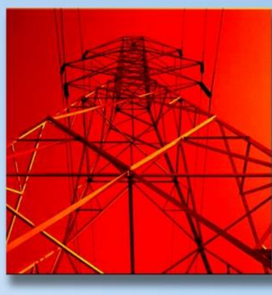
Fundamentals-Based Analysis of Saamis Solar Project Value to City of Medicine Hat Ratepayers

Prepared For:

—Medicine Hat Utility Ratepayers Association—



Report prepared for:
Medicine Hat Utility Ratepayers Association

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Disclaimer

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Executive Summary

August 2024, the City of Medicine Hat ("CMH") advised the AUC (Proceeding #29273) that it intended to immediately purchase the 325 MW Saamis Solar Project and construct at least 1 75 MW phase ("Saamis").

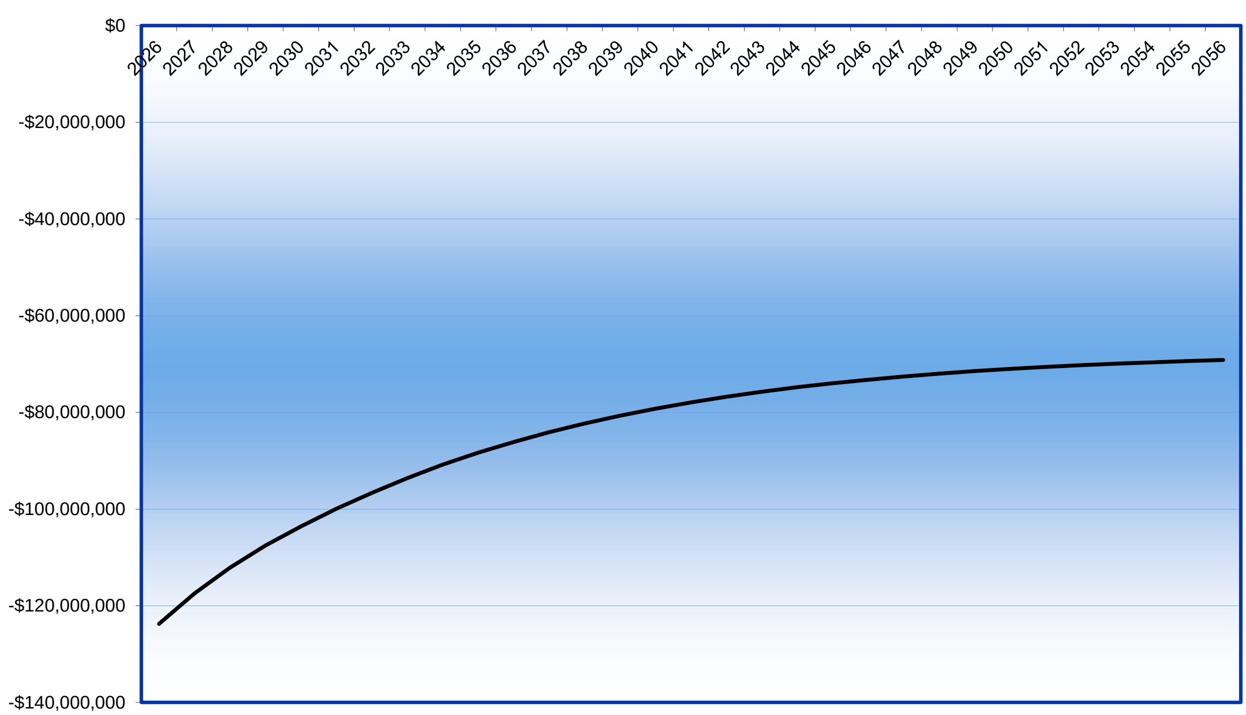
October 2024, the Medicine Hat Utilities Ratepayers Association ("MHURA") contracted EDC Associates Ltd. ("EDCA") to provide a 30 year fundamental-based analysis of the economic value of the Saamis. MHURA was concerned that given the provincial government and system operator's hostility towards intermittent capacity, coupled with a sharp reversion in federal carbon policy, the acquisition and subsequent development of Saamis could result in CMH ratepayers shouldering a substantial economic burden for decades to come.

EDCA is uniquely positioned to deliver on this objective, as, since 1992, it has advised on over $50 billion worth of development activities in the province of Alberta.

CMH operates a very integrated portfolio – a combination of load, gas-fired generation, cogen PPA, wind PPA and imports/exports from/to Alberta's power grid. As such, without detailed confidential information it would be impossible to quantity the exact economic impact to the CMH's portfolio. However, by modeling Saamis as a standalone proposition, one can determine the direction and magnitude of the investment as it would be incredibly unlikely that a strong (weak) performing asset on a standalone basis would all of a sudden become a weak (strong) performing asset inside of an integrated portfolio.

Based on EDCA's current Alberta outlook (Q4-2024, issued to industry on a fee-for-service basis on November 1, 2024), Figure 1 illustrates Saamis' cumulative discounted cash flow using a 10% NPV to reflect the time value of money. The analysis suggests that CMH ratepayers should be very concerned that the purchase and subsequent build out of Saamis (assumed as 75 MW in this analysis) will burden CMH ratepayers will substantial financial costs for decades.

Figure 1 – Fundamental-Based Forecast of Saamis Cumulative Discounted (10%) Cash Flow



Forecast Methodology

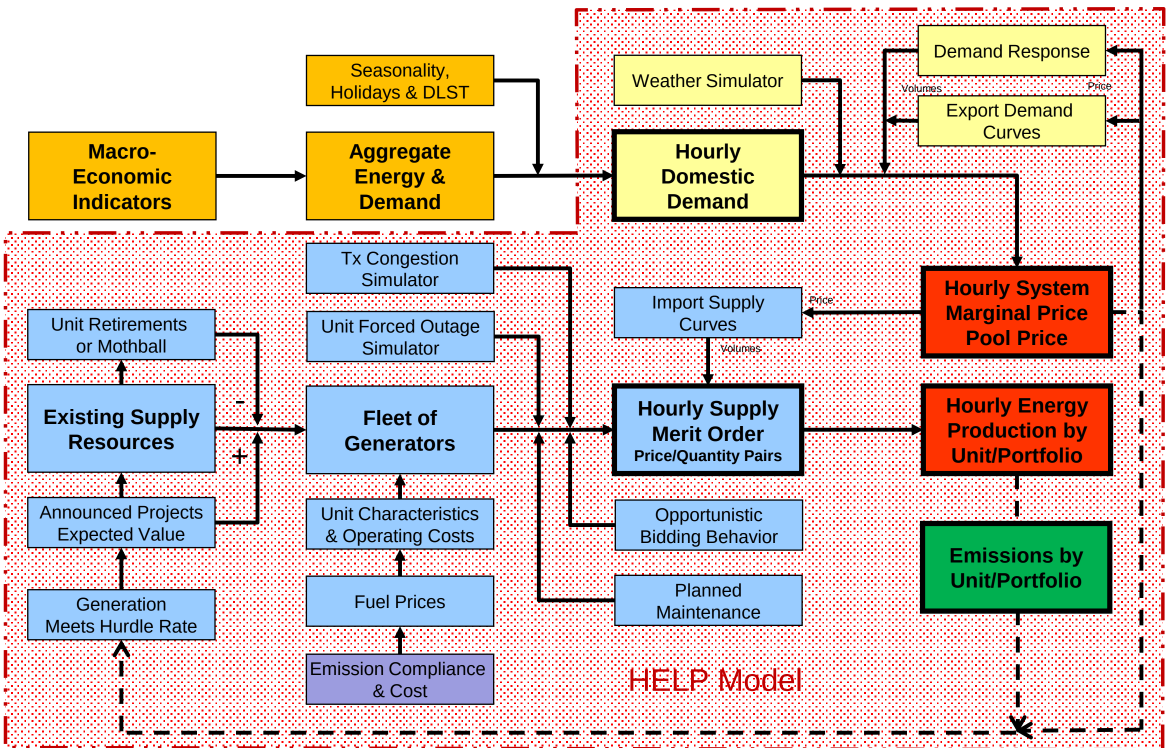
This section describes EDCA's approach to forecasting Alberta's electricity market.

EDCA's models have been used in expert testimony in valuing PPAs and by generators for financing, sale and audit purposes, quantifying damages in litigations and in justifying transmission additions and tariffs, both in front of regulatory tribunals and for confidential use by clients.

Energy Market Simulation

EDCA's generation dispatch and energy pricing model (Hourly Electricity Load Pricing, or "HELP", see Figure 2) is an analytical toolset incorporating Monte Carlo techniques to forecast wholesale electricity prices and generator output on an hourly basis over the short and long-term. The following flowchart provides an overview of the modeling components and structure.

Figure 2 – General Dispatch and Energy Pricing Model



Electric Energy Demand Forecast

Electricity demand is provided as an exogenous input to the main model and is derived from an external, bottom-up fundamental macro-economic forecast process, profiled hourly to reflect historical random seasonality, diurnally and weather-induced changes. Export demand is modeled hourly, based on the forecast price differential between Alberta and other markets (such as Mid-C), as constrained by an Available Transfer Capacity ("ATC") forecast in that hour.

Economic activity in Alberta is forecast using a proprietary suite of models. The models combine assumptions about exogenous macro variables—including economic growth in the US and Canada, inflation, interest rates, exchange rates, Canadian unemployment rates, and crude oil and natural gas prices—to estimate intermediate values for crude oil and natural gas production, provincial Gross Domestic Product ("GDP"), source population plus net migration, labour force, households and unemployment rates for Alberta.

Figure 3 provides a schematic of how the electric energy demand forecast is built up from its components. Electric energy can be broken into sectors: residential, farm & irrigation, commercial, oil & gas, and other industrial.

