PNNL-ACT-10150

The Packwood Solar, Storage, and Microgrid (PSSM)

A Feasibility Study

October 2025

X Ma [1]
V Chalishazar [1]
D Baldwin [1]
R Rebich [2]
W Wang [1]
D Wu [1]
J Barcco [1]
L Canfield [3]

[1] Pacific Northwest National Laboratory
[2] Energy Northwest
[3] Lewis County Public Utility District

Prepared for Energy Northwest and
Lewis County Public Utility District

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Pacific Northwest National Laboratory
Richland, Washington 99352

Executive Summary

The Packwood Solar, Storage, and Microgrid (PSSM) project is a collaboration between Energy Northwest (EN), Public Utility District No. 1 of Lewis County ("Lewis County PUD" or LCPUD), and Lewis County Emergency Management (LCEM). The project features a 1.6 MWac canal-spanning photovoltaic (PV) solar development, coupled with a 1 MW/4 MWh of state-of-the-art utility-scale battery storage. As a solar plus storage facility at the utility scale, PSSM will benefit LCPUD by increasing the amount of green energy in its overall power supply. LCPUD's 2020 Integrated Resource Plan has determined that the utility will be at least 2 MW short of state-mandated Renewable Energy Credits beginning in 2026. The PSSM will help to offset this shortfall. The battery storage can also lower LCPUD's daily system peaks if required or supplement the overall power supply during low regional electricity flows. In addition, it will enhance resilience for residents of the Lewis County area in the event of a loss of transmission capability by LCPUD.

Chartered in 1936, LCPUD provides electric and fiber broadband services to much of Lewis County and several surrounding areas. Currently, the District serves 34,770 customer connections across approximately 2,450 square miles, encompassing 3,014 miles of electric transmission and distribution lines. The PUD is governed by three locally elected commissioners who are responsible for overseeing the operations of the utility and setting of all policies, including budget adoption and rate setting. Additionally, the PUD owns and operates the Cowlitz Falls Hydroelectric Project, located near Randle in eastern Lewis County, with a nameplate generating capacity of 70 megawatts (MW). On average, this project generates 262,000 megawatt-hours (MWh) of electricity annually.

Chartered in 1957 as a joint operating agency, EN is a consortium of 29 PUDs and municipalities across Washington state. EN takes advantage of economies of scale and shared services to help utilities run their operations more efficiently and at lower costs, to benefit more than 1.5 million customers. EN develops, owns, and operates a diverse mix of electricity-generating resources, including hydro, solar, wind, and battery energy storage projects — and the Northwest's only nuclear energy facility. These projects provide enough reliable, affordable, and environmentally responsible energy to power more than a million homes each year. EN continually explores new generation projects to meet its customers' needs.

The PSSM feasibility and techno-economic assessment was led by the Pacific Northwest National Laboratory (PNNL), leveraging its advanced modeling and analytical capabilities in hydro hybridization. The use cases considered in this project include black start capability, peak demand management, and resilience enhancement. This report documents the proposed optimization framework for assessing different hydro hybrid design options, encompassing an in-depth examination of use cases and value propositions, assumptions and inputs, modeling methods, case studies, as well as key findings. The following key lessons and implications can be drawn from the study:

1. **Tailrace Water Temperature Control**

   - The proposed solar panel shading strategy was found to be insufficient in reducing the elevated tailrace water temperatures. Analysis of the monitored water temperature data revealed that temperatures at the Packwood Lake Outlet have consistently exceeded the critical threshold of 19.4°C from early July to late August. It was determined that the primary cause of elevated water temperatures originates from the lake itself, rather than from solar radiation exposure at the tailrace canal. This finding highlights the need for a reassessment of strategies to address the issue. Future research will focus on developing alternative approaches that tackle this root cause of elevated water temperatures.

2. **LCPUD's Benefits**

- In grid-connected mode, the microgrid demonstrated significant improvements in peak load management, reducing peak demand at the Packwood substation by approximately 50% during high-demand winter months and achieving nearly complete peak reduction during lower-demand summer months, as illustrated in Figure ES.1. This capability allows LCPUD to significantly reduce its reliance on external grid power, resulting in substantial cost savings and greater operational flexibility.

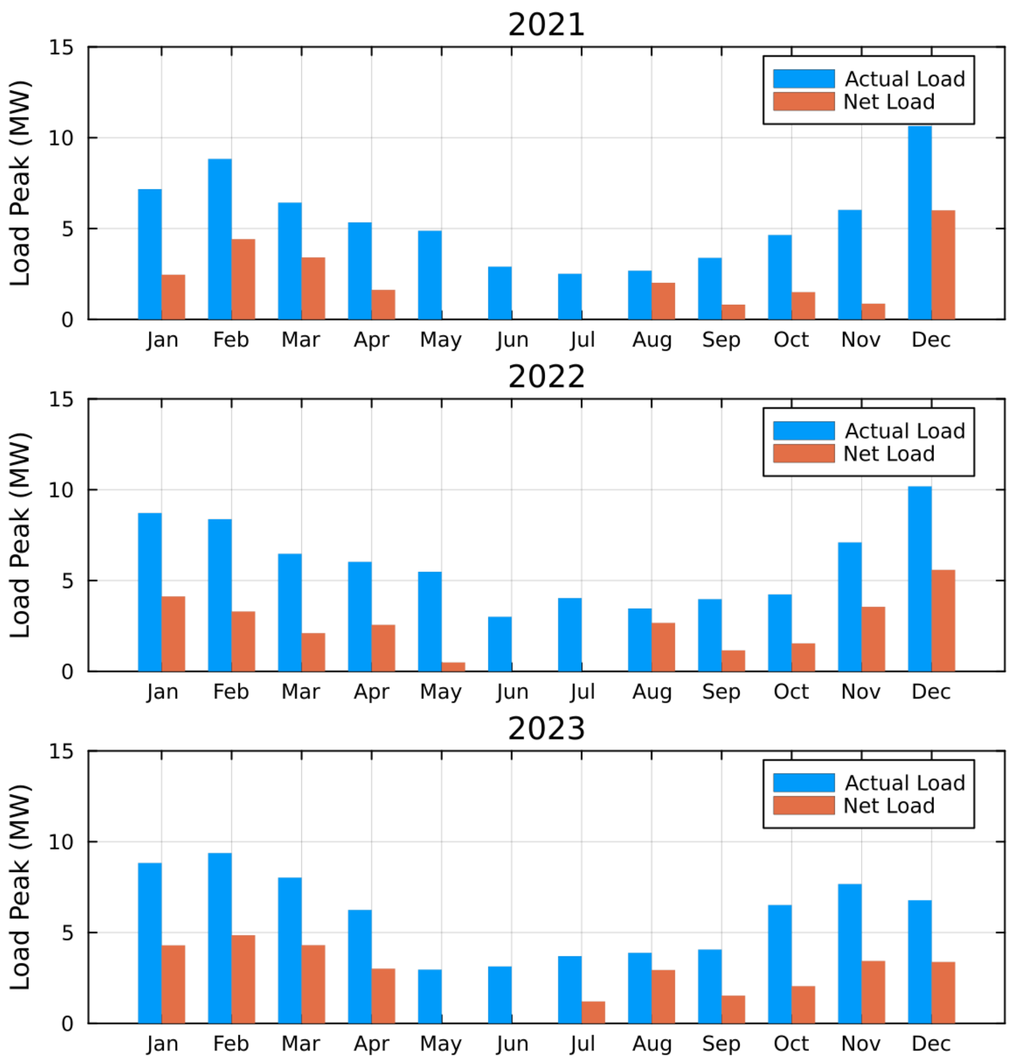

Figure ES.1. Packwood substation's monthly peak reduction from 2021 to 2023

- In islanding mode, the microgrid — utilizing the full generation capacity of the Packwood Hydro facility — exhibited robust resilience, successfully enduring historical outage events recorded at the Packwood substation, as shown in Table ES.1. However, synthetic outage simulations for August (see Table ES.2) have highlighted certain challenges, as the current microgrid configuration struggles to sustain critical services when the hydropower unit is offline due to annual maintenance. This limitation underscores the need for enhanced BESS capacity to ensure system reliability and provide uninterrupted support to residents during maintenance periods.

Table ES.1. Resilience enhancement with PSSM during historical outage events

Year	Number of Events	Survived Events	Survivability	Total Outage Duration (h)	Served Hours (h)	Served Time Ratio
2021	6	6	100%	22	22	100%
2022	2	2	100%	22	22	100%
2023	1	1	100%	2	2	100%

Table ES.2. Resilience analysis with synthetic outage events in August

Year	Number of Events	Survived Events	Survivability	Total Outage Duration (h)	Served Hours (h)	Served Time Ratio
2021	100	4	4.00%	500	74	14.80%
2022	100	0	0.00%	500	1	0.20%
2023	100	0	0.00%	500	2	0.40%

Table ES.3. Annual revenue improvement by optimization with PV and BESS

	Annual Revenue Improvement		
	2021	**2022**	**2023**
Revenue Increase by Optimal Dispatch	$1,175,000	$2,385,000	$1,699,000
Revenue Increase by BESS Only	$33,000	$50,000	$51,000
Revenue Increase by PV and BESS	$121,000	$175,000	$169,000

3. **EN's Benefits**

- Optimal power generation dispatch strategies were developed by applying PNNL's advanced hydropower model. It showcased the potential to increase annual revenue from energy arbitrage by $1.2 million to $2.4 million — representing a 35% to over 50% improvement compared to recorded historical operations from 2021 to 2023. The integration of solar panels and BESS further enhances revenue opportunities, contributing an additional $121,000 to $175,000 annually. These annual revenue improvement results have been summarized above in Table ES.3.
- Beyond revenue increase, the proposed hydropower modeling has incorporated mileage penalties designed to reduce the ramping frequency (as an example, see Figure ES.2 for simulations with various mileage penalties for a typical year 2022), effectively mitigating wear and tear on Packwood Hydro's components. This approach can help EN balance the financial performance with long-term operational resiliency, extending the hydropower facility's lifespan and reducing system maintenance costs.

