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of the Rockies**

Technoeconomic Opportunity Analysis for Local Power Generation in Falls City, Nebraska

Simon Sandler, Meenakshi Narayanaswami, William Scott
Carron, and Jamie Lopp

National Laboratory of the Rockies

The National Laboratory of the Rockies is a national laboratory of the U.S. Department of Energy, Office of Critical Minerals and Energy Innovation, operated under Contract No. DE-AC36-08GO28308.

Technical Report
NLR/ TP-6A20-97066
September 2026

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List of Abbreviations

AC	Alternating Current
BESS	Battery Energy Storage System
CAPEX	Capital Expenditures
Communities LEAP	Communities Local Energy Action Program
DC	Direct Current
DOE	U.S. Department of Energy
EIA	Energy Information Administration
kW	kilowatt
kWh	kilowatt-hour
LMP	Locational Marginal Pricing
NPV	Net Present Value
NLR	National Laboratory of the Rockies
PV	Photovoltaic
SAM	System Advisor Model
SPP	Southwest Power Pool
TMY	Typical Meteorological Year
W	Watt
W _{DC}	Watts Direct Current

Executive Summary

Falls City is a small community in Nebraska interested in understanding how energy from solar photovoltaic (PV) and battery energy storage systems (BESS) could support the community's economic development planning. With limited and often inadequate access to power supply for potential load growth, the Falls City community coalition has identified immediate needs for energy to overcome their energy challenges and to encourage economic development. To address the current community needs and address the future energy demand, technical assistance conducted through Communities Local Energy Action Program (Communities LEAP) assessed the technical and economic opportunities of adding PV and BESS capacity to Falls City's municipally owned and operated electric utility system.

The analysis considered the technical and economic feasibility of PV and BESS using the System Advisor Model. The analysis explored a combination of three technology configurations, weather data, wholesale electricity cost data, and wholesale electricity cost escalation rates as shown in the table below.

Table 1. Core modeled scenario parameters summary

Scenario Parameters	Values
Technology Configuration	PV, PV+BESS, and BESS
Wholesale Cost and Weather Data	2015–2022 and a typical meteorological year
Wholesale Electricity Escalation Rates	0.3% and 2.5%
Technology Design	PV: 1,000 kilowatt-alternating current (kW-AC) BESS: 1,000 kW-AC and 2,000 kWh-AC (2-hour duration)
Technology Costs	PV only: \$1.54/Watts Direct Current (W_{DC}) PV + BESS: \$2.50/ W_{DC} BESS only: \$1.16/ W_{DC}

Results from the modeling performed showed that at current capital expenditure costs and wholesale electricity costs only four of the 54 scenarios analyzed provide a positive net present value (NPV); and these scenarios were largely driven by high wholesale costs and the higher (2.5%) electricity escalation rate. The positive NPV scenarios were either PV or PV + BESS configurations while BESS alone scenarios had no positive NPVs. Across all technology configurations and scenarios, notable capital expenditure cost reductions would be required to return an average positive NPV if wholesale market conditions endure with expected growth between 0.3% and 2.5%. Notably under the assumed market conditions, investment in BESS is not financially viable since modeled revenue does not cover operations and maintenance expenses.

Identifying additional financial support, changes in market conditions (e.g., lower capital costs or higher escalation of wholesale electricity prices), and tapping into additional revenue streams (such as compensation for grid services provided) could result in more economically viable projects. In locations where PV or BESS can receive compensation for other grid services and capacity payments or wholesale rates increase consistently, projects will return better NPVs. The technical assistance and modeling results presented here are based on fixed assumptions that are

subject to change. As actual market conditions vary, re-evaluation may be necessary and opportunities for PV or BESS projects that provide greater economic benefits to the Falls City community may materialize.

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Introduction

Falls City is a rural community of approximately 4,000 residents in the far southeastern corner of the state of Nebraska. The community pursued technical assistance to support their economic development planning through Communities Local Energy Action Program (Communities LEAP). Citing limited and often inadequate access to power for potential new load growth, the Falls City community coalition has identified immediate needs for energy to overcome their energy challenges and to encourage economic development. The Falls City community coalition has identified long-term economic expansion opportunities focused on the development of an industrial Rail Park intending to attract biofuel and biopolymer manufacturers to the region. In addition to the corn-based feedstock, the production of biofuels, including sustainable aviation fuel and ethanol, requires a significant amount of energy, amounts that are currently not available to the Falls City municipally owned and operated electric utility (Muni). While the city has decided to pursue transmission projects to address capacity needs on their existing grid, redundancy and resilience concerns remain unaddressed. Further, implementation of energy sources, including solar photovoltaic (PV) and battery energy storage (BESS) technologies, could make Falls City more attractive to potential manufacturers and could provide cost savings to ratepayers.

To address the current community needs as well as address potential future energy demand from efforts to attract biofuel and biopolymer manufacturers, the Falls City community coalition is exploring how to integrate PV and BESS technologies into their energy and economic development planning. The technical assistance conducted through Communities LEAP assesses the technical and economic opportunities of adding PV and BESS capacity to Falls City Muni distribution system. The analysis provides Falls City community coalition with a more robust understanding of the technical and financial considerations of deploying PV and BESS technologies in their community and assists with the development of energy implementation strategies.

