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Techno-economic assessment of grid-tied photovoltaic systems in interior British Columbia

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Photovoltaics (PV) are crucial for global decarbonization, but their economic viability is limited in regions heavily reliant on low-cost hydroelectric power. This study aims to address this paradox by conducting a techno-economic analysis of a 153.30 kWp rooftop PV system in British Columbia, Canada. By combining empirical performance data with validated simulations, we demonstrate that rooftop PV can achieve grid parity, even in a hydro-dominated, low-tariff environment. Leveraging Canada's 30% Investment Tax Credit (ITC) and achieving a 99% self-consumption rate, which minimizes grid exports under strict net-metering constraints, the system achieves an unsubsidized Levelized Cost of Electricity (LCOE) of 9.25 ¢ per kWh. With ITC, LCOE improves to 6.60 ¢ per kWh, compared to local commercial rates of 8.83 ¢ per kWh. Empirical validation of PVSyst and PVSol software outputs (within 2% deviation from measured data) addresses a critical gap in PV performance predictability. The system offsets 17% of onsite demand, while ITC reduces the payback period from 20.9 to 15.6 years. These results challenge the notion that hydro-rich regions must solely rely on legacy renewables and provide a replicable model for high-self-consumption PV deployment in similar markets, such as parts in Scandinavia, Quebec and the Pacific Northwest. Policy recommendations emphasize tailoring fiscal incentives to local tariff conditions, while technical insights highlight the importance of aligning PV generation with onsite demand to maximize economic returns.

Broader context

Solar photovoltaics (PV) are growing rapidly worldwide, yet deployment lags in hydro-reliant, low-tariff grids where inexpensive electricity and export caps dilute the value proposition for distributed PV. This creates a shortage of empirically grounded benchmarks for commercial systems, especially at scales that exceed program eligibility and must operate with very high self-consumption. This study provides such a benchmark using a 153.30 kWp commercial rooftop system in interior British Columbia that was deliberately sized to align generation with building demand. Measured operation combined with calibrated PVSyst and PVSol simulations demonstrates a validated pathway to near-total self-consumption with negligible exports at commercial scale. The techno-economic analysis identifies capital cost, realized output, discount rate, and tariff trajectories as the dominant feasibility levers, and shows that an upfront capital incentive can shift levelized cost below prevailing tariffs and shorten payback. Because the climatic resource and pricing structures closely mirror those in Quebec, Manitoba, southern Scandinavia, and the U.S. Pacific Northwest, the findings offer globally relevant guidance. The study recommends sizing large systems for very high self-consumption when they exceed cap limits, validating designs with calibrated models, and pairing projects with appropriate capital incentives to accelerate cost-competitive, distributed decarbonization in hydro-reliant electricity systems.

1. Introduction

The global energy transition has reached a critical juncture, with 2024 confirmed as the warmest year on record,[1] and thus, the urgency to decarbonize electricity systems is accelerating. Photovoltaics (PV) accounted for over 60% of new electricity capacity additions worldwide in 2023,[2] however, this global growth masks a stark regional disparity. In markets dominated by low-cost hydroelectric power such as British Columbia (BC), Canada, rooftop PV deployment stagnates despite falling module prices and abundant solar resources.[3] For example, the Okanagan Valley receives an estimated 1100–1200 kWh kWp^{-1} annually,[4] yet the province's installed solar capacity stands at only 101 MW. This is less than 5% of Alberta's 2145 MW PV capacity despite Alberta's retail electricity tariffs being nearly double those in BC and 10–15% higher solar irradiance.[5,6] Similarly, hydro-dominated provinces such as Manitoba and Quebec, which also benefit from sizable irradiance and

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structurally low tariffs, have installed just 39 MW and 17 MW of capacity, respectively.[5] These interprovincial disparities underscore the critical role of electricity pricing and policy incentives in shaping PV adoption. This paradox is largely economic, commercial electricity rates as low as 8.83 ¢ per kWh (ref. 7) and restrictive net-metering policies suppress the financial viability of PV systems, particularly where subsidies and storage integration are absent.[8,9] This economic situation is now being revisited given BC's rising summer peak demands, where solar PV's generation profile offers a natural complement to hydro's seasonal output gaps and enhances grid resilience.[10,11]

This hydro-solar inverse relationship manifests differently across hydro-dominated markets. In low-tariff jurisdictions such as Scandinavia, Quebec, and Manitoba, capped export rates and thin retail margins suppress rooftop PV deployment despite strong irradiance.[12–14] Conversely, in hydro-reliant Brazil, high electricity tariffs have instead driven solar uptake as a hedge against escalating bills.[15] The result is a systemic barrier that prevents solar from fulfilling its distributed potential, particularly in industrial and commercial scale settings where demand is high but margins are low. These constraints are exacerbated by net-metering programs that impose export limits, critically reducing the value of surplus generation.[16,17]

In such low-tariff environments, accurate PV yield prediction is essential. Simulation tools like PVSyst and PVSol are widely used in feasibility studies and system design.[18,19] However, most validation studies are conducted in temperate or desert climates, with limited attention to regions characterized by seasonal snow, cloud transience, and hydro-based grid dynamics. For example, Merodio *et al.*[20] noted that uncertainty in albedo measurements especially in high-latitude and snow-covered environments can become a dominant source of error in energy yield estimation for bifacial PV systems. Similarly, Thevenard and Pelland[21] demonstrated that increased solar intermittency, particularly in mountainous regions, has a measurable impact on the long-term reliability of photovoltaic power output. In high-margin markets, these errors are tolerable; in low-margin contexts like BC, they can render projects economically unviable. Yet to date, few studies have empirically validated simulation accuracy using operational data from rooftop PV systems in BC or similar hydro-dominated regions.

Grid-tied PV systems worldwide typically report performance ratios (PRs) ranging from 78% to 86%, reflecting the robustness of modern systems when properly designed.[22,23] While PV modeling tools are standard in Canadian feasibility assessments,[24] empirical post-installation validation especially in BC remains rare. Studies in other regions, such as comparative work in Turkey[18] and simulation-based analyses,[25] have demonstrated that region-specific calibration and detailed modeling improve accuracy. However, these findings underscore rather than resolve the critical gap in localized validation within Canada's hydro-reliant electricity landscape.

Moreover, the economic case for rooftop PV in such contexts increasingly hinges on demand-side design strategies, particularly maximizing self-consumption. Prior research shows that self-consumption rates above 70% significantly improve system payback and reduce sensitivity to policy shifts.[26–28] Yet most studies assume moderate feed-in tariffs or dynamic pricing conditions that differ from those available under FortisBC and BCHydro, regional utility energy providers.[29,30] The financial performance of ultra-high self-consumption systems (>95%) under capped net-metering and low export compensation is largely unquantified. In this respect, rooftop PV is no longer just a technical and environmental solution but a design optimization challenge shaped by policy and tariff constraints.

Policy incentives such as Canada's 30% Clean Technology Investment Tax Credit (ITC) offer new economic levers to close the viability gap by reducing upfront capital costs in commercial or industrial settings.[31] Analogous programs in the U.S. and Europe have been shown to improve project internal rates of return and bring Levelized Cost of Electricity's (LCOE) in line with retail electricity prices.[32–34] However, the combined effect of the ITC and demand-driven PV system design remains insufficiently quantified in hydro-reliant provinces like BC. In particular, there is a lack of empirical studies that validate the predictive accuracy of widely used simulation tools such as PVSyst and PVSol against measured operational data in these low-tariff, hydro-dominated settings. Moreover, few analyses have systematically examined how maximizing self-consumption, through deliberate system sizing and load alignment, interacts with fiscal incentives to shape economic viability under restrictive net-metering policies.

This research addresses these gaps by empirically benchmarking simulation outputs against operational performance, while also quantifying the economic impacts of high self-consumption and the ITC in a real-world rooftop PV deployment. The resulting framework provides actionable insights for policymakers and system designers in hydro-rich, policy-constrained markets globally. To this end, the study conducts a comprehensive techno-economic assessment of a 153.30 kWp rooftop PV system installed atop an institutional building in Kelowna, BC. Drawing on six months of high-resolution operational data spanning both summer and winter conditions, this analysis validates energy predictions from PVSyst and PVSol, evaluates the system's self-consumption dynamics, and models the financial impacts of Canada's 30% ITC on the LCOE and payback period. Although limited to half a year, the dataset captures representative seasonal variation. The study is guided by the following research questions:

(1) How accurately can PVSyst and PVSol predict real-world PV performance under Kelowna's climatic conditions?

(2) To what extent does the rooftop PV system offset building electricity demand?

(3) How does the unsubsidized LCOE compare to prevailing commercial electricity rates in BC?

(4) What is the effect of Canada's 30% ITC on system LCOE and payback period?

(5) Can high self-consumption mitigate the economic limitations imposed by net-metering export restrictions?

By empirically validating simulation outputs and quantifying the combined effects of self-consumption and fiscal incentives, this study establishes a replicable framework for rooftop PV deployment in hydro-dominated, low-tariff markets. The findings deliver practical guidance for energy modeling, system design, and policy development in regions such as Scandinavia, Quebec, Manitoba, and the Pacific Northwest, where conventional assumptions about PV economics are constrained by local market realities.

2. Methodology

This section details a structured, four-phase methodology as illustrated in Fig. 1, encompassing site and climatic data acquisition, system design and simulation, empirical validation against operational data, and comprehensive economic and sensitivity analyses.

Each phase is tailored to the unique characteristics of hydro-dominated, low-tariff markets, ensuring that the techno-economic assessment is both empirically grounded and broadly replicable. All data processing and figure generation were performed using Origin and JMP Pro for time-series manipulation and visualization.[35,36] The following subsections describe the specific procedures and analytical frameworks adopted in this study.

2.1. Climatic and site conditions

A precise understanding of local climatic factors is essential for accurately simulating PV performance and informing system design.[18,25] Kelowna, located in the southern interior of British Columbia, experiences a humid continental climate (Köppen classification) with notably hot, dry summers and cold, cloudy winters.[37] To capture these dynamics, hourly time-series inputs for the 2023 calendar year were obtained from Solcast's dataset,[38] including global horizontal irradiance (GHI), diffuse horizontal irradiance (DHI), ambient temperature, wind speed, surface albedo, cloud opacity, and roof snow-soiling losses, all crucial for accurately assessing energy yield in a region with modest but non-negligible snowfall. These raw data were aggregated into monthly ranges and annual sums (for irradiance) or averages (for other parameters) for use in PVSyst and PVSol modeling (Table 1).