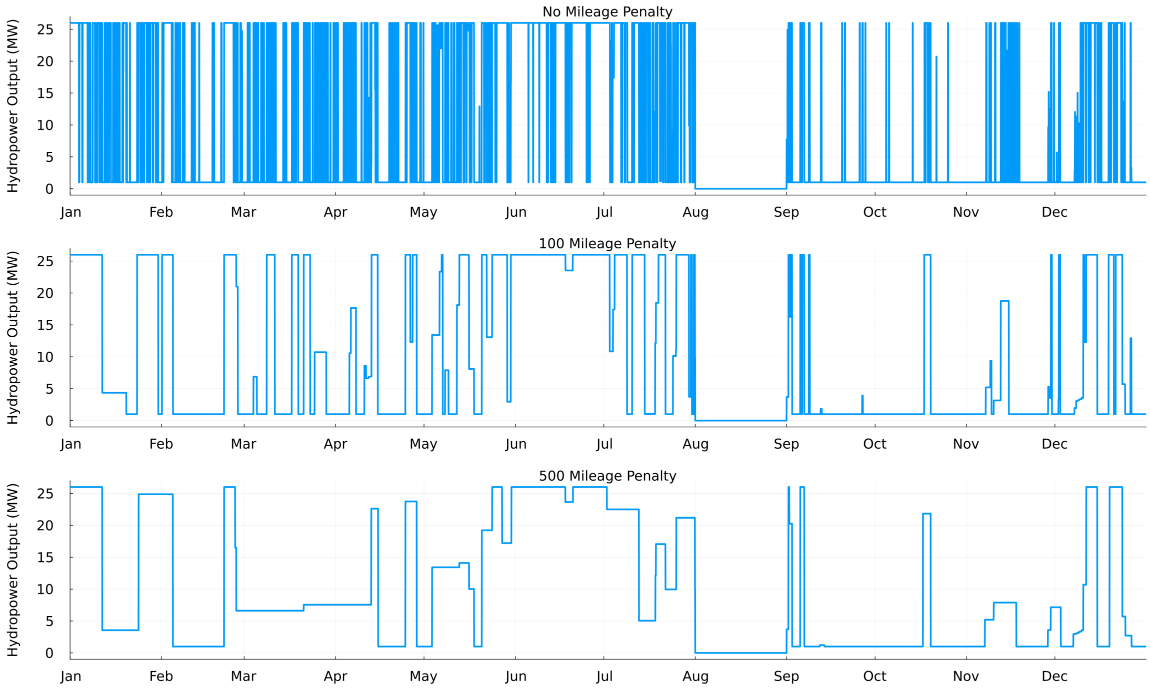

Figure ES.2. Hydropower outputs with different mileage penalties for 2022

- EN currently relies on a 125 kW diesel generator to conduct black start operations. This process can typically be completed within four hours and requires up to 0.5 MWh of energy. The proposed BESS is sufficient to meet this energy demand, providing a reliable alternative for black start capability. By leveraging the BESS, EN can eliminate its reliance on the diesel generator, reducing operational emissions and improving system sustainability.
- From EN's perspective, the economic viability of BESS sizing based solely on energy arbitrage is insufficient to justify the investment cost. The proposed 1 MW/4 MWh BESS has an estimated capital cost of $3.4 million, which significantly outweighs the cumulative revenue that could be generated through energy arbitrage over the expected battery lifespan of 10 to 15 years. This underscores the need to consider additional value streams to enhance the overall economic justification for deploying the BESS.

Acknowledgments

The authors gratefully acknowledge the financial support and technical leadership provided by the Washington State Department of Commerce and the U.S. Department of Energy's Water Power Technologies Office. We also wish to express our sincere gratitude to Allison Krienke, Michael Connerly, and Michael Stevens of Energy Northwest, as well as Luke Canfield and Willie Painter of the Lewis County Public Utility District, for their collaboration and contributions to this work.

Acronyms and Abbreviations

BESS	battery energy storage system
BPA	Bonneville Power Administration
cfs	cubic feet per second
EN	Energy Northwest
FERC	Federal Energy Regulatory Commission
LCEM	Lewis County Emergency Management
LCPUD	Lewis County Public Utility District
MW	megawatt(s)
MWh	megawatt-hour(s)
O&M	operation and maintenance
PLO	Packwood Lake Outlet
PNNL	Pacific Northwest National Laboratory
PSSM	Packwood Solar, Storage, and Microgrid
PUD	Public Utility District
PV	photovoltaic(s)
REC	renewable energy credit
RTE	round-trip efficiency
SOC	state-of-charge

Notation

Sets

$\mathcal{D}$	A set that contains all days within the optimal dispatch / sizing time frame
$\mathcal{K}$	A set that contains all hours within the optimal dispatch / sizing time frame
$\mathcal{K}_d$	A set that contains all hours within day $d \in \mathcal{D}$
$\mathcal{K}_i$	A set that contains all hours within outage event i

Indices

d	Day index
k	Hour index
l	Month index
n	Turbine unit index

Parameters

A	Lake area
E_1^{batt}, E_K^{batt}	BESS initial and final energy state levels
$E_{\text{day}}^{\text{batt}}$	BESS maximum daily discharged energy
$E_{\text{max}}^{\text{batt}}$	BESS energy capacity (a decision variable for optimal sizing)
$E_{\text{min}}^{\text{batt}}$	BESS minimum energy state in grid-connected mode
f^{L}	Intra-hour fluctuation in percentage of the hourly load
f^{pv}	Intra-hour fluctuation in percentage of the PV generation
L_k	System native load during hour k
M	A sufficiently large constant used for big-M constraints
$p_{\text{max}}^{\text{batt}}$	BESS rated power (a decision variable for optimal sizing)
$p_{\text{max}}^{\text{pv}}$	PV nominal power (a decision variable for optimal sizing)
p_n^{ramp}	Ramping limit of turbine n
q_k^{byp}	Bypass flow at hour k
q_k^{in}	Water inflow into the lake at hour k
$Q_n^{\text{g-max}}$	Maximum plant flow of turbine n
$Q_n^{\text{g-min}}$	Minimum plant flow of turbine n
r_k^{pv}	Normalized PV output at hour k
V_1, V_K	Initial and final lake water levels
V_k^{max}	Maximum lake water level at hour k
V_k^{min}	Minimum lake water level at hour k
α^{gen}, β^{gen}	Linear coefficients that convert plant flow into hydro generation
γ	Hydro mileage penalty weight
ΔT	Time step size

η	Hydro output scaling factor
η^+	BESS discharging efficiency
η^-	BESS charging efficiency
λ_k	Energy price during hour k
μ_l	Peak demand price of month l

Decision Variables

C^{dmd}	Annual demand charges
d_l	Peak demand of month l
e_k^{batt}	BESS energy state at the end of hour k
L_k^{net}	System net load at hour k
L_k^{uns}	Unserved system load at hour k
L_k^{upk}	Unserved peak load at hour k
$m_{n,k}$	Operational mileage of turbine n at hour k
p_k^+	BESS discharging power at hour k
p_k^-	BESS charging power at hour k
p_k^{batt}	BESS power output at hour k
$p_{n,k}^{\text{gen}}$	Hydropower output generated by turbine unit n at hour k
p_k^{hyd}	Total hydropower output at hour k
p_k^{pv}	PV power output at hour k
$p_k^{\text{res}+}$, $p_k^{\text{res}-}$	BESS operational reserves at hour k
p_k^{sys}	Integrated system's power output at hour k
$p_k^{\text{urs}+}$, $p_k^{\text{urs}-}$	Unserved operational reserves at hour k
$q_{n,k}^{\text{gen}}$	Plant flow through turbine unit n at hour k
q_k^{gen}	Total plant flow through all turbines at hour k
q_k^{out}	Water outflow from the lake at hour k
q_k^{spl}	Water spill at hour k
v_k	Lake water level at hour k
z_k^{batt}	A binary variable that denotes BESS charging or discharging at hour k
$z_{n,k}^{\text{gen}}$	A binary variable that denotes the generation mode of turbine unit n at hour k
$z_{n,k}^{\text{set}}$	A binary variable that denotes the setpoint change of turbine unit n at hour k

Contents

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CHAPTER 1

Introduction

Chartered in 1936, Public Utility District No. 1 of Lewis County ("Lewis County PUD" or LCPUD) provides electric and fiber broadband services to much of Lewis County and several surrounding areas. Currently, the District serves 34,770 customer connections across approximately 2,450 square miles, encompassing 3,014 miles of electric transmission and distribution lines. The PUD is governed by three locally elected commissioners who are responsible for overseeing the operations of the utility and setting of all policies, including budget adoption and rate setting. Additionally, the PUD owns and operates the Cowlitz Falls Hydroelectric Project, located near Randle in eastern Lewis County, with a nameplate generating capacity of 70 megawatts (MW). On average, this project generates 262,000 megawatt-hours (MWh) of electricity annually.

Founded as a joint operating agency by the Washington State Legislature in 1957, Energy Northwest (EN) is a consortium of 29 PUDs and municipalities. By leveraging economies of scale and shared services, EN enables its member utilities to operate efficiently and cost-effectively, benefiting more than 1.5 million customers across Washington State. The agency is committed to improving the quality of life throughout the Northwest by generating reliable electricity from a diverse portfolio of nuclear, wind, hydro, and solar energy projects. Specifically, EN owns and operates four electricity-generating facilities: the White Bluffs Solar Station, the Packwood Lake Hydroelectric (Packwood Hydro) Project, the Nine Canyon Wind Project, and the Columbia Generating Station. EN also provides operations and maintenance services for generating facilities owned by other utilities.

Awarded as part of the Grid Modernization program administered by the Washington State Department of Commerce, the Packwood Solar, Storage, and Microgrid (PSSM) project, located in Lewis County, Washington, is a collaborative effort among EN, LCPUD, and Lewis County Emergency Management (LCEM). The project seeks to establish a microgrid by integrating EN's Packwood Hydro with a 1.6 MWac canal-spanning photovoltaic (PV) array and a 1 MW/4 MWh utility-scale battery energy storage system (BESS). This feasibility study will assess the potential economic benefits of integrating hydro generation with the proposed PV and BESS.

Constructed in 1960 and operated since 1964, Packwood Hydro is EN's first electric power project. A diagram of this hydro facility (Lewis County PUD, 2024) is shown in Figure 1.1. Packwood Lake sits at an elevation of 2,857 feet. Water flows from the lake into a concrete intake structure located about 424 feet downstream from the lake's outlet. From the intake building, the water enters a six-foot diameter underground pipeline that stretches over five miles, descending about 1,800 feet in elevation before reaching the powerhouse near Packwood. When the water arrives at the powerhouse, it is under 780 pounds per square inch of pressure, which drives the turbine generator to produce up to 27.5 MW of electricity. Since LCPUD has a 14.25% off-taker agreement with EN, it receives approximately 3.85 MW of Packwood Hydro's output, at full production. The remainder of the hydroelectric generation is off taken by EN's other member PUDs.

After passing through the turbine, water is discharged into the nearby Cowlitz River via an asphalt lined tailrace canal, as shown in Figure 1.2. The lined canal has a uniform trapezoidal

