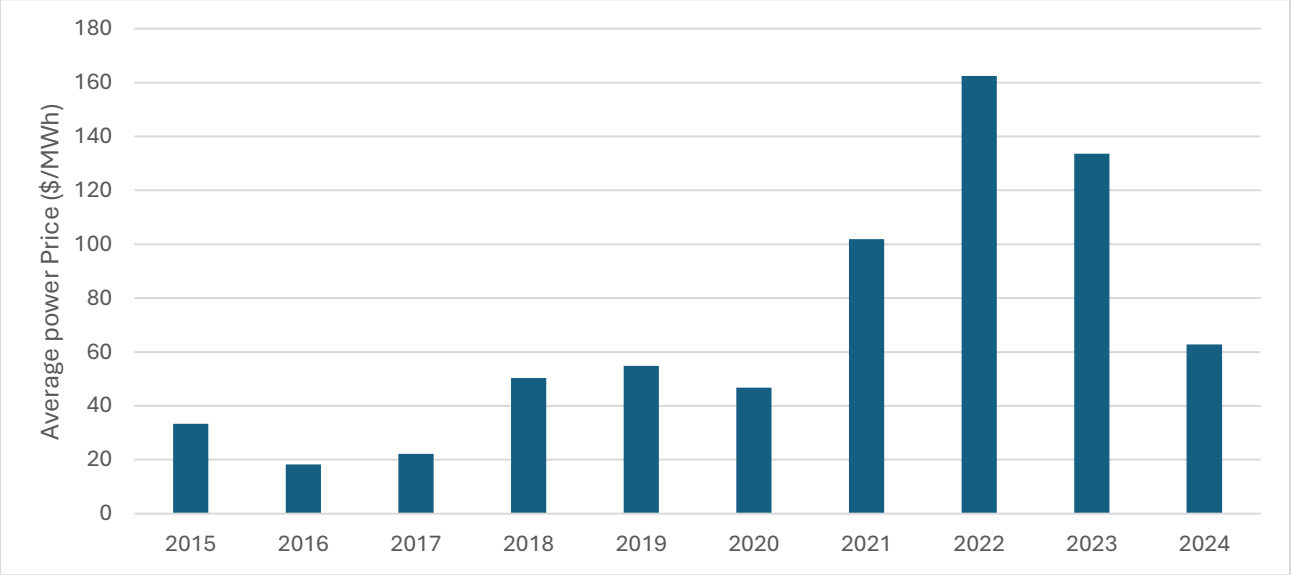


Figure 13: AESO annual average electricity pool prices ($/MWh)

In order to derisk the project it is recommended to pursue a PPA to contract stable power prices. Due to the small size of the project, larger off takers that typically contract energy will be less interested and the project should look to identify alternative options for contracts. Additionally, the energy market in Alberta has seen a reduction in demand for renewable contracts over the last two years, with total contracted capacity going from 2,865 MW in 2021-2023, to just 58 MW in 2024 and 2025 [14].

To mitigate this, a focus on local entities could prove fruitful and align with the community centric nature of this project. Potential off takers in the Pincher Creek Region include the Cavvy gas plant, the Pincher Creek Co-op, Livingstone School District, Town of Pincher Creek, or MD of Pincher Creek.

Alternatively, the proposed structure provides a unique advantage in sourcing PPAs from organizations pursuing a triple-bottom-line approach by delivering environmental, economic, and social value in a single offtake agreement. Unlike conventional power contracts, purchasing energy from a locally owned project directly supports community self-determination, economic development, and long-term revenue that stays in the region. With a small size, the contract value will have minimal financial impact on overall corporate power costs, but purchasing from a community owned plant could provide strong marketing potential. Organizations can

therefore demonstrate not just emissions reductions, but also tangible social impact. Some examples of organizations who may be interested include the larger cities in Alberta, Alberta Universities, Canadian Banks, Amazon, Microsoft, and impending data center operators.

Solar with Batteries

Batteries can be used in a variety of ways to add value to the project. These include optimizing export timing, providing ancillary services, or contracting into the FFR program. There are minimum thresholds that must be met to enter some markets such as 5 MW for supplemental reserves. For this analysis it is assumed that those minimums can be met through aggregation with other assets. The Alberta Restructured Energy Market (REM) is also expected to lower the minimums to 1 MW within the next two to three years therefore allowing for direct bidding of this project scale.

Batteries can be used to optimize the daily energy output which can fluctuate significantly as shown below on May 5, 2021 in Figure 14. The battery does this by storing energy during low periods and exporting during peak times which can increase the value of the Solar PPA, however based on historic pricing this value is not enough to offset the additional cost of the batteries.

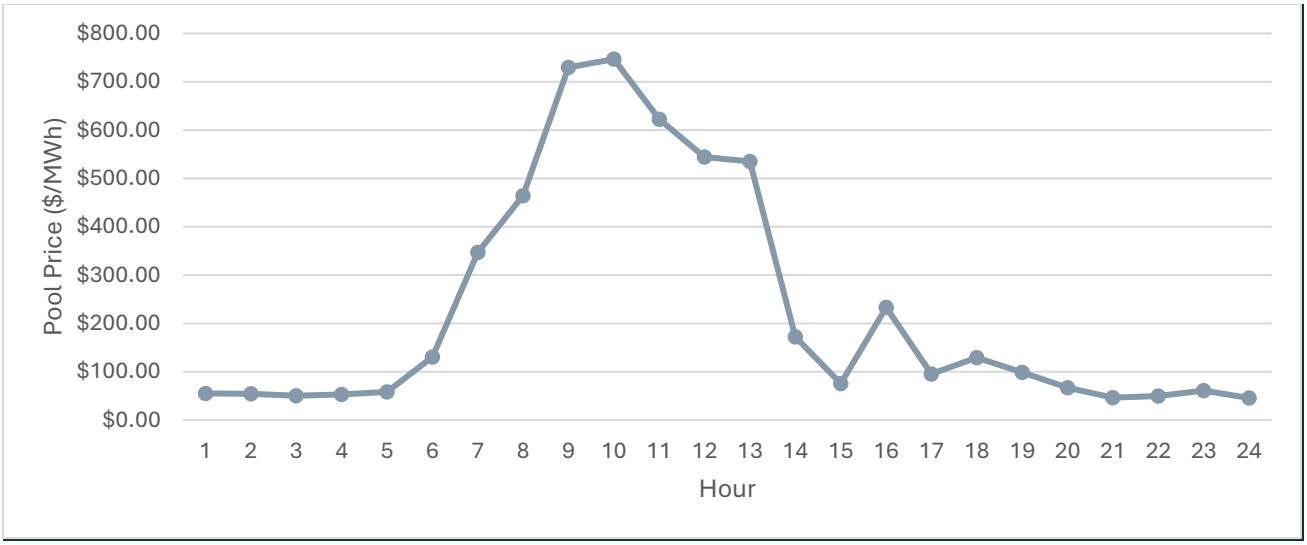


Figure 14: AESO Power pool price for May 27, 2025 [10]

The ancillary markets provide an alternative revenue source which is benchmarked against the pool price but has historically provided higher returns. Based on the 2024 Market Report the volume of reserves procured stays consistent around 5,700 GWh per year within approximately 10%. The valuation of these reserves is more stable than the pool pricing but is still subject to

fluctuations as shown below in Figure 15. Assuming 1 MW bid into the market for 8,760 hours the income would range from $192,000 to $713,000 annually [13]