Key irradiance benchmarks confirm Kelowna's relevance as a proxy for other hydroelectric-reliant, low-tariff jurisdictions: Quebec's annual GHI (1141 kWh per m^2 per years),[39] Manitoba's annual GHI (1177.8 kWh per m^2 per years),[39] and southern Scandinavia's annual GHI (850–1100 kWh per m^2 per years).[39] While minor discrepancies may exist between datasets, the close alignment supports the applicability of these Solcast-derived inputs for feasibility analyses in similar hydro-dominated contexts. These climatic attributes guide both the system design and performance modeling discussions presented in subsequent sections.

2.1.1. Location and site characteristics. The VEDA Exclusive Student Living complex (hereafter "VEDA") comprises two 4-storey residences, Sunset Ridge and Apex, completed in September 2018 and situated on a southwest-facing hill (49.8889° N, 119.4950° W; elevation 520 m above sea level) immediately adjacent to the University of British Columbia's (UBC) Okanagan campus. The combined rooftop area is 1834 m^2 (1116 m^2 at Sunset Ridge; 718 m^2 at Apex), providing unobstructed solar access with no shading from nearby buildings or vegetation. Sunset Ridge's roof plane faces true south, while Apex is rotated 13° west of south. Mechanical equipment, including two HVAC units, and a small amenity patio occupy less than 5% of the total surface, leaving over 1740 m^2 available for photovoltaic modules. Fig. 2 illustrates the rooftop layout and existing solar array installation.[40]

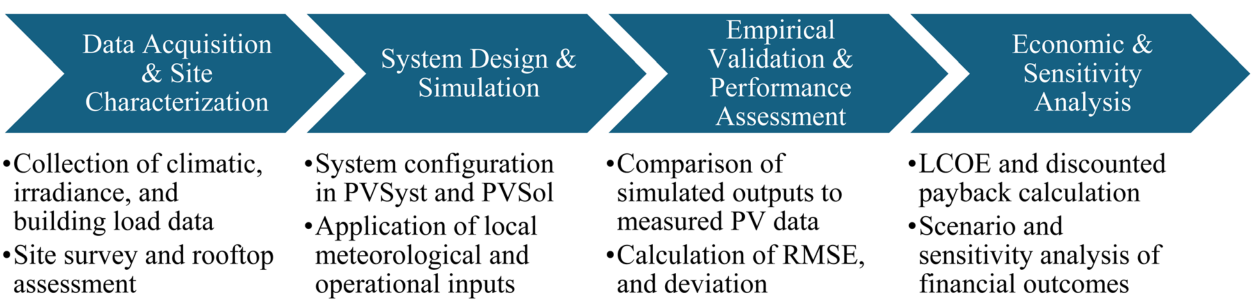

Fig. 1 Methodological workflow for PV system assessment.

Table 1 Derived monthly ranges and annual totals/averages of Kelowna climatic inputs (Solcast 2023 data)

Parameter	Monthly range	Annual total/average
Ambient temperature (°C)	−6.5 to 18.8	6.6 °C (avg)
GHI (kWh m^2)	30.7–205.5	1352 kWh per m^2 per years (sum)
DHI (kWh m^2)	19.0–73.0	545 kWh per m^2 per years (sum)
Wind speed (m s^{-1})	1.19–1.68	1.43 m s^{-1} (avg)
Albedo	0.099–0.406	0.176 (avg)
Cloud opacity (%)	9.7–29.6	21.7% (avg)
Roof snow-soiling loss (%)	0–64.7	14.0% (avg; critical for winter-yield accuracy)

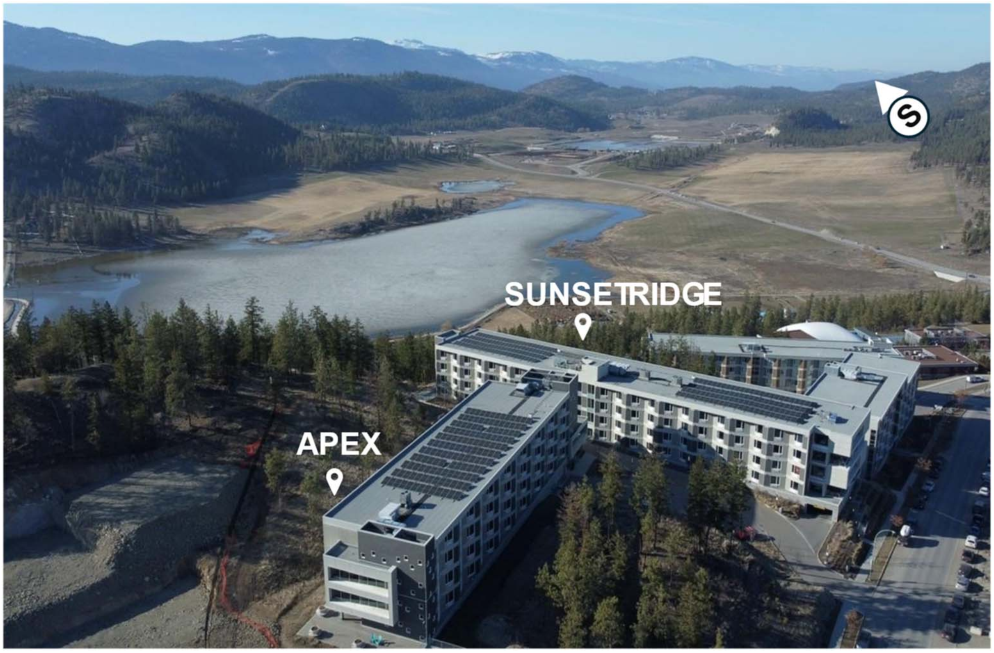

Fig. 2 Rooftop layout and surrounding area of the VEDA exclusive student living residences.[40]

2.1.2. Building energy consumption. To establish VEDA's baseline electricity and natural gas consumption, we obtained four calendar years (2021–2024) of hourly interval meter data from FortisBC, complemented by monthly utility billing records.[41] This dataset covers all 316 residential units, with electrically powered packaged terminal air conditioner (PTAC) units supplying heating and cooling, common-area heating served by natural gas, and the Parkade heated electrically. Occupancy, crucial for per-person normalization, was estimated *via* aggregate keycard-swipe counts, yielding monthly resident-day totals. Raw meter readings underwent quality control removing anomalies and interpolating missing intervals before aggregation into monthly totals. These monthly totals were divided by resident-day counts to derive average daily per-person consumption for both electricity and natural gas. In parallel, hourly electricity data were grouped by month and averaged across all days to generate 24-hour load profiles for diurnal demand analysis. Mean monthly outdoor temperatures, sourced from Solcast and cross-checked against Environment and Climate Change Canada records, were appended only to the monthly time series to support subsequent correlation studies.[37,38] Fig. 3a–c present the methodological outputs: monthly consumption trends, daily per-person loads *versus* temperature, and monthly-averaged hourly demand curves. This rigorous multi-scale characterization underpins the PV sizing and self-consumption analyses that follow, ensuring that modeled generation profiles align with observed building load dynamics.

2.2. PV system design and simulation

This section describes the configuration, structural integration, and simulation approach used to model the rooftop PV system. Two simulation platforms, PVSyst v7.4.8 and PVSol Premium 2024 R3, were used to ensure cross-validation and enhance modeling reliability.[18,42]

2.2.1. System configuration and modeling inputs. The system comprises 333 LONGi LR4-72HPH-455M mono-crystalline modules, with a total DC capacity of 153.30 kWp, installed across the rooftops of Sunset Ridge and Apex. Each array was modeled using 3D environments within both platforms to replicate actual roof geometry, tilt, and potential shading. Module azimuths are 0° (Sunset Ridge) and −13° (Apex), consistent with building orientation, and modules are mounted at a fixed 10° tilt that was structurally imposed (roof and wind load limits) rather than irradiance-optimized. To estimate the performance penalty, further modeling was conducted in PVSyst at tilt 0° to 90°, with an interval of 10°, holding all inputs constant. Row spacing of 1.04 m and a pitch of 3.10 m were selected to minimize inter-row shading and allow snow shedding. The total rooftop area across both buildings is 1834 m^2. Inverter deployment includes two 30 kWac SMA Sunny Tripower units at Sunset Ridge and one 50 kWac unit at Apex, yielding DC to AC ratios of 1.46 and 1.28, respectively. These configurations maintain high inverter loading while minimizing energy clipping during peak irradiance. All inverters are compliant with local grid voltage and frequency requirements and support partial generation during isolated inverter failures. Table 2 summarizes the simulation input parameters.

2.2.2. Structural integration and simulation parameters. All modules were installed on a non-penetrative ballasted mounting system (TerraGen TGR), constructed from aluminum 6063-T6 and galvanized steel G90 GR50, with a rubber membrane beneath each rail to protect the underlying bituminous roofing membrane.[43] No additional roof reinforcement