Figure 3 – Electricity Demand Buildup

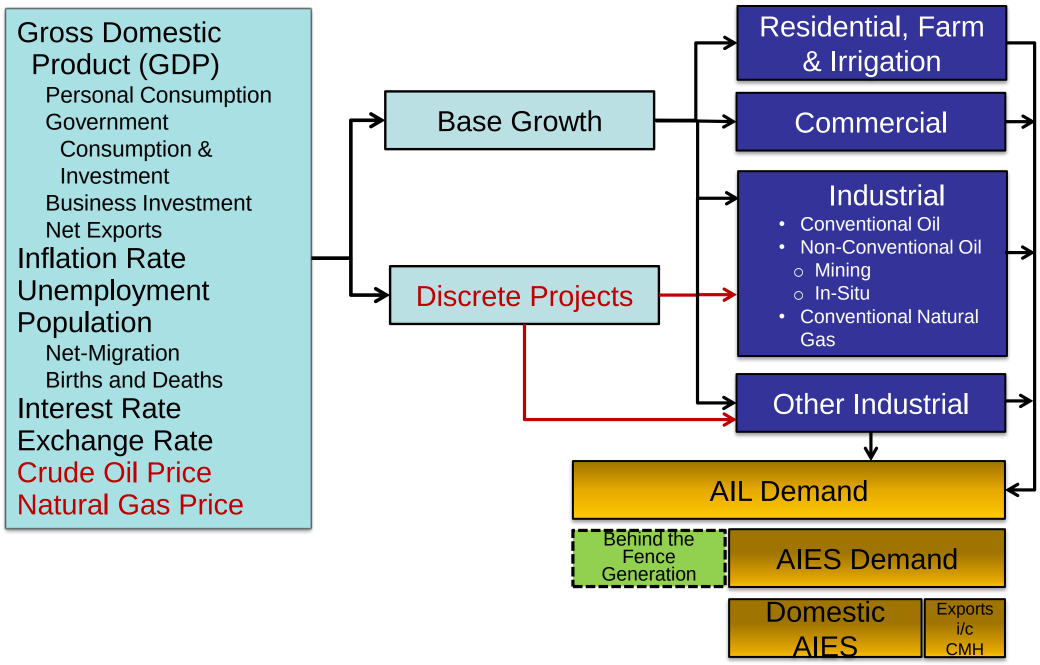
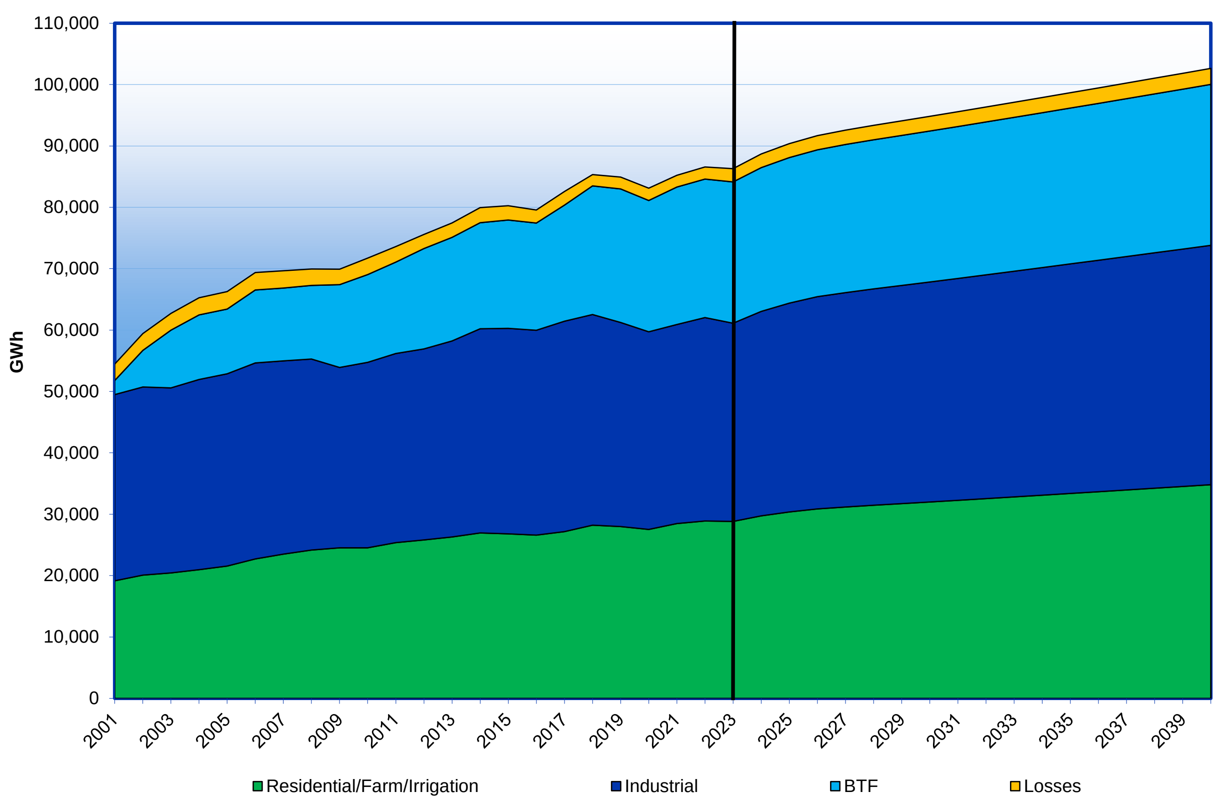


Figure 4 – Alberta Load Forecast



EDCA's current (Q4-2024) long-term load forecast averages around 1%. The load forecast takes into account factors such as energy efficiency and increased microgeneration, but is tempered by transformative technologies that are expected to provide a counter-balance by increasing electricity consumption, such as the penetration of electric vehicles and the move to carbon capture utilization and storage. Oil and gas is expected to remain the primary source of electricity consumption in the province, although other sectors, such as petrochemicals and technology, have to potential to see significant consumption increases over the next decade.

Resource Supply Development

EDCA's modelling toolset incorporates many of the intricacies and non-linearity of both supply and demand.

Near-term generator additions are derived from projects that have announced long-term off-take and/or financial close, primarily combined-cycle, cogeneration and simple-cycle natural gas-fired units, as well as wind, solar and energy storage. New additions are typically limited more by physical (availability of labor, steel fabrication, concrete), regulatory, economic and transmission constraints than by a lack of projects.

Future simple-cycle and combined-cycle growth is driven by when energy prices alone are sufficient to earn adequate return of/on investment. Cogeneration growth is treated as an exogenous variable because their investment decision is less likely to be governed by pure electricity fundamentals and more by operational and capital budgeting considerations of the core business.

Future renewable growth is based on the assumption that corporate PPA programs will continue to attract developer interest to the province.

Figure 5 illustrates EDCA's current (Q4-2024) yearly capacity additions/retirements forecast while Figure 6 illustrates how it translates into an aggregate generating capacity forecast. Alberta has just completed a substantial build cycle – seeing over 13,000 MW of new resources commissioned since 2020, and so no new supply is needed until the supply/demand balance becomes more in sync, which is not expected until the early-to-mid-2030s.

Figure 5 – Yearly Capacity Additions/Retirements

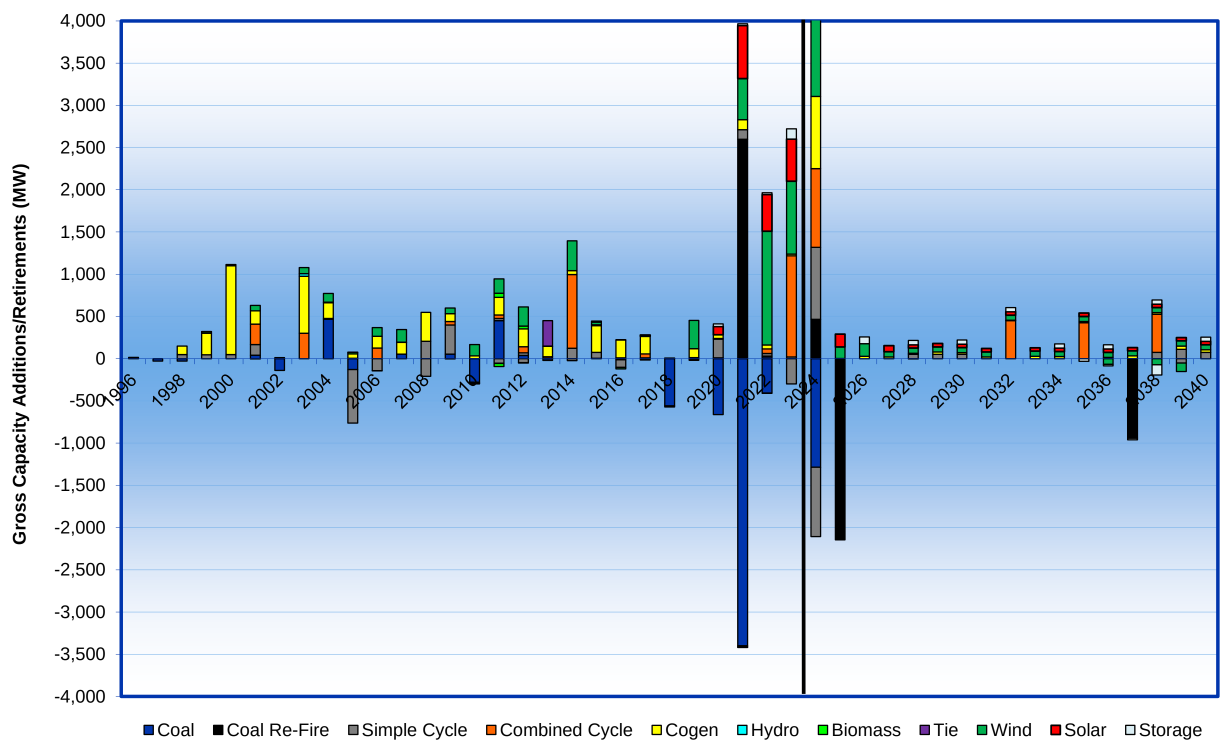
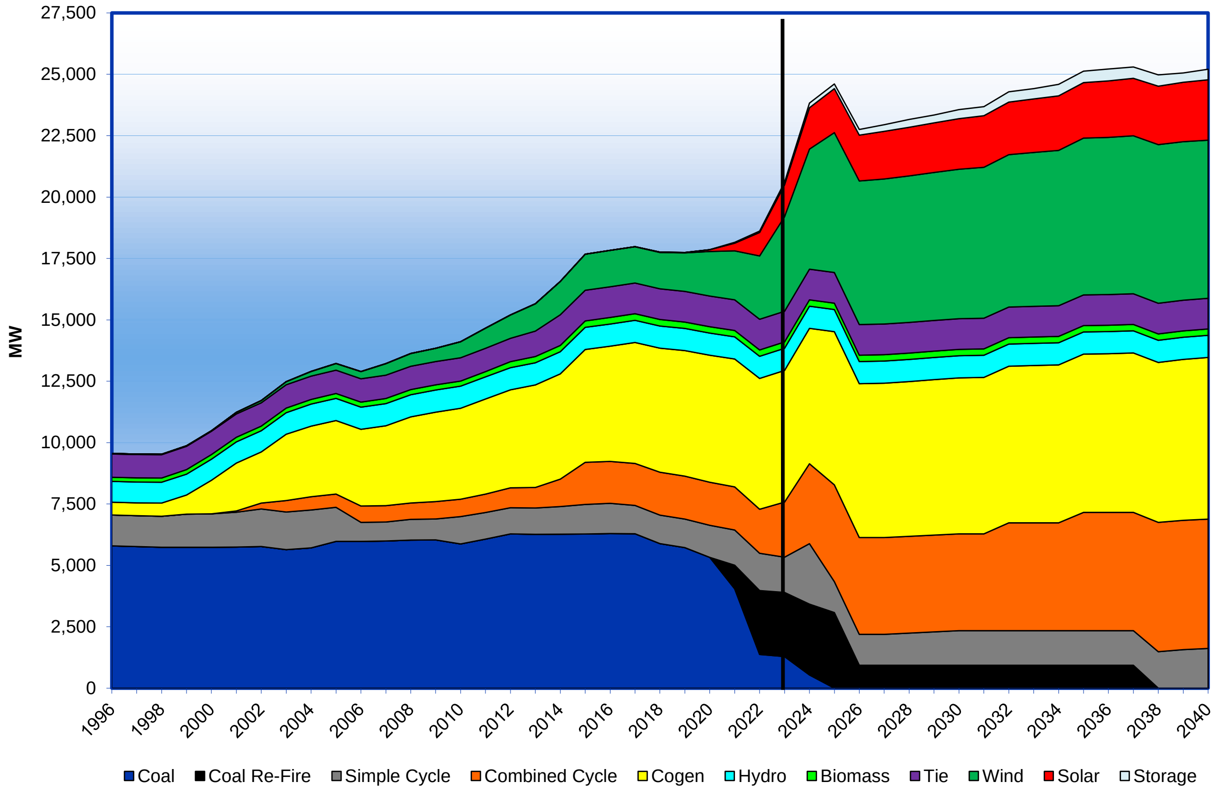