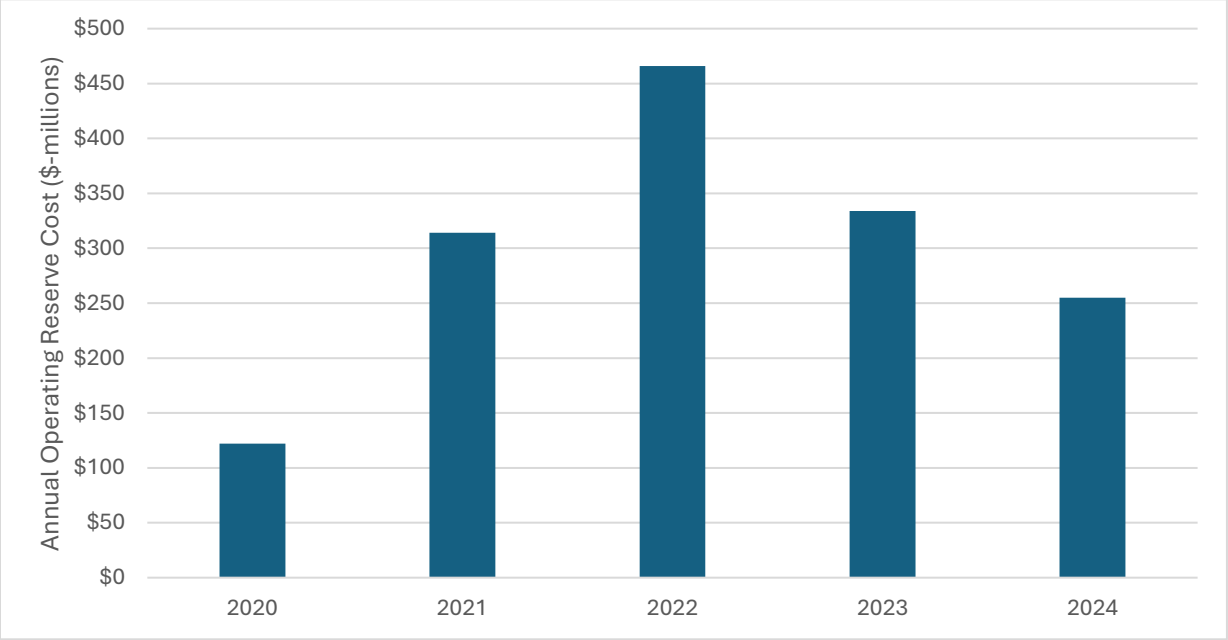


Figure 15: Annual AESO operating reserve costs

Technical Analysis

For a solar and battery storage project there are several factors that are considered within the design and development. The foundation of this is the solar resource which indicates how much energy can be generated. The environmental impact of the project in construction, operations, and decommissioning must also be acknowledged and mitigated. Finally, an operations plan must be developed to ensure the project is able to maximize uptime and returns.

Solar Resource

The solar resource throughout the MD of Pincher Creek is estimated using the NRCan Photovoltaic potential and solar resource maps of Canada and the Global Solar Atlas using a south facing latitude tilt at various locations throughout the MD[15][16]. The resource estimates are displayed as kWh/kWp which represents the amount of electricity that will be generated each year for every kW of DC capacity that is installed. Based on the Global Solar Atlas tool, the resource within the MD ranges from 1,458 kWh/kWp in the Northwest to 1,566 kWh/kWp on the Eastern side of the MD. These values are approximately 15% higher than the NRCan results which indicated 1,274 kWh/kWp annually at latitude tilt, although the NRCan

map only allows for the closest municipality to be chosen. For the purposes of this analysis the NRCan data will be used.

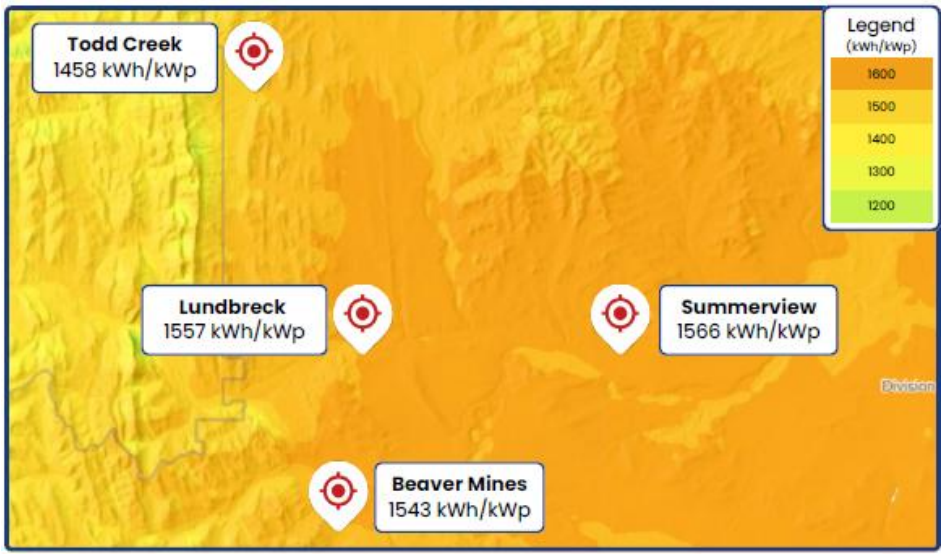


Figure 16: Solar resource potential within the MD of Pincher Creek from the Global Solar Atlas[15]

Project Features

The project will be composed of a fixed tilt ground mounted solar array with the potential to add a battery storage system. The project will require DC to AC inverters, a main power transformer to increase voltage to match the distribution line, protection and switchgear to meeting the distribution operator's requirements, monitoring and control, and a revenue grade meter, The solar array will be sized at 1.5 MW of AC output to meet the restrictions of Site 8 which is being used as the reference site for the business plan.

Solar Array

The design criteria for the solar array is shown below in Table 3. Bifacial panels are chosen to increase generation potential, optimizing for light reflecting off the ground or snow. The tilt of the panels is set to the latitude value which is industry standard for fixed tilt projects. In order to optimize generation, the DC capacity of the solar array is oversized to the AC capacity by 30%. By installing more DC capacity than the AC export capacity, the project loses some energy when at peak conditions, called "clipping", however increases the energy produced at all other times. Peak conditions require optimal tilt, time of day, atmospheric conditions, and time of year, therefore generally occur a small percentage of the time. The increased generation outside of peak times outweighs the losses at peak, with clipping losses reported at approximately 3% of annual energy [17]. With these criteria established the annual generation

for the proposed site is 2,236 MWh which degrades at an expected 0.5% per year due to panel efficiency losses.

Table 3: Technical design criteria and outputs for a 1.5 MW solar array

Criteria	Value
AC Size	1.5 MW
DC Size	1.95 MW
Panel Type	Bifacial
Panel Tilt	49.5^0
Clipping Losses	3%
Inverter Efficiency	93%
Annual Generation	2,236 MWh
Lifespan	30 years

Battery Energy Storage System

A battery energy storage system (BESS) can be added to the project to increase flexibility and diversify the markets accessible to the owners. The technical specifications for the BESS are shown below in Table 4. For the chosen site a 1 MW/4 MWh BESS is chosen to maintain export flexibility. The battery will tie in directly to the DC side of the system to reduce conversion losses and limit requirements for additional equipment.