Through consultation with the Falls City community coalition, which included the Falls City Muni, it was determined that a project developed and owned by the city's municipal utility was most likely to be realized. The Falls City Muni provides electricity service to its customers using multiple sources of generation. Falls City is included in the Southwest Power Pool (SPP) regional transmission organization. This means that electricity purchased wholesale by the Falls City Muni is provided through the SPP market and its transmission system. Falls City Muni produces power using their own diesel generator and purchases additional power from the SPP. The electricity purchased from the SPP comes in two forms, firm contracts with two separate generators and purchasing real-time energy market electricity. PV and BESS would be able to displace or reduce the amount of electricity purchased from the SPP real-time energy market. Therefore, the business-as-usual case assumes Falls City Muni continues purchasing power from SPP's real-time energy market, and the analysis models the financial impact of installing and operating PV and BESS relative to business-as-usual.

The techno-economic analysis in this report summarizes the methods and results of modeling PV and BESS implementation on the Falls City Muni grid. The modeling provides insights by highlights different possible system configurations, project economic considerations, and projected financial savings for the municipal utility.

Methods

The System Advisor Model (SAM) was utilized to conduct a techno-economic analysis. SAM is an externally vetted, proven software developed by NLR to evaluate the performance and financial feasibility of renewable energy systems. At the request of Falls City community coalition, three distinct technology configurations were analyzed to explore a range of deployment scenarios: PV (solar-only), PV + BESS (solar integrated with battery storage), and standalone BESS systems (battery storage-only). Running different scenarios allowed assessment of the techno-economic performance of each configuration, including metrics such as energy production, net present value (NPV), and cash flow over time. The PV-only scenario evaluates the feasibility of solar power in isolation, while the PV + BESS scenario provided insights on the cost and operational benefits of hybrid systems, and the standalone BESS scenario assessed the viability of using energy storage alone for energy arbitrage.

The techno-economic analysis incorporated rigorous tests to evaluate the performance of energy systems under varying SPP energy market and local weather conditions. Hourly locational marginal pricing (LMP) data for 2024, the most recent available year, was combined with typical meteorological year (TMY) weather data for one scenario. TMY data represents the typical or average weather patterns at a location based on 30 years of historical recordings providing a reasonable estimate for simulating solar generation and battery performance. The 2024 LMP data reflects the most recent wholesale market conditions and was paired with TMY data as actual 2024 weather data is not available at this time. Additional scenarios were run with hourly weather data for eight years in the last decade (2015 through 2022) and were paired with the respective year's hourly LMP price data. Running these eight scenarios helps capture the variations in climate conditions and market dynamics that impact project performance and economics.

Each of these scenarios was run using a 25-year project life and the LMP market values were modeled under two annual escalation rates, 0.3% (low-rise scenario) and 2.5% (high-rise scenario). A summary of the scenarios modeled are laid out in Table 2 for reference throughout the remainder of this report.

Table 2. Complete List of All Year and Escalation Rate Scenarios Modeled for Each Technology Configuration

PV Only			PV + BESS			BESS Only		
Scenario	Escalation Rate	Year Modeled	Scenario	Escalation Rate	Year Modeled	Scenario	Escalation Rate	Year Modeled
1A	0.30%	Average	2A	0.30%	Average	3A	0.30%	Average
1B		2022	2B		2022	3B		2022
1C		2021	2C		2021	3C		2021
1D		2020	2D		2020	3D		2020
1E		2019	2E		2019	3E		2019
1F		2018	2F		2018	3F		2018
1G		2017	2G		2017	3G		2017
1H		2016	2H		2016	3H		2016

PV Only			PV + BESS			BESS Only		
Scenario	Escalation Rate	Year Modeled	Scenario	Escalation Rate	Year Modeled	Scenario	Escalation Rate	Year Modeled
1I		2015	2I		2015	3I		2015
1J	2.50%	Average	2J	2.50%	Average	3J	2.50%	Average
1K		2022	2K		2022	3K		2022
1L		2021	2L		2021	3L		2021
1M		2020	2M		2020	3M		2020
1N		2019	2N		2019	3N		2019
1O		2018	2O		2018	3O		2018
1P		2017	2P		2017	3P		2017
1Q		2016	2Q		2016	3Q		2016
1R		2015	2R		2015	3R		2015

The low- and high-rise escalation rate values were implemented by NLR to place bounds on an expected range of increases in LMP rates over the life of the project. As LMP rates increase, so does the revenue (also referred to as savings) that can be realized by PV or BESS systems that have low operational costs relative to their sunk capital costs. The low-rise scenario's 0.3% escalation rate was selected using the historical slope of average SPP annual LMP using all available data from 2013 through 2024. The annual average LMP for these years is plotted in Figure 1 as well as the trend line described by a ~\$0.3/MWh slope. Slope describes the change in LMPs for each year providing a conservative trend of annual increases.