Figure 6 – Evolution of Alberta's Gross Generating Capacity



Energy Market Merit Order

Price-quantity offers for each supply resource are developed from marginal cost based characteristics and expected bidding practices of the various market participants, as observed in the AESO's "Offer Snapshot" reports. Strategic multi-block bidding behaviours are derived from observed historical bidding preferences and behaviours across the range of short-run market supply/demand balance, with offer prices ranging from a floor of $0/MWh to a high of $999.99/MWh (with $1,000.00/MWh being an administrative signal for load shed).

Cost characteristics include unit availability adjusted for planned and unplanned maintenance outages, natural gas prices, unit-specific cost structures such as emissions and constraints (unit efficiency or heat rate, fuel contracts, losses and non-fuel O&M costs). Operating reserves and demand response are also included. The pool price is determined by the intersection of the offer stack and the demand that will just clear the market, with the calculation performed on an hourly basis.

The supply curve has four major segments.

The first segment represents a large fraction of the total fleet offering in at $0/MWh to ensure they will be dispatched. These zero-bidders are comprised of the minimum stable generation of boiler re-fired coal facilities and combined-cycle units, intermittent renewables (wind and solar), a large portion of hydro, as well as cogeneration with required host steam needs. Periodically the demand falls low enough in a particular hour that the price actually settles at $0/MWh.

The second segment – marginal cost – is driven by natural gas prices and the cost of carbon. Combined-cycle gas turbines have the lowest heat rate (7-8 GJ/MWh), followed by less efficient peaking simple-cycles (8-12 GJ/MWh), and then coal plants that re-fired their boiler to burn gas instead of coal (10-13 GJ/MWh).

Figure 7 illustrates EDCA's current (Q4-2024) AECO-C natural gas forecast. Increased access to new markets through LNG is expected to cause a positive uplift in natural gas prices, but the uplift will be constrained by producers continuing to produce (i.e., matching supply with demand).

Figure 7 – AECO-C Natural Gas

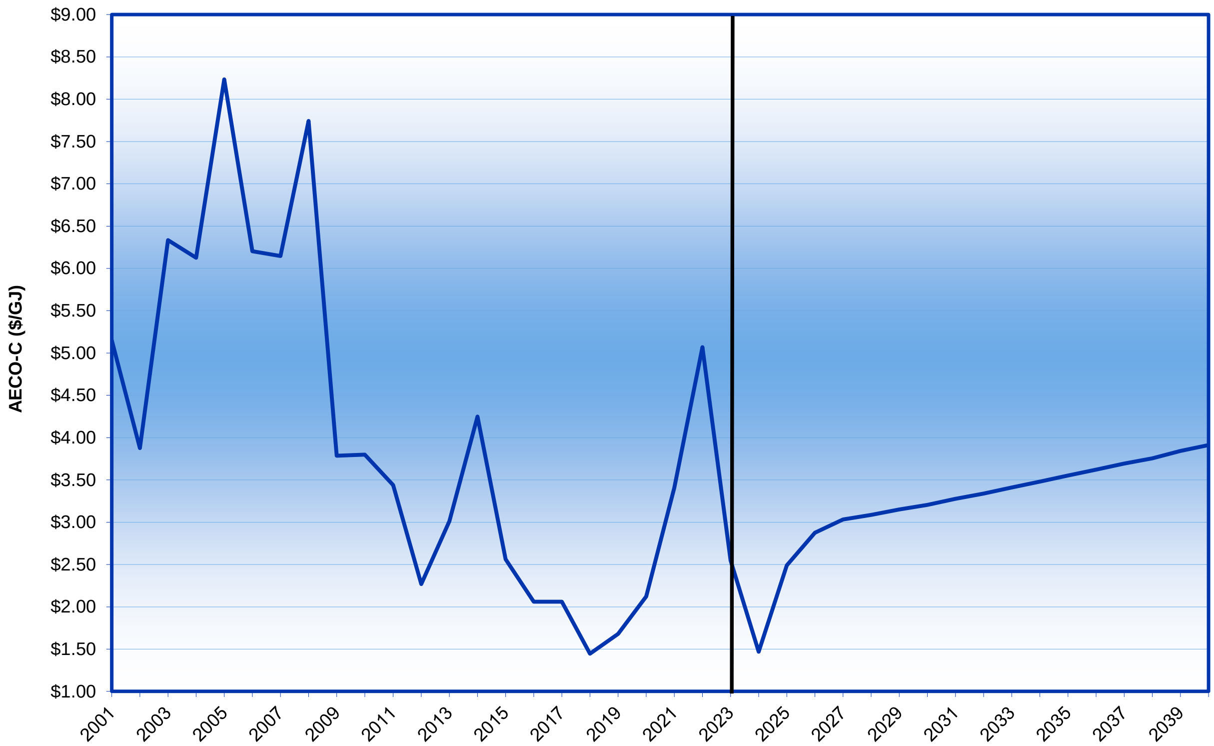


Figure 8 – Carbon Policy Assumptions

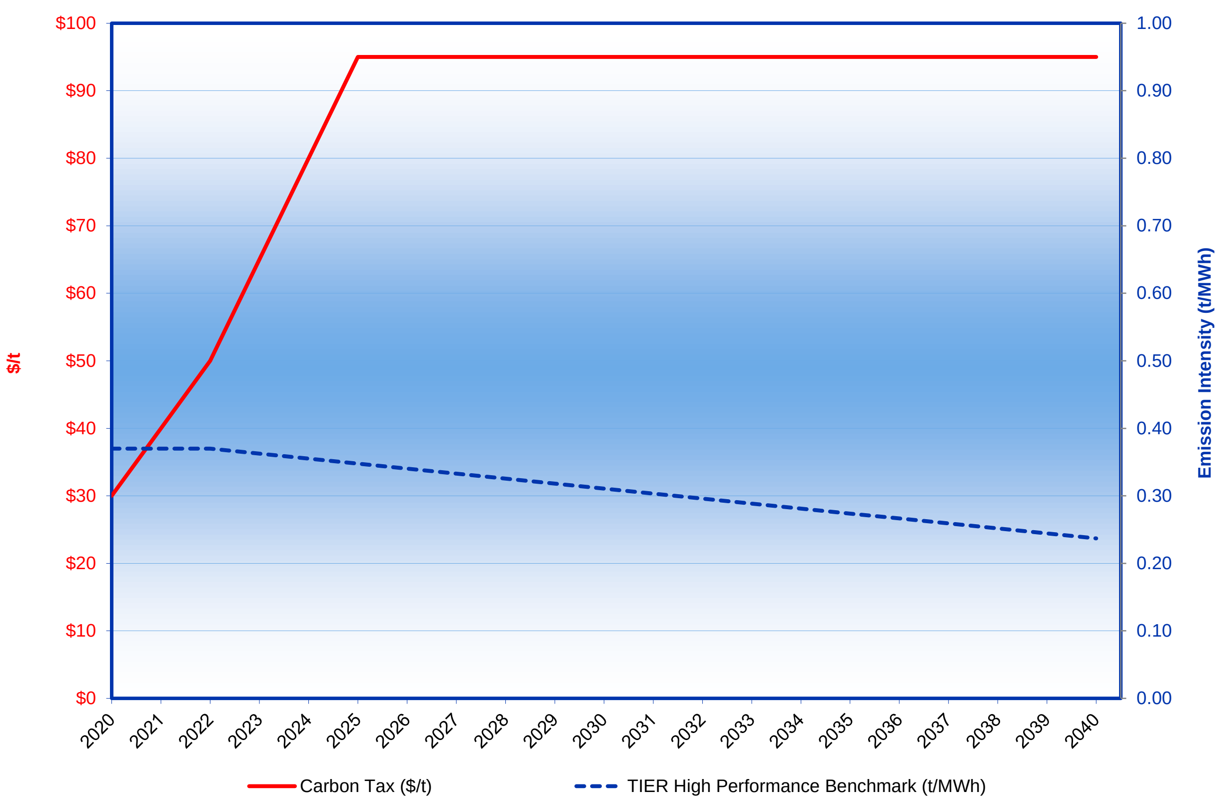


Figure 8 above summarizes EDCA's current (Q4-2024) carbon policy assumptions. Effectively TIER's High Performance Benchmark ("HPB"; t/MWh) for the electricity sector is forecast to decline 2%/yr into perpetuity to support the provincial government's goal of "Net-Zero by 2050".