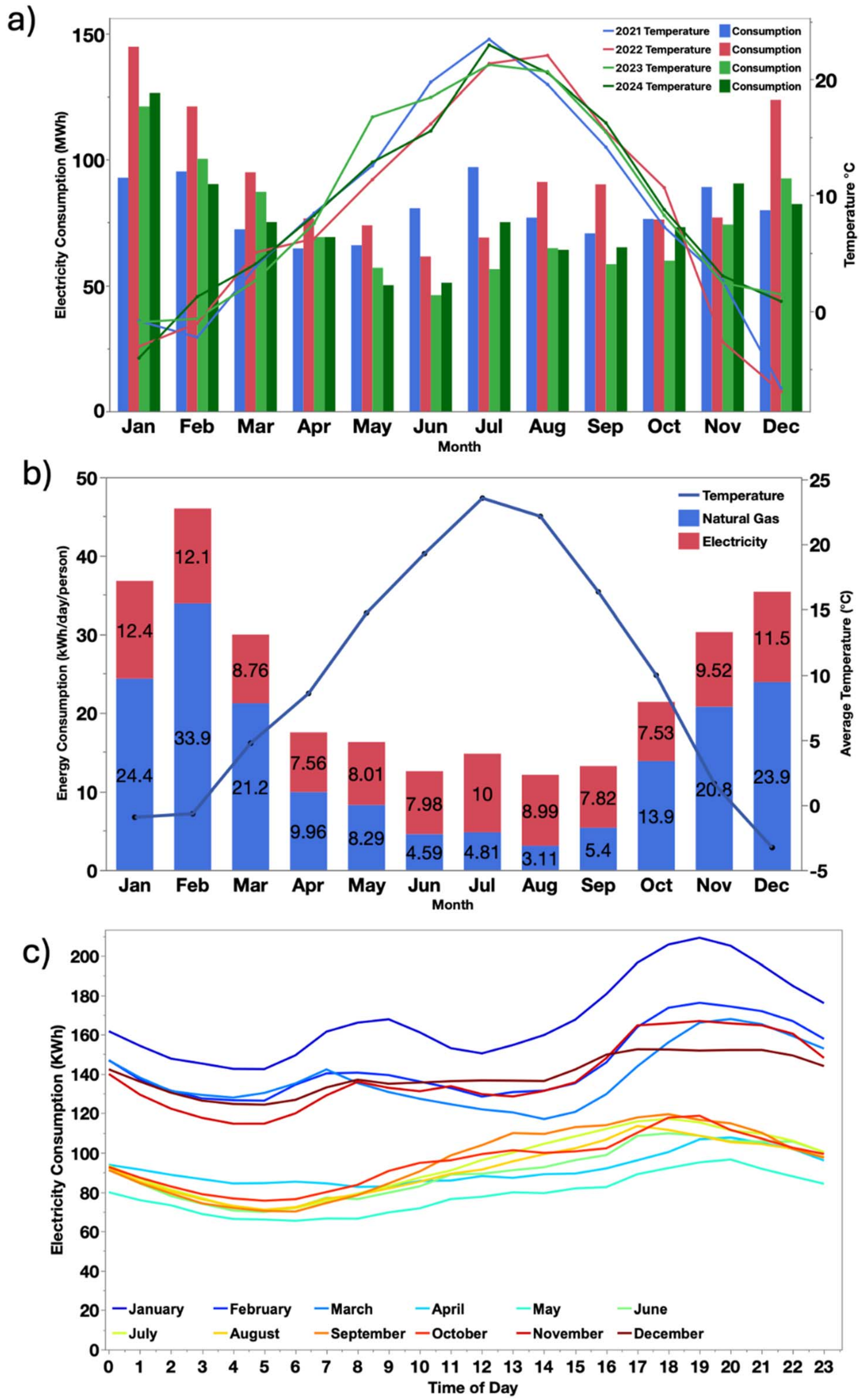

Fig. 3 (a) Monthly electricity consumption of the student residence correlated with average temperatures per month in Kelowna, BC, in the years 2021 to 2024. (b) Average monthly temperatures from 2021 to 2024 and electricity and natural gas consumption per month in kWh per person per day over the same period. (c) Hourly electricity consumption profile per month.

was required. Structural assessments were performed in accordance with the National Building Code of Canada (NBCC),[44] and the design incorporated these assumptions: 1.46 kilopascal (kPa) for snow load, 0.4 kPa for wind, 0.9g ($g = 9.81$ m s^{-2}) for seismic loading, and a global distributed load of 0.20 kPa. Notably, neither the NBCC nor current provincial Building

Table 2 PV system design parameters (simulation inputs)

Parameter	Sunset ridge roof	Apex roof
Number of modules	192	141
DC capacity (kWp)	89.16	64.16
Module model	LONGi LR4-72HPH-455M	LONGi LR4-72HPH-455M
Inverter configuration	2 × 30 kWac SMA	1 × 50 kWac SMA
DC to AC ratio	1.46	1.28
Tilt angle (°)	10	10
Azimuth (°)	0	−13
Roof area (m^2)	1116	718
Row spacing (m)	1.04	1.04
Front-to-front pitch (m)	3.10	3.10

Table 3 Default simulation loss parameters in PVSyst and PVSol

Loss parameter	PVSyst	PVSol
Temperature model	NOCT ($U_c = 29$ W m^{-2} K^{-1}, $U_v = 0$ W m^{-3} K^{-1} m s^{-1})	NOCT model (empirical coefficients)
DC wiring loss (%)	1.5	1.5
AC wiring loss (%)	0.5	0.5
Module mismatch (%)	2.0	2.0 (per string)
Light-induced degradation (%)	1.5	1.5
Soiling loss	Monthly values from Solcast	Monthly values from Solcast
System unavailability (%)	0.3	0.3
Inverter loss	Manufacturer-specific efficiency curve	Dynamic inverter performance thresholds

Code editions mandate "solar-ready" structural allowances for future PV retrofits on commercial buildings, a constraint that influenced the as-built 10° tilt.[44]

Meteorological data, including hourly GHI, DHI, ambient temperature, wind speed, albedo, and monthly snow and soiling losses, were sourced from Solcast[38] and uniformly applied in both simulation platforms. All non-site-specific system losses were retained at default settings, summarized in Table 3.

Simulated energy outputs, generated using these harmonized assumptions, form the basis for the economic analysis presented in Section 2.3 and are validated against measured performance data. As part of this validation, the PR was calculated to quantify system efficiency relative to theoretical output. In accordance with IEC 61724–1:2021, PR is defined as:[45]

$$\mathrm{PR} = \frac{E_{\mathrm{AC}}}{P_{\mathrm{DC}} \times H_{\mathrm{POA}}} \tag{1}$$

where E_{AC} is the measured AC energy output (kWh), P_{DC} is the installed Direct Current (DC) capacity (kWp), and H_{POA} is the plane-of-array irradiance (kWh m^{-2}) over the assessment period. Validation also included the root mean square error (RMSE) and percentage deviation to quantify the difference between simulated and measured energy outputs.

2.3. Economic analysis and cost modeling methodology

This section outlines the analytical methods used to evaluate the financial feasibility of the rooftop PV system. It includes the procedures used to determine installed system costs, normalized cost-per-watt values, and long-term electricity generation costs. Energy yield data were sourced from harmonized outputs of PVSol and PVSyst simulations as detailed in Section 2.2. The key financial performance indicators analyzed include the LCOE and the Discounted Payback Period (DPP). Sensitivity analyses were also conducted to assess the robustness of these metrics under varying input assumptions. All monetary values are expressed in CAD.

2.3.1. Contractor tendering and system cost composition. A competitive procurement process was initiated to identify a qualified solar contractor. Five companies operating in the Okanagan region were invited to submit bids based on a common site profile and building load characteristics. Each submission was evaluated using both quantitative and qualitative criteria. Quantitative metrics included installed DC capacity, cost-per-watt, warranty coverage, and inverter selection. Qualitative criteria involved company experience, past reference projects, and design configuration quality.

Although all bidders received identical site information, variations in proposed system capacities and prices were observed. These differences stemmed from the use of different module technologies, inverter topologies, labor cost assumptions, and mounting approaches. The selected contractor's proposal was validated using independent simulations in PVSol and PVSyst to confirm that the proposed system layout and capacity were technically sound and would achieve the expected performance.

To standardize financial evaluation, cost breakdowns from each quotation were disaggregated into four main components: photovoltaic modules, inverters and balance-of-system (BOS) electrical hardware, structural racking systems, and ancillary charges including labor, permitting, and engineering design. Freight, contingency allowances, and auxiliary charges were appropriately allocated to the most relevant category to allow consistent cross-comparison among bidders.

2.3.2. Installed cost per watt scaling. To analyze how system size affects cost-efficiency, quotations for PV systems ranging from 5 kWp to 200 kWp were collected. For each system, the installed cost per watt (C_{watt}) was calculated using the following expression:

$$\text{Cost per watt} = \frac{C_{\text{total}}}{P_{\text{DC}}} \tag{2}$$

where C_{total} represents the total quoted installation cost (pre-tax), and P_{DC} is the rated DC system capacity. This normalization facilitates equitable comparisons across systems of varying sizes and highlights the potential for economies of scale. To characterize the empirical relationship between system size and installed cost per watt, a least-squares regression was conducted using a quadratic polynomial model:

$$C_{\text{watt}}(x) = \alpha + \beta_1 x + \beta_2 x^2 \tag{3}$$

where $x = \log_{10}(P_{\text{DC}})$, α is the intercept, and β_1 and β_2 are regression coefficients. The quadratic model was selected for its ability to capture the nonlinear scaling observed in the dataset. All quotations were screened for completeness and accuracy before inclusion in the regression analysis. The model fit was assessed using the coefficient of determination (R^2), providing a measure of explanatory strength. This methodology follows the approach in ref. 46 and 47.

2.3.3. Levelized cost of electricity (LCOE). The LCOE metric provides a comprehensive measure of the lifetime cost of electricity generation per lifetime energy produced. This can be calculated from the eqn (4) and (5),[46,48]

$$\text{LCOE} = \frac{\text{Discounted lifetime cost}}{\text{Discounted lifetime energy generation}} \tag{4}$$

$$\text{LCOE} = \frac{\sum_{t=0}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{5}$$

where I_t, M_t, and F_t denote the investment (Capital expenditure (CAPEX)), Operation and Maintenance (O&M), and financing costs in year t, respectively. The variable r is the discount rate, taken as 3.5% to align with infrastructure investment standards. The system lifetime n is assumed to be 25 years. The term E_t is the projected electricity output in year t, calculated as:

$$E_t = S \times (1 - d)^{t-1} \tag{6}$$

where S is the simulated first-year yield from PVSol and PVSyst outputs, and d is the annual degradation rate, assumed to be 0.5% following.[49] No salvage value was considered at the end of year 25; therefore, residual value associated with components that may remain serviceable beyond this period, such as structural racking, is not reflected in the LCOE calculation. The model includes a 4% annual escalation in electricity prices, consistent with recent FortisBC tariff adjustments ranging from 1.0% to 6.74% over the 2020–2024 period,[50] with an average close to 4%, although all cash flows are evaluated in real terms; this assumption is further examined through the sensitivity analysis across a range of escalation scenarios. Annual maintenance costs are estimated at CAD 1000, and an inverter replacement is scheduled at year 12. The baseline scenario includes a 5% Goods and Services Tax (GST) applied to capital expenditure. An alternative case includes a 30% ITC, applied at year 0 to reduce initial capital expenditure.