Table 4: Battery Energy Storage System design specifications

Criteria	Value
Capacity	1 MW
Storage Time	4 Hours
Energy Capacity	4 MWh
Interconnection	DC Coupled

Operations Plan

The long-term operations and maintenance (O&M) strategy for the solar project and optional BESS is designed to ensure reliable performance, minimize downtime, and support local participation in the project's upkeep.

The technical operations such as inverter servicing, transformer and switchgear maintenance, racking system inspections, and battery monitoring will be contracted out to a qualified O&M provider. This contractor will also handle system performance tracking, diagnostics, and annual reporting. Equipment warranties help reduce long-term risk, with solar modules typically carrying 25–30-year performance warranties and 10–12-year product warranties, inverters are typically covered for 5–10 years, racking systems warrantied for 20–30 years, and battery systems backed by 10–15-year or cycle-life guarantees depending on the supplier.

Non-technical site work will be supported locally. Vegetation control will be performed on a recurring schedule to manage shading, weeds, and maintain safe access, which can be delivered by local land management groups or agricultural operators. Fencing repairs, minor site cleanup, and general upkeep will also be carried out by community groups or local businesses. Access road maintenance will fall to either the MD or the private road owner, depending on existing road responsibilities, with the project contributing as required to ensure year-round access for maintenance crews.

Environmental Impact

The project has been designed to minimize environmental impact and reflects extensive input gathered through consultation with the community and Council. Opportunities to improve land condition and remediate brownfield sites have also been identified.

Site selection was guided by feedback from open houses, surveys, community conversations, and formal presentations to Council, which consistently emphasized the importance of avoiding disruption to undisturbed lands. As a result, the project prioritizes development on brownfield sites to reduce environmental disturbance and preserve high-value agricultural and natural areas.

Vegetation and weed management will be undertaken by site operators through routine mowing and targeted mitigation to protect surrounding lands in partnership with local land owners and the MD. The use of screw-pile foundations, a design choice supported during community engagement sessions for its low-impact characteristics, further reduces soil

disturbance and eliminates the need for concrete. These foundations will be fully removed during decommissioning, allowing the site to be restored to its pre-project condition. Overall, the project's environmental approach reflects both engineering best practices and the priorities identified through meaningful community and council engagement.

Agricultural benefits can be realized from the addition of solar as well ranging from increasing soil health to supporting topsoil regeneration. By adding solar panels over a cover crop it helps to reduce water evaporation and heat stress under the summer sun. These cover crops can cause reintegration of nutrients into the soil and development of biomaterial to replenish the topsoil removed during the previous site developments. Integrating livestock such as sheep can also help to promote topsoil regeneration and support the management of vegetation, lowering requirements for manual mowing [18].

Financial Analysis

The financial analysis of the solar project integrates the expected electricity generation, market cost of electricity, market opportunities for batteries, as well as the associated costs. The costs include the development and design phases of the project, capital expenditures in construction, and ongoing O&M costs. The following sections review these factors and present the results of a financial model indicating the return characteristics. A sensitivity analysis is also completed to identify the impact of changing different criteria within the project.

Income

The expected income for the project is benchmarked against the current market rates noted in the Market Analysis section and shown below in Table 5. The electricity rate and carbon rate is assumed at \$80/MWh and \$30/t$CO2_e$ respectively to align with the current market rates. With the estimated generation of 2,236 MWh annually, those products produce an estimated income of \$179,000 and \$20,700 respectively for a total annual income of \$199,000. Adding the batter at a conservative estimate of \$250,000/MWyear produces an extra \$250,000 for a total income of \$449,000. The energy and battery rates are increased at 1% each year to account for inflation, while the carbon value is kept consistent at its reduced value due to uncertainty in the carbon markets moving forward. These estimates are conservative as they are lower than current market rates and increases will be explored in the sensitivity analysis.

Table 5: Income values for the Pincher Creek solar and battery projects

Resource	Unit Rate	Annual Value
Electricity	$80/MWh	$179,000
Carbon Credits	$30/$tCO2_e$	$20,700
Solar+Carbon		**$199,000**
Battery	$250,000/MWyear	$250,000
Solar+Carbon+Battery		**$449,000**

Capital Cost

The capital cost of the system is estimated through industry standard values. The solar and BESS industry is in a mature state where prices and installation costs have become relatively well understood. NREL has modeled the system cost for a small-scale community solar project which are estimated between $USD1,489/kWdc and $USD1,761/kWdc or $CAD2,084/kWdc and $CAD2,465/kWdc at the current conversion of 1.4 CAD/USD. These values align with current Canadian market estimates and have been used as a baseline to develop the cost estimates for this project. The component costs are broken down in Table 6 below and include the modules, inverters, electrical balance of plant, structural balance of plant, labour, design, and development costs. Physical components include a 15% profit margin. The development costs include permitting and approvals, interconnection costs, agreement negotiation and investment attraction. The design costs include electrical, civil, and geotechnical engineering aspects of the project. The electrical balance of plant includes all associated electrical equipment including but not limited to protection and controls, feeders, switchgear, and SCADA system. The structural balance of plant includes but is not limited to racking, foundations, piling, and access. Interest during construction is the interest paid on the loan prior to the project generating income, and reserve accounts are funded at the end of construction to cover any debt payments in the case of a low electricity year or large maintenance items [19]. The capital cost of the project is estimated at $2,301/kWdc for a total of $4,487,100 which should be verified by contractor quotes in future stages of the project.

Table 6: Capital costs for community solar project

Component	Unit Rate	Total Cost
Development	$120/kWdc	$234,000
Design	$127/kWdc	$247,500
Overhead and Admin	$77/kWdc	$150,000
Modules	$600/kWdc	$1,167,900
Inverters	$79/kWdc	$153,800
Electrical Balance of Plant	$415/kWdc	$810,000
Structural Balance of Plant	$248/kWdc	$483,400
Labour	$361/kWdc	$704,000
5% contingency	$101/kWdc	$197,500
Interest during construction	$59/kWdc	$114,000
Reserve accounts	$115/kWdc	$225,000
TOTAL	**$2,301/kWdc**	**$4,487,100**

Adding a 1 MW/4MWh battery to this project increases costs for some components including the cost of the BESS itself, foundation, and additional labour. There is also shipping considerations, additional overhead, and profit to be added [19]. The total project costs with the addition of the BESS are displayed below in Table 7.

Table 7: Capital cost of Pincher Creek community Solar plus BESS

Component	Unit Rate	Total Cost
Development	$120/kWdc	$234,000
Design	$127/kWdc	$247,500
Overhead and Admin	$77/kWdc	$150,000
Modules	$600/kWdc	$1,167,900
Inverters	$79/kWdc	$153,800
Electrical Balance of Plant	$415/kWdc	$810,000
Structural Balance of Plant	$248/kWdc	$483,400
Labour	$361/kWdc	$704,000
5% contingency	$101/kWdc	$197,500
Interest during construction	$59/kWdc	$114,000
Reserve accounts	$115/kWdc	$225,000
SOLAR	**$2,301/kWdc**	**$4,487,100**
Battery components	$452/kWh (BESS)	$2,170,560
Extra Labour	$78/kWdc	$152,800
Foundation	$24/kWdc	$23,800
5% contingency	$61/kWdc	$118,000
Interest during construction	$35/kWdc	$71,000
BESS	-	**$2,536,160**
Solar+BESS	-	**$7,023,260**

Operational Cost

The operational costs for the project are composed of administration, property taxes, asset management, Insurance, lease, equipment replacements, inspections, and site maintenance. The costs are estimated from industry standard values are shown in Table 8 below. The property tax is estimated using the industrial mill rate of 10.5553 in the MD of Pincher Creek and an industry standard depreciation schedule for the asset. The lease is assumed to be $5,000 per year for a 10-acre parcel which is significantly above market rate and part of the community benefit incentive of the project. The asset management and O&M contract is estimated at $37,500 per year escalating at CPI annually based on conversations with solar contractors throughout Alberta. The final cost is general administration such as tax filing and insurance estimated at $3,750 annually and escalating at CPI annually. Altogether the costs range from approximately $31/kW to $40/kW depending on the deprecation of the asset affecting property taxes. These costs are corroborated by the values found in the NREL Capital Cost and Performance characteristics which reports annual O&M costs to be $USD20.23/kW ($CAD28.32/kW) and the community energy system from the U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks of approximately $USD25/kW ($CAD35/kW) without the inclusion of subscriber management[19] [20]. Approximately 40% of the O&M costs reported for NREL community solar projects comes from subscriber management which are minimized but not completely removed in for the purpose of this analysis.