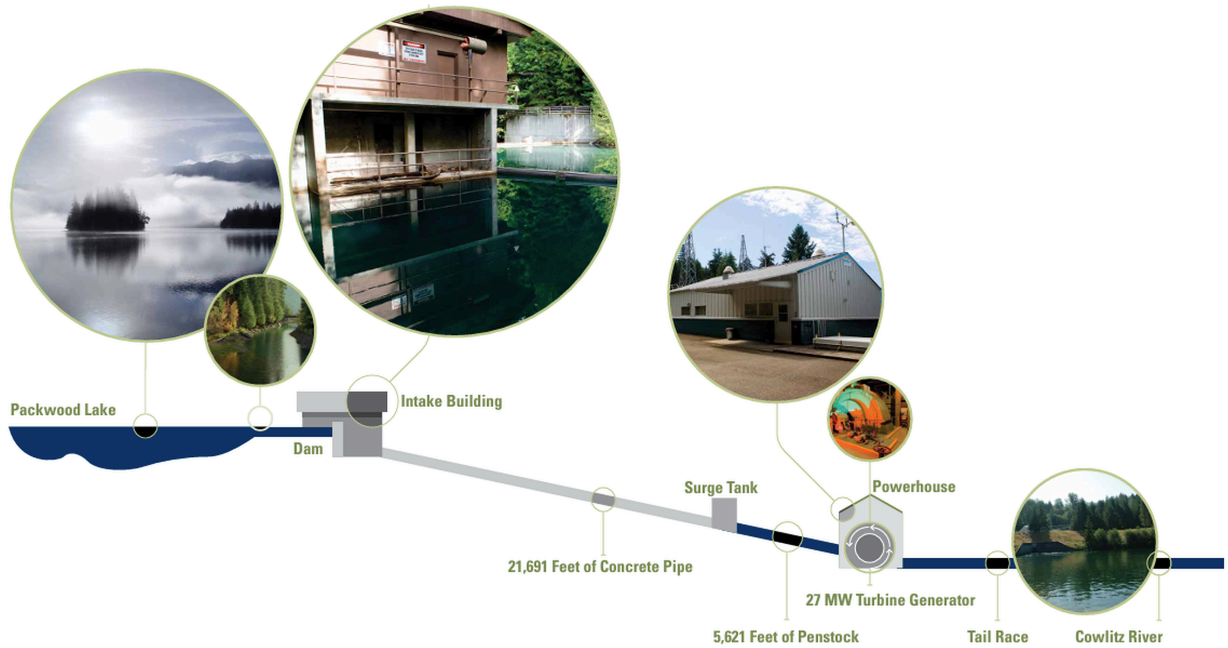

Figure 1.1. A diagram of the Packwood Hydro facility

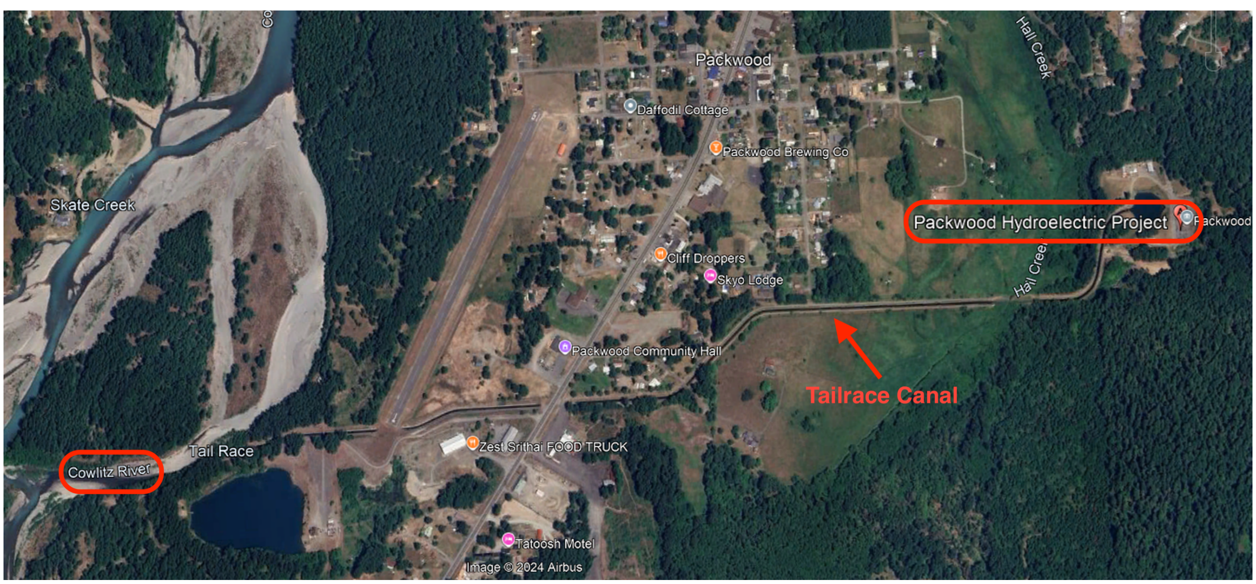

Figure 1.2. A Google Earth map that shows the locations of the Packwood Hydro facility, the tailrace canal, and the Cowlitz River

cross section with bottom width of 9 feet and 1.75 H:1 V side slopes. The length of the canal slope is approximately 6,570 feet with a uniform 0.04% slope. Figures 1.3 and 1.4 show two typical canal sections and the tailrace profile, respectively. This tailrace path is consistently monitored by EN as required by the Washington State Department of Ecology. Tailrace water temperature must not exceed site-specific 7-DADMax standard of 19.4°C and must be lowered accordingly for the plant to remain in operation during the monitoring period. To meet this requirement, EN has proposed to lower the water temperature by providing shade from direct sunlight using canal-spanning solar panels installed over the tailrace canal.

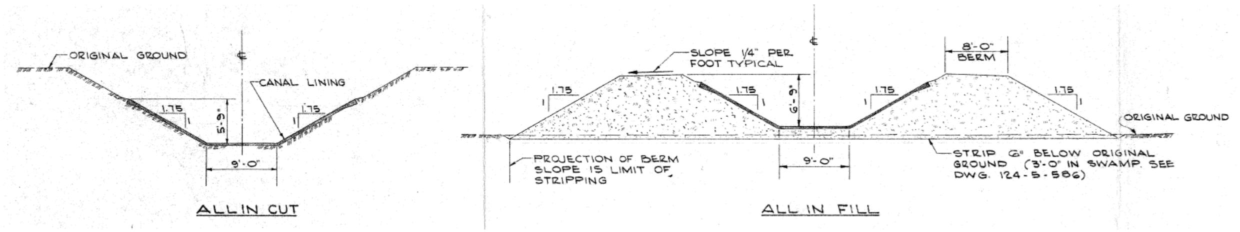

Figure 1.3. Typical canal sections

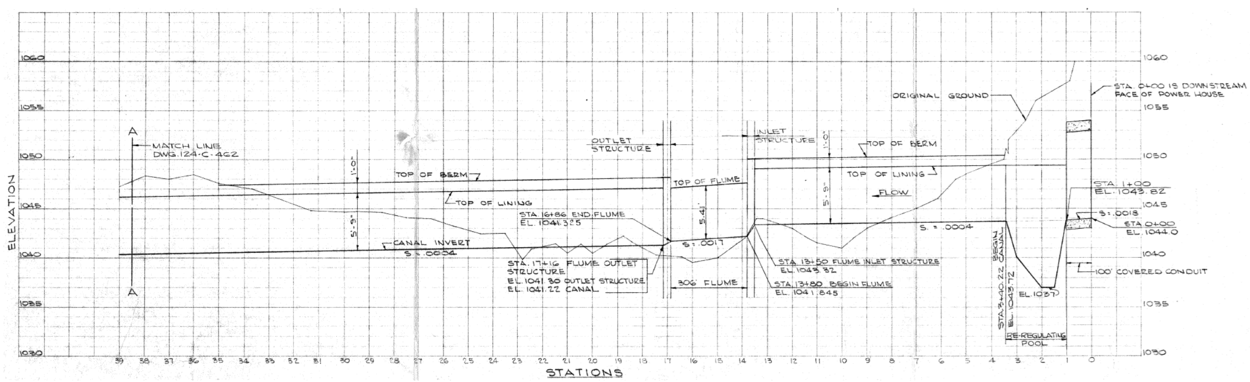

Figure 1.4. Profile of the tailrace canal

The Packwood Hydro facility relies on external electricity to initiate operations during a grid outage, a process known as “black start.” Currently, this is achieved using a diesel generator. Installing a localized grid-scale battery backup system would enable the facility to perform black start procedures using non-emitting sources of electricity.

As a utility-scale solar-plus-storage facility, PSSM will also provide significant benefits to LCPUD by increasing the proportion of green energy in its overall power supply. LCPUD’s existing electrical infrastructure enables the isolation of the town of Packwood from the larger grid, allowing it to be powered exclusively by Packwood Hydro.

Additionally, LCPUD’s 2020 Integrated Resource Plan projects a shortfall of at least 2 MW in state-mandated renewable energy credits (RECs) starting in 2026. The PSSM project will play a critical role in addressing this deficit. It can also help LCPUD reduce daily system peaks and provide supplemental power during periods of low regional electricity availability. Furthermore, the system will enhance resilience for Lewis County residents by ensuring a reliable power supply in the event of a disconnection from the main transmission grid.

This work will investigate the best methods to integrate existing islanding capabilities on LCPUD’s transmission and distribution systems, with electricity generation from the Packwood Hydro facility. The investigation will also examine the possibilities for adding additional microgrid options to buildings or areas that are specifically used for emergency response efforts as designated by LCEM officials. Moreover, a financial assessment will be performed to determine the economic viability of the system and the ideal circumstances to charge and discharge the battery to maximize profitability.

Pacific Northwest National Laboratory (PNNL) led the techno-economic assessment effort for PSSM, leveraging its advanced modeling and analytical capabilities in hydro hybridization to understand the potential benefits for different grid and end-user services. This report presents a thorough techno-economic assessment, encapsulating use cases, modeling and valuation framework, case studies, and concluding remarks.

CHAPTER 2

Tailrace Water Temperature Control

One of EN's primary concerns is that operations at the Packwood Hydro facility have been found to elevate tailrace water temperatures beyond Washington State's regulatory limits. In response, EN has implemented continuous compliance monitoring to ensure adherence to environmental standards and has rescheduled its annual maintenance outage to coincide with periods of peak water temperature. However, water temperature data collected over the past five years indicate that this revised maintenance outage schedule alone is insufficient to achieve compliance with the required temperature standards. As a result, alternative water temperature control strategies must be considered.

This chapter provides a concise overview of the Packwood Hydro project's background, summarizes water temperature monitoring data collected from 2019 to 2023, and offers a preliminary assessment of the feasibility of EN's proposed mitigation strategy, i.e., installing canal-spanning PV panels over the tailrace canal to reduce water temperature by providing shade from direct sunlight. Additional temperature reduction strategies are also discussed.

2.1 Background

The initial 50-year operating license for the Packwood Hydro project expired in July 2010. To prepare for this, EN submitted a license renewal application to the Federal Energy Regulatory Commission (FERC) in February 2008 (Energy Northwest, 2008), followed by a comprehensive suite of re-licensing studies. These studies concluded that project operations, specifically the discharge of tailrace water into the Cowlitz River after power generation, have elevated water temperatures above the Washington Department of Ecology's site-specific 7-DADMax[1] standard of 19.4°C. In response, and in accordance with Condition 4.5 of the Project's 401 Water Quality Certification (Washington Department of Ecology, 2009) and Resource Protection Measure #8 from the National Marine Fisheries Service, EN was required to shift the annual maintenance outage from early October to a typical peak temperature period (August 15 to September 15). These requirements were formally incorporated into the new FERC license issued on October 11, 2018 (Federal Energy Regulatory Commission, 2018).

To assess the effectiveness of this adjustment, the renewed FERC license also mandated continuous water temperature monitoring at key locations within the project area from June 25 to October 5 during the first three operational years (2019–2021). However, water temperature data collected over the past five years (2019–2023) have shown that this revised maintenance outage schedule alone was still insufficient to achieve compliance with Department of Ecology's water temperature standards. Thus, according to the Tailrace Water Temperature Monitoring and Enhancement Plan submitted by EN (EES Consulting, 2008), which is also referenced as Appendix A of the approved 401 Water Quality Certification, EN must provide a more detailed and actionable strategy for achieving compliance.

[1] 7-DADMax represents the arithmetic average of seven consecutive daily maximum temperatures.

To achieve compliance with water temperature requirements, EN collaborated with McMillen in 2024 to develop a Water Quality Attainment Plan (Energy Northwest & McMillen, 2024). The plan recommends further shifting the annual maintenance outage to an earlier period, starting from August 1 to August 31. In addition, EN has proposed installing canal-spanning PV panels to provide shade over the tailrace canal. The goal is for these PV panels to reduce solar heat gain during the summer months, thereby lowering the tailrace water temperature.

2.2 Water Temperature Monitoring Summary

In addition to the continuous water temperature monitoring conducted during the relicensing process, EN has collected five seasons of tailrace water temperature data from 2019 to 2023. Despite implementing the annual maintenance outage from August 15 to September 15, the collected data show that in all five operational seasons, the water temperature at the lower tailrace compliance point (POWT2) exceeded the site-specific 7-DADMax criterion of 19.4°C, with violations ranging from 12 to 47 days.