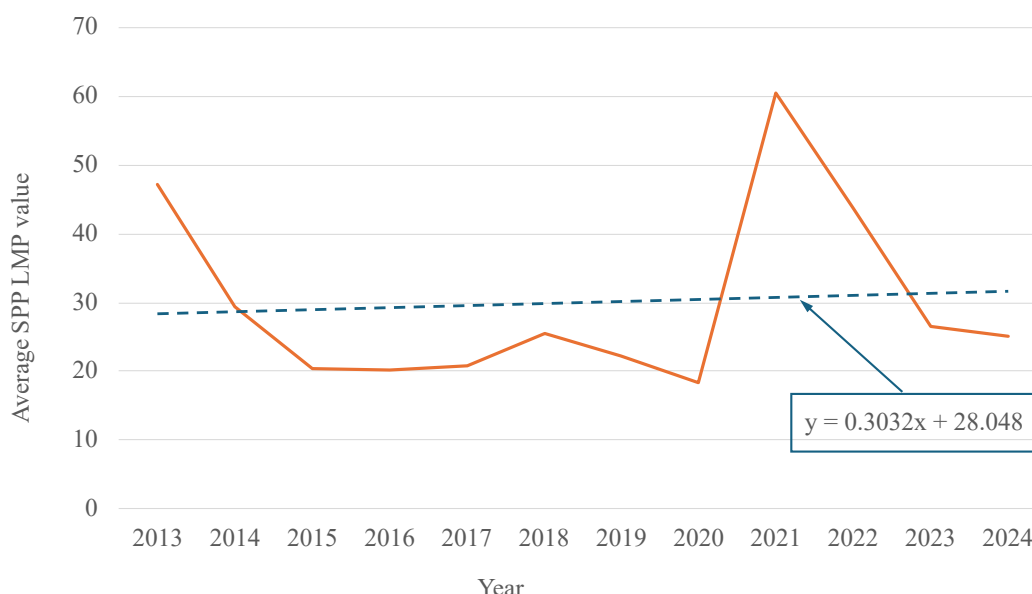


Figure 1. Average locational marginal price 2013 – 2024 in the Southwest Power Pool (SPP) and the year over year trend of price increases

The high-rise scenario uses the national historical average¹ rate of increases in electrical retail rates, 2.5%, as reported by the Lawrence Berkely National Laboratory and NLR (Forrester et al. 2024). The use of 2.5% is likely higher than expected as the cost of wholesale energy does not include other factors like electrical distribution system maintenance, which is included in retail rates. However, this value is meant as an upper bound of expected possible scenarios and not an actual projection of what will occur.

Exploring the U.S. Energy Information Administration's (EIA's) 2025 Annual Energy Outlook, the weighted projected compounding annual growth rate for the generation and transmission portion of electricity costs over the next 26 years is 1.53% nationally (EIA 2025). This growth rate falls somewhere in the middle of the high- and low-rise scenarios. Notably this analysis looks over the life of the project and therefore accounts for the average escalation rate. While specific years over the project life may see larger increases than even the 2.5% upper end modeled, the average over the life is projected to fall somewhere between the low- and high-rise scenario values.

SAM provides a comprehensive suite of built-in functionalities for modeling energy systems, including PV arrays, BESS, and hybrid configurations of PV and BESS. One of the key strengths of SAM is its ability to offer detailed outputs based on user-provided inputs such as system size, location, financial parameters, and electricity market conditions. This makes it highly effective at assessing techno-economic scenarios. However, SAM does not make decisions for the user nor recommend optimal strategies; it does not inherently account for subjective considerations, regulatory constraints, or site-specific challenges. Instead, the tool provides objective performance and financial metrics that help inform decision-making by modeling systems under varied assumptions. For this analysis, SAM generated results based on preset weather years, system specifications, and revenue parameter sensitivities, enabling an in-depth examination of project feasibility under different market conditions.

Leveraging its ability to simulate various configurations and technologies, the analysis was centered on the “merchant plant” financial model² native to SAM. The merchant plant model assumes that the facility sells power directly into the wholesale energy market under real time market-based conditions. This is fitting as the PV and BESS will be displacing electricity purchased from the SPP wholesale market. This model is particularly useful for understanding how the project's financial viability is impacted by electricity price variations, system performance, and market uncertainties, as it does not assume stable or predictable revenue streams like those associated with power purchase agreements.

To assess the financial feasibility of the project configurations (PV, PV + BESS, and BESS), NPV simulations were conducted over a 25-year ownership timeline for each scenario. The NPV analysis incorporated revenue streams from energy sales and operational costs, capturing the

¹ Average from the last decade of data per the Lawrence Berkeley National Laboratory and NLR source.

² Merchant projects present a unique opportunity and risk profile. Renewable merchant projects can sell energy at times of high market demand or provide valuable grid services, such as frequency regulation or arbitrage (buying electricity during low-price periods and selling it during high-price periods). However, they are also exposed to significant financial risks, as revenue depends on variable market conditions and may not always cover operating and capital costs.

long-term financial impact of price escalation, system performance, and market variability. The projects were modeled using historical LMP prices, which include periods of negative energy pricing. Effectively, nine independent 25-year forecast models for each technology configuration and pricing structure were run.

This approach underscores the importance of accounting for real-world market fluctuations in merchant plant financial planning, including negative LMP values which highlight potential revenue risks during periods of system oversupply. Escalation rates of 0.3% and 2.5% offer a range of future growth scenarios, demonstrating the variability in financial outcomes depending on market factors. By combining historical weather and market data with forward-looking escalation assumptions for each of the scenarios, the study delivers a comprehensive view of the financial risks and opportunities associated with merchant solar, storage, and hybrid energy systems under diverse conditions.

Performing analysis in SAM requires technical system parameters as well as financial details. PV and BESS have both common technical parameters and technology specific parameters. Laid out below in Table 3 and Table 4 are the technical parameters assumed for each technology.

Table 3. Technical PV System Design Parameter Assumptions as Modeled in SAM

PV Parameter	Value
System Location	40.03°, -95.42°
Nameplate	1,230 kilowatts-direct current (kW-DC) / 1,000 kilowatts-alternating current (kW-AC)
AC:DC Ratio	1.23
Tilt	33°
Azimuth	180°

Table 4. Technical BESS System Design Parameter Assumptions as Modeled in SAM

BESS Parameter	Value
System Location	40.03°, -95.42°
Nameplate	1,000 kW-AC / 2,000 kWh-AC
Duration	Two hours
Battery Degradation	Cycle and Calendar
Replacement	None
Depth of Discharge	90%
Round Trip Efficiency	~85%
Charging	Grid (and PV when paired)
Dispatch	Perfect 24-hour look ahead

The systems were modeled assuming they would be installed at the Falls City Water Treatment Plant, located at 70434 661 Ave, Rulo, NE 68431 (40.03°, -95.42°). The Falls City community coalition shared four sites that were under consideration for development but determined that

modeling a project at the water treatment plant was the best site at the time. The water treatment plant could benefit from a possible future resilience component if a battery was determined to be feasible.