Table 8: Approximate Operations and Maintenance costs for the Pincher Creek community solar project

Cost Center	Annual Cost
Technical O&M	$37,500
Property Tax	$31,000
Overhead and Admin	$3,750
Lease	$5,000
TOTAL	**$77,250**

Adding a battery to the system increases the technical O&M costs as well as the property tax which is evaluated based on the value of the asset. These extra costs are shown below in Table

9With the 1 MW BESS, an additional $38,000 is added in technical O&M and $13,000 in property taxes bringing the total annual cost to approximately $148,500 or $76/kWdc aligning with the $USD58/kWdc ($CAD81/kWdc) from the U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark.

Table 9: Approximate Operations and Maintenance Costs for the Pincher Creek community solar and BESS project

Cost Center	Annual Cost
Technical O&M	$75,500
Property Tax	$44,000
Overhead and Admin	$3,750
Lease	$5,000
TOTAL	**$148,500**

Financing

To construct the project, it is expected to use a standard 80/20 debt to equity ratio that is typical with larger infrastructure projects. There are also several grant streams available to support project initiatives like this which are integrated into the financial model along with the Federal Investment Tax Credit (ITC) for 30% of eligible capital expenditures after grants. The financing details are displayed below in Table 10. The Federation of Canadian Municipalities offers a grant for 15% of project costs, while they also offer a grant for up to $200,000 for the design aspects of the project [21] Within the capital program there is also a loan available for 80% of the project costs, which is typically at a lower interest rate than conventional financing. Based on previous project experience this is expected to be approximately 2.1%. It is assumed that the project starts on a construction loan at 6% over the two-year construction timeline and then refinances to the lower rate, however this is conservative considering the FCM loan could cover the construction period. The values below are approximations based on the funding available and subject to change with program rules, cashflow timing, and other circumstances.

Table 10: Sources of funding for the Pincher Creek community solar and BESS project

Source	Rate	Solar Value	Solar+BESS Value
Equity	20%	$897,960	$1,409,800
FCM development grant	$200,000	$200,000	$200,000
FCM CAPEX grant	15%	$600,607	$984,486
FCM low interest loan	2.1%	$3,591,843	$4,851,611
ITC	30%	$1,005,948	$1,640,475

The final annual costs include the debt repayment associated with financing which is paid out of cashflow after operating expenses, and the income tax payments for profits once the depreciation is exhausted. These values are shown below in Table 11 for each project respectively. The financing payment remains fixed while the interest and principal portions adjust each year based on how much cost still remains to be paid out. The income tax payment is 11% based on the Alberta tax rate for businesses with $500,000 or less of revenue.

Table 11: Annual financing payment for the Pincher Creek community energy projects

Cost	Solar Value	Solar+BESS Value
Financing payment	$122,969	$193,502

Equity Strategy

Based on the community energy model, two potential models for raising the equity are analysed. The first is the conventional method of raising capital through a corporate structure, and the second a co-operative model where shares in the project are sold to community members.

For the co-operative model, it is assumed that shares will be worth $5,000 each based on feedback from the open house held on October 23, 2025. This would mean 180 shares would need to be sold for the solar project, or 282 shares for the solar and BESS project.

Project Economics

The project economics reviewed in this section include a cashflow analysis and overall returns for the project as a whole as well as individual share holders within the co-op structure. The estimates presented in the sections are based on indicative values and projected returns and should be reviewed by a qualified professional prior to investment. The unlevered annual cashflow and cumulative cash for the solar project alone is shown below in Figure 17. The cumulative cashflow breaks even at year 13 with the return of the ITC at year upon commercial operation of the plant and net cash return of approximately $3.2 Million. Unlevered cash flows indicate a project financed completely by equity with all cash returning to the equity holder. This can be preferred when debt payments over burden the annual income or when there is significant equity available.

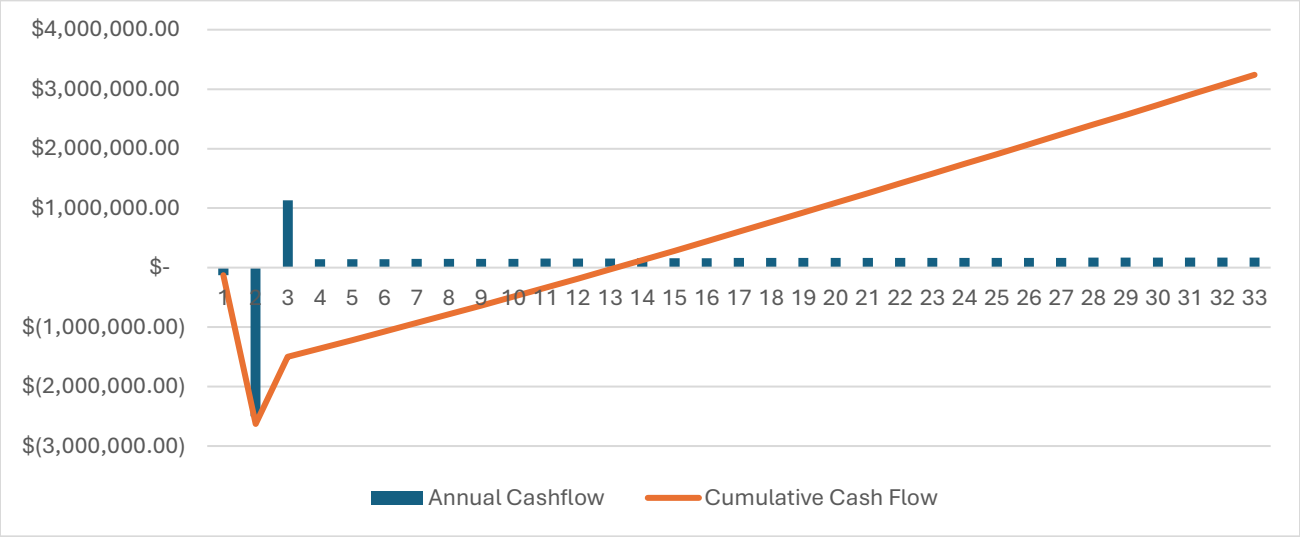


Figure 17: Pincher Creek Community Solar Project unlevered cashflows

The unlevered cumulative cash and annual cashflows for the Solar with BESS project are shown in Figure 18. The cumulative cash shows a breakeven in year 10 with the 30% ITC returned in year 3 and net cash return of approximately $9.5 Million.