These monitored temperature data are presented below in Figure 2.1. As shown, tailrace water temperatures most frequently exceed the state's regulatory threshold (indicated by the solid red horizontal line) between early July and mid-August. This pattern suggests that the current maintenance outage period from August 15 to September 15 (highlighted in orange) does not adequately encompass the full duration of all temperature exceedances. In fact, the August 15 start date for the maintenance outage is too late, as the temperature exceedances often begin several days before the annual project shutdown.

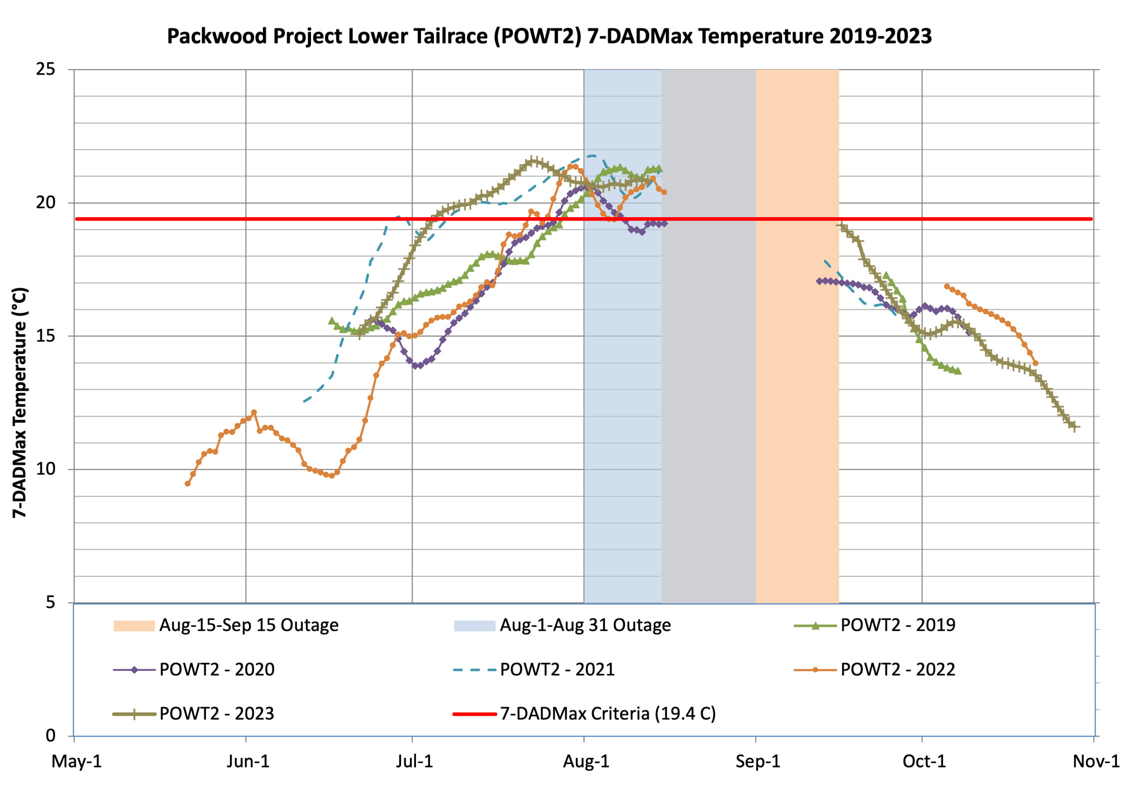

Figure 2.1. Monitored tailrace water temperatures with maintenance outage

Analysis of the monitored data reveals a consistent pattern of temperature exceedances occurring from late July through late August (or early September) across all five operational seasons. Notably, the prolonged heat waves in 2021 and 2023 had significant impacts, with exceedances beginning as early as late June and becoming sustained by early July — more than 40 days before the current outage start date of August 15. For instance, exceedances were recorded from June 27 to June 29 in 2021, with prolonged periods starting on July 7 in 2021 and July 5 in 2023.

In addition, a histogram illustrating the number of days exceeding the 7-DADMax limit from 2019 to 2023 is presented in Figure 2.2. The figure shows that for each day between late July and mid-August, exceedances occurred in at least four of the five years. This provides further evidence that the peak tailrace water temperature begins in late July. Based on this analysis, therefore, McMillen has recommended in the Water Quality Attainment Plan that EN adjust the annual maintenance outage period to run from August 1 to August 31, as highlighted in blue in Figure 2.1.

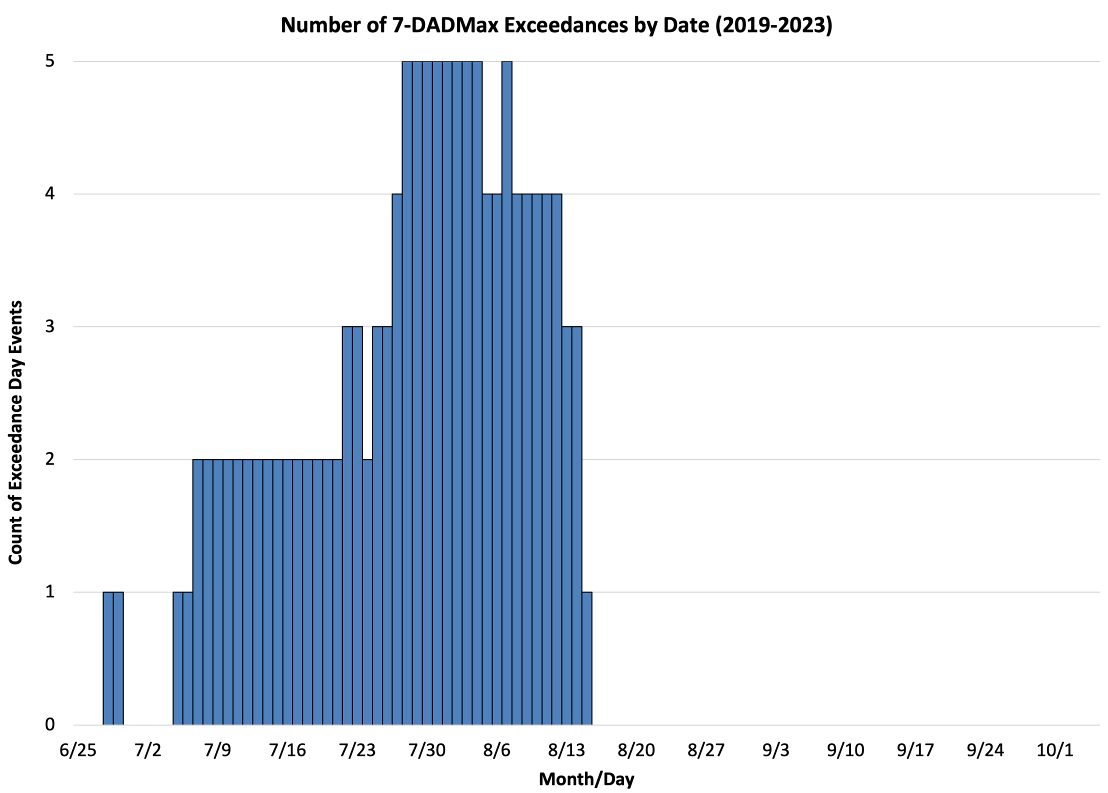

Figure 2.2. A histogram of exceedance days from 2019 to 2023

2.3 Preliminary Assessment of the Proposed Tailrace Water Temperature Control

While shifting the maintenance outage period to begin on August 1 may help reduce the number of temperature exceedance days, this adjustment only partially addresses the issue. Notably, extreme heat events in early July — such as those observed in 2021 and 2023 — underscore the fact that adjusting the outage schedule alone is insufficient in particularly hot years. In theory, a complete shutdown of the hydro facility from early July through late August could bring tailrace water temperatures into full compliance. However, such an extended outage would significantly reduce EN's annual revenue from electricity generation and sales to the regional power grid.

We now present a preliminary feasibility analysis of the PV panel shading strategy proposed by EN. Our assessment concludes that this approach alone is insufficient to effectively reduce the tailrace water temperature. To support this conclusion, we requested more monitored water temperature data from EN, specifically at the Packwood Lake Outlet (PLO), for the years 2019 to 2023. These data are plotted in Figure 2.3. As we can see, water temperatures at the PLO have consistently exceeded the 19.4°C threshold from early July through late August in all five years. This indicates that the elevated tailrace temperatures originate primarily from the water source itself, rather than from exposure to solar radiation within the tailrace canal. While the canal-spanning PV panels may provide certain mitigation by reducing direct solar heating, they do not address the root cause of the problem. To sum up, we conclude that neither of the current strategies proposed by EN — adjusting the maintenance outage schedule or installing PV panels for shading — will fully resolve the tailrace water temperature compliance issue.

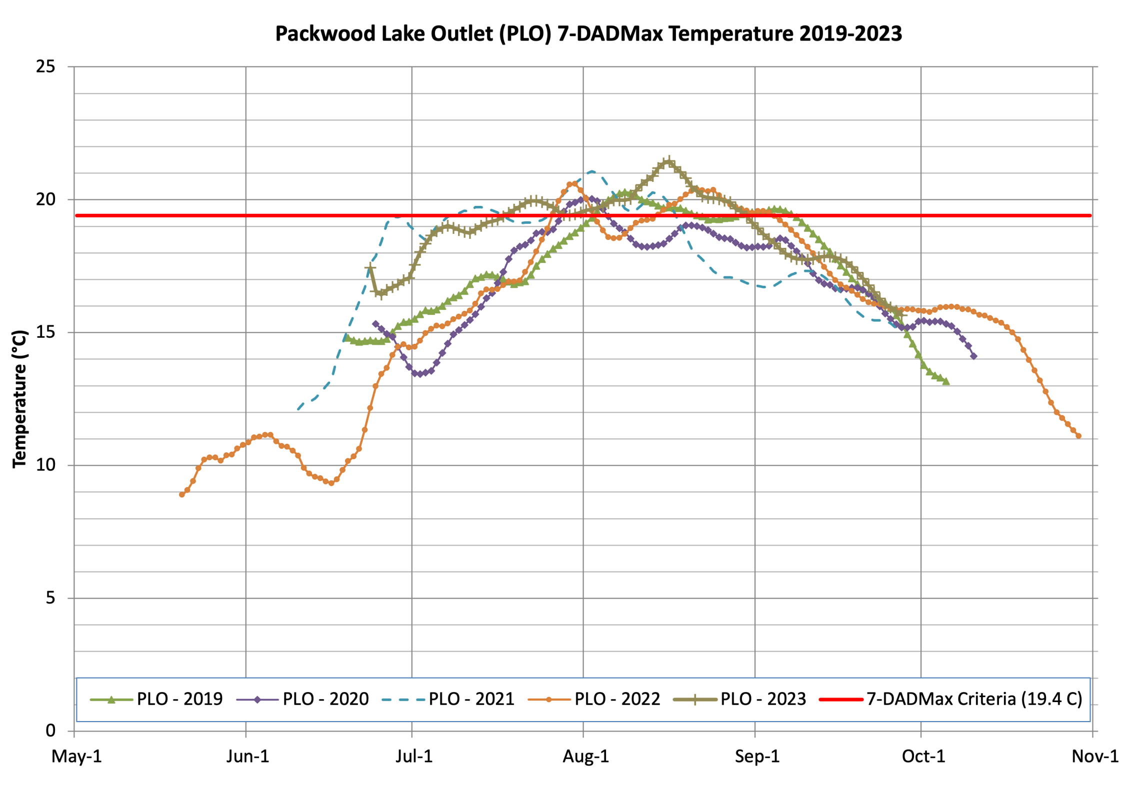

Figure 2.3. Monitored Packwood Lake water temperatures

2.4 Alternative Approaches for Future Research

PNNL and EN are investigating scenarios and working together to further study the possibilities to lower the tailrace temperature in economically feasible ways. One of the challenges to this problem is that the hydro unit is seldom shut down due to water temperature exceedances. Although some revenue is lost during these unanticipated shutdowns, it is difficult to justify the expense to chill the water from an economic standpoint. We plan to explore two alternative approaches that may offer a fundamental solution to the tailrace water temperature compliance issue:

- PNNL proposes investigating the use of mechanical cooling (e.g., cooling towers and chillers) installed at the tailrace canal to actively reduce water temperatures. The mechanical cooling could be powered by electricity generated on-site at the Packwood Hydro facility, thereby avoiding additional energy costs. By considering the tailrace canal's water volume and its typical water flow rate, we can determine the optimal cooling capacity required to meet the regulatory temperature standards.