All systems have a 1,000 kW-AC nameplate, even under a hybrid PV+BESS scenario, and the BESS scenarios include a battery with a duration of two hours. The PV was assumed to face due south (180° azimuth) in conjunction with a 33° tilt to maximize annual production. The BESS system requires operational parameter inputs as well. The BESS can charge from the grid or the PV in all PV+BESS scenarios (scenario 2); otherwise, the BESS will only charge from the grid in BESS only scenarios (scenario 3). The battery has a 90% depth of discharge, which means that functionally it can only use 90% of the 2,000 kWh-AC it has. We account for both the degradation of the battery because of time (calendar degradation) and use via charging and discharging (cycle degradation). We assume that the battery does not get replaced regardless of how much it is degraded to reduce costs in future years. This means that the functional energy available will reduce with time and use.

SAM provides several options for BESS dispatch. SAM attempts to mimic real world BESS operations for a merchant based on market price signals. We used an optimistic model to determine the best possible outcome for a battery's dispatch assuming that the BESS system has perfect foresight for 24 hours. This means that in each hour, the BESS controller will look forward at 24 hours of wholesale electricity prices and determine if the battery should charge, discharge, or do nothing in the current hour to maximize its profit over the next 24 hours.

The financial parameters for both PV and BESS were based on NLR's annual technology baseline (NLR 2024) and the Solar Photovoltaic System Cost Benchmarks from the U.S. Department of Energy (U.S. DOE 2024).³ Values from both reports were used and scaled to the relevant system sizes modeled for use in SAM. The capital expenditure/cost (CAPEX) of PV+BESS (scenario 2) is based on a combined total installed cost of both technologies on a per PV DC nameplate. Furthermore, the BESS CAPEX components were discounted 10% from BESS only costs due to efficiencies gained by building a hybrid system. These values along with other financial parameters are listed in Table 5 by the three technology configurations.

Table 5. Financial PV and BESS System Assumptions as Modeled in SAM

Financial Parameter	PV	PV + BESS	BESS
Capital Cost	\$1.54/W-DC	\$2.50/W-DC	\$1.16/W-DC
O&M	\$22.48/kW-DC	\$33.13/kW-DC	\$28.49/kW-AC
Inflation Rate		2.5%	
Discount Rate		0%	
Nominal Discount Rate		2.5%	
Income Tax		0%	

³ Technology characteristics are based on the prevailing market and installed systems. This includes things such as the BESS being based on of lithium-ion systems and mono-facial solar modules being deployed for commercial size PV systems.

Financial Parameter	PV	PV + BESS	BESS
Property Tax		0%	
Sales Tax		5.50%	
Debt Percent	0%	75%	0%
Debt Tenor	N/A	15 yrs	N/A
Interest Rate	N/A	4.42%	N/A
Incentives	30% Investment tax credit		
Installed Cost Before Incentives	\$1,898,640	\$3,079,442	\$1,156,520

The only notable difference between scenarios other than the capital and operational costs is the financing method. The Falls City community coalition shared that projects with a capital outlay of less than \$2 million could likely be funded in cash without a debt component. Projects over \$2 million would utilize a 25% cash payment and 75% loan. For the debt, an interest rate of 4.42% was shared by the coalition and a preference to have a 15-year debt period. Therefore, the PV only and BESS only systems (scenarios 1 and 3) do not require a debt component, while the PV+BESS system (scenario 2) does.

Results

Running the numerous scenarios provided a series of results with varying outcomes. Based on the methods laid out above we present technical and financial results of the SAM models for all scenarios broken out by technology pairings.

The PV only scenarios resulted in largely negative NPVs for most years modeled. 2021 LMPs and solar production returned a positive NPV for both the 0.3% and 2.5% LMP wholesale escalation rates, while 2022 had a positive NPV for the 2.5% escalation rate only. The revenue generated directly correlates with the NPV as the lower the revenue generated by PV the lower the NPV will be. Annual PV production varies from year to year based on the actual weather for each year, which also has an impact on the revenue generated. Notably, the TMY year results are similar from the average of the eight historical years modeled, including the positive NPV values.

Table 6. Scenario 1A-1I Financial and Technical Results for PV Only With a 0.3% Escalation Rate

Scenario	Year	NPV*	Revenue Generated	PV Generation Yr. 1 (kWh)
1A	TMY (2024 LMPs)	(\$829,097)	\$1,189,690.00	1,801,535
1B	2022	(\$93,486)	\$1,950,680.00	1,847,470
1C	2021	\$572,973	\$2,595,750.00	1,808,317
1D	2020	(\$1,300,076)	\$727,910.00	1,795,661
1E	2019	(\$1,087,309)	\$919,710.00	1,751,861
1F	2018	(\$1,037,036)	\$966,868.00	1,710,423
1G	2017	(\$1,171,035)	\$833,962.00	1,776,369
1H	2016	(\$1,173,743)	\$829,894.00	1,796,518
1I	2015	(\$1,197,265)	\$811,691.00	1,785,553
Average (excluding TMY)		(\$810,872)	\$1,204,558	1,785,967

* Values in parentheses (and red text) represent negative values

Table 7. Scenario 1J-1R Financial and Technical Results for PV Only With a 2.5% Escalation Rate