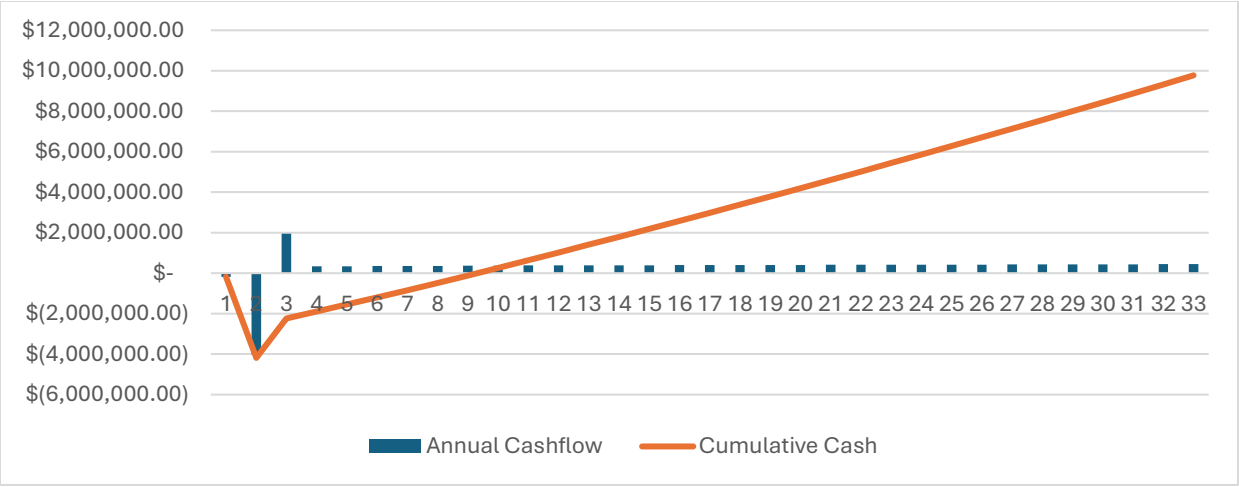


Figure 18:Pincher Creek Community Solar and BESS Project unlevered cashflows

The breakdown of after tax leveraged cashflow is shown in Figure 19 below broken down into O&M expenses, debt repayment, and cashflow to equity. For the solar only project, the percentage of cashflow is dominated by the debt repayment at 59% of annual income, while with the Solar & BESS project the debt repayment is only 43% of annual income. With OPEX percentages at 33% and 27% respectively, the remaining income is transferred to the equity holder amounting to $16k or $136k. For the solar only project, this means that only 8% of the total cashflow returns to the owner after debts are repaid which indicates a less favourable leverage situation than in the Solar & BESS project where they are able to return 30% of the annual cashflow to equity.

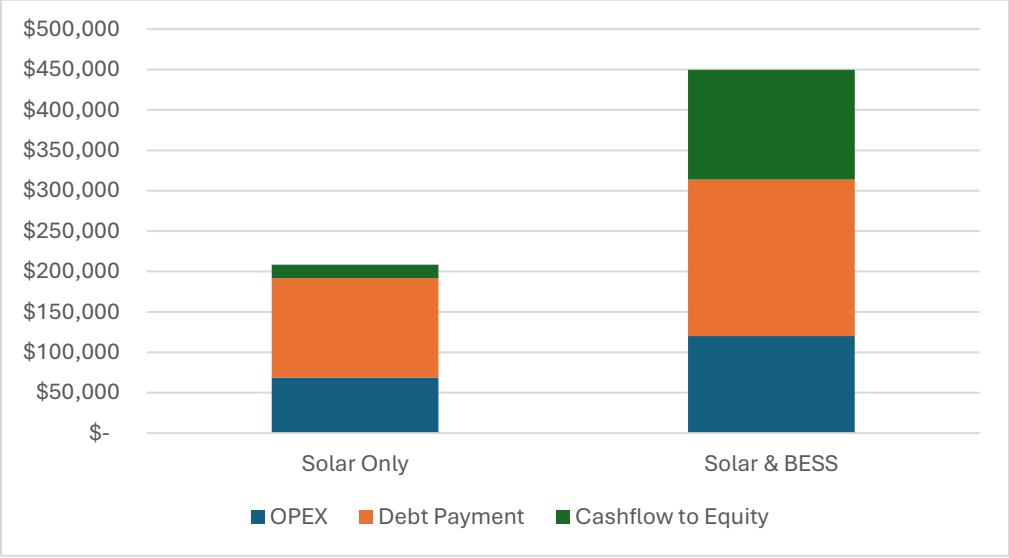


Figure 19: Annual cashflow breakdown for the Pincher Creek community energy projects

For the co-op structure the annual for each share holder is shown below in Table 12. For each project case respectively, the return to equity is divided by the number of shares to provide an annual distribution value. This return value will fluctuate year to year as cost and income varies. At a share price of $5,000 with the anomalous year when the ITC is returned, the payout occurs at year 9 for the Solar + BESS project with the remaining income as profit.

Table 12: Pincher Creek Community Energy Project estimated annual return to co-op shareholders.

	Solar (180 shares)	Solar + BESS (282 shares)
Annual return	$93	$481
ITC year	$687	$1,074

The after tax leveraged cashflows are presented below in Figures 20 and 21 for the respective project configurations. For the solar project alone, although the equity requirement is low, as noted above, the financing repayment ends up taking up a significant portion of the cashflow and returns to equity are lower than they would be with an unleveraged project. Cumulative cash flow doesn't break even until year 25 and net cashflow returned to equity of $185,600. A noticeable decrease in cashflow occurs in year 19 when the project completes it's depreciation and begins to get taxed. For the BESS addition, the financing payment is a much lower proportion of total income, therefore the leverage supports a higher equity return. With the addition of the BESS the leveraged cash breaks even in year 9 with a net cash return to equity of $4.1 Million. These cashflows are indicative and can be optimized with further tax, financing, and amortization adjustments by a finance professional.