The cost of carbon ($/t) is expected to flatline at $95/t following the next federal election.

As the supply cushion shrinks, generator offers become more aggressive, hitting "high-priced" offers - the third segment of the merit order - which are typically multiples of operating costs, and then finally the last segment of the curve consisting of "strategic" offers that are usually at some fixed price independent of operating costs. In these steeper two sections, very small changes in demand can cause large shifts in the resultant System Marginal Price ("SMP") in the minute and the pool price during the hour.

Alberta utilizes an "energy-only" market design. As such, economic withholding (i.e., pricing above marginal cost) by pivotal suppliers is expected and, in fact, is required in order to recover all fixed costs and earn an adequate return of/on investment. Without "high priced" offers neither incumbents nor IPPs would be able to operate profitably across a year as there are no additional major revenue streams available in Alberta, such as capacity payments.

Restructured Energy Market

March 2024, a new dynamic was injecting into Alberta's electricity market when the government announced that consumers needed to experience a material, and sustained, drop in the amount they pay for electricity. The government then instructed the AESO to begin the REM process in order to achieve these objectives.

As a first step the AESO quickly introduced two new regulations – the Market Power Mitigation Regulation and the Supply Cushion Regulation – designed to address economic and physical withholding, respectively.

These two changes are in effect from mid-2024 through to the end of November 2027. During this time period the AESO intends to re-structure the market by adding new design elements and features (although still retain the energy-only concept).

The majority of industry is opposed to the REM but the government continues to champion it and so the REM is assumed to come to fruition. As such, EDCA's forecast currently aligns with the AESO's starting point for the REM, effective January 2027:

- Price floor drops from $0/MWh to -$100/MWh
- Unit offer price caps drops from $999.99/MWh to $800/MWh
- Market price cap lifts from $1,000/MWh to $3,000/MWh via an operating reserves demand curve
    - More specifically, the market price cap is modeled as increasing to $1,500/MWh at a 500 MW supply cushion (contingency reserves activated), and then to $3,000/MWh at a 250 MW supply cushion (50% contingency reserves remaining)
- Market Power Mitigation and Supply Cushion regulations carried forth into perpetuity

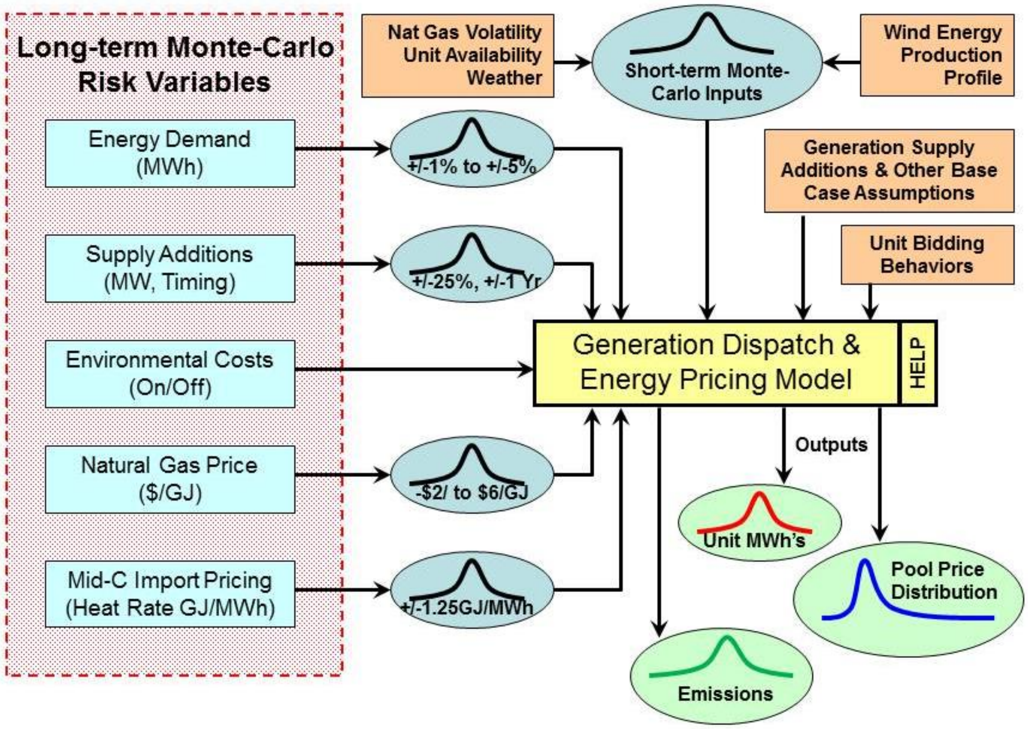
Incorporation of Stochastic Volatility

When constructing a baseline forecast EDCA typically uses a 50 iteration (seed)/year Monte-Carlo simulation with short-run stochastic volatility. When incorporating short-run volatility, several key energy market input variables – load, natural gas, wind/solar/hydro production profiles and outages – are allowed to vary seed-to-seed in order to introduce the inherent volatility of the market, but the volatility is short-run and designed to be neutral such that, while the hourly composition of each seed is different, each seed is mean reverting around the initial annual assumptions.

Because this approach focuses on constructing a centerline, it becomes difficult to analyze the risk exposure of market events without undertaking extensive deterministic scenario analysis. In order to address this challenge, a 100 iteration (seed)/year Monte-Carlo simulation can be run, applying greater stochastic volatility to the input variables within the forecast in order to create a full risk distribution spread in the outputs (i.e., meaningful P10/P90 spreads). With this level of stochastic volatility all key input variables - load, natural gas, supply, Mid-Columbia prices, outages and GHG costs - are allowed a much wider range in order to further define the tail-ends of the distributions. The full stochastic volatility process is designed to fan out over time to reflect the fact that the further we move away from the present the greater the uncertainty. This process differs from a deterministic sensitivity in that value of the underlying variables is determined stochastically. For example, one seed could see a demand growth of 2% because of randomly selected robust economic conditions, and the next seed could see demand growth decline by 1% because of randomly selected poor economic conditions.

Figure 9 illustrates a stylized depiction of the process flow for stochastically simulating pool prices and electricity output. Note that while distributions of input variables are shown as being normal, this is done strictly for depiction purposes; actual distributions are based on historical movements.

Figure 9 – Stochastic Process Flow to Determine Pool Price & Electricity Output (Stylized)



Results (Base)

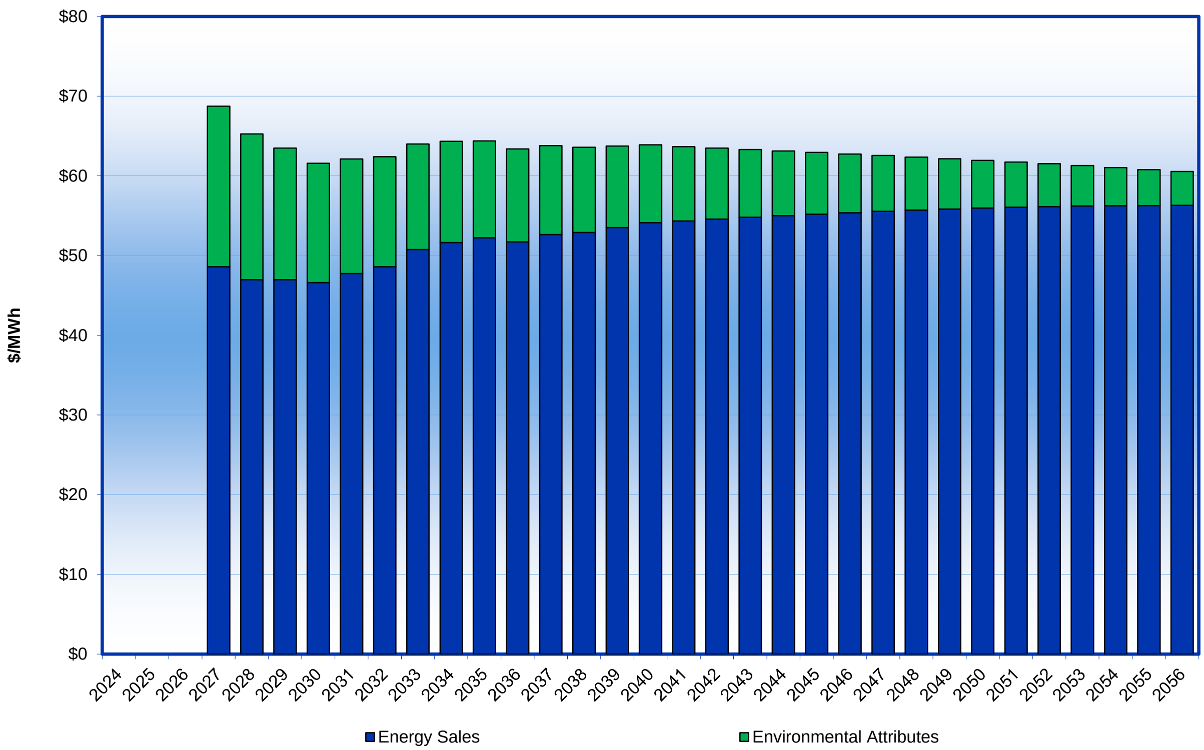
This section presents the results of the fundamentals-based forecast for Saamis, as derived from a 50 seeds (iterations) per year Monte Carlo simulation using short-run weather based volatility.