Scenario	Year	NPV*	Revenue Generated	PV Generation Yr. 1 (kWh)
1J	TMY (2024 LMPs)	(\$502,550)	\$1,516,240.00	1,801,535
1K	2022	\$441,935	\$2,486,100.00	1,847,470
1L	2021	\$1,285,456	\$3,308,240.00	1,808,317
1M	2020	(\$1,100,279)	\$927,708.00	1,795,661
1N	2019	(\$834,867)	\$1,172,150.00	1,751,861
1O	2018	(\$771,650)	\$1,232,250.00	1,710,423
1P	2017	(\$942,129)	\$1,062,870.00	1,776,369
1Q	2016	(\$1,173,554)	\$829,894.00	1,796,518
1R	2015	(\$974,472)	\$1,034,480.00	1,785,553

Scenario	Year	NPV*	Revenue Generated	PV Generation Yr. 1 (kWh)
Average (excluding TMY)		(\$508,695)	\$1,506,712	1,785,967

* Values in parentheses (and red text) represent negative values

The PV with BESS technology pairing resulted in a similar trend to the PV alone but with generally lower NPVs. The only positive NPV came in 2021 under the 2.5% high rise scenario. The PV energy generated for each scenario is the same as the PV only scenarios, therefore we do not present it again. Since the BESS can be charged from PV or the grid in this technology pairing we do report the amount of energy supplied from each source. While solar does charge the BESS at times, most of the battery energy is supplied from the grid in all scenarios.

Table 8. Scenario 2A-2I Financial and Technical Results for PV + BESS Only With a 0.3% Escalation Rate

Scenario	Year	NPV*	Revenue Generated	Yr. 1 Energy to BESS from PV (kWh)	Yr. 1 Energy to BESS from Grid (kWh)
2A	TMY (2024 LMPs)	(\$2,052,752)	\$1,658,160.00	14,066	296,984
2B	2022	(\$1,118,119)	\$2,646,050.00	23,215	342,849
2C	2021	(\$356,662)	\$3,441,020.00	18,401	313,928
2D	2020	(\$2,724,546)	\$1,006,990.00	9,684	344,726
2E	2019	(\$2,471,426)	\$1,254,210.00	9,381	367,763
2F	2018	(\$2,454,102)	\$1,280,610.00	9,772	339,977
2G	2017	(\$2,624,899)	\$1,095,410.00	7,998	334,494
2H	2016	(\$2,662,780)	\$1,072,800.00	5,597	351,789
2I	2015	(\$2,686,625)	\$1,061,130.00	4,797	354,649
Average (excluding TMY)		(\$2,137,395)	\$1,607,278	11,106	343,772

* Values in parentheses (and red text) represent negative values

Table 9. Scenario 2J-2R Financial and Technical results for PV + BESS with a 2.5% Escalation Rate

Scenario	Year	NPV*	Revenue Generated	Yr. 1 Energy to BESS from PV (kWh)	Yr. 1 Energy to BESS from Grid (kWh)
2J	TMY (2024 LMPs)	(\$1,611,009)	\$2,109,950.00	14,066	296,984
2K	2022	(\$420,761)	\$3,367,890.00	19,529	323,831
2L	2021	\$554,179	\$4,385,440.00	18,439	314,753
2M	2020	(\$2,465,789)	\$1,281,370.00	9,684	344,726
2N	2019	(\$2,142,814)	\$1,596,680.00	9,381	367,763
2O	2018	(\$2,120,595)	\$1,630,330.00	9,772	339,977

Scenario	Year	NPV*	Revenue Generated	Yr. 1 Energy to BESS from PV (kWh)	Yr. 1 Energy to BESS from Grid (kWh)
2P	2017	(\$2,338,157)	\$1,095,410.00	7,998	334,494
2Q	2016	(\$2,386,221)	\$1,365,720.00	5,597	351,789
2R	2015	(\$2,416,397)	\$1,351,140.00	4,797	354,649
Average (excluding TMY)		(\$1,717,069)	\$2,009,248	11,029	336,552

* Values in parentheses (and red text) represent negative values

The BESS only scenarios returned the worst economics of all three technology pairings. Under no scenarios modeled did BESS by itself provide a positive NPV. Stand-alone BESS does not generate any energy but exclusively utilizes grid power for charging. Therefore, the only value we report is the amount of energy the system draws from the grid. Revenue for BESS is derived from the differential in the wholesale electricity LMP during charging and discharging hours.

Table 10. Scenario 3A-3I Financial and Technical Results for BESS Only With a 0.3% Escalation Rate

Scenario	Year	NPV*	Revenue Generated	Battery energy charged from grid Yr. 1 (kWh)
3A	TMY (2024 LMPs)	(\$1,865,649)	\$356,180.00	313,233
3B	2022	(\$1,753,849)	\$496,524.00	346,260
3C	2021	(\$1,779,806)	\$546,300.00	334,817
3D	2020	(\$2,022,405)	\$209,805.00	357,231
3E	2019	(\$2,012,654)	\$236,444.00	381,872
3F	2018	(\$2,051,326)	\$211,281.00	353,091
3G	2017	(\$2,067,031)	\$179,388.00	345,171
3H	2016	(\$2,098,926)	\$163,722.00	360,824
3I	2015	(\$2,098,296)	\$171,562.00	363,692
Average (excluding TMY)		(\$1,985,537)	\$276,878	350,688

* Values in parentheses (and red text) represent negative values

Table 11. Scenario 3J-3R Financial and Technical Results for BESS Only With a 2.5% Escalation Rate