2.3.4. Discounted payback period (DPP). DPP reflects the number of years required to recover the initial investment, accounting for the time value of money. This is formally defined as the smallest $k \in [0, n]$ satisfying:

$$\sum_{t=0}^{k} \frac{B_t + C_t}{(1+r)^t} \geq 0 \tag{7}$$

where B_t represents the benefits from avoided utility electricity costs, and C_t includes all expenditures incurred in year t, including operations and maintenance as well as the inverter replacement in year 12. The discount rate r used here is the same 3.5% employed in the LCOE formulation. The DPP offers a practical time horizon metric for evaluating financial return on investment. The methodology is aligned with ref. 47 and 51.

2.3.5. Sensitivity analysis. To examine how parameter uncertainty impacts financial viability, a one-at-a-time sensitivity analysis was performed. Each input variable was varied individually while holding others constant. The variables tested include the discount rate (0–5%), degradation rate (0–0.55%), capital cost (±10%), and annual electricity price escalation (0–8%). This analysis quantifies the sensitivity of LCOE on the base scenario (without ITC) and discounted payback period to each parameter. The method follows Talavera *et al.*,[47] ensuring consistency with established sensitivity testing procedures in PV techno-economic studies.

3. Results and discussion

3.1. Simulation accuracy and validation

Accurate simulation of PV system output is critical in hydro-dominant regions such as British Columbia, where low utility tariffs and limited net-metering incentives necessitate precise sizing for economic viability. Predictive models must accurately estimate annual energy yield, monthly generation profiles, and export behavior, as these factors directly influence financial viability and system optimization. Unlike regions benefiting from high feed-in tariffs, PV systems in British Columbia must closely match building loads, minimizing uncompensated energy exports. Following the final design iteration, the PV system was projected to operate at a nominal capacity of 153.30 kWp. Simulations using industry-standard tools, PVSyst and PVSol, estimated annual energy yields of 182 MWh and 183 MWh, respectively. These projections represent 17% of the annual electricity demand for the VEDA building, highlighting strategic sizing relative to onsite consumption. Fig. 4a and b illustrate simulated monthly energy generation and associated grid exports as predicted by PVSyst and PVSol, respectively. Both platforms indicate peak generation during summer

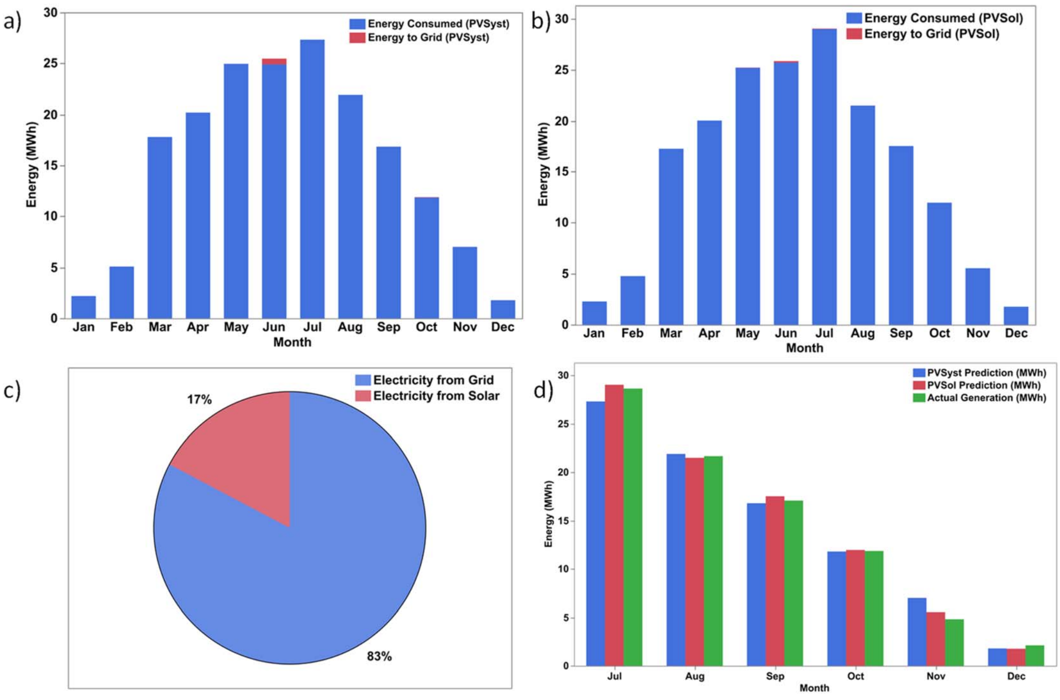

Fig. 4 Total anticipated monthly electricity production by the PV system (10° tilt), divided into on-site usage and grid-fed generation determined by (a) PVSyst and (b) PVSol. (c) Estimated percentage of total electricity demand met by the PV system and the grid. (d) PVSyt and PVSol energy prediction against actual energy generated by installed PV system.

months (May through August), consistent with increased irradiance and extended daylight hours typical of the Okanagan Valley. July energy production is estimated at 27.33 MWh by PVSyst and 29.10 MWh by PVSol. In June, slightly lower production is forecasted at 25.47 MWh (PVSyst) and 25.69 MWh (PVSol), yet grid exports peak at 550 kWh (PVSyst) and 220 kWh (PVSol). Reduced building occupancy and lower electricity demand during this period drive the increased exports, despite slightly lower solar availability relative to July. Conversely, winter generation significantly declines, with December forecasts of 1.79 MWh (PVSyst) and 1.77 MWh (PVSol) due to shorter daylight hours and decreased solar insolation. This pronounced seasonal variation emphasizes the necessity for careful system sizing and management strategies to optimize energy utilization and minimize operational inefficiencies. Interestingly, although July achieves the highest absolute energy generation, June records the greatest net surplus electricity generation (total PV production minus immediate building loads). This result stems from comparatively lower cooling loads and occupancy, leading to higher net surplus despite lower overall solar availability. First-year projections indicate minimal annual grid exports, accounting for 0.3% (550 kWh, PVSyst) and 0.1% (220 kWh, PVSol) of total generation. The corresponding self-consumption rates approach 99.7% (PVSyst) and 99.9% (PVSol), underscoring effective alignment between PV generation and building load profiles. Such high onsite consumption rates reduce reliance on external power sources, contribute to local energy resilience, and mitigate transmission losses, aligning closely with findings by Luthander *et al.*,[27] who highlighted significant operational benefits of high self-consumption rates. Fig. 4c further reveals the proportion of the building's total energy demand met by the PV system and the grid. The data clearly demonstrate the effectiveness of strategic system sizing, with the PV installation significantly offsetting building loads. Specifically, the PV system provides 17% of the total annual energy consumption, reinforcing the high self-consumption strategy adopted to minimize uncompensated exports. Empirical validation using measured data from July through December 2023 confirms robust predictive accuracy from both modeling platforms. Fig. 4d visually compares actual monthly energy production with simulation outputs of same duration, illustrating close agreement throughout the evaluated period. Actual energy production totaled 86.2 MWh for this period. PVSyst predicted 86.7 MWh, demonstrating a deviation of only 0.63%, while PVSol forecasted 87.8 MWh, resulting in a slightly higher deviation of 1.82%. These deviations correspond to RMSE values of 0.23 MWh for PVSyst and 0.65 MWh for PVSol, quantitatively supporting the predictive reliability of both tools over the observed period. The six-month validation window, however, permits only partial direct empirical verification of model accuracy over a full annual cycle and therefore introduces bounded uncertainty in extrapolated annual performance. While the dataset includes periods of both high and low generation, the resulting annual estimates remain partially reliant on simulation rather than complete empirical validation. The slight differences observed between these two simulation tools primarily arise from variations in their meteorological modeling capabilities and temperature sensitivity calculations, as noted by Dirlik *et al.*[18]

PVSyst's smaller deviation suggests higher accuracy under the climatic and operational conditions at the VEDA site, particularly given its detailed diagnostic precision for monocrystalline silicon modules. This aligns with De Souza Silva *et al.*,[42] who similarly reported greater predictive precision with PVSyst compared to PVSol's conservative estimates. Moreover, the deviations recorded here are well within industry-standard expectations. Dirlik *et al.*,[18] reported typical annual deviations below 10% as acceptable benchmarks, placing both models' performance within excellent predictive standards.

Table 4 consolidates essential performance indicators, demonstrating how minor differences in modeling assumptions yield approximately a 1% variance in annual production estimates and summarizing critical validation metrics comprehensively.

Notably, the simulated specific annual yields for PVSyst (1192 kWh kWp^{-1}) and PVSol (1191.56 kWh kWp^{-1}) fall within the expected PV potential range for the Okanagan Valley (1100–1200 kWh kWp^{-1}),[4] further validating the accuracy of the models in the regional context. Likewise, the projected PR of 82.15% (PVSyst) and 82.88% (PVSol) closely align with the established industry range of 78–86% noted by Sharma *et al.* and Shukla *et al.*[22,23] Comparable PRs were reported by Messina *et al.*,[52] who documented ratios between 81.83% and 84.28% in Mexico, and by Shiva Kumar and Sudhakar,[53] reporting annual PRs around 85% in India. These benchmark comparisons underscore the reliability of simulation tools for accurately assessing PV performance across diverse climates and operational contexts.

Leveraging the validated PVSyst model, a site-specific tilt-angle sensitivity analysis assessed seasonal and annual performance across fixed module inclinations from 0° to 90°. Fig. 5 presents the normalized yields for summer (May–August), winter (November–February), and the full year. Each curve is scaled to its respective maximum to reveal relative efficiency and highlight sensitivity to tilt. The summer curve peaks broadly around 12°, aligning with high solar elevation and optimal midday irradiance capture. Beyond 20°, summer output declines sharply due to increasing angular mismatch with the overhead sun. In contrast, the winter curve shows a continuous rise, reaching a maximum at 42°, where steeper panels more effectively intercept low-angled sunlight. Below 25°, winter performance drops significantly. The annual curve reaches its peak near 28°, representing a balanced compromise between seasonal extremes, with relatively modest performance losses for deviations within ±10° of this optimum. The as-built 10° configuration closely aligns with summer optimum conditions but performs far below potential in winter. Panels at this tilt deliver substantially less winter energy and are prone to snow accumulation, which further limits production during a period when grid demand is typically highest. Steeper winter-optimized tilts not only enhance low-sun irradiance capture but also promote passive snow shedding, improving operational reliability.