For simplicity, the analysis assumes Saamis is only built as a 75 MW facility (and not the full 325 MW), commissioning January 2027.

Revenue Forecasts

Figure 10 illustrates the yearly revenue forecast on a $/MWh basis. Gross revenues are forecast to cumulate to $63/MWh over the forecast period, with energy sales accounting for the majority (84%), with the remainder (16%) coming from the sale of environmental attributes.

Figure 10 – Yearly Revenue Forecast ($/MWh)



Energy Value

With respect to the energy sales revenue component, in order to understand if this is a “good” or “bad” value, one needs to compare it to the all-hours pool price, as seen in Figure 11 below.

The energy value proposition of Saamis is beneath the all-hours pool price forecast because of the substantial solar growth Alberta has seen over recent years, with utility scale capacity having surged from 15 MW back in 2019 to almost 2,000 MW as of the end of 2024, and distributed energy resource solar having exploded from around 5 MW to over 300 MW over the same period of time.

Solar output is highly correlated and so the more of this resource there is on the grid, the more it cannibalizes its own returns (because of there being a large amount of output running simultaneously, pulling down on the market price, and then there being a large block of output simultaneously unavailable, thus leading to supply scarcity and higher prices). This effect is then exacerbated by incumbents offering their dispatchable units at very high prices when renewable output is weak in order to drive the price high during these hours and recover margin lost during hours when renewable output was strong.

Figure 11 – All-Hours Pool Price vs Received Energy Price Forecasts

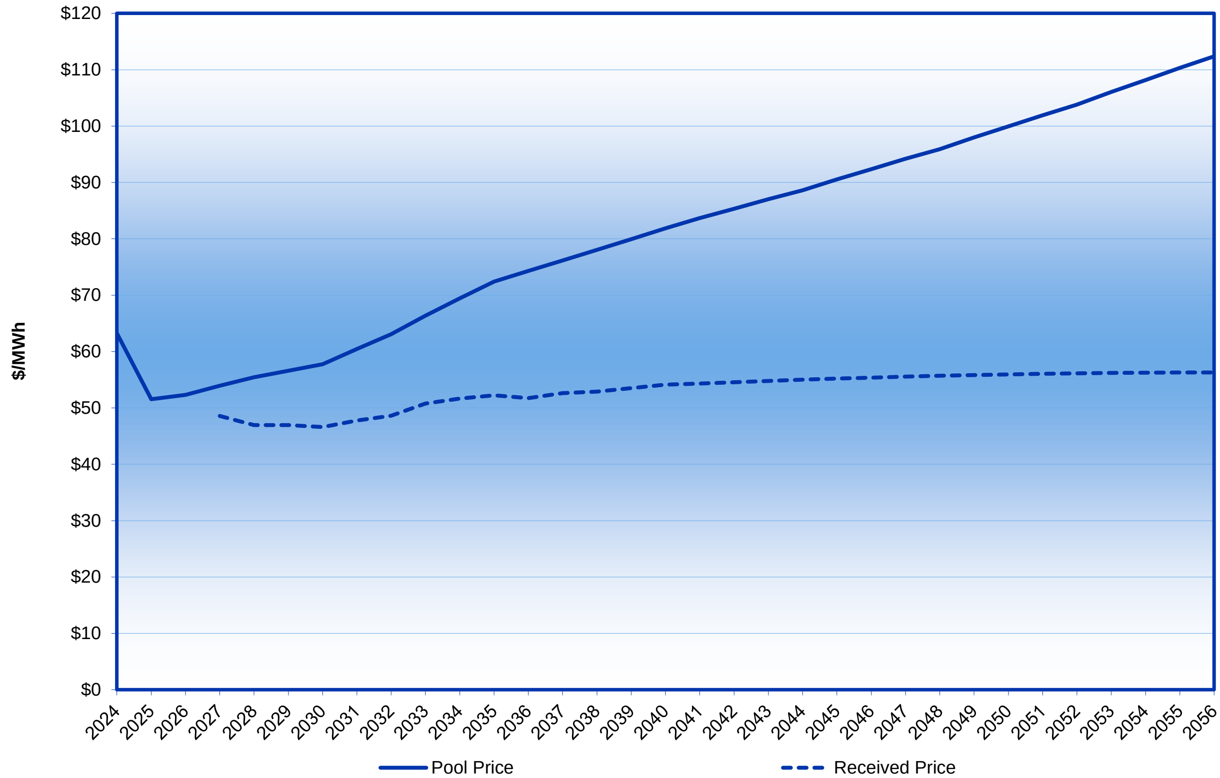
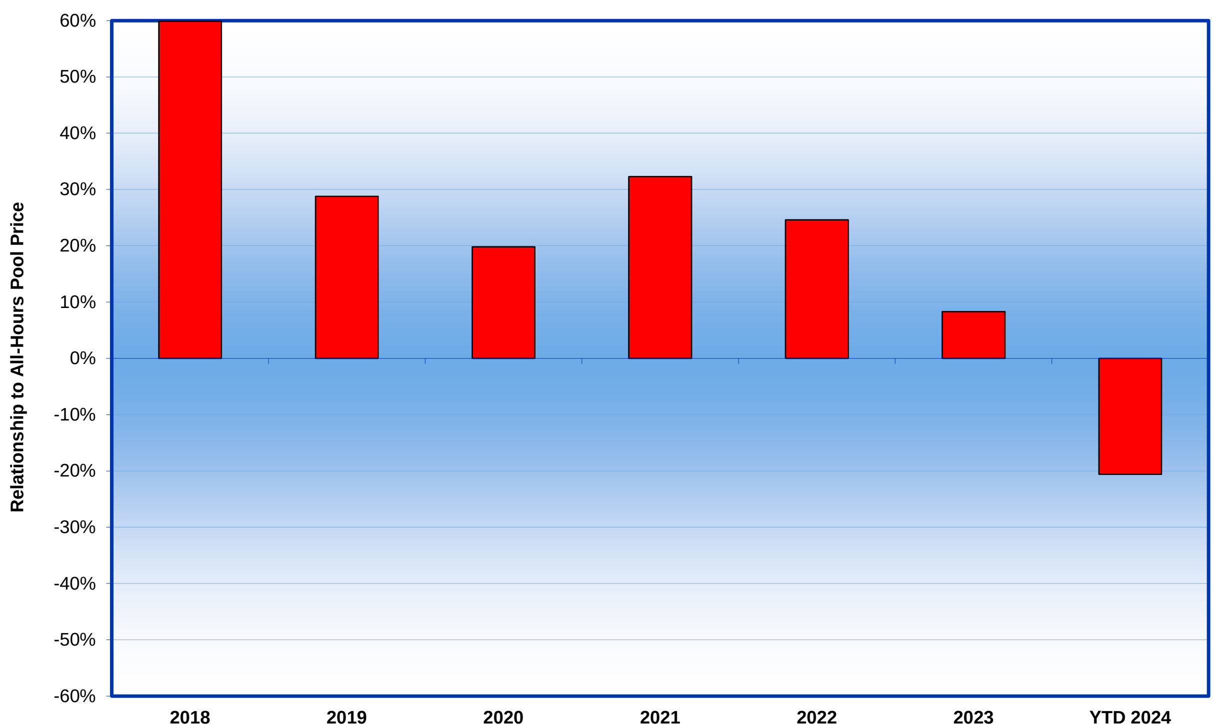


Figure 12 – Evolution of Alberta Solar Energy Value Relationship to Pool Price



The expectation of solar capturing less energy sales revenue than the all-hours pool price is already being experienced in the Alberta market, with solar's 2024 energy received price, as of the end of October 2024, being a 20% discount, as compared to a 60% premium back in 2018 when there was minimal installed capacity on the grid.

Carbon Value

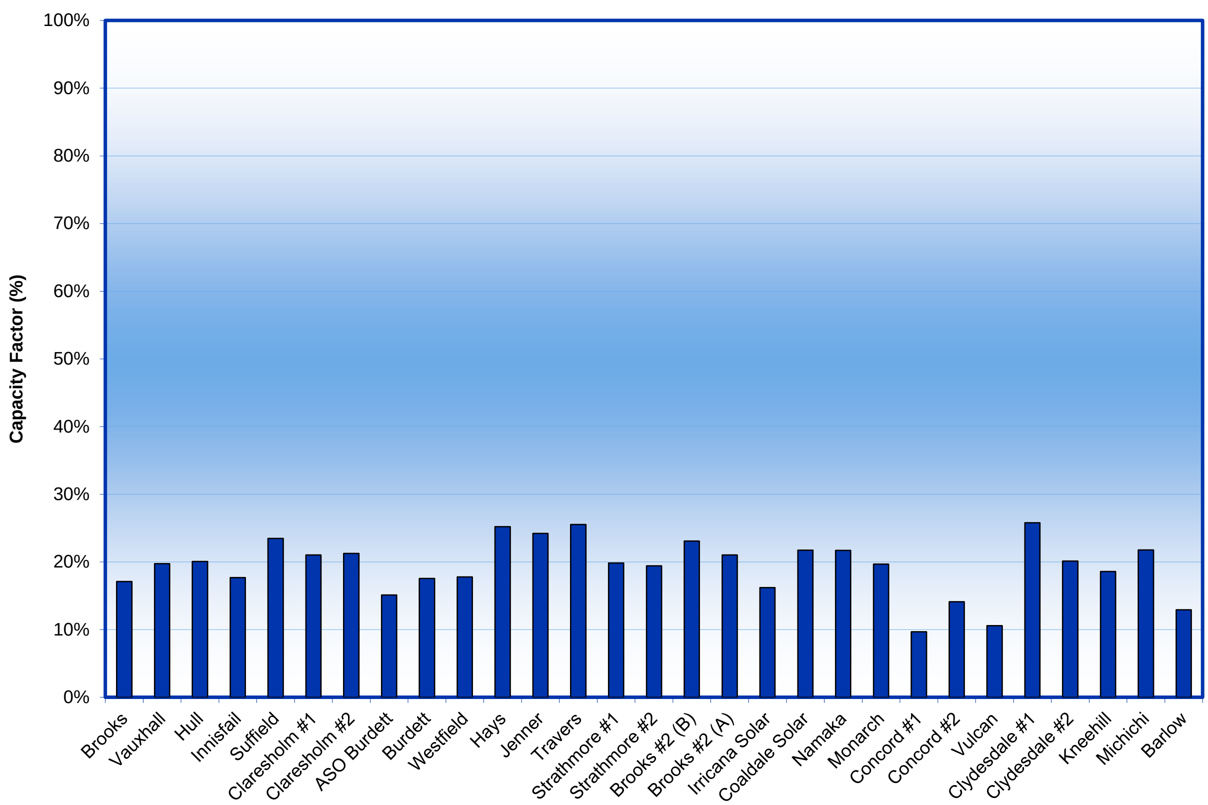
The project sees weak carbon value for two reasons.