- EN is considering the introduction of a natural stream flow into Packwood Lake. This strategy could serve a dual purpose: i) increasing the overall water volume available for hydropower generation and ii) providing a source of cooler water, which may help lower the Packwood Lake water temperature at its origin. PNNL will work closely with EN to further evaluate the feasibility and effectiveness of this option.

These two strategies outlined above represent promising alternatives that could provide a more comprehensive and long-term solution for meeting water temperature compliance requirements and eliminating curtailments. However, due to the time and budget constraints of the current project, a detailed evaluation of these options will be reserved for future research.

CHAPTER 3

Use Cases

Energy storage can store energy produced at one time for use at a later time, and thereby provide various grid and end-user services, including bulk energy, ancillary, transmission, distribution, and customer energy management services (Balducci et al., 2018). In this study, we have identified a list of highly valued use cases to benefit Packwood Hydro and LCPUD, which includes energy arbitrage, hydro wear and tear reduction, black start capability, peak demand management, and resilience enhancement.

Since ownership of the BESS has not yet been determined, this report aims to provide a comprehensive analysis to support further discussions between EN and LCPUD, regarding which party would benefit more from owning the battery. To this end, we evaluated potential BESS use cases from two perspectives: those that would primarily benefit LCPUD, and those that would be more advantageous for EN.

From LCPUD's perspective, the integration of BESS and PV could support the development of a microgrid, offering benefits such as peak demand management and system resilience for the Packwood substation. From EN's perspective, pairing the BESS with the Packwood Hydro facility could enhance its annual revenue through energy arbitrage while also helping to reduce wear and tear on the hydroelectric system by smoothing load fluctuations. By replacing the current diesel generator, the BESS can also provide black start capability, offering additional benefits to EN.

3.1 Use Cases from LCPUD's Perspective

If LCPUD owns the BESS, they could integrate the battery system with PV resources and their 14% share of hydropower generation from Packwood Hydro to develop a microgrid (PSSM).

- In grid-connected mode, the PSSM would enable LCPUD to manage its peak load demand more effectively. LCPUD is a Slice/Block customer of the Bonneville Power Administration (BPA) and receives roughly 85% of its power supply from BPA. As a planned product customer, LCPUD is responsible for managing its peak load demand through external market purchases and the use of owned or contracted non-federal resources. By effectively managing the system's peak load with integrated PV and BESS, LCPUD can achieve cost avoidance by reducing the need to purchase power from the external markets during periods of peak demand or resource supply shortages. Such a proactive approach to load management helps mitigate the financial impacts during high-demand events and enhances LCPUD's overall system reliability.

- In islanding mode, when power and transmission from the Packwood Hydro facility to the main grid are disconnected, the full generation capacity of Packwood Hydro can be utilized exclusively by the PSSM. This allows the microgrid to enhance LCPUD's system resilience and reliability at the Packwood substation, helping to maintain critical services and support the residents of Lewis County during extended power outages.

3.1.1 Peak Demand Management

Peak demand management refers to strategies and practices aimed at reducing or shifting electricity consumption during periods of highest demand, which are typically when the grid experiences its greatest strain. These peak periods often occur during extreme weather events — particularly during winter in Lewis County — when numerous customers simultaneously draw significant amounts of power. In this project, the development of PSSM will play a crucial role in mitigating LCPUD's system peaks by reducing reliance on external power sources during high-demand periods. Additionally, the combination of hydropower, PV, and BESS will bolster LCPUD's overall power supply, ensuring greater resilience and reliability during times of low regional electricity availability.

According to LCPUD, the utility is currently operating under a Slice/Block contract for power supply with BPA. This type of contract means there is no market-based capacity compensation mechanism from BPA for LCPUD if they successfully reduce their monthly peak load. However, implementing an effective peak demand management strategy will enable LCPUD to avoid incurring additional costs associated with purchasing expensive electricity from the external grid during high-demand periods. By reducing reliance on costly out-of-contract power sources during peak events, LCPUD can achieve significant cost savings, which will ultimately benefit the utility and its customers by improving financial efficiency and stabilizing rates.

3.1.2 Resilience Enhancement

Resilience has become a high priority for federal and local governments, and is moving into the industrial and commercial sectors (Wu et al., 2020). Recent developments in various distributed energy resources make them valuable assets in microgrids (Balducci et al., 2020).

Outage mitigation refers to the strategies and measures taken to prevent or minimize the impact of power outages, which may occur due to various reasons, such as natural disasters, equipment failures, maintenance issues, and grid instability as well. Outage mitigation focuses on reducing the interruptions caused by outages and ensuring the reliability and continuity of essential services.

This PSSM project can significantly enhance LCPUD's resilience by providing a localized, independent power source that can operate autonomously during grid disruptions. In the event of an outage or extreme weather event, the microgrid can isolate itself from the main grid and continue to supply electricity to critical facilities and essential services within the Lewis County area, maintaining power reliability for local residents. Additionally, with integrated hydropower, PV, and BESS, the microgrid can reduce dependence on external power supplies, mitigating the impacts of regional outages or transmission failures. This increased flexibility and reliability can help LCPUD ensure a more resilient energy supply.

There are different approaches to measuring resilience. For example, resilience can be modeled in a simple manner where financial losses are expressed as a function of unserved energy. By including the financial losses in the objective function, the same formulation for economic analysis can then be applied to capture resilience benefits. However, economic and resilience performance are two different metrics. In practice, it is difficult for a facility manager or system operator to quantify the value of resilience and estimate the cost associated with an outage occurring at different times with varying durations and magnitudes. More importantly, resilience performance and requirements cannot be fully captured as a monetary value.

In this report, the resilience analysis is based on an improved approach (Wu et al., 2020) to explicitly model the resilience performance instead of treating it as a monetary value stream. To quantify resilience, we adopt a "survivability" metric defined as the probability that a microgrid can survive a random outage. The microgrid is said to survive a random outage provided it can satisfy all the following conditions during the full length of the outage:

- The microgrid provides sufficient power to meet the system load;
- Given estimated intra-hour variations of load and PV production, the microgrid has sufficient power capacity to meet system peaks under the worst circumstances;
- The microgrid has sufficient energy reserve to meet the intra-hour load variation under the worst circumstances.

We should note that when modeling system operation in islanding mode, in addition to meeting the hourly load, instantaneous peak demand must be met considering intra-hour variability from load and PV. There must be enough flexibility from BESS to balance fast changes from the load and PV in both directions. The microgrid cannot survive an outage unless all the requirements are met during the outage.

In our analysis, survivability is purely derived from an operational point of view for measuring resilience. In some previous energy storage assessment projects, we have estimated the dollar value of outage mitigation or resilience enhancement based on the Interruption Cost Estimate (ICE) (https://www.icecalculator.com/build-model?model=interruption) developed by Lawrence Berkeley National Laboratory. This tool estimates the cost per interruption event, per average kW, per unserved kWh, and the total cost of sustained electric power interruptions that only depend on region and type of customers. Therefore, it represents some average cost. In the real world, however, the cost could vary significantly from one system to another. It is difficult for a facility manager or system operator to quantify the dollar value of resilience and estimate the cost associated with an outage occurring at different times with different durations and magnitudes. That is the reason why we use survivability in this analysis to quantify resilience.

3.2 Use Cases from EN's Perspective

3.2.1 Energy Arbitrage

Should EN retain ownership of the BESS, the integration with Packwood Hydro would enable more efficient daily dispatch and potentially maximize EN's annual economic returns through strategic energy arbitrage. Specifically, the BESS can store excess electricity generated during periods of low market demand — typically when electricity prices are lower — and discharge that stored energy during periods when prices are higher. This energy-shifting capability allows EN to capture higher market value for the electricity produced, thereby increasing annual revenue without requiring additional water releases from the hydro system. Additionally, this operational flexibility would enable better alignment of generation with existing market conditions and grid needs, improving both profitability and system efficiency for the hydro facility.

3.2.2 Wear and Tear Reduction

Integrating a BESS with EN's Packwood Hydro also offers operational benefits — particularly in reducing mechanical wear and tear on the hydropower system. By supporting more stable and flexible plant operations, the BESS can help preserve the longevity of critical components while improving overall efficiency.

- One of the primary sources of mechanical degradation in hydropower systems is frequent ramping, where the plant must rapidly increase or decrease its output to follow changes in grid demand. These frequent load adjustments place significant stress on turbines, wicket gates, bearings, and other mechanical parts. With a BESS in place, short-term fluctuations in demand can be absorbed by the battery, allowing the hydro facility to operate at a more consistent and optimal output level.
- The presence of a BESS also enables more strategic water use. The BESS helps by storing surplus hydro generation during off-peak or low-price periods and releasing it when energy prices are higher, allowing the hydro plant to operate more efficiently while preserving water reserves. This approach ensures more efficient use of water while reducing unnecessary turbine operation, further decreasing wear and tear on mechanical systems and improving long-term sustainability.
- The BESS can also help reduce the frequency of emergency shutdowns and startups, which are particularly damaging to the hydroelectric equipment. Sudden stop-start cycles generate substantial stress and wear, especially when they occur without adequate ramping time. By providing immediate power injection or absorption, the BESS can smooth out sudden grid imbalances, reducing the need for rapid hydro response and extending equipment life.

All of these benefits listed above contribute to lower maintenance costs and longer intervals between overhauls. Reducing operational stress on the hydro system can help extend the life of major components, improve system reliability, and decrease the frequency of costly downtime. For EN, it translates into both operational resilience and long-term economic savings. To realize these benefits, we will conduct a comprehensive hydro plant optimization analysis for Packwood Hydro, focusing on reducing wear and tear on equipment and implementing strategic water management. This optimization framework will be developed and detailed in the next chapter.

3.2.3 Black Start Capability

Black start capability refers to a power plant's ability to restart operations independently, without drawing electricity from the main grid. This capability is essential during large-scale blackouts, as it enables the plant to initiate power generation and gradually assist in restoring grid stability. Traditionally, black start units rely on backup energy sources (such as diesel generators) to provide the initial startup power to bring a facility online and begin the process of reestablishing normal grid operations.

As previously mentioned, EN currently depends on a diesel generator to perform black start operations for the Packwood Hydro facility. In this study, we aim to assess whether a BESS can provide an alternative by delivering sufficient power and energy duration to support Packwood Hydro's black start requirements. The evaluation will focus on the BESS's ability to i) supply the required startup power, ii) maintain power delivery to stabilize hydro operations, and iii) perform reliably under various operating conditions. This assessment is critical in determining whether the BESS can replace the diesel generator as a potentially more sustainable solution for black start capability at Packwood Hydro.