These limitations arise not from solar geometry but from structural constraints imposed by Canada's 2020 National Building Code, which mandates strict snow, wind, and seismic load checks but omits solar-specific allowances for additional dead load.[44] While Natural Resources Canada's Photovoltaic-Ready Guidelines recommend allocating extra rooftop capacity and conduit access, these remain voluntary. British Columbia's solar-hot-water-ready provisions apply only to certain residential cases and exclude commercial retrofits such as VEDA.[54,55] Taken together, these findings highlight the importance of incorporating structural allowances for PV optimization. Without enforceable support for steeper module tilts, rooftop systems will continue to underperform in winter seasons, precisely when improved solar output is most valuable for supporting seasonal load peaks. Simulation-led design and targeted policy reform are therefore essential to unlock the full technical and economic potential of distributed PV in hydro-dominated, low-tariff regions.

3.2. Self-consumption

Analysis of four years of building energy data reveals pronounced seasonal and interannual variability in electricity demand, closely coupled to ambient temperature and occupancy dynamics. Over this period, the combined electricity consumption of the two buildings averaged 967.40 MWh per year. As depicted in Fig. 3a, the highest monthly consumption, 144.90 MWh, occurred in January 2022 (mean temperature = −3 °C), reflecting increased heating demand during the coldest months. The lowest monthly usage, 46.40 MWh, was recorded in June 2023, representing less than one-third of the January maximum. An unusual pattern is evident in 2021, when the peak load shifted to July, rather than the typical winter period. This summer peaking coincided with an unprecedented heatwave, during which temperature increased to 49.6 °C in BC, breaking Canadian national temperature record by 4.6 °C.[56] This resulted in elevated electricity demand for air-conditioning, an effect that is increasingly relevant in the context of climate change. On a broader scale, the IEA,[57] has

Table 4 Performance metrics from two modelling tools PVSyst and PVSol alongside operational data of VEDA's installed PV system

	PVSyst (annual)	PVSol (annual)	Actual (Jul–Dec)
Energy production (MWh)	182	183	86.2
Spec. annual yield (kWh kWp^{-1})	1192	1191.56	563.39
Performance ratio (%)	82.15	82.88	N/A
Percentage deviation (%)	0.63	1.82	N/A
RMSE (MWh)	0.23	0.65	N/A

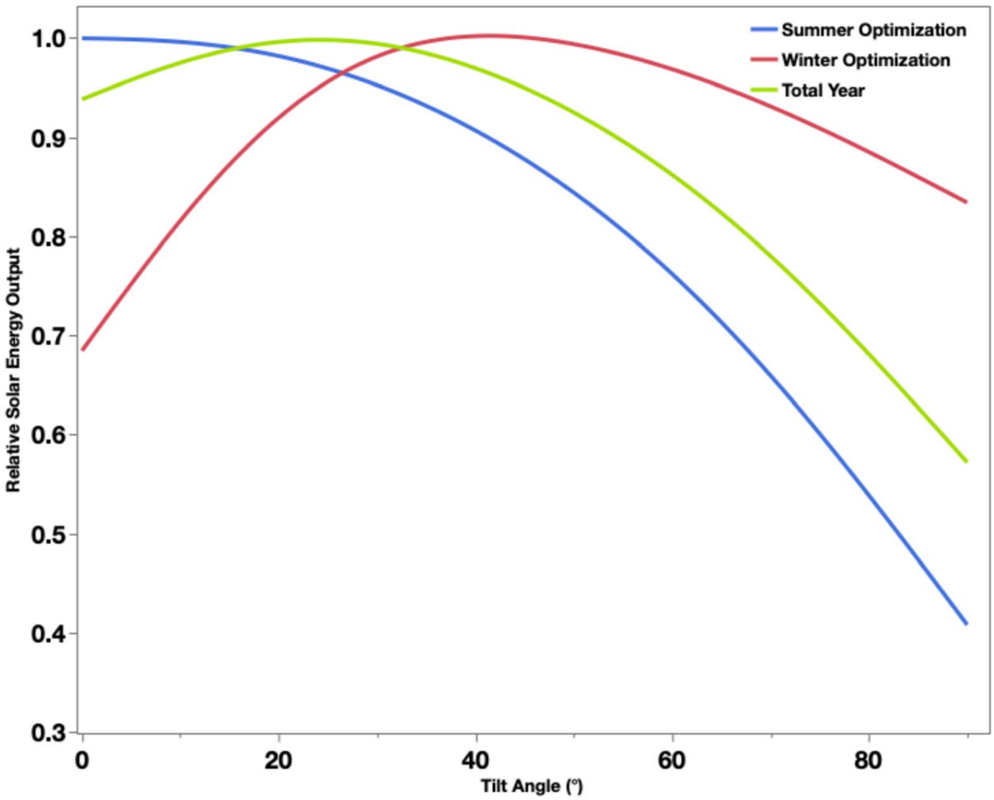

Fig. 5 Normalized PV energy yield *versus* fixed tilt angle for the VEDA rooftop system. The annual curve peaks at 28°, representing the optimal compromise between summer and winter generation. The as-built 10° tilt aligns with optimum summer conditions but significantly underperforms in winter, reflecting structural constraints imposed by current building code requirements.

identified rising cooling demand as the world's second-largest contributor to electricity demand growth over the coming decades, surpassed only by electric vehicle expansion. The overall lower energy consumption observed in 2021 is attributable to pandemic-related occupancy reductions, as reflected in reduced keycard-swipe counts due to remote instruction at UBC. Fig. 3b provides further resolution by depicting average monthly temperatures (2021–2024) alongside daily per-person energy consumption for both electricity and natural gas. The highest per-person energy requirement (46.0 kWh per day per person) was recorded in February (mean temperature = −1 °C), while the lowest (12.10 kWh per day per person) aligned with August's warmer temperatures (22.2 °C) and reduced occupancy. On average, each resident consumed approximately 14.50 kWh of natural gas and 9.40 kWh of electricity per day, for a total of 23.90 kWh daily per person. These trends highlight the importance of both climatic and behavioral drivers in shaping aggregate and normalized building energy demand.

Diurnal load profiles, as illustrated in Fig. 3c, illustrate the impact of both seasonality and occupancy schedules. Between September and March, electric heating produces elevated morning (7:00–9:00 AM) and evening (6:00–8:00 PM) peaks, with the maximum hourly usage (209.2 kWh) occurring in January at 8:00 PM. These peaks coincide with the academic term, when residential activity is highest. In summer, the load profile is flatter, with lower overnight consumption and a gradual increase to a 6:00 PM peak (119.5 kWh), primarily due to air-conditioning and increased appliance use during extended daylight hours. Understanding these seasonal, monthly, and hourly trends is essential for PV system sizing and maximizing on-site utilization. Detailed characterization of both electric and natural gas consumption, as well as occupancy-adjusted metrics, underpins accurate modeling of self-consumption potential and informs the operational strategy for building-integrated PV systems.

The relationship between PV generation and building load is visualized in Fig. 6, which shows monthly PV energy output with total building demand.

Throughout all months of the year, building consumption remains well above PV generation, yielding an exceptionally high self-consumption rate of 99%. During the summer, when PV output is maximized, the building load remains sufficiently high to absorb nearly all generated energy, thus minimizing uncompensated exports to the grid. However, short periods of overproduction can occur during peak midday irradiance when supply momentarily exceeds instantaneous demand; these transient surpluses are not apparent in the monthly averages shown in Fig. 6. This operational outcome is a direct result of intentional system sizing and aligns closely with the findings of Luthander *et al.*,[27] who demonstrated the economic and grid benefits of maximizing self-consumption in PV applications.

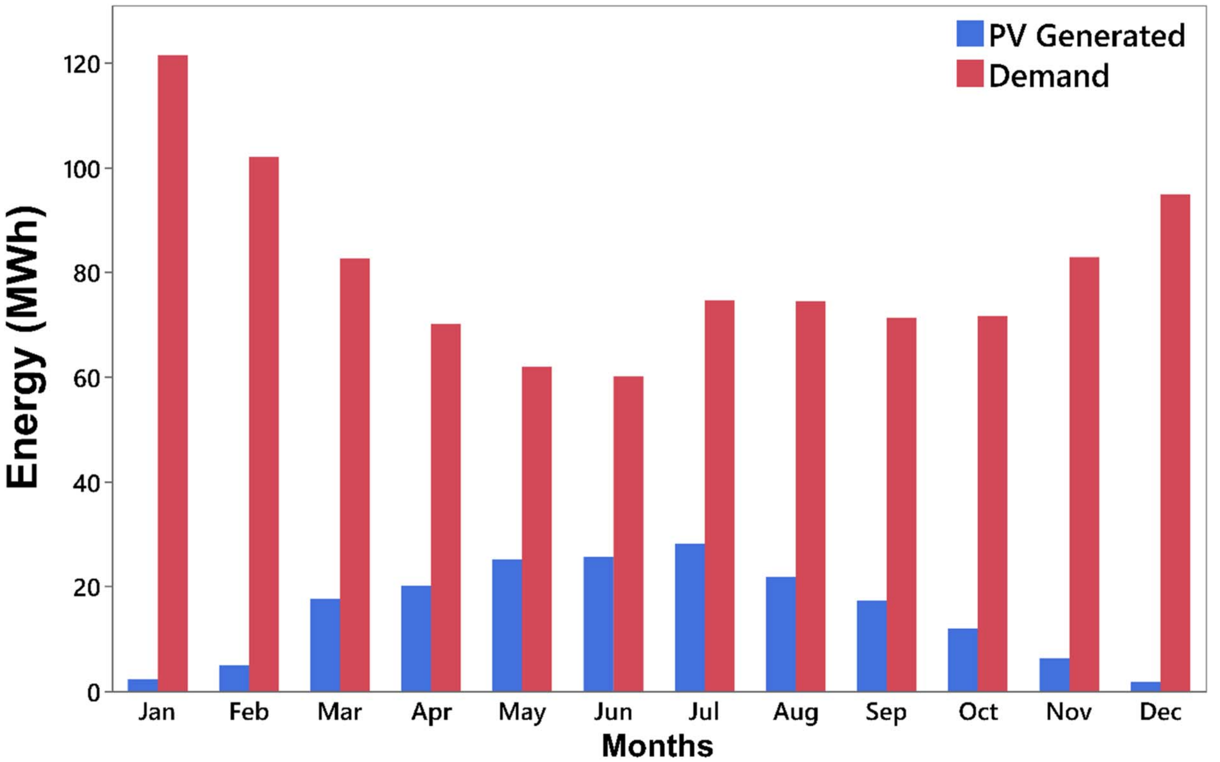

Fig. 6 PV energy generated and building demand (10° module tilt).