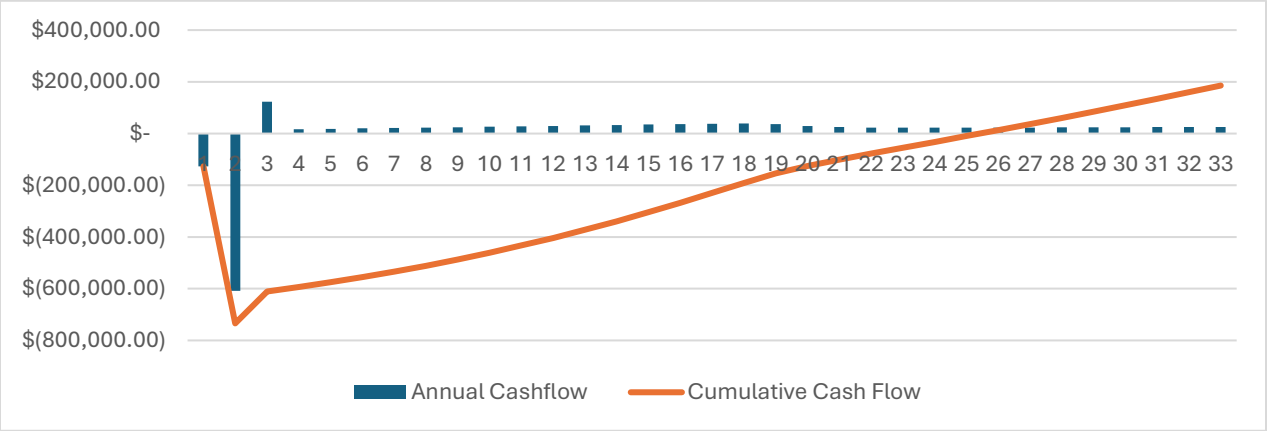


Figure 20: Pincher Creek Community Solar Project leveraged cashflows

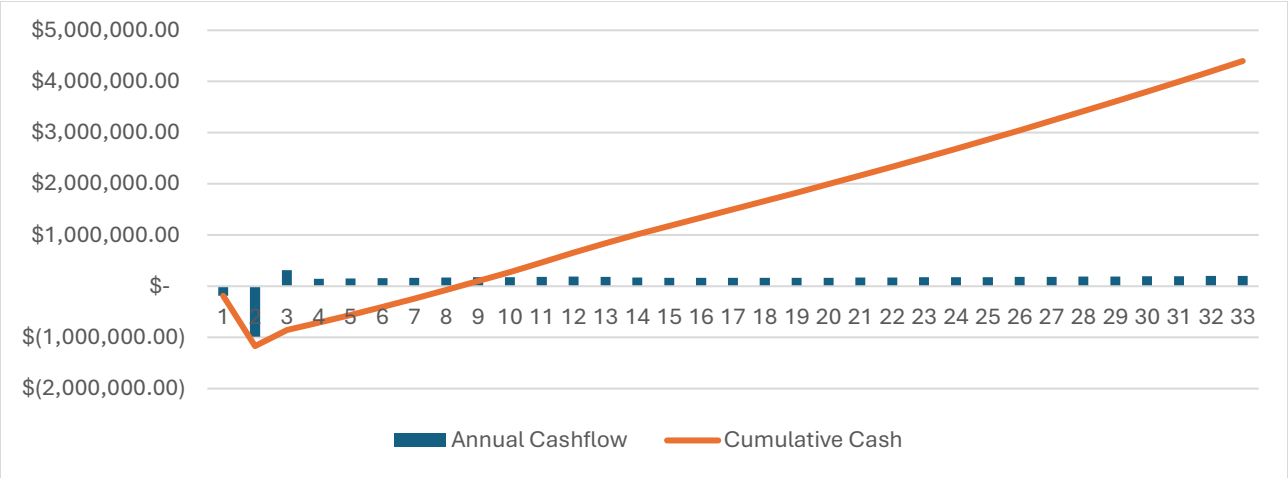


Figure 21: Pincher Creek Community Solar and BESS Project leveraged cashflows

Based on the presented cashflows, the internal rate of return is calculated for each case and presented below in Table 12. Based on industry standard metrics, an internal rate of return of approximately 9-12% is targeted prior to approving investment. The solar project has an indicative IRR of 8% and leveraged equity IRR of 2%, both of which are below the standard for investment. For the Solar & BESS scenario, the indicative IRR is 13% and 15% respectively indicating a stronger investment case. These values should continue to be refined as further project estimates are attained with detailed design and contract estimates, as well as offtake contracts for the energy and carbon attributes.

Table 13: Internal Rate of Return for the Pincher Creek community energy projects

Case	Solar IRR	Solar + BESS IRR
Unlevered	8%	13%
Equity after-tax	2%	15%

Sensitivity Analysis

The estimates used to generate the analysis presented in this report are subject to fluctuation as further details and market conditions are uncovered. To mitigate the risk of these factors, a sensitivity analysis is performed to understand the impact of certain changes on the overall project economics. For the purpose of this analysis the energy price, reserve market returns, carbon price, capital costs, financing rate, and operational costs are all adjusted up down by 30% in 10% increments. A final test was done at 100% increase to observe the effects if certain

factors were to double. The unleveraged and leveraged IRR is shown in Figures 22 and 23 for the Solar only project. Based on these results it is evident that the project faces economic challenges and is sensitive to any adverse events such as cost increases or electricity price drops. The financing rate has the least impact on the project, even if it were to double in rate. The rate of return was most sensitive to capital cost and energy rates meaning if even a 15% reduction in cost can be achieved or a 20% increase in electricity cost, the project could become viable based on typical investment criteria. Overall the leveraged IRR was more sensitive to changes than the unleveraged.