First, carbon credits are transacted (bought/sold) bi-laterally. Historically transacted prices were at a 10-15% discount to the face value of carbon, reflecting the back-end/administrative efforts needed to use carbon credits to meet environmental compliance requirements versus simply paying cash.

However, carbon market dynamics have materially shifted over recent years, with the current transactional discount being around 30-35%. This was caused by supply ramping up and demand for attributes decreasing (from spot buyers becoming term buyers at the same time that some buyers began to implement internal abatement activities which lowered their requirements and, in some cases, turned them into suppliers). This dynamic is expected to persist over the foreseeable future as carbon capture activities ramp up throughout the province.

Second, a solar farm's capacity factor is only in the low-to-mid-20% range. This means across 80% of the year it is losing value because it has no/reduced output (compared to a baseload thermal power plant that could see 100% utilization without accounting for outage or de-rating).

Figure 13 – Alberta Solar Farm Capacity Factors (2023)



Cash Flow Forecast

Power plants are not free – they require a capital spend and ongoing maintenance. And so the question becomes, do the above revenue streams offset these costs.

For our modeling we will use the solar values presented in the AESO's 2021 Long-Term Outlook[1].

The capital cost - $1,650/kW – is the most influential component, so we also compare to recent quotes from industry for confirmation of this value. As per Kiwetinohk's Q1-2024 financials, their 400 MW Homestead project is estimated to cost $675 million, which is roughly $1,690/kW, so inline with AESO estimates.

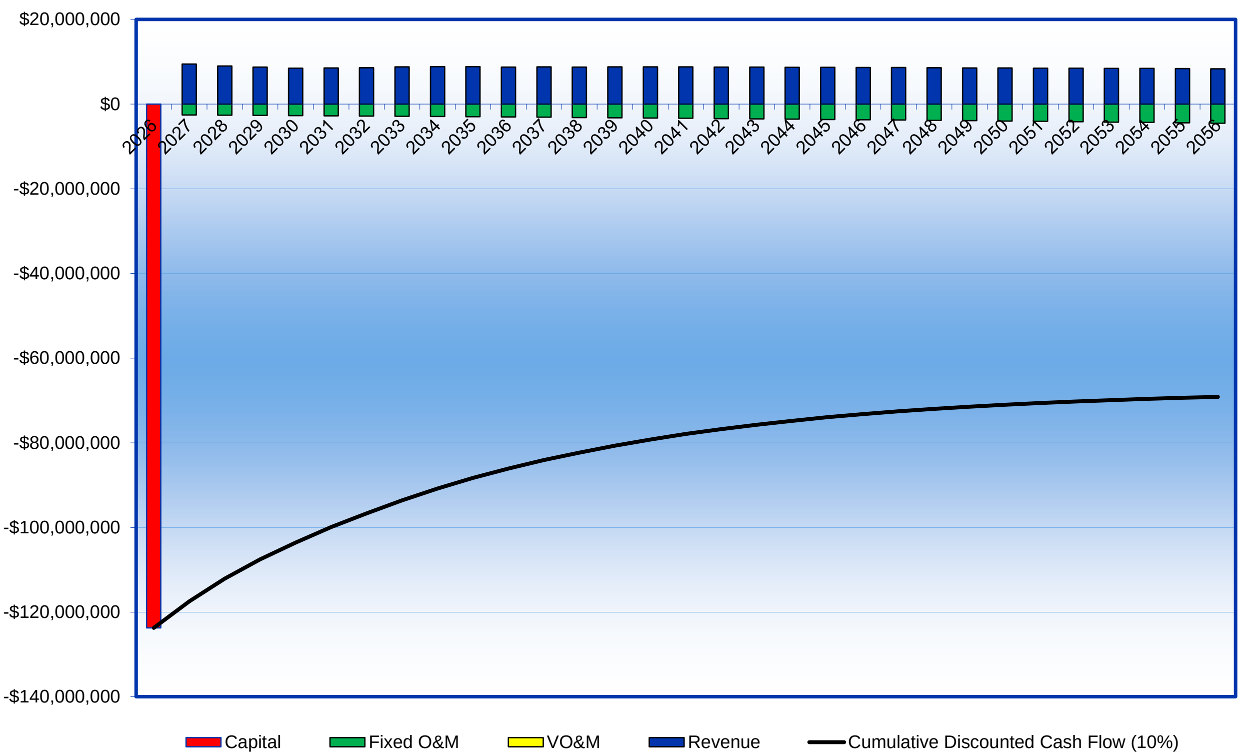
For simplicity we model the entire capital spend being made in 2026 (Year 0), with the project commissioning in 2027 (Year 1). In reality, projects will take on debt financing and spread the cost out over 15-20 years. However, this introduces additional complexity to the modeling, so the upfront spend was used to simplify assumptions.

As per Figure 14, annual revenues/costs are shown by bars (capital spend, fixed o&m, variable o&m[2], energy/carbon revenues), with the cumulative discounted (10% NPV) shown as the solid black line.

A simple cumulative cash flow could also be presented, but is not typically used in this type of analysis as one needs to account for the time value of money (hence the 10% discount).

The cumulative discounted cash flow is sharply negative, indicating that substantial monies are expected to be lost.

Figure 14 – Annual Revenue/Cost Components & Cumulative Discounted Cash Flow



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[1] https://www.aeso.ca/assets/Tariff-2021-BR-Application/Appendix-K-AESO-2021-Long-term-Outlook.pdf

[2] The AESO's 2021 LTO presents a $0/MWh VO&M. EDCA does not believe VO&M should be $0/MWh for solar, but it is quite low and not material to this analysis so $0/MW was used in order to align with AESO assumptions

Results (Sentivities)

This section presents sensitivity analysis around the baseline fundamentals-based forecast for Saamis.

Similar to the base modeling, this section assumes Saamis is only built as a 75 MW facility (and not the full 325 MW), commissioning January 2027.

Stochastic Risk Distribution

The base case scenario presents a "most-likely" outcome if all major market events occur as forecast. Its advantage is that it illustrates a coherent year-to-year path that could reasonably occur. However, because this approach focuses on constructing a centerline, it becomes difficult to analyze the risk exposure of any project. The fully stochastic modeling addresses this challenge by applying both short-run weather-based and long-run economic based volatility to produce a greater distribution of the key inputs of the forecast in order to create a more fully developed risk profile.

Figure 15 illustrates an example of this for carbon pricing assumptions. The base carbon tax assumption is that the cost of carbon flat lines at $95/t following the next federal election, which is around the level needed to incent Alberta's lowest cost carbon capture activities. The low bound is set at $50/t, the previous point the provincial government had agreed to prior to the federal Liberal government taking control of carbon policy. The high bound is set at $170/t (with growth thereafter) to reflect the unlikely event of the provincial government maintaining the Liberals' existing Greenhouse Gas Pollution Pricing Act following the next election.

Figure 15 – Example of Stochastic Distribution (Cost of Carbon)