3.3. Economic analysis

3.3.1. Tendering process results. Quotations from five regional contractors yielded proposed system sizes between 151 kWp and 200 kWp, with installed costs ranging from CAD 239 000 to CAD 312 000 and cost-per-watt values from CAD 1.48/W to CAD 2.04/W as illustrated in Table 5. Contractor A was ultimately selected, based on a balance of competitive pricing (CAD 1.68/W), suitable racking design, and demonstrated experience with comparable commercial PV installations.

The final as-built system size increased marginally from the original proposal (151.5 kWp) to 153.3 kWp, reflecting the addition of four modules to maximize roof utilization. This minor capacity adjustment did not materially alter the project's cost structure or the selection rationale. Variation among all bids primarily reflected differences in module technology, racking systems, and contractor-specific pricing strategies, consistent with broader Canadian market trends.[58]

3.3.2. Composition of cost: balance of system and module cost fraction. Analysis of cost breakdowns from all five contractors reveals that PV modules constitute the largest single cost component, averaging 35.1% of total system cost across quotations. The remaining BOS elements include inverters and associated electronic components (23.6%), racking and

Table 5 PV system design proposed by five local contractors

Company	A	B	C	D	E
System size (kWp DC)	151.5	153.1	155.0	200.0	152.8
Module manufacturer	LONGi	Canadian solar	Q-cell	Canadian solar	Q-cell
Module type	Mono PERC	Poly PERC	Mono PERC	Poly PERC	Mono PERC
Module power (Wp)	455	405	440	Not specified	400
Panel warranty: power output (years)	25	25	25	25	25
Inverter	SMA	SolarEdge	SMA	SMA	Solar edge
Inverter warranty (years)	10	12	10	10	12
Racking system	TerraGen	Unirac RM10	Schletter fix grid 18	KB racking	Kinetic racking
Racking tilt (degrees)	10	10	20–30	Not specified	15
Quote (kWh kWp^{-1})	1126	1107	1166	Not specified	1307
System warranty (years)	3	5	1	5	2
System cost (without GST) (CAD)	$255 145	$246 053	$239 100	$295 000	$311 607
System cost (with GST) (CAD)	$267 902	$258 356	$251 055	$309 750	$327 423
Cost per watt ($ per watt)	1.68	1.61	1.54	1.48	2.04

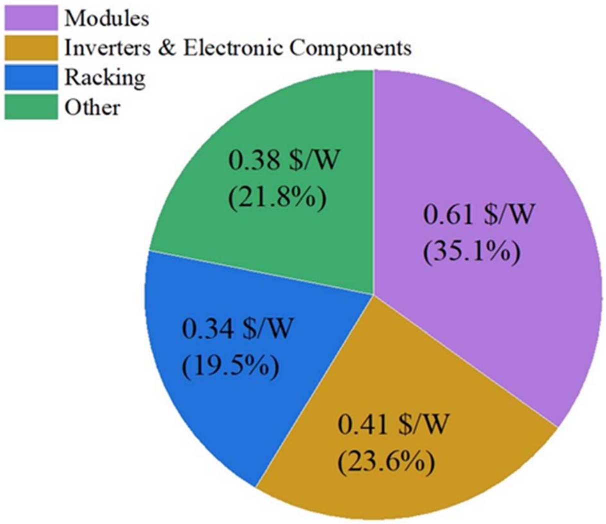

Fig. 7 Percentage breakdown of modules and BOS from contractor A through E.

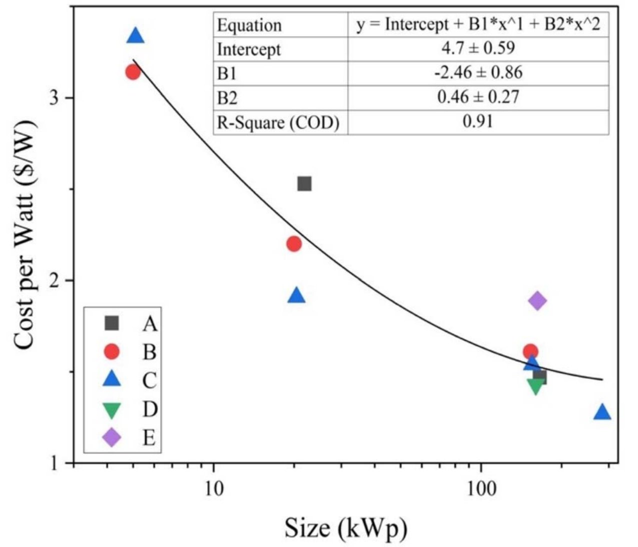

Fig. 8 Cost per watt for PV system sizes in the Okanagan region ranging from 5–200 kWp.

structural systems (19.5%), and auxiliary charges, such as labor, permitting, and engineering, which comprise 21.8%. Fig. 7 presents the average cost distribution for mid-sized commercial rooftop PV projects from all 5 contractors. This cost structure is consistent with contemporary Canadian PV market reports and reflects the global trend of declining module prices, which, despite substantial reductions, still represent the primary capital expenditure.[46,58] The proportional shares for BOS, particularly for racking and inverters, underscore the continued significance of site-specific engineering and procurement in shaping total project cost. Variations between contractor quotations are primarily attributable to differences in module selection, racking solutions, and local labor rates, highlighting the need for granular cost assessments during project planning.

3.3.3. Cost per watt *vs.* system size. A pronounced economy of scale is evident in the cost-per-watt values obtained from contractor quotations for system sizes spanning 5 kWp to 200 kWp. The data show that the installed cost declined from CAD 3.24 per watt for the smallest (5 kWp) systems to CAD 1.27 per watt for the largest (200 kWp) system, representing a reduction of 61%. The steepest cost gradient occurs below 50 kWp; above this size, the curve gradually flattens, and systems exceeding 120 kWp achieve only marginal additional reductions. The 153.30 kWp system analyzed in this study achieved a cost-per-watt of CAD 1.61, which places it within the lower quartile of commercial-scale quotations collected, as illustrated in Fig. 8.

This scale-driven cost reduction can be primarily attributed to the dilution of fixed costs, such as permitting, engineering, and mobilization, which become marginal at larger capacities. Additionally, volume-based discounts on modules and balance-of-system components further lower unit prices. The empirical data are well described by a power-law relationship, with a R^2 of 0.91, which confirms the consistency of the trend with regional market behavior. These findings align with the broader literature, which identifies system size as the principal driver of PV cost optimization in mature markets, especially where permitting and interconnection requirements are significant.[46] For systems above 150 kWp, the observed cost-per-watt approaches a flatter asymptote, and further reductions are constrained by regional market factors such as supply chain limitations and site-specific installation challenges. Rather marginal cost savings are realized for capacities beyond this threshold. These results confirm that, for the Okanagan region, commercial sized PV projects achieve favorable cost efficiency at sizes above 120 to 150 kWp, as further increases in system size provide diminishing economic returns due to persistent market-specific frameworks (*e.g.* net metering constraints, building demand).

3.3.4. Local electricity context and net metering constraints. The economic feasibility of large commercial PV installations in the Okanagan is fundamentally shaped by the region's prevailing electricity pricing structure and the limitations imposed by net metering policies. For commercial customers under FortisBC's standard rate structure, as of January 2025, the applicable tariff includes a customer charge of CAD 69.06 per 30-day billing period, a demand charge of CAD 14.53 per kW (for demand above 40 kW), and an energy charge of 8.83 ₵ per kWh.[7] This rate schedule, underpinned by the province's hydroelectric resource base, results in some of the lowest commercial electricity costs nationally. Given these baseline tariffs, the margin for cost savings from PV self-generation is intrinsically limited. The competitiveness of PV-generated electricity is further constrained by FortisBC's net metering policy, which restricts participation to systems of 50 kWp or less.[3,59] The installation analyzed in this study, at 153.30 kWp, exceeds this threshold and is consequently ineligible for net metering credits on exported generation. As a result, system sizing must prioritize internal consumption, as any surplus generation is uncompensated. Analysis of annual load and generation profiles for the facility reveals that surplus exports constitute less than 0.3% of total PV output, reflecting a close alignment between PV generation and building demand. This high degree of self-consumption (>99%) is consistent with both simulation studies and empirical data from commercial systems in regions with similarly restrictive net metering policies.[27,47] Literature consistently demonstrates that, in markets characterized by low retail electricity prices and constrained export compensation, maximizing self-consumption becomes the principal economic driver of PV project viability.[3,58] The prevailing 50 kWp net metering cap in the FortisBC service territory (or 100 kWp in BCHydro service territory) thus necessitates rigorous system sizing and load analysis to optimize on-site consumption and project economics.[59,60] These conclusions are reinforced by published studies documenting the effects of net metering policy on PV system design and performance in hydro-dominated markets.[13,27] Within the current regulatory framework, commercial PV projects in the Okanagan can achieve optimal economic performance only when generation is primarily consumed on-site, with the net metering cap remaining a critical constraint for installations seeking to leverage economies of scale. This high self-consumption also displaces grid electricity, which can result in lifecycle emission reductions over the system lifetime,[61] although the hydro-dominated nature of BC's grid limits marginal carbon savings relative to fossil-fuel-intensive regions.