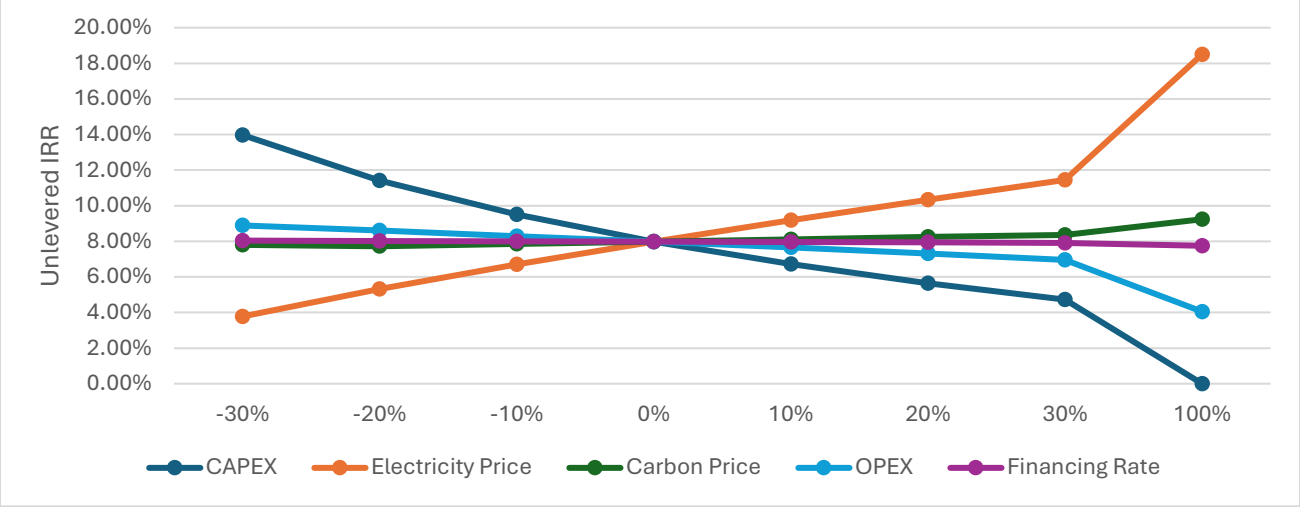


Figure 22: Pincher Creek Community Solar Project unlevered IRR sensitivity

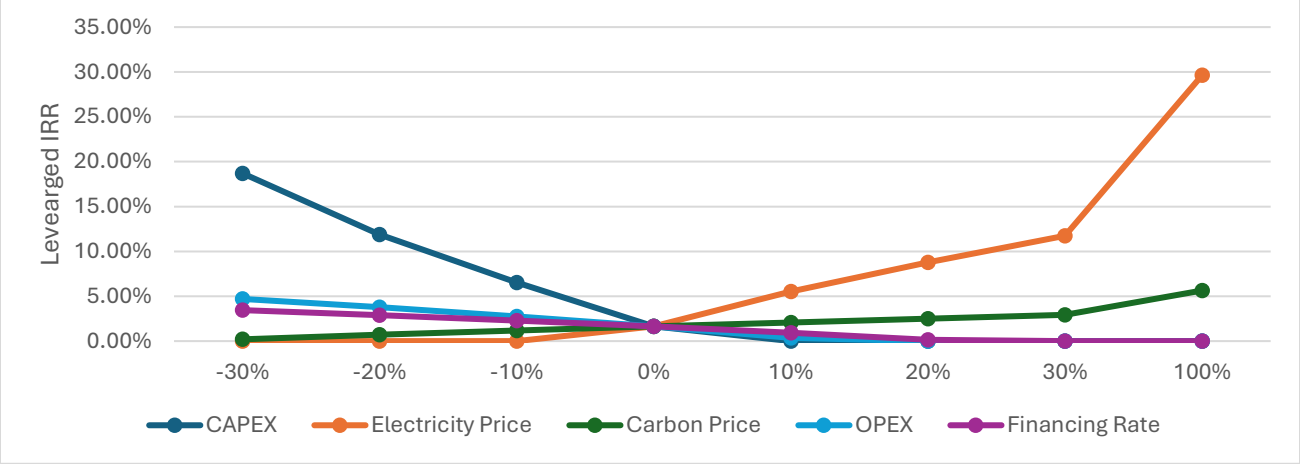


Figure 23: Pincher Creek Community Solar Project leveraged IRR sensitivity

Adding the BESS to the project produced an alternative sensitivity to the various changes which is shown in Figures 24 and 25 below. Overall, the project is more resilient to negative factors, with the investment case being challenged only at capital expenditures rising 20% or reserve market and energy pricing falling by 30%. The leveraged scenario is able to absorb more negative fluctuation and stays within the typical investment range for most cases, although it is impacted less by positive changes as well. Again the capital costs caused the highest sensitivity to change, while the carbon price and financing rate had minimal effect.

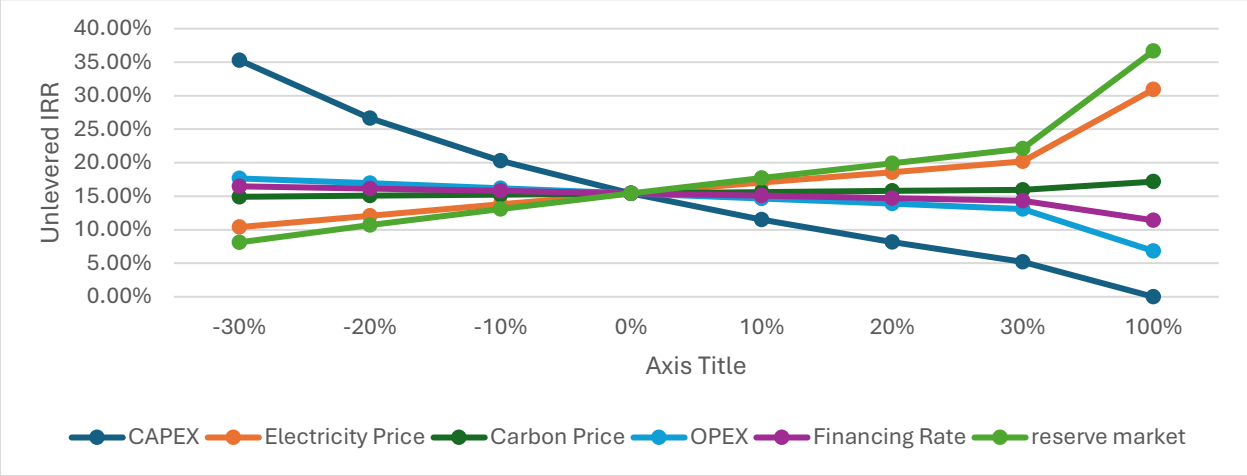


Figure 24: Pincher Creek Community Energy Project unlevered IRR sensitivity with BESS

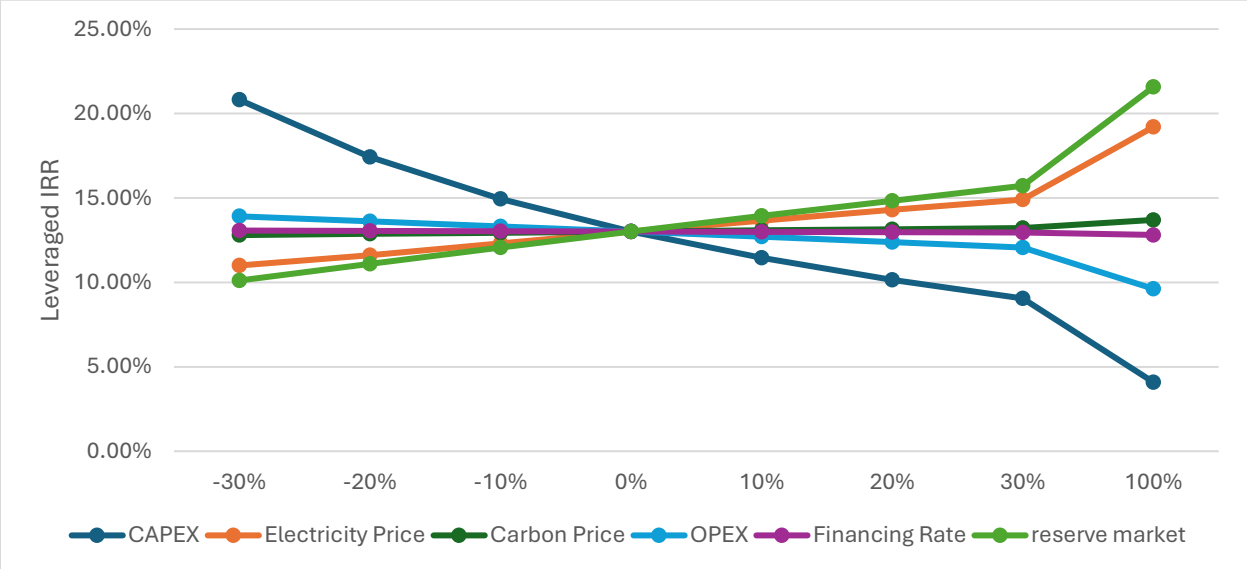


Figure 25: Pincher Creek Community Energy Project leveraged IRR sensitivity with BESS

Risk Analysis

This section outlines the principal risks associated with the development of Pincher Creek Community Energy Project and identifies mitigation measures to maintain project viability and manage uncertainty throughout development, construction, and operations.

Risk: Regulatory and Market Design Uncertainty

Alberta's electricity market is undergoing review, including the potential introduction of a Locational Marginal Pricing (LMP), and additional policy changes that could alter revenue stability and long-term project economics. These evolving rules may affect how distribution-connected solar is compensated, how congestion is priced, and how developers plan project output. Because these changes remain uncertain, they pose a direct risk to the financial predictability and long-term viability of the project.

> **Mitigation:**
> The project will apply conservative revenue forecasts and model performance across multiple policy scenarios to minimize exposure to future regulatory shifts. Securing long-term power offtake agreements with municipalities, institutions, or commercial partners will further reduce reliance on volatile merchant revenues. Ongoing engagement with the AESO, Fortis, and relevant industry associations will allow the project team to stay informed of regulatory developments and adjust planning and design decisions accordingly.

Risk: Distribution System Capacity Constraints

Rural southwest Alberta has limited hosting capacity on many distribution feeders, which may lead to interconnection delays, significant system upgrade requirements, or curtailment risk. Without early assessment, the project could face unexpected capital costs or operational limitations associated with constrained capacity on the local grid. These uncertainties affect the siting, financial structure, and construction schedule of the project.