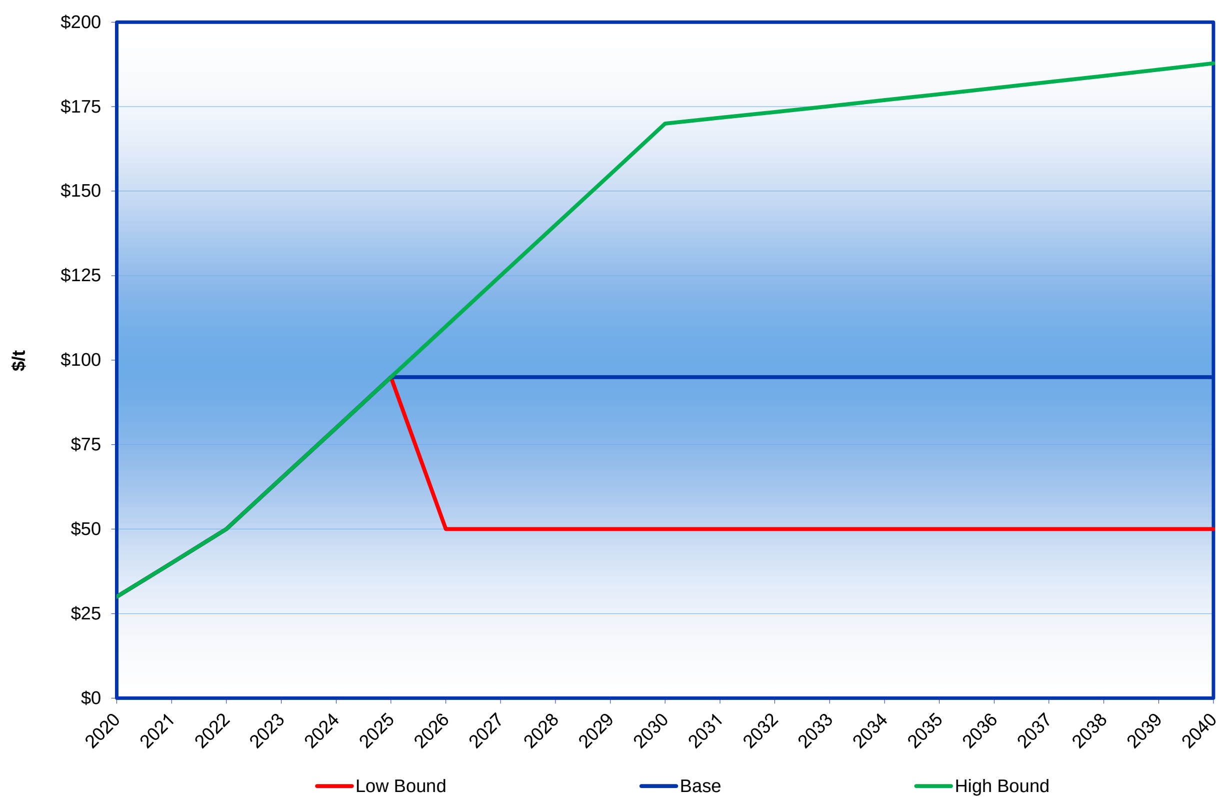
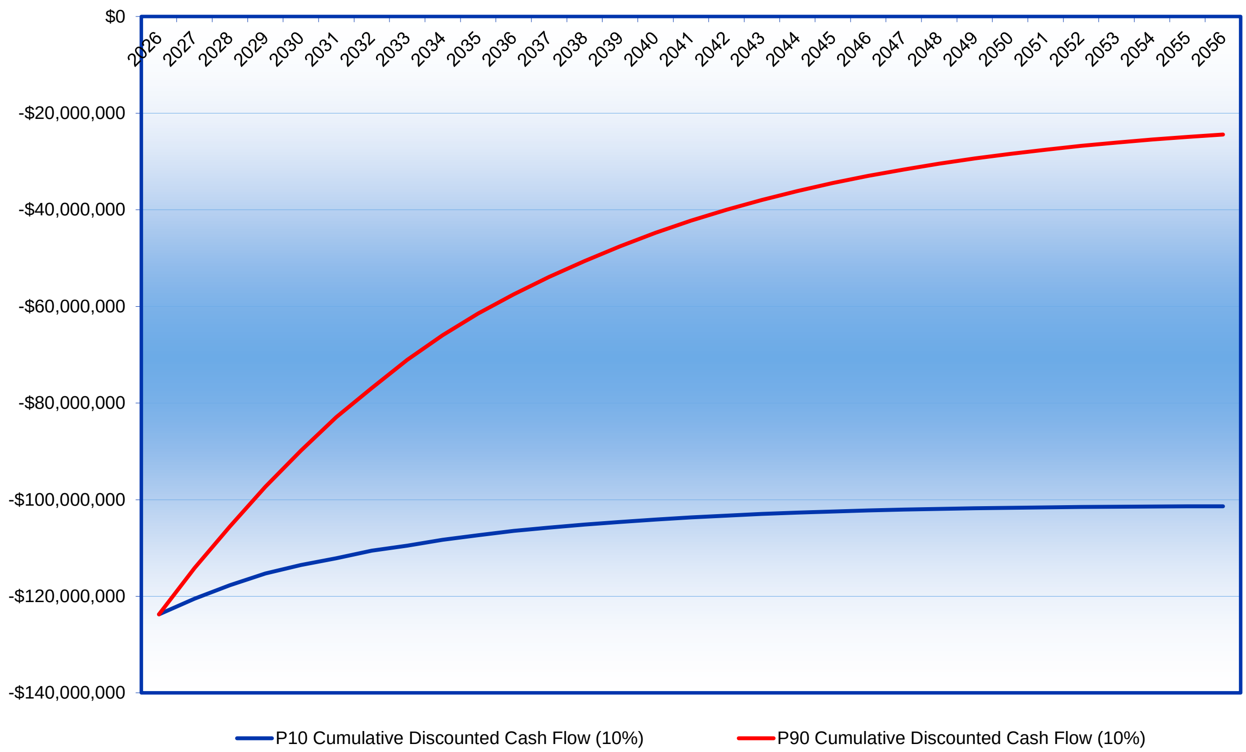


Figure 16 illustrates the stochastic risk distribution around the discounted (10%) cash flow forecast. More specifically, it presents the P10/P90 boundaries of the stochastic forecast (i.e., the range of values that are likely within the 80% confidence interval, based upon the underlying fundamental assumptions and distributions used). The P10 value represents the low end of the spectrum (i.e., 10% of the observations are lower than this point) and the P90 represents the high end of the spectrum (i.e., 90% of values are lower than this point). This nomenclature is consistent throughout all of EDCA's publications and custom forecasts.

Figure 16 – Stochastic Risk Distribution of Discounted (10%) Cash Flow



The stochastic derivation suggests that it will be highly unlikely Saamis will produce a positive net financial result, even using the most optimistic modeling assumption (i.e., the P90).

Carbon Policy

EDCA's baseline modeling assumed the carbon tax is held flat at $95/t following the next federal election (on/before October 2025). This is the 2025 value set in regulation and around the level needed to incent the lower cost carbon capture activities in the province.

As astute observer will point out that this mis-aligns with the current federal regulation (Greenhouse Gas Pollution Pricing Act), which the Supreme Court has confirmed the federal government may enforce on those provinces that do not comply with the pricing schedule.

Current election polls (Figure 17) show the Conservatives hold a historic, and overwhelming, lead over the Liberals as Canadians are tired of Liberal policies.

The Conservatives are campaigning on "Axe the (Carbon) Tax", and so it is highly unlikely they will continue to enforce Liberals carbon policies.

That said, EDCA prepared a sensitivity of the discounted (10%) cash flow if current Liberal carbon regulations (i.e., growth to $170/t) remained in force. Although an improvement from the base analysis, it is still negative across the 30 year term, reflecting solar's low capacity factor (and thus low GHG value) coupled low energy value from how over-saturated Alberta's energy market has become with solar and how dispatchable units are reacting to it (i.e., driving prices higher when renewable facilities have weak output, and letting prices soften when renewable facilities have strong output).

Figure 17 – Canadian 2025 Election Polls (November 2024)[3]

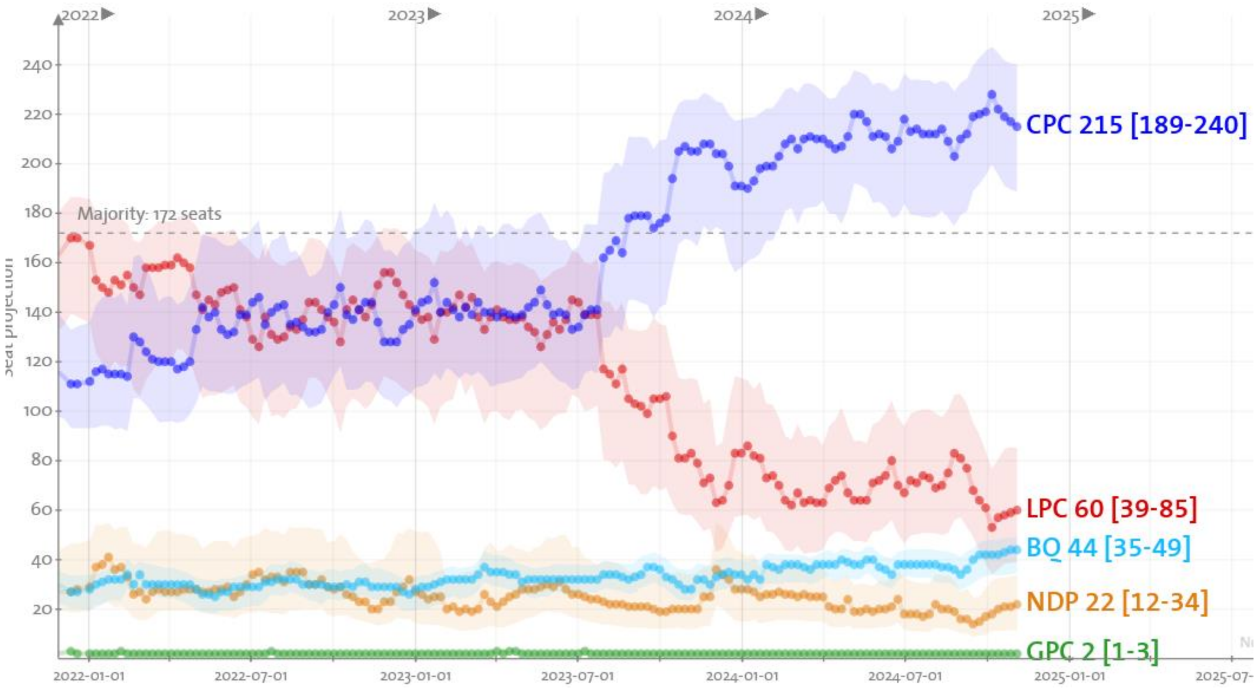
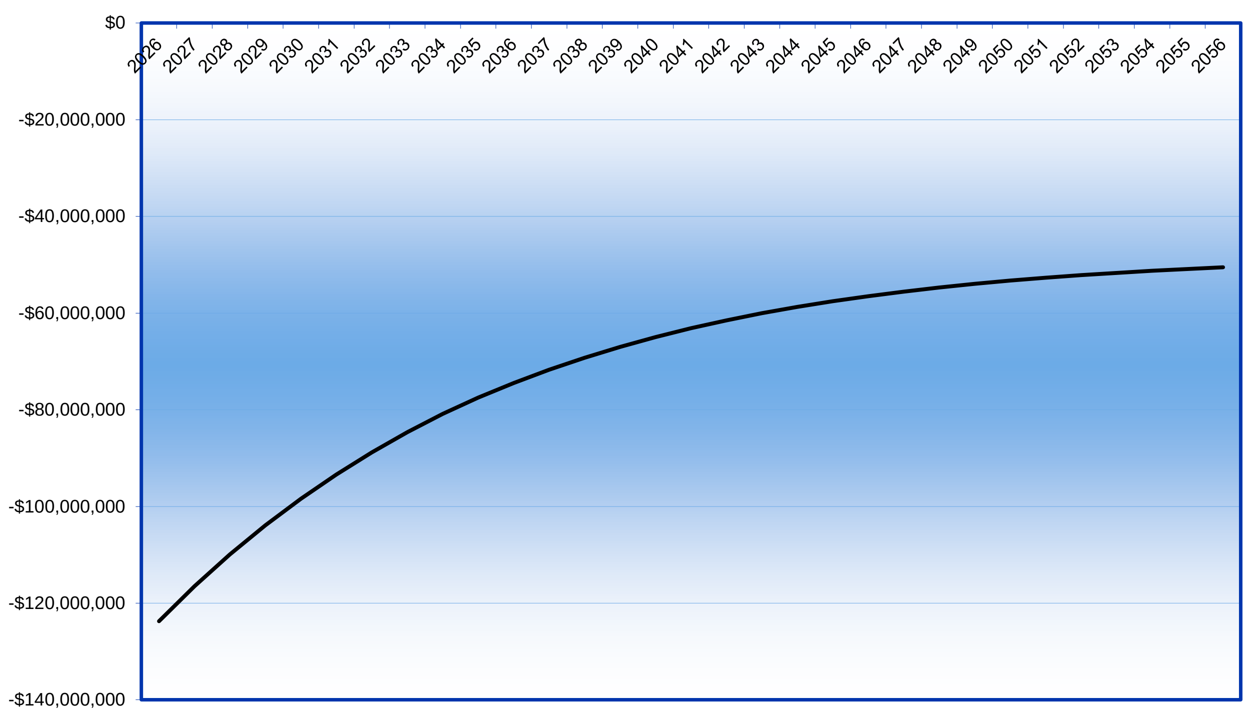