Scenario	Year	NPV*	Revenue Generated	Battery energy charged from grid Yr. 1 (kWh)
3J	TMY (2024 LMPs)	(\$1,777,140)	\$450,772.00	313,233
3K	2022	(\$1,635,746)	\$628,285.00	346,260
3L	2021	(\$1,668,994)	\$691,539.00	335,777

Scenario	Year	NPV*	Revenue Generated	Battery energy charged from grid Yr. 1 (kWh)
3M	2020	(\$1,975,615)	\$265,431.00	357,231
3N	2019	(\$1,963,264)	\$299,158.00	381,872
3O	2018	(\$2,012,164)	\$267,368.00	353,091
3P	2017	(\$2,031,970)	\$227,059.00	345,171
3Q	2016	(\$2,072,445)	\$829,894.00	360,824
3R	2015	(\$2,071,522)	\$217,201.00	363,692
Average (excluding TMY)		(\$1,928,965)	\$428,242	350,795

* Values in parentheses (and red text) represent negative values

Given the overall low NPVs for most scenarios, a sensitivity analysis was run for each scenario to determine the CAPEX on a per unit basis that would bring the project to a breakeven NPV. The CAPEX is reported in \$/W-DC. For the PV and BESS technology pairing, we also report the all-in CAPEX as the unit cost for PV and BESS are not based on the same DC units due to battery duration. A “N/A” denotation means that the system cannot return a positive NPV unless the CAPEX is less than \$0/W. Scenarios with a positive NPV under nonsensitivity modeling were not reported since they have already achieved a NPV above \$0.

Table 12. Sensitivity Results for all PV Only Scenarios Showing Breakeven CAPEX (Modeled CAPEX for PV Only Scenario = \$1.54/W-DC)

Year	Scenario	CAPEX for 0 NPV	Scenario	CAPEX for 0 NPV
TMY (2024 LMPs)	1A	\$0.41	1J	\$0.68
2022	1B	\$1.00	1K	-
2021	1C	-	1L	-
2020	1D	\$0.18	1M	\$0.18
2019	1E	\$0.19	1N	\$0.40
2018	1F	\$0.23	1O	\$0.45
2017	1G	\$0.13	1P	\$0.32
2016	1H	\$0.12	1Q	\$0.31
2015	1I	\$0.10	1R	\$0.29
Average (excluding TMY)		\$0.44		\$0.62

Table 13. Sensitivity Results for 2A-2I (0.3% Escalation Rate) PV + BESS Scenarios Showing Breakeven CAPEX (Modeled CAPEX for PV + BESS Scenario = \$2.50/W-DC)

Scenario	Year	CAPEX for 0 NPV	Net CAPEX
2A	TMY (2024 LMPs)	\$0.32	\$391,176
2B	2022	\$1.02	\$1,255,020
2C	2021	\$1.59	\$1,955,880

Scenario	Year	CAPEX for 0 NPV	Net CAPEX
2D	2020	N/A	N/A
2E	2019	\$0.01	\$16,299
2F	2018	N/A	N/A
2G	2017	N/A	N/A
2H	2016	N/A	N/A
2I	2015	N/A	N/A
Average (excluding TMY)		\$0.87	\$1,075,733.00

Table 14. Sensitivity Results for 2J-2R (2.5% Escalation Rate) PV + BESS Scenarios Showing Breakeven CAPEX (Modeled CAPEX for PV + BESS Scenario = \$2.50/W-DC)

Scenario	Year	CAPEX for 0 NPV	Net CAPEX
2J	TMY (2024 LMPs)	\$0.65	\$798,651.00
2K	2022	\$1.53	\$1,890,680.00
2L	2021	\$2.26	\$2,787,130.00
2M	2020	\$0.01	\$16,299.00
2N	2019	\$0.25	\$309,681.00
2O	2018	\$0.26	\$325,980.00
2P	2017	\$0.11	\$130,392.00
2Q	2016	\$0.07	\$81,495.00
2R	2015	\$0.04	\$48,897.00
Average (excluding TMY)		\$0.57	\$698,819.25

Table 15. Sensitivity Results for all BESS Only Scenarios Showing Breakeven CAPEX (Modeled CAPEX for BESS Only Scenario = \$1.16/W-DC)

Year	Scenario	CAPEX for 0 NPV	Scenario	CAPEX for 0 NPV
TMY (2024 LMPs)	3A	N/A	3J	N/A
2022	3B	N/A	3K	N/A
2021	3C	N/A	3L	N/A
2020	3D	N/A	3M	N/A
2019	3E	N/A	3N	N/A
2018	3F	N/A	3O	N/A
2017	3G	N/A	3P	N/A
2016	3H	N/A	3Q	N/A
2015	3I	N/A	3R	N/A
Average (excluding TMY)		N/A		N/A

From these scenarios it is immediately obvious that notable reductions in CAPEX, either via market trends or external funding support, would be required to get to a positive NPV. In the case of BESS, whether alone or in conjunction with PV, this trend is taken to the extreme with all scenarios revealing no viable CAPEX.

The results and underlying technical and financial factors that drive them will be explored and explained in the findings section.

Findings

The results of the analysis demonstrate that PV by itself is the most economically viable option among the technology configurations analyzed, though achieving a positive NPV remains challenging across most scenarios. The PV only configurations revealed negative NPVs with notable exceptions in 2021 and 2022 due to advantageous market conditions including higher than average LMPs. In 2021, the LMPs combined with solar production delivered positive NPVs for both the low- and high-rise wholesale escalation rate scenarios. The 2022 scenario showed a positive NPV only in the high-rise escalation scenario. The correlation between revenue generated and NPV underscores the importance of strong PV production levels and favorable (higher) electricity pricing conditions. In years with lower LMP prices or solar output the economics of PV alone are less favorable. The importance of expected wholesale escalation rates therefore also correlates with NPV outcomes. The higher the expected increase in LMPs year over year drives increased project revenue. If the escalation rate stays low in SPP, like it has over the past 11 years (2013–2024), then PV NPVs will remain largely negative.