> **Mitigation:**
> Early interconnection pre-studies with Fortis will help identify feeders capable of accepting a project without substantial upgrades. Where necessary, the project may adopt modular sizing to align with available capacity and reduce the likelihood of curtailment. Potential upgrade costs will be incorporated into the financial model, and

discussions with Fortis will explore the possibility of cost-sharing arrangements or alternative connection pathways to minimize financial and scheduling risks.

Risk: Limited Access to Capital

Community-scale solar projects often face challenges attracting investors or securing competitive debt financing, especially in the absence of guaranteed long-term revenue contracts. The limited scale of the project also reduces leverage for negotiating financing terms, potentially slowing development or creating higher-than-anticipated financing costs that impact overall project feasibility.

Mitigation:

The development team will pursue federal and provincial funding opportunities including NRCan, PrairiesCan, and Emissions reduction alberta to reduce capital requirements and strengthen the financial profile of the project. A well-defined community benefits model, along with early partnership commitments and memorandums of understanding, will improve lender confidence. Leveraging impact investors and lenders will further support access to capital for a project with strong social and environmental value.

Risk: Supply Chain and Construction Cost Variability

The solar industry continues to experience supply chain instability, including fluctuating module and inverter prices, shipping delays, and limited availability of regional EPC contractors. These factors can impact both the cost and timeline of the project, particularly for smaller developments that lack bulk-purchasing advantages.

Mitigation:

The project team will mitigate these risks by securing early procurement agreements or price-hold arrangements for major equipment, ensuring predictable costs. A construction contingency allowance will be incorporated into the budget to absorb unexpected cost escalations or schedule impacts while maintaining project feasibility.

SWOT Analysis

The following information in Table 14 provides details on the strengths, weaknesses, opportunities, and threats of the proposed Pincher Creek Community energy project. While the project faces challenges related to its smaller scale such as higher unit costs, limited economies of scale, and potential line-capacity constraints it also benefits from expected local load growth and the favourable perception of community-led energy initiatives. Significant opportunities exist through the Fortis Community Energy Generator program, as well as Federal and Provincial grants that can enhance financial feasibility and create a repeatable development model for other rural communities. Partnerships with local institutions and co-benefits such as agricultural integration further strengthen the project's value proposition. Key threats include uncertainty around Alberta's market redesign, potential impacts from REM and locational marginal pricing, and continued volatility in energy prices and interconnection costs. Despite these risks, the project offers a resilient, community-aligned pathway to local energy generation, economic diversification, and long-term rural energy security.

Table 14: Strengths, Weaknesses, Opportunities, and Threats analysis for the Pincher Creek Community energy Project

STRENGTHS	WEAKNESSES
• Strong Community Support • Existing Infrastructure • High Solar Resource • Favourable Market Perception • Low Visual Impact	• Limited Economies of Scale. • Potential Line Capacity Constraints • Limited Access to Capital • Exposure to Merchant Pricing. • Project Management Overhead
OPPORTUNITIES	**THREATS**
• Fortis Community Energy Generator Program • Federal & Provincial • Repeatable Development Model • Corporate & Institutional Demand • Co-benefits for Agriculture • Grid Reliability Benefits	• Sustained low energy prices • Restructured energy market • Rising Interconnection Costs • Supply Chain Volatility

Timeline

The timeline for the project is shown in Figure 22 and encompasses the initial consultation started in 2024 through to the design stage beginning in early 2026, fundraising in Q2 2026, permitting in early 2027 and construction over the summer of 2027. This schedule is tentative and subject to change based on funding availability, permitting, contract award, and construction, however an in service date of Fall 2027 is established for a baseline.

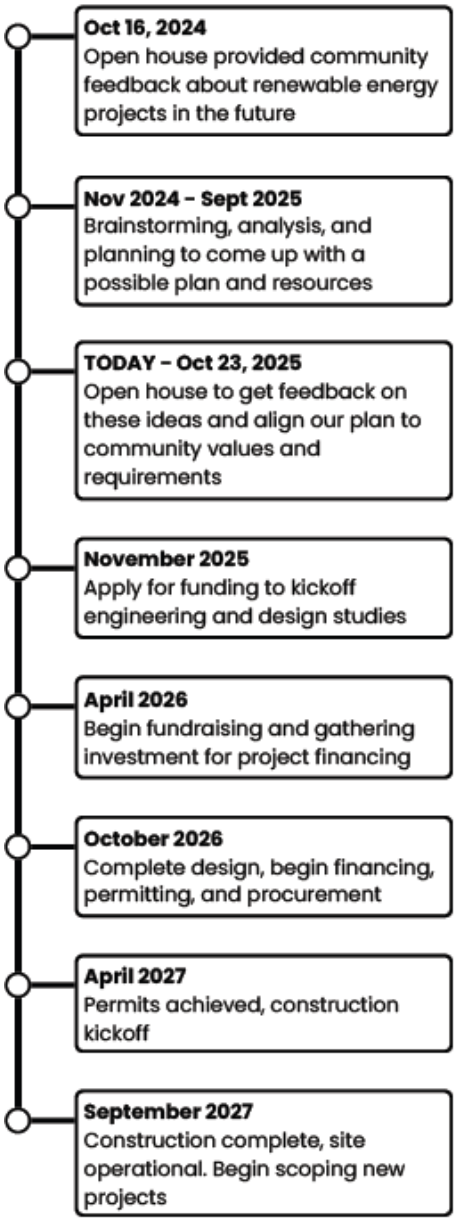


Figure 26: Pincher Creek Community Energy Project Proposed Timeline

Conclusion

The proposed Pincher Creek community solar project, sized at 1.5 MWac / 1.95 MWdc with an optional 1 MW / 4 MWh battery energy storage system (BESS), represents a strong pathway to advance local renewable energy development built on a foundation of community engagement and guidance. Site identification has been guided by previous technical assessments, community engagement, and council direction, with a deliberate emphasis on repurposing brownfield locations like gravel pits and abandoned wells. Several suitable sites have now been identified in proximity to distribution, providing flexibility and reducing land-use conflict. Current market conditions including electricity pricing between 7–10 ¢/kWh and the ability to monetize carbon credits at approximately $30 per tonne further enhance the value proposition. In addition, the reserve market for battery services, estimated at roughly $250,000 per MW, creates a compelling incentive to integrate storage.

Financial analysis indicates that the standalone solar installation, with a capital cost of $4,487,100 and annual operating costs of approximately $77,250, is expected to generate around $199,000 in annual income. Under this configuration, the project is projected to achieve an unlevered IRR of approximately 8% and a leveraged IRR of about 2%, lacking a strong investment case. When the optional BESS is incorporated, capital requirements increase to $7,023,260 with annual operating expenses of roughly $148,500; however, expected annual income increases substantially to approximately $449,000. This added value arises from energy shifting, ancillary service revenues, and improved participation in Alberta's evolving electricity market. With these enhancements, project IRR increases to approximately 13% unlevered and 15% leveraged. Grants and financial supports including the Federation of Canadian Municipalities (FCM) programs and the Federal Investment Tax Credit are expected to be pursued to reduce upfront capital requirements and further strengthen the overall business case.

Although the project benefits from strong solar resource potential, community support, and the availability of brownfield sites, it must continue to navigate key risks such as regulatory uncertainty associated with Alberta's market redesign and potential distribution system capacity limitations. At the same time, significant opportunities remain through grant funding, carbon credit revenues, and expanded revenue streams associated with battery storage. Overall, the project is well positioned to deliver long-term economic, environmental, and energy-resilience benefits to the community and stands as a strong candidate for replication in similar rural regions across southwest Alberta.

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