CHAPTER 4

Modeling and Valuation Methods

The benefits of hydro hybrid systems (including PV and BESS) are highly dependent on the technical characteristics and operational capabilities of each individual energy asset. In this study, all modeling and analysis methods were developed based on PNNL's existing expertise. Specifically, we have leveraged PV and BESS models from previous projects, along with hydropower models refined through prior hydro-battery integration studies.

4.1 Modeling of Individual Energy Assets

4.1.1 Hydropower System

In this subsection, we introduce a generalized mathematical model for hydropower facilities. The model is designed to be applicable not only to Packwood Hydro but also to other hydropower systems. The model accommodates flexible configurations, such as the presence of multiple turbines, which makes it adaptable to a wide range of scenarios. However, in the next chapter, when we focus specifically on the system configuration of Packwood Hydro, its single-turbine setup will allow us to further simplify the mathematical model presented here.

4.1.1.1 Hydro Generation

The hydropower generation can be controlled by adjusting the plant flow of each turbine. Let us assume that the hydropower facility has N turbine units in total. Then, during each hour $k \in \mathcal{K}$ (where set $\mathcal{K} = \{1, \cdots, K\}$ contains all hours), a turbine unit n, with $1 \leq n \leq N$, may either work in generation mode or stay in standing-by mode. When the turbine is generating, its plant flow should be within the range of $Q_n^{\text{g-min}}$ to $Q_n^{\text{g-max}}$. While in standing-by mode, the turbine is shut down and, therefore, the corresponding plant flow should be zero.

In this work, we employ a binary decision variable $z_{n,k}^{\text{gen}}$ to denote the generation status of turbine n at hour k, where $z_{n,k}^{\text{gen}} = 1$ represents that the turbine's generation mode is on, and is off when $z_{n,k}^{\text{gen}} = 0$. Let $q_{n,k}^{\text{gen}}$ denote the plant flow through turbine n at hour k. Also let $Q_{n,k}^{\text{g-min}}$ and $Q_{n,k}^{\text{g-max}}$ denote the minimum and maximum plant flow of turbine n at hour k, respectively. Thus, the plant flow through each turbine can be modeled as:

$$z_{n,k}^{\text{gen}} Q_n^{\text{g-min}} \leq q_{n,k}^{\text{gen}} \leq z_{n,k}^{\text{gen}} Q_n^{\text{g-max}}, \quad \forall 1 \leq n \leq N, \quad \forall k \in \mathcal{K}, \tag{4.1}$$

$$z_{n,k}^{\text{gen}} \in \{0, 1\}, \quad \forall 1 \leq n \leq N, \quad \forall k \in \mathcal{K}. \tag{4.2}$$

Therefore, the total plant flow q_k^{gen} of all turbines at hour k can be written as:

$$q_k^{\text{gen}} = \sum_{n=1}^{N} q_{n,k}^{\text{gen}}, \quad \forall k \in \mathcal{K}. \tag{4.3}$$

The hydropower output $p_{n,k}^{\text{gen}}$ generated by turbine n at hour k can be converted from plant flow $q_{n,k}^{\text{gen}}$ using the following linear model:

$$p_{n,k}^{\text{gen}} = \alpha^{\text{gen}} q_{n,k}^{\text{gen}} + \beta^{\text{gen}}, \quad \forall 1 \le n \le N, \quad \forall k \in \mathcal{K}, \tag{4.4}$$

where α^{gen} and β^{gen} are two coefficients that convert plant flow into hydropower. The following ramping constraints are imposed to prevent abrupt changes of turbine output:

$$p_{n,k}^{\text{gen}} - p_{n,k-1}^{\text{gen}} \le p_n^{\text{ramp}}, \quad \forall 1 \le n \le N, \quad \forall k \in \mathcal{K}, \tag{4.5}$$

$$p_{n,k-1}^{\text{gen}} - p_{n,k}^{\text{gen}} \le p_n^{\text{ramp}}, \quad \forall 1 \le n \le N, \quad \forall k \in \mathcal{K}, \tag{4.6}$$

where p_n^{ramp} is the ramping limit of turbine n. Additionally, our next set of constraints enforces the hydropower's setpoint of turbine n to be unchanged for at least two hours:

$$p_{n,k-1}^{\text{gen}} - M z_{n,k}^{\text{set}} \le p_{n,k}^{\text{gen}} \le p_{n,k-1}^{\text{gen}} + M z_{n,k}^{\text{set}}, \quad \forall 1 \le n \le N, \quad \forall k \in \mathcal{K}, \tag{4.7}$$

$$z_{n,k-1}^{\text{set}} + z_{n,k}^{\text{set}} \le 1, \quad \forall 1 \le n \le N, \quad \forall k \in \mathcal{K}, \tag{4.8}$$

where binary variable $z_{n,k}^{\text{set}}$ indicates whether the hydropower's setpoint of turbine n is changed or not at hour k, and $M \ge 0$ is a sufficiently large constant used for the big-M constraint. Lastly, the total hydro generation p_k^{hyd} at hour k can be expressed by:

$$p_k^{\text{hyd}} = \sum_{n=1}^{N} p_{n,k}^{\text{gen}}, \quad \forall k \in \mathcal{K}. \tag{4.9}$$

4.1.1.2 Operational Mileage

In this work, we calculate the mileage of hydro operation by the following two steps: i) measure the differences in turbine generation across all time steps, and ii) calculate the sum of the absolute values of those differences. Hence, controlling the total operation mileage under a certain level can help us significantly reduce the wear and tear of the hydro facility.

In Figure 4.1, we present an illustrative example of observed turbine operations from 8 to 9 a.m., where the operation profile was recorded at a 5-minute resolution. In this example, by following the calculation steps defined above, we know that the total mileage can be calculated by summing up all the vertical red lines in Figure 4.1.

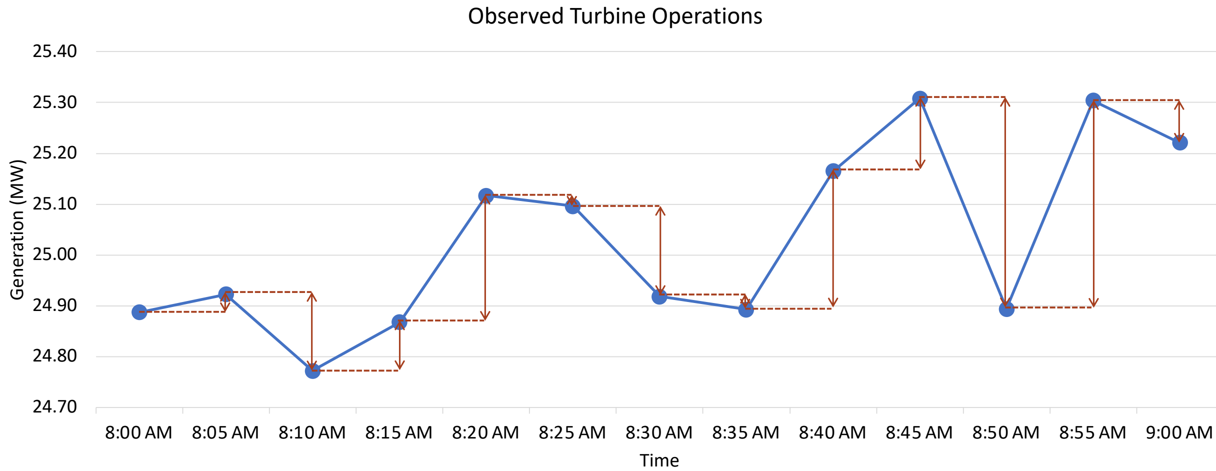

Figure 4.1. An illustration of how to calculate the mileage of turbine operations

Mathematically, let us stack all differences of turbine n's generation from time 1 to K as:

$$p_n^{\text{gen-diff}} = \left[p_{n,1}^{\text{gen}},\ p_{n,2}^{\text{gen}} - p_{n,1}^{\text{gen}},\ \cdots,\ p_{n,K}^{\text{gen}} - p_{n,K-1}^{\text{gen}}\right]^\top,$$

then the total mileage of turbine n's operation from time 1 to K can be written as the 1-norm of the $p_n^{\text{gen-diff}}$ vector:

$$\left\|p_n^{\text{gen-diff}}\right\|_1 = \left|p_{n,1}^{\text{gen}}\right| + \left|p_{n,2}^{\text{gen}} - p_{n,1}^{\text{gen}}\right| + \cdots + \left|p_{n,K}^{\text{gen}} - p_{n,K-1}^{\text{gen}}\right|. \tag{4.10}$$

4.1.1.3 Lake Level

We use q_k^{out} to represent the total water outflow of the lake at hour k. It consists of three parts: total plant flow through all turbines q_k^{gen}, bypass flow q_k^{byp}, and water spill q_k^{spl}. Thus, we have:

$$q_k^{\text{out}} = q_k^{\text{gen}} + q_k^{\text{byp}} + q_k^{\text{spl}}, \quad \forall k \in \mathcal{K}. \tag{4.11}$$

Let q_k^{in} and v_k represent the water inflow and water level at hour k, respectively. The dynamic change of lake level during hour k can be modeled as:

$$v_{k+1} = v_k + (q_k^{\text{in}} - q_k^{\text{out}})\Delta T/A, \quad \forall k \in \mathcal{K}, \tag{4.12}$$

where A denotes the area of the lake. A key assumption in this analysis is that the surface area of the lake remains constant regardless of fluctuations in water level. The lake level should also be within its lower and upper limits:

$$V_k^{\text{min}} \leq v_k \leq V_k^{\text{max}}, \quad \forall k \in \mathcal{K}. \tag{4.13}$$

Additionally, the initial and final lake levels are specified by:

$$v_1 = V_1 \ \text{ and } \ v_K = V_K, \tag{4.14}$$

with V_0 and V_K being the given initial and final lake levels, respectively.

4.1.2 The Integrated System with PV and BESS

A BESS can be modeled as a scalar linear dynamical system that resembles simplified energy state dynamics parameterized by charging and discharging power limits, energy state limits, and efficiencies (Wu et al., 2021). To capture one-way efficiencies, two non-negative auxiliary variables p_k^+ and p_k^- can be introduced to represent discharging and charging power at the point of common coupling, respectively. The discharging and charging power ranges are given by:

$$0 \leq p_k^+ \leq z_k^{\text{batt}} p_{\text{max}}^{\text{batt}}, \quad 0 \leq p_k^- \leq (1 - z_k^{\text{batt}}) p_{\text{max}}^{\text{batt}}, \quad \forall k \in \mathcal{K}, \tag{4.15}$$

$$z_k^{\text{batt}} \in \{0, 1\}, \quad \forall k \in \mathcal{K}, \tag{4.16}$$

where $p_{\text{max}}^{\text{batt}}$ is the BESS rated power. Binary variable z_k^{batt} is introduced to avoid the BESS being charged and discharged simultaneously. Thus, the BESS power output can be expressed as:

$$p_k^{\text{batt}} = p_k^+ - p_k^-, \quad \forall k \in \mathcal{K}, \tag{4.17}$$

where a positive p_k^{batt} means discharging and negative means charging. The battery's maximum daily discharged energy is limited by:

$$\sum_{k \in \mathcal{K}_d} p_k^+ \Delta T \leq E_{\text{day}}^{\text{batt}}, \quad \forall d \in \mathcal{D}, \tag{4.18}$$

where $E_{\text{day}}^{\text{batt}}$ represents a maximum of daily discharged energy of the BESS, $\mathcal{D}$ denotes the set that contains all days within the optimization time frame, $\mathcal{K}_d$ is a set that contains all hours for any day $d \in \mathcal{D}$, and ΔT represents the 1 hour time step. The dynamics of the BESS energy state can be modeled as:

$$e_k^{\text{batt}} = e_{k-1}^{\text{batt}} - (p_k^+/\eta^+ - p_k^- \eta^-)\Delta T, \quad \forall k \in \mathcal{K}, \tag{4.19}$$

where e_k^{batt} is the energy state at the end of hour k, η^+ and η^- are discharging and charging efficiencies, respectively. The energy state of BESS should be within its lower and upper limits as:

$$E_{\text{min}}^{\text{batt}} \leq e_k^{\text{batt}} \leq E_{\text{max}}^{\text{batt}}, \quad \forall k \in \mathcal{K}, \tag{4.20}$$

where $E_{\text{min}}^{\text{batt}}$ is the lower limit and $E_{\text{max}}^{\text{batt}}$ is BESS energy capacity. The initial and final energy states are specified by:

$$e_1^{\text{batt}} = E_1^{\text{batt}} \text{ and } e_K^{\text{batt}} = E_K^{\text{batt}}, \tag{4.21}$$

with E_1^{batt} and E_K^{batt} being the given initial and final energy state levels, respectively. In addition, the PV power output can be expressed as:

$$0 \leq p_k^{\text{pv}} \leq r_k^{\text{pv}} p_{\text{max}}^{\text{pv}}, \quad \forall k \in \mathcal{K}, \tag{4.22}$$

where r_k^{pv} is the PV's normalized hourly power output in maximum power point tracking (MPPT) mode and $p_{\text{max}}^{\text{pv}}$ denotes the nominal power. Finally, the total power output p_k^{sys} of the integrated system at hour k can be expressed as follows:

$$p_k^{\text{sys}} = \eta \cdot p_k^{\text{hyd}} + p_k^{\text{batt}} + p_k^{\text{pv}}, \quad \forall k \in \mathcal{K}, \tag{4.23}$$

where η is a scaling factor representing the proportion of hydropower output considered in the analysis. If the integrated system is owned and operated by EN to maximize its benefits, we set $\eta = 1$. If the integrated system is instead operated as a microgrid for LCPUD, then during grid-connected mode, LCPUD can only access its 14% share of Packwood Hydro's generation, so we set $\eta = 0.14$. However, in islanding mode (when Packwood Hydro is disconnected from the main grid), LCPUD can utilize the full generation capacity of Packwood Hydro. In this case, we also set $\eta = 1$.

4.2 Valuation Methods

By applying the mathematical models developed above for each energy asset, we can establish methodologies to quantify the value of all use cases identified in the previous chapter.

4.2.1 Use Cases for LCPUD

4.2.1.1 Peak Demand Management

To evaluate LCPUD's peak demand management, we assume knowledge of a perfect system load profile and consider all hourly system operations throughout the year as decision variables. Since the demand charge is paid in a monthly manner, we define $\boldsymbol{s}(l)$ and $\boldsymbol{e}(l)$, respectively, as the starting and ending hour indices of month l, for all $1 \leq l \leq 12$.

Given LCPUD's native load L_k at hour k and the integrated system's output p_k^{sys}, the system net load L_k^{net} at hour k can be written as:

$$L_k^{\text{net}} = L_k - p_k^{\text{sys}}, \quad \forall k \in \mathcal{K}. \tag{4.24}$$

It is important to note that when evaluating the integrated system from LCPUD's perspective, the power output from Packwood Hydro should be scaled by $\eta = 0.14$, reflecting LCPUD's 14% ownership share of the facility's total generation. Therefore, the monthly peak d_l of month l can be expressed as:

$$d_l = \max\{L_k^{\text{net}} : \boldsymbol{s}(l) \leq k \leq \boldsymbol{e}(l)\}. \tag{4.25}$$

Written in an epigraph form, constraint (4.25) can be equivalently transformed into:

$$d_l \geq L_k^{\text{net}}, \quad \text{for all } \boldsymbol{s}(l) \leq k \leq \boldsymbol{e}(l). \tag{4.26}$$

The total demand charge over the total time span $\mathcal{K}$ is given by:

$$C^{\text{dmd}} = \sum_{l=1}^{12} \mu_l d_l, \tag{4.27}$$

where μ_l denotes the peak demand price for month l.

4.2.1.2 Resilience Enhancement

We evaluate the microgrid resilience by estimating its survivability against a number of outage scenarios that are characterized by different BESS initial SOC, outage start time, and duration. The probability of the microgrid surviving a random outage is equal to the number of outages survived over the total number of random outages. An optimization problem must be solved to determine whether an outage can be survived, as presented below.

For each random outage i, there must be a power balance equation satisfied between hourly generation and load for all time:

$$p_k^{\text{sys}} + L_k^{\text{uns}} = L_k, \quad \forall k \in \mathcal{K}_i, \tag{4.28}$$

where $\mathcal{K}_i$ is the set of hours during the given outage i, $L_k^{\text{uns}} \geq 0$ is the unserved load variable during hour k, and L_k is LCPUD's hourly system load. Additionally, there must exist sufficient power capacity to meet the instantaneous peak load, considering intra-hour fluctuations in load and PV generation:

$$\eta \cdot p_k^{\text{hyd}} + p_{\text{max}}^{\text{batt}} + \left(1 - f^{\text{pv}}\right) r_k^{\text{pv}} p_{\text{max}}^{\text{pv}} + L_k^{\text{upk}} \geq \left(1 + f^{\text{L}}\right) L_k, \quad \forall k \in \mathcal{K}_i, \tag{4.29}$$

where $L_k^{\text{upk}} \geq 0$ is the unserved peak load variable during hour k, f^{pv} represents the intra-hour fluctuation parameter in percentage of the PV's hourly generation in MPPT mode, and f^{L} is the intra-hour fluctuation parameter in percentage of the hourly load. Sufficient operational reserves are also required to maintain the power balance for all time. The operational reserves that can be provided by a BESS are expressed as follows:

$$p_k^{\text{batt}} + p_k^{\text{res}+} \leq p_{\text{max}}^{\text{batt}}, \quad \forall k \in \mathcal{K}_i, \tag{4.30}$$

$$p_k^{\text{res}-} \leq p_k^{\text{batt}} + p_{\text{max}}^{\text{batt}}, \quad \forall k \in \mathcal{K}_i, \tag{4.31}$$

$$e_k^{\text{batt}} - p_k^{\text{res}+} \Delta T / \eta^{+} \geq 0, \quad \forall k \in \mathcal{K}_i, \tag{4.32}$$

$$e_k^{\text{batt}} + p_k^{\text{res}-} \Delta T \eta^{-} \leq E_{\text{max}}^{\text{batt}}, \quad \forall k \in \mathcal{K}_i, \tag{4.33}$$

where $p_k^{\text{res}+},\ p_k^{\text{res}-} \geq 0$ denote the BESS's operational reserves within hour k for discharging and charging, respectively. Thus, the system-level operational reserve constraints can be written as:

$$p_k^{\text{res}+} + p_k^{\text{urs}+} \geq f^{\text{pv}} r_k^{\text{pv}} p_{\text{max}}^{\text{pv}} + f^{\text{L}} L_k, \quad \forall k \in \mathcal{K}_i, \tag{4.34}$$

$$p_k^{\text{res}-} + p_k^{\text{urs}-} \geq f^{\text{pv}} r_k^{\text{pv}} p_{\text{max}}^{\text{pv}} + f^{\text{L}} L_k, \quad \forall k \in \mathcal{K}_i, \tag{4.35}$$

where $p_k^{\text{urs}+},\ p_k^{\text{urs}-} \geq 0$ denote the system's unserved operational reserves. Thus, if any optimal solution of L_k^{uns}, L_k^{upk}, $p_k^{\text{urs}+}$, or $p_k^{\text{urs}-}$ is strictly greater than zero, it means that the system is not capable of surviving outage event i. Hence, we can run a large number of random outage tests and then calculate the survivability of the microgrid in islanding mode.

4.2.2 Use Cases for EN

4.2.2.1 Energy Arbitrage with Penalized Mileage

For Packwood Hydro, it is important to note that the objectives of maximizing EN's economic benefits from energy arbitrage and minimizing operational mileage are inherently competing against each other. To balance these conflicting goals and identify an optimal trade-off, we introduce a weighted penalty cost for operational mileage into the energy arbitrage objective function:

$$\text{maximize} \quad \sum_{k=1}^{K} \lambda_k p_k^{\text{sys}} \Delta T - \gamma \sum_{n=1}^{N} \left\| p_n^{\text{gen-diff}} \right\|_1, \tag{4.36}$$

where λ_k denotes the energy price during hour k, and $\gamma \geq 0$ is the parameter we applied for tuning the penalty weight. From the case studies presented in Chapter 6, we would learn that putting a low weight on mileage reduction could usually yield a good balance between annual benefits and operational mileage.

Another optimization technique we can apply here is the introduction of auxiliary decision variables to handle the 1-norm term that appears in (4.36). This allows us to reformulate the problem as linear programming. The equivalent linear objective function becomes:

$$\sum_{k=1}^{K} \lambda_k p_k^{\text{sys}} \Delta T - \gamma \sum_{n=1}^{N} \sum_{k=1}^{K} m_{n,k}, \tag{4.37}$$

where $m_{n,k}$ are auxiliary variables introduced to linearize the absolute value terms originally present in the 1-norm expression:

$$\begin{aligned} m_{n,k} \geq 0, &\quad \forall 1 \leq n \leq N, \quad \forall k \in \mathcal{K}, \\ -m_{n,1} \leq p_{n,1}^{\text{gen}} \leq m_{n,1}, &\quad \forall 1 \leq n \leq N, \\ -m_{n,2} \leq p_{n,2}^{\text{gen}} - p_{n,1}^{\text{gen}} \leq m_{n,2}, &\quad \forall 1 \leq n \leq N, \\ &\vdots \\ -m_{n,K} \leq p_{n,K}^{\text{gen}} - p_{n,K-1}^{\text{gen}} \leq m_{n,K}, &\quad \forall 1 \leq n \leq N. \end{aligned} \tag{4.38}$$

4.2.2.2 Black Start Capability

In this study, the black start capability is evaluated through a post-processing procedure. Based on the historical outage records from the main grid, we could identify all past events that would have required black start capability for the Packwood Hydro facility. Specifically, such events are defined as instances where Packwood Hydro was offline and simultaneously experienced a grid outage, meaning no external power was available for startup. According to EN, these black start events were relatively rare in recent years. However, based on the characteristics of these historical events, we can generate synthetic outage scenarios for simulation purposes.

For each simulated event, we could examine the initial state-of-charge (SOC) of the BESS under the proposed optimal dispatch strategy and assess whether sufficient energy remains in the battery to initiate a black start without support from the main grid. If the BESS is capable of performing the black start for Packwood Hydro under these conditions, we can further evaluate the value of this service.

4.3 Optimization Formulations

In this section, we first formulate two optimal dispatch problems from the perspectives of LCPUD and EN, respectively. Specifically, if the system is utilized by LCPUD as a microgrid, the focus is on peak demand management and resilience enhancement. Conversely, if the integrated system is operated by EN, the objective is to maximize energy arbitrage benefits. Following the annual dispatch optimization, we can further extend our approach to formulate optimal sizing problems, where the capacities of PV and BESS are introduced as additional decision variables.

Once these optimization problems are formulated, we can solve the optimal sizing problems first to determine the most cost-effective capacities for PV and BESS. With the optimal PV and BESS sizes established, the dispatch optimization can then produce the most profitable annual operation schedules for the integrated system — either to maximize annual benefits or minimize operational costs. Subsequently, with this annual operation schedule in hand, we can conduct a post-processing analysis to evaluate outage survivability and black start capability.