Figure 18 – Cumulative Discounted (10%) Cash Flow Forecast if Continuation of Existing Liberal Regulations



[3] https://338canada.com/federal.htm

Results (Translating to a Portfolio)

As discussed with MHURA, CMH operates a very integrated portfolio – a combination of load, gas-fired generation, cogen PPA, wind PPA and imports/exports from/to Alberta's power grid. As such, without detailed confidential information it would be impossible to quantity the exact economic impact to the CMH's portfolio (i.e., the purchase and subsequent buildout of Saamis is forecast to add/subtract $X/MWh from your power bills).

However, by modeling Saamis as a standalone proposition, one can determine the direction and magnitude of the investment as it would be incredibly unlikely that a strong (weak) performing asset on a standalone basis would all of a sudden become a weak (strong) performing asset inside of an integrated portfolio.

As seen from the above analysis, when viewing Saamis from this lens the expectation is that it will cost ratepayers **substantial** money (i.e., the direction is down, and the magnitude is a lot).

From a qualitative/logical perspective, we struggle to see how wrapping Saamis into CMH's portfolio would materially alter the value proposition.

The energy value of solar has rapidly eroded in Alberta because of how much installed solar capacity Alberta has commissioned in the province over the last 36 months, coupled with how incumbents have re-acted to it with their dispatchable facilities (i.e., price more aggressively when solar output is weak). Given power prices are soft during hours when solar has strong output, it would seem more logical to import low-cost power from the grid during these hours rather than paying a large capital expenditure to have physical power during these hours.

Also compounding the energy value discussion is that the province and AESO are currently in the process of re-designing Alberta's electricity market. All design elements being discussed are negative when it comes to intermittent capacity (wind/solar), so a question becomes, if part of CMH's business case involves exporting surplus solar power to Alberta's grid, why choose an asset class (intermittent generation) that the government and system operator are expressly designing a system against in order to try to incent dispatchable/reliable generation to develop?

The carbon value of solar is weak because of solar's low capacity factor coupled with the carbon market's supply/demand balance shifting towards over-supply (and likely to become even more grossly over-supplied as lower cost carbon capture activities begin to start). If the intent of adding solar into the portfolio is to access its carbon attributes to meet the environmental compliance costs of its gas-fired units, the more logical solution would be to capitalize on the carbon market's weakness and enter into term contracts to purchase carbon credits at very low prices rather than make a large capital spend to physically create a low value product.

For example, the federal government recently entered into a 20 year term contract with 2 solar providers for carbon credits valued at approximately $35/t[4].

In short, while we cannot tell the MHURA with 100.00% confidence that the inclusion of Saamis into CMH's portfolio will result in ratepayers seeing a large increase in their power bills over the coming decades, the analysis suggests that this is a highly likely outcome and at a bare minimum CMH needs to provide much more extensive cash flow analysis to illustrate the value proposition to ratepayers, especially compared to other alternatives such as importing more low-cost power from the grid, building additional reliable/dispatchable gas-fired generation and using its municipal-grade status to purchase carbon attributes directly from developers at very low prices.

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[4] https://www.canada.ca/en/treasury-board-secretariat/news/2024/10/government-of-canada-commits-to-purchase-carbon-dioxide-removal-services-to-green-government-operations-and-achieve-net-zero-emissions.html

Appendix A – EDC Associates Ltd.

Corporate Overview

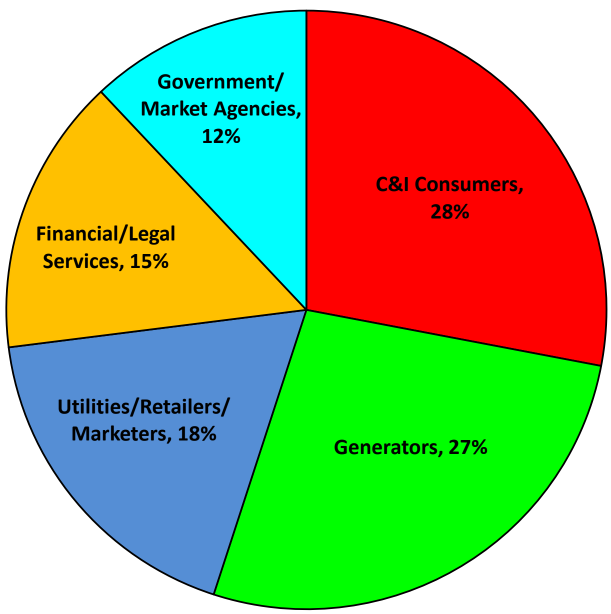
Incorporated in 1992, EDC Associates Ltd. is an independent energy-consulting firm based in Calgary, Alberta, Canada that provides consulting services with respect to electricity and natural gas pricing, generation development, electricity and natural gas procurement, regulatory and legal issues, and power market training.

EDCA has been the premier supplier of independent electricity, natural gas price forecasts and generation energy production simulations in Alberta since the start of the electric energy industry re-structuring in 1996. EDCA has been retained to prepare case by case client specific market analysis and forecasts for a wide range of industry participants including marketers, retailers, generation developers, large commercial & industrial customers, financial & legal entities, regulators and governmental agencies.

EDCA publishes several multi-client studies, newsletters and reports on its own volition that are widely circulated (over 300 active company subscriptions, including the Alberta Electric System Operator) on a fee for service basis. In addition, EDCA routinely prepares and files expert evidence and acts as an expert witness in legal, arbitration and regulatory proceedings in Alberta and other provincial jurisdictions. EDCA's electricity and natural gas expertise are heavily referenced by system operators and provincial utilities, such as in the Alberta Electricity System Operator's Transmission Rate Impact Projection modeling.

Figure 19 illustrates EDCA's typical client base segmented by broad customer category.

Figure 19 – EDCA's Customers by Category



EDCA maintains strict neutrality between commodity suppliers, generation developers, marketers and equipment suppliers. EDCA owns no generation assets or capacity rights and has no preferred commodity suppliers. This neutrality ensures our actions and advice are always independent, unbiased and without conflict of interest.

Typical Consulting Service Areas

As part of the **energy pricing consulting services** provided by EDCA, the company has been retained to prepare case by case client specific market analysis and forecasts for a wide range of industry participants, including marketers, retailers, generation developers, industrial customers, regulators, governmental departments and agencies and also publishes several multi-client studies, newsletters and reports on its own volition that are widely circulated to industry clients on a fee for service basis. EDCA has conducted many surveys and regularly canvasses a broad spectrum of participants to gain more detailed insights into the underlying market fundamentals.

As part of the **generation economic development services** provided by EDCA, the company has been retained by its clients to provide independent and rigorous analysis with respect to generation feasibility and economic modeling used by those considering generation development, value optimization, acquisition or divestiture. EDCA incorporates Monte-Carlo analysis with respect to quantifying volume, price and other key risk components related particularly to asset valuation, energy production, risk/hedging analysis and financing activities as part of any generation economic or technology configuration options study. EDCA incorporates cumulative and discounted cash flow models to quantify and assess the relative economics and financial position of the various energy producing technologies. Models conform to GAAP accounting principles to calculate EBITDA, net income (before or after tax), and IRR, cumulative discounted cash flow, simple and discounted payback under any number of capital costs and structures with respect to debt or equity. Models can be used to derive relative generation technology “levelized” unit production costs given a consistent set of capital structure, cost and other financing assumptions.

As part of the **energy procurement consulting services** provided by EDCA, the company has been retained by electricity and natural gas suppliers and consumers to facilitate energy procurement and sale processes. EDCA provides services in regards to: requests for quote and proposal development, purchase/sale recommendations, purchase/sale strategies, portfolio monitoring services, budget assistance and reporting. EDCA has made recommendations and negotiated vendor contract terms in respect of electricity and natural gas over-the-counter agreements up to 25 years in length. EDCA regularly provides clients with custom load shaped wholesale and retail pricing for a variety of typical or specified pricing products (regulated, indexed, blocked or full requirements / load following etc.).

As part of the **regulatory and legal consulting services** provided by EDCA, the company has on many occasions prepared and filed evidence in all legal, arbitration and regulatory proceedings in Alberta and other provincial jurisdictions. EDCA staff has been prepared as an expert witness on many occasions on behalf of several clients and proceedings with several appearances in front of the Alberta Energy Regulator (“AER”) and Alberta Utilities Commission (“AUC”).

EDCA has a team of well qualified and experienced energy analysts that have been engaged in consulting activities with respect to the electricity and natural gas industry, covering a wide spectrum of issues. Fundamental market analysis, asset valuation, risk management, procurement, environmental and emissions issues, policy, financial and economic impact have been a significant part of the analytical work completed by staff at EDCA over the last 30 years.