3.3.5. Discounted payback period (DPP). DPP reflects the investment horizon required to recover the net system cost, here CAD 267 902, accounting for the time value of money with a 3.5% discount rate, 0.5% annual module degradation, 4% annual tariff escalation, and first-year energy output of 182.5 MWh. Under these baseline assumptions, the DPP is calculated as 20.9 years. This value falls just within the 25-year product warranty, characteristic of British Columbia's low-tariff electricity environment. When 30% ITC is applied, the DPP is reduced to 15.6 years, improving investment attractiveness by 25.3%. This result demonstrates the pivotal role of upfront incentives in accelerating PV adoption in hydro-dominated markets. To analyze the factors shaping project feasibility, Fig. 9a–e present the DPP response to independent variation of key techno-economic parameters. Fig. 9a shows that reducing annual module degradation from 0.55% to 0% shortens the DPP from 20.9 years to 19.5 years. This confirms that, within typical degradation rates for crystalline silicon PV systems, this parameter has only a modest effect on capital recovery.[49] Fig. 9b demonstrates that the discount rate is a far more influential variable. As the real discount rate is varied from 0% to 5%, the DPP extends beyond the system's service life, while a 0% discount rate accelerates payback to 17.8 years. This highlights the critical impact of financing conditions on project viability.[46,47] Annual operating and maintenance costs, examined in Fig. 9c, increase the DPP by less than 1.2 years over a CAD 0 to 1500 range, which indicates a relatively minor effect compared to other variables. In Fig. 9d, variations in first-year electricity output between 146 and 195 MWh shift the DPP from 25.4 years to 19.7 years, underscoring system output (*e.g.* influenced by module tilt, see Fig. 5) as the dominant technical determinant for investment returns.

This result aligns with observed performance ratios and capacity factors in comparable international studies.[62] Fig. 9e shows that higher electricity price escalation rates significantly enhance economic viability. Raising the tariff escalation from 4% to 8% reduces the DPP from 20.9 years to 15.8 years, further highlighting the sensitivity of PV investments to future utility rate trajectories.[63] To facilitate direct comparison, Fig. 9f presents a spider plot summarizing the sensitivity analysis. The steeper slopes of the electricity output, tariff escalation, and discount rate curves indicate that these parameters exert the greatest leverage on DPP. In contrast, the flatter curves for O&M costs and module degradation demonstrate their relatively limited effect. This visual ranking is consistent with prior findings for commercial PV economics.[32,47] Collectively, these results show that project feasibility in BC's hydro-rich, low-tariff context is determined primarily by factors directly tied to system performance and local electricity pricing, rather than by secondary technical or operational variables. This sensitivity analysis not only validates established modeling approaches, but also highlights the unique importance of system sizing and tariff structure for maximizing the value of large-scale PV in regions constrained by both utility rates and net metering policy.

3.3.6. Levelized cost of electricity. The LCOE is a central metric for evaluating the lifecycle cost-effectiveness of the 153.30 kWp rooftop PV system. Under baseline conditions without direct incentives, the system yields an LCOE of 9.25 ₵ per kWh. This value is approximately 0.42 ₵ per kWh (4.8%), higher than FortisBC's prevailing commercial tariff of 8.83 ₵ per kWh in the first year of operation.[7] This modest difference highlights the challenge posed by British Columbia's low hydroelectricity prices for PV economic viability at this scale. From a temporal perspective, historical PV system costs were substantially higher, and ongoing declines in module prices together with improvements in system performance are expected to further reduce LCOE in future deployments.[2,32] As noted in prior studies, however, even modest future increases in grid electricity rates can quickly narrow this gap, enhancing the competitiveness of solar PV over a 25-year system lifetime.[46,63] When the federal 30% ITC is applied, the LCOE falls to 6.60 ₵ per kWh. This represents a 28.6% reduction relative to the baseline case, positioning PV electricity well below the utility tariff and firmly within the range of cost-competitive distributed energy resources. The magnitude of this improvement is consistent with literature emphasizing the importance of upfront capital cost incentives in accelerating PV adoption in markets where baseline tariffs are low.[32,64] Fig. 10 summarizes the results of the LCOE sensitivity analysis under the base scenario (no ITC).

CAPEX exerts the strongest influence, with a ±30% variation in CAPEX shifting the LCOE from 6.60 to 11.91 ₵ per kWh. System output and the discount rate are also highly influential. For example, a reduction in first-year generation to 153.9 MWh raises the LCOE to 10.8 ₵ per kWh, while an increase in the discount rate from 3.5% to 5% lifts the LCOE to 10.5 ₵ per kWh. In contrast, varying annual O&M costs and module degradation rates (within tested ranges of 0.3 to 0.55%) produces less than

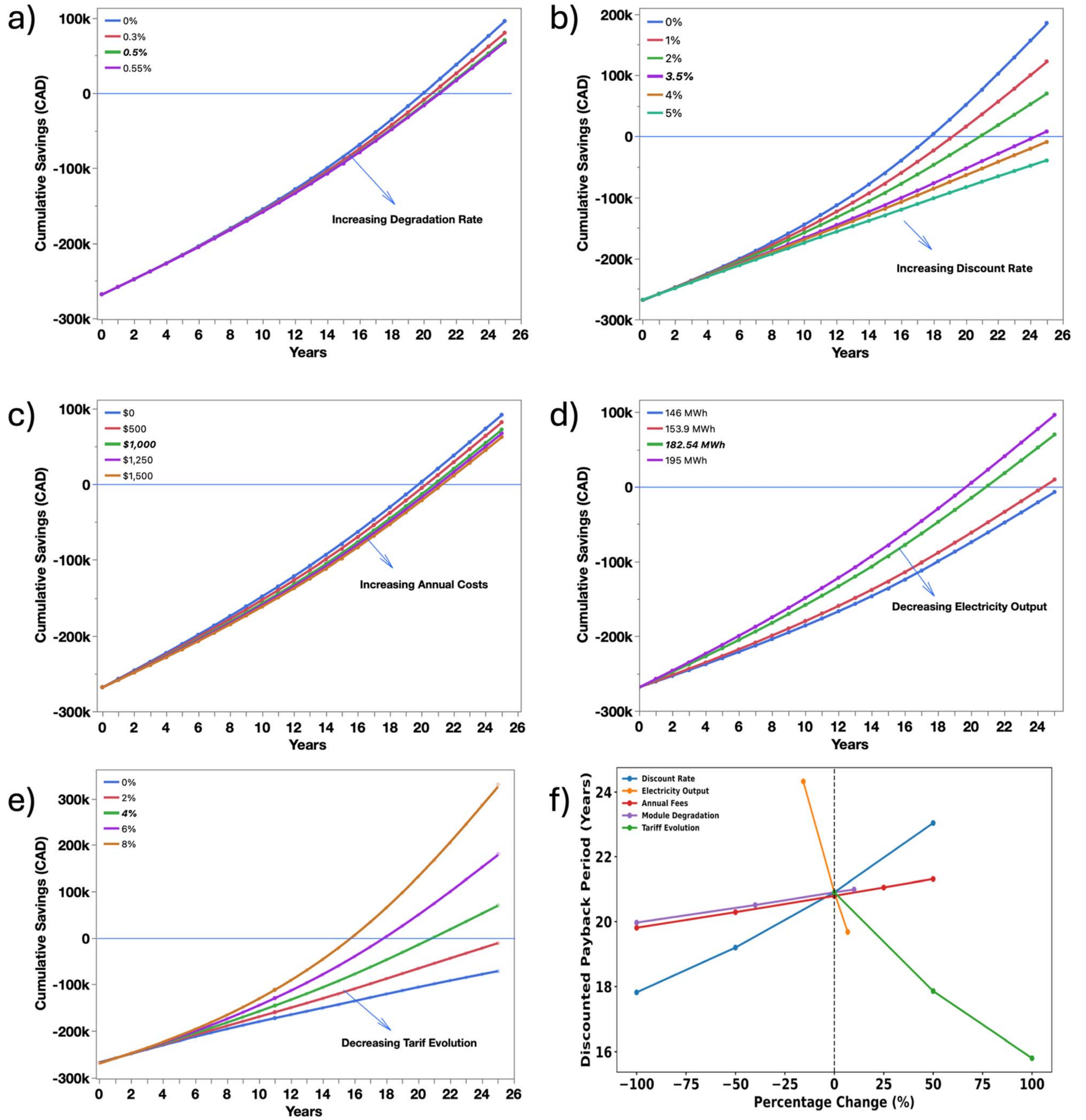

Fig. 9 (a–e) Payback period estimation for different cost scenarios, including differing degradation rates, discount rates, annual fees, electricity output and tariff evolutions, respectively. All base assumptions (in bold) were held constant. (f) Sensitivity analysis on the impact of parameter variations on the discounted Payback Period.

8% deviation from the baseline, confirming their more limited impact.[46,64] The steepness of each curve in Fig. 10, indicates the sensitivity of LCOE to that parameter. Steeper curves, such as those for CAPEX, output, and discount rate, show that small changes in these inputs can significantly alter LCOE, while flatter curves for O&M and degradation reflect a more modest effect. This hierarchy is consistent with the established literature on PV system economics in North America and Europe, where cost-competitive installations typically exhibit LCOEs between 6 and 10 ₵ per kWh, depending on incentive structures, capital costs, and local market conditions.[32,47] Finally, in the context of this study, high self-consumption rates, achieved through careful system sizing and alignment with building load, help to ensure that the calculated LCOE reflects real investment returns even under restrictive net metering regimes.[27] These findings reinforce the critical importance of capital cost management, accurate performance modeling, and stable policy frameworks in achieving cost parity for rooftop PV