The analysis of PV + BESS showed a similar trend to PV alone but with generally poorer economics. The addition of BESS to a PV system generally degraded the overall financial performance, with only the 2021 scenario under the high-rise escalation scenario yielding a positive NPV. Notably, the energy generated by PV systems in these configurations remained equal to the PV-only scenarios. However, the inclusion of BESS introduced additional complexity and project costs without introducing notable financial benefits. The SAM model chose to charge the battery from the grid rather than from PV most of the time. Pairing BESS with PV in this scenario would largely provide value if the cost of energy from PV is lower than LMP rates, allowing PV to charge the BESS at a low cost and sell it to the grid at peak times. Based on the scenario results, this price paradigm is not common at the current LMP and CAPEX. The inability to significantly increase revenues through BESS integration, coupled with the higher CAPEXs inherent to BESS systems, fails to make a compelling economic case for the PV + BESS pairing under the modeled scenarios.

The BESS-only configurations consistently returned the worst economic performance of the three technology configurations, with no scenarios yielding positive NPVs. These systems rely entirely on the differential in wholesale electricity prices during charging and discharging to generate revenue. However, the combined effect of overall narrow price spreads and capital and operational & maintenance costs made stand-alone BESS financially unfeasible across all scenarios. While all scenarios modeled returned a negative NPV, the least poor years correlated with greater variability in LMP prices. As can be seen in Table 16, the average LMP is not only higher in 2022 and 2021, but the standard deviation in hourly LMPs is the largest in those years

resulting in NPVs which were the least negative for the low and high rise escalation rate scenarios.

Table 16. Annual Average Hourly Locational Marginal Price (LMP) and Standard Deviation for Modeled Years

Specific Model Year	Average LMP	Hourly LMP Standard Deviation
2022	\$38.88	44.46
2021	\$62.90	335.57
2020	\$16.41	13.73
2019	\$22.24	13.64
2018	\$24.83	12.52
2017	\$20.55	10.52
2016	\$20.88	9.21
2015	\$20.85	8.57

Sensitivity analyses revealed that even substantial reductions in CAPEXs would often be insufficient to bring BESS systems to a positive NPV, with many scenarios requiring CAPEXs to fall to levels below zero before economic viability could be achieved. This underscores the significant barriers that standalone storage systems face in competitive merchant markets without additional incentives or revenue streams.

Across all configurations, this analysis highlights the critical role of external factors in influencing financial outcomes. The results show that all else held constant, without reductions in CAPEXs via market trends, funding support, or other avenues, positive NPVs are unlikely for most scenarios. The potential for additional funding through state, federal, or non-governmental programs are therefore a notable consideration. Such external support could significantly improve the financial viability of PV and PV + BESS systems.

The sensitivity analysis highlights how the financial viability of PV-only, PV + BESS, and standalone BESS systems depends on their CAPEXs relative to current CAPEX figures of \$1.54/W_{DC} for PV-only, \$2.50/W_{DC} for PV + BESS, and \$1.16/W_{DC} for standalone BESS. These sensitivity results demonstrate the net CAPEX from the project owner's perspective necessary to achieve positive NPV, which is essential for investment feasibility. Understanding these thresholds can help decision-makers identify opportunities for cost savings, external incentives, or market strategies.

For PV-only systems, the current CAPEX of \$1.54/W_{DC} which is relatively close to achieving financial viability in some scenarios, such as the 2022 high rise escalation, where financial viability could be reached with CAPEX reductions to approximately \$1.00/W_{DC}. However, less favorable scenarios require more aggressive cost declines to an average of \$0.44–\$0.62/W_{DC} or as low as \$0.1/W_{DC}, which may not be attainable in the short term without external financial support. Meanwhile, ongoing cost reductions in PV manufacturing and installation provide a realistic path toward reaching 1.00/W_{DC}, making PV-only systems possibly viable in the future.

For PV + BESS systems, the integration of energy storage raises the financial reduction necessary. With the current CAPEX of \$2.50/W_{DC} this technology configuration depends on lower PV and BESS costs. For instance, certain scenarios may become viable at system-wide

CAPEX levels of \$1.59/W_{DC}, though others demand reductions to around \$0.87/W_{DC}, which presents a much steeper challenge of nearly 65% reduction in CAPEX. While these reductions may take time, the increasingly competitive battery storage market and opportunities to monetize storage through grid services or capacity payments could make PV + BESS systems progressively more viable.

Standalone BESS systems face the greatest economic challenges as modeled. At the current CAPEX of \$1.16/W_{DC}, they have a lower upfront cost than PV + BESS systems but generate less revenue, making them financially inviable under all modeled scenarios. Even with sharp reductions in CAPEX assumptions, including up to a 100% reduction (essentially a no-cost system) financial viability remains out of reach. This highlights the lack of revenue-generating opportunities as a primary obstacle in addition to a need for lower operation and maintenance costs before NPVs will turn positive. To address this shortfall, standalone BESS projects would require alternative revenue streams such as capacity payments, grid services, or methods to stack multiple revenue streams to close the cost-revenue gap.

Alternative to cost reductions, if wholesale energy costs in SPP increases at a faster rate than modeled in the high-rise scenario, it is possible projects become viable. The Falls City Muni is located centrally within the SPP service area. This is relevant as LMP values are driven by both electricity production and transmission cost components. LMP average prices and the variability in price hour to hour is affected by transmission congestion. Falls City Muni takes transmission service from the MEAN_FCU_OPPD node in SPP, which is noted in Figure 2.