4.3.1 Optimal Dispatch

4.3.1.1 Optimization from LCPUD's Perspective

When the integrated system with PV and BESS is used by LCPUD as a microgrid, the primary economic objective is to reduce LCPUD's annual demand charges. At the same time, system resilience constraints are incorporated to ensure the microgrid can support enhanced reliability during grid disturbances. Hence, the optimal dispatch problem for LCPUD can be formulated as follows:

$$
\begin{array}{llll}
(\mathbf{P}_{\text{LC}}) & \text{minimize} & (4.27) \\
& \text{subject to} & \text{Hydro model: } (4.1) - (4.9), \\
& & \text{Lake level: } (4.11) - (4.14), \\
& & \text{BESS model: } (4.15) - (4.21), \\
& & \text{PV model: } (4.22), \\
& & \text{Integrated system: } (4.23), \\
& & \text{Peak demand: } (4.24), (4.26), \\
& & \text{Resilience: } (4.28) - (4.35).
\end{array}
$$

In this problem $\mathbf{P}_{\text{LC}}$, since it is formulated from LCPUD's perspective, we should set $\eta = 0.14$ in the integrated system's constraint (4.23).

4.3.1.2 Optimization from EN's Perspective

As discussed in the previous sections, if the integrated system is deployed by EN to maximize its annual benefits through energy arbitrage, it is also important to account for the reduction of operational mileage (i.e., wear and tear on the hydro facility). To balance these two competing objectives, we formulate the following multi-objective optimization problem:

$$
\begin{array}{llll}
(\mathbf{P}_{\text{EN}}) & \text{maximize} & (4.37) \\
& \text{subject to} & \text{Hydro model: } (4.1) - (4.9), \\
& & \text{Lake level: } (4.11) - (4.14), \\
& & \text{BESS model: } (4.15) - (4.21), \\
& & \text{PV model: } (4.22), \\
& & \text{Integrated system: } (4.23), \\
& & \text{Hydro mileage: } (4.38).
\end{array}
$$

In this problem $\mathbf{P}_{\text{EN}}$, since it is formulated from EN's perspective, we should set $\eta = 1$ in the integrated system's constraint (4.23).

4.3.2 Optimal Sizing

The optimal sizing problem formulation can be built upon the two dispatch problems $\mathbf{P}_{\text{LC}}$ and $\mathbf{P}_{\text{EN}}$ developed above, with the capacities of PV and BESS introduced as additional decision variables. The goal of optimal sizing is to determine the most cost-effective capacities of the integrated system that either maximize net annual benefits or minimize net operational costs, accounting for the annualized capital costs of PV and BESS. To avoid redundancy, the full mathematical formulation of the optimal sizing problems is omitted here. Nonetheless, this approach will enable us to systematically identify the optimal configuration of the integrated system by solving the corresponding sizing problem.

CHAPTER 5

Case Studies and Inputs

Before we dive into the presentation of techno-economic analysis results, let us first introduce our main assumptions and input parameters for this numerical study.

5.1 Packwood Hydro's Operational Data

5.1.1 A Linear Hydro Generation Model

We received the historical hourly generation data (in MW) and the corresponding plant flow data (in cubic feet per second, cfs) from EN for several past years. Using this dataset, we performed a linear regression analysis to characterize the relationship between hydropower generation and plant flow. Our goal was to develop a simple yet effective linear model that captures how plant flow influences power output.

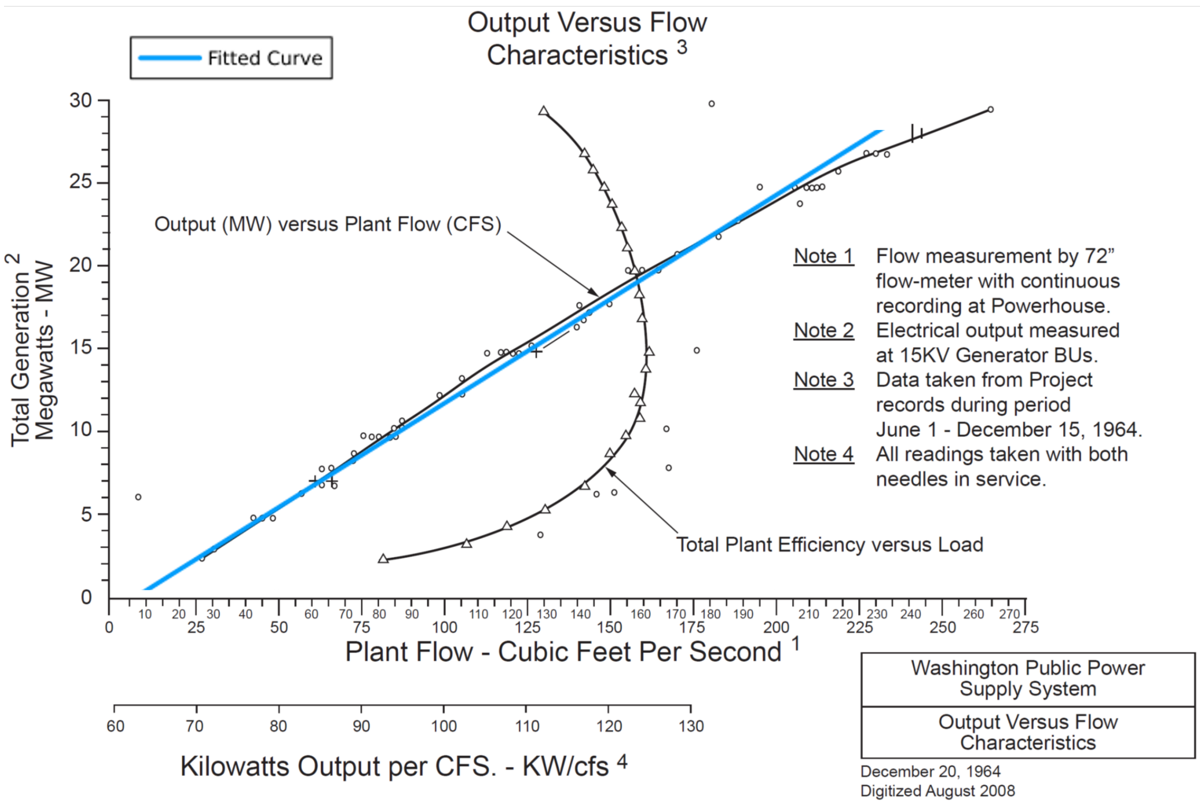

Figure 5.1. Hydropower output versus plant flow

The resulting linear regression model is given by:

$$\text{Plant Flow (cfs)} = 7.95 \times \text{Hydropower Output (MW)} + 6.63.$$

To validate this model, we compared it against Packwood Hydro's original *Output versus Flow Characteristics*, documented by EN on December 20, 1964, as shown in Figure 5.1. We also overlaid our regression model onto this original chart, and the results show an excellent match. Such a strong agreement confirms the validity and accuracy of our linear regression model. Additionally, EN has confirmed that the Packwood Hydro facility operates with a single turbine unit. This allows us to apply the regression model to further estimate the values of parameters α^{gen} and β^{gen} in Equation (4.4) with greater confidence and consistency.

5.1.2 Historical Water Flow Data

We also received historical daily water flow data from EN, covering all the years 2018 to 2024. Table 5.1 presents a sample of this dataset, showing daily water flow records for the first ten days of 2024. The dataset includes measurements such as the Packwood Lake level (in feet), the corresponding license-based minimum lake level (in feet), daily bypass flow (in cfs), plant flow (in cfs), water spill (in cfs), and lake inflow (in cfs).

Table 5.1. Examples of historical water flow data: Early January 2024

Day of the Year	Lake Level License Restriction (ft.)	Lake Level Daily Reading (ft.)	Bypass Flow License Restriction	Bypass Flow Daily Use	Plant Usage Daily Use	Lake Inflow	Spill
1-Jan-24	2849.00	2857.02	4	5	54	64	0.0
2-Jan-24	2849.00	2857.02	4	5	54	59	0.0
3-Jan-24	2849.00	2857.01	4	5	54	59	0.0
4-Jan-24	2849.00	2857.02	4	5	54	59	0.0
5-Jan-24	2849.00	2856.97	4	5	54	53	0.0
6-Jan-24	2849.00	2856.97	4	5	54	58	0.0
7-Jan-24	2849.00	2856.97	4	5	54	55	0.0
8-Jan-24	2849.00	2856.95	4	5	55	56	0.0
9-Jan-24	2849.00	2856.96	4	5	71	105	0.0
10-Jan-24	2849.00	2857.11	4	5	50	64	0.0

According to EN, the license has required that the Packwood Lake level must be maintained between 2856.5 and 2858.5 feet from May 1 through September 15. For the remainder of each year, the acceptable lake level range is 2852 to 2858.5 feet. If the lake level exceeds the upper limit of 2858.5 feet, any excess water will be automatically spilled.

In this work, we will use only the daily bypass flow and daily lake inflow as input parameters to our optimization problems. Since this dataset shared by EN is reported on a daily basis, we may further assume that each hourly value remains constant throughout the 24 hours of every day. Moreover, the surface area of Packwood Lake is 452 acres. Based on these assumptions and input data, we can estimate the hourly changes in lake level for any given hour of the year by applying our models (4.11) and (4.12). Specifically, we have:

$$\text{Hourly Change (ft.)} = \left[\text{Lake Inflow (cfs)} - \text{Lake Outflow (cfs)}\right] \times (3600 \text{ s}) \,/\, (452 \times 43560 \text{ sq. ft.}),$$

where lake outflow equals the summation of plant flow, bypass flow, and water spill.

5.1.3 Operational Limitations

Other operational limitations of the Packwood Hydro facility include a generation output range between 1 MW and 26 MW. Additionally, the facility undergoes a full system shutdown annually from August 1 to August 31. Such a scheduled outage is implemented to mitigate the risk of water temperature exceedances in the tailrace canal during peak summer heat conditions.

5.1.4 Historical Energy Prices

To evaluate the potential economic benefits that EN could gain from participating in energy arbitrage, we also obtained historical hourly energy prices from the Mid-Columbia (Mid-C) energy market for the years 2021 through 2023. These price signals serve as key inputs for modeling revenue opportunities associated with storing energy during low-price periods and dispatching during high-price periods. Using these data, we can solve the proposed optimal dispatch and sizing problems from EN's perspective, aiming to maximize net annual benefits while considering Packwood Hydro's operational constraints and system performance.

5.1.5 Historical Black Start Events

A one-line diagram of the Packwood substation, provided by EN, is shown in Figure 5.2. As illustrated, off-site power to Packwood Hydro is supplied through breaker PW-7. Therefore, if PW-7 is unavailable and Packwood Hydro simultaneously experiences an unplanned outage, then black start capability will be required to restart the hydro facility. Such events have been very rare in recent years.

Currently, EN owns a 125 kW diesel generator in preparation for facilitating the black start operations. In the event of a black start, according to EN, the diesel generator will be used to excite the hydro turbine, stabilize the hydro generation, and synchronize it with the main grid. The entire process takes no longer than four hours. In our analysis, therefore, we can assume that each black start event will consume no more than 500 kWh of electrical energy from the integrated system. Based on this assumption, we can further evaluate whether or not the PV and BESS have sufficient capacity to provide black start services.

5.2 LCPUD System Specifications

To conduct the PSSM feasibility analysis from LCPUD's perspective, we also obtained a dataset provided by LCPUD that includes the utility's substation load profiles and past outage incidents.