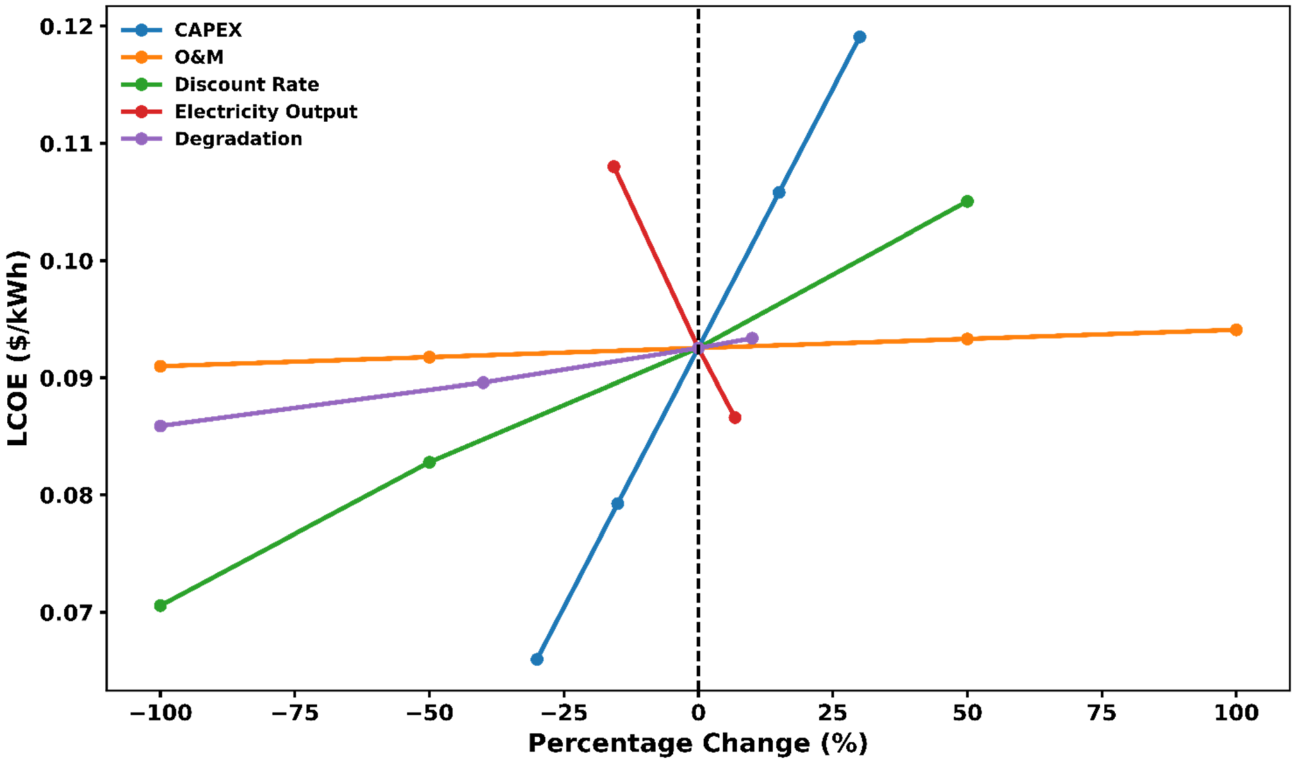

Fig. 10 Sensitivity analysis on the impact of parameter variations on the LCOE.

in hydro-rich, low-tariff electricity markets. Alternative PV technologies such thin-film or emerging technologies may influence LCOE through differences in module efficiency, degradation rates, and cost structures.[2,48] However, the fundamental economic drivers identified in this study, particularly the impact of low utility tariffs and the importance of high self-consumption, remain applicable across technology types.

3.3.7. **Broader implications for PV adoption in hydro-dominated regions.** The empirical results of this study demonstrate that, despite strong solar resource potential in the Okanagan Valley and similar hydro-rich regions, large-scale PV deployment remains highly constrained by economic and policy factors rather than technical limitations. British Columbia, Manitoba, and Quebec collectively account for less than 6% of Canada's installed solar PV capacity, even though their southern regions achieve annual insolation levels comparable to northern European countries such as Germany and Sweden.[4,5] In contrast, Alberta, with higher commercial electricity tariffs and more flexible net metering, has surpassed 2100 MW of installed solar, outpacing cumulative totals in the aforementioned hydro-dominated provinces.[5] The primary driver of these disparities is economic rather than technical. In 2024, retail electricity prices for large power customers in hydro-rich cities such as Montreal (5.74 ₵ per kWh), Winnipeg (6.00 ₵ per kWh), and Vancouver (8.12 ₵ per kWh) remained substantially lower than in Calgary (10.46 ₵ per kWh) or Edmonton (13.17 ₵ per kWh), directly impacting the economic case for distributed solar generation.[6] The findings of this study reinforce this context. Although the baseline LCOE for the 153.3 kWp rooftop PV system in Kelowna was calculated at 9.25 ₵ per kWh, when modelled over its full 25-year lifetime and with projected rate escalation, the system achieves cost parity and generates net savings even without targeted financial incentives. Application of Canada's 30% ITC, as modeled here, reduces the LCOE to 6.60 ₵ per kWh, providing a strong economic pathway that is directly relevant to similar hydro-dominated regions.[31] International and regional literature consistently corroborate these findings. Studies in the Nordic region, for instance, show that resource potential is often not the limiting factor; rather, the combination of low-cost hydropower, insufficient incentives, and underdeveloped policy frameworks serves as the main barrier to wider PV deployment.[12,13] Recent analyses in Norway found that, while southern regions receive solar irradiation comparable to Germany, uptake remains suppressed by the lack of compelling financial drivers and the absence of robust regulatory mandates for distributed generation.[13] Similarly, in Sweden and rural EU regions, the gap between technical potential and actual adoption is maintained by low electricity prices, social and informational barriers, and inconsistent policy supports.[14] Beyond Europe, Brazilian experience illustrates how targeted net metering policy reforms and investment incentives can sustain strong PV adoption, even in markets dominated by hydroelectric generation.[15] As these examples collectively demonstrate, maximizing on-site self-consumption, aligning system sizing with local load, and providing stable, predictable financial incentives are critical to unlocking distributed PV in hydro-dominated grids. The present study's findings, including the near-total self-consumption achieved through deliberate system design, reinforce the importance of these strategies for project feasibility where uncompensated excess generation or grid exports prevail.[27,47] While the Canadian ITC currently applies only to commercial and industrial settings, similar support for residential rooftop PV, such as tax credits or upfront subsidies, has proven effective in accelerating adoption in other jurisdictions, notably Germany and United States.[32,33] Policymakers seeking to close the gap between technical potential and real-world deployment in hydro-rich regions should expand access to targeted financial incentives for residential customers. In BC, the recent extension of the Canada Greener Homes Loan program, which offers interest-free loans of up to CAD 40 000 over ten years for residential PV installations, represents an important step toward improving project economics at the residential level.[65] This approach is particularly relevant in markets with high homeownership, distributed loads, and persistent barriers to project economics posed by low utility rates and net metering constraints. It is important to note, however, that the direct transfer of policy instruments across jurisdictions may be affected by differences in regulatory structures, market maturity, and social context. As such, while the empirical patterns and policy responses highlighted here offer actionable guidance, successful adaptation will require careful consideration of local institutional, economic, and cultural factors. Sustained progress in expanding distributed solar adoption in hydro-dominated regions will ultimately depend on coordinated policy evolution, robust empirical benchmarking, and the broad availability of capital incentives for both commercial and residential PV deployment.

4. Conclusion

This study confronts the hydro-solar paradox by showing that, in hydro-dominated regions like British Columbia, technical potential for rooftop PV is high yet deployment is held back by economic and policy barriers. We empirically validated PVSyst and PVSol projections against six months of measured data in Kelowna, finding deviations consistently under 2%. While this validation provides strong confidence in model performance, the analysis remains subject to the inherent limitations of extrapolating annual performance from partial-year observations. Strategically sized, the 153.30 kWp rooftop system offsets 17% of the building's annual electricity use and achieves a 99% self-consumption rate, thereby minimizing uncompensated exports under restrictive net-metering provisions.

Economically, the system's unsubsidized LCOE (9.25 ₵ per kWh) slightly exceeds today's commercial tariff (8.83 ₵ per kWh); however, when analyzed over its 25-year lifetime with 4% tariff escalation, it reaches cost parity without incentives and yields a payback period within the 25-year module warranty period. Applying Canada's 30% ITC lowers the LCOE to 6.60 ₵ per kWh and shortens the payback from 20.9 to 15.6 years, underscoring how targeted incentives decisively improve economics even in low-tariff markets. Leveraging the validated model, a site-specific tilt-angle sensitivity analysis showed that the as-built 10° configuration aligns well with summer conditions but performs far below potential in winter, capturing only a fraction of the low-sun seasonal yield. This performance loss arises not from meteorological factors but from current absence of PV-related language in Canada's building codes. The 2020 National Building Code mandates snow, wind, and seismic load checks, yet omits rooftop design allowances for solar-specific applications. Natural Resources Canada's Photovoltaic-Ready Guidelines recommend allocating additional roof capacity and conduit pathways, but these remain voluntary. In British Columbia, solar-hot-water-ready regulations, although not specific to PV, apply narrowly to certain residential dwellings and do not extend to commercial retrofits such as VEDA. Such limitations hinder both seasonal optimization and broader PV deployment. Amendments to the provincial building code requiring enforceable solar-ready provisions could enable steeper module tilts that enhance winter energy capture and improve grid alignment during peak seasonal loads. Complementary increases in BC's net-metering thresholds would further support the economic case for larger, more efficient rooftop systems. Collectively, our analytical framework combining rigorous modeling, empirical validation, and sensitivity analysis provides a robust roadmap for unlocking distributed solar in hydro-rich, low-tariff regions worldwide.

Author contributions

Abdul-Mubarak Y. Yidana: writing – original draft, visualization, validation, software, methodology, investigation, formal analysis, data curation. Amandine A. Drew: writing – original draft, visualization, validation, software, methodology, investigation, formal analysis, data curation. Sunil Suresh: writing – review, methodology, editing, supervision. Noah McIntosh: writing – review & editing. Christopher Paul: writing – review & editing. Alexander R. Uhl: writing – review & editing, supervision, resources, methodology, conceptualization.

Conflicts of interest

The authors declare no competing interests.

Data availability

Meteorological and irradiance inputs were obtained from Solcast for the study site at 49.8889° N, 119.4950° W (elevation 520 m). The Solcast data product and access information are available at https://solcast.com/.

Building operations data, including hourly electricity meter data, load profiles, and PV energy outputs for the VEDA site, were provided by the building owner–operator, VEDA Exclusive Student Living (Sunset Ridge and Apex residences; https://vedaliving.ca/kelowna/). These operational datasets contain commercially sensitive and occupant-related information and are not publicly shareable for confidentiality reasons. Aggregated statistics used in the analysis are presented within the article's tables and figures.

Climatological reference data used for cross checks are available from Environment and Climate Change Canada, Canadian Climate Normals, at https://climate.weather.gc.ca/climate_normals/.

The PV performance simulations were conducted with PVSyst v7.4.8 and PVSol Premium 2024 R3. Product information and downloads are available at https://www.pvsyst.com/ and https://valentin-software.com/en/products/pvsol-premium/. Data processing and figure generation used OriginPro 2024b (10.1) and JMP Pro 18.2.1, available at https://www.originlab.com/and https://www.jmp.com/.

No custom code was developed for this study. All model inputs and configuration parameters required to reproduce the simulations are reported in the manuscript's methods and tables.

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