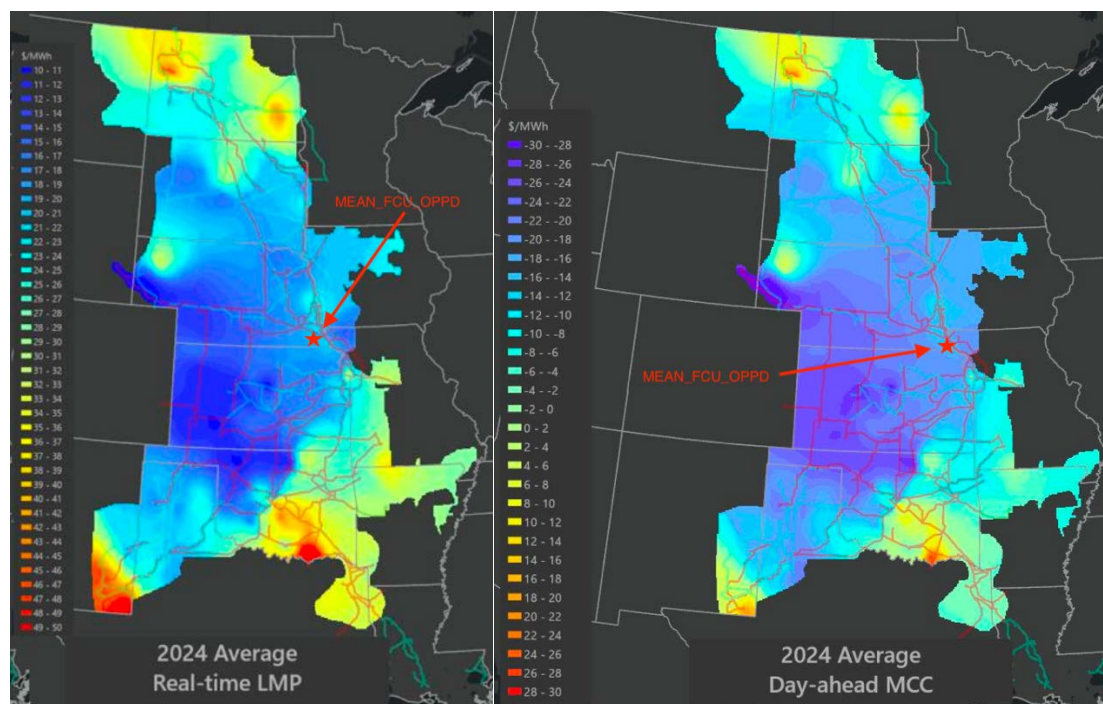


Figure 2. The average real time LMP across SPP's territory (left) and the average day ahead marginal congestion component (right)

Figure 2 show that the MEAN_FCU_OPPD node is located in one of the less congested and lower average LMP regions. As electricity needs and generator outputs change in future years, it is possible for these conditions to change altering the economics of PV or BESS.

Past market conditions and modeled system performance provides valuable insights, but it does not necessarily predict future conditions or performance. Given that this analysis is based on historical data, it is worth considering the other benefits that PV or BESS can provide. PV offers longer-term rate stabilization and certainty where market-based energy can fluctuate, exemplified by the change in average LMP shown in Figure 1.

This analysis underscores the relative financial potential of each technology configuration given the current CAPEX figures. PV-only systems pose the least financial barrier with some scenarios returning a positive NPV. PV + BESS systems, while less favorable do still reveal one positive NPV scenario. Standalone BESS systems appear economically unfeasible at today's costs and market structure.

Conclusion

To provide Falls City Muni and the Falls City community coalition with an understanding of the financial potential of PV and BESS systems, a series of scenarios were modeled using SAM. The models explored three technology configurations (PV, PV+BESS, and BESS) using multiple years of historical weather and wholesale cost data, and two different wholesale escalation rates.

Results from the models showed that at current CAPEX costs and under current SPP wholesale electricity costs local to Falls City, no technology configuration averaged across the scenarios returns a positive NPV. While a few specific scenarios modeled for PV and PV + BESS returned positive NPVs, these were largely driven by high wholesale costs in that year. Regardless of wholesale costs or spread between high and low, BESS alone never provided positive economics. Also modeled was the net project owner CAPEX necessary to obtain a positive NPV for all scenarios run. Across all technologies and scenarios, notable CAPEX cost reductions would be required to return a positive NPV if wholesale market conditions endure with expected growth between 0.3% and 2.5%. Notably under the assumed market conditions, BESS will not be financially viable under any CAPEX values above \$0.

In addition to reductions in system costs, external financial support, changes in market conditions, and additional revenue streams would help create more economically favorable projects. Where PV or BESS can receive compensation for other grid services or capacity or SPP LMP rates or congestion costs increase consistently, projects will return better NPVs. Falls City community coalition should take the findings of this report in context and recognize that all results are fixed in time and based on assumptions that are subject to change. As conditions change re-evaluation may be necessary and the outcomes of this analysis may no longer apply as widely.

Furthermore, the analysis performed is focused on the financial benefit of energy supply offsets only. The costs and benefits of utilizing solar or storage for resilience was not included and additional analysis would be necessary to determine the value. Falls City community coalition would need to explore the cost premium of installing a system that can operate off grid as well as the value of lost load that solar or storage would displace in a grid outage. Understanding these costs and benefits will enable a comparison to determine if resilience factors would close the revenue gap necessary to create more positive project NPVs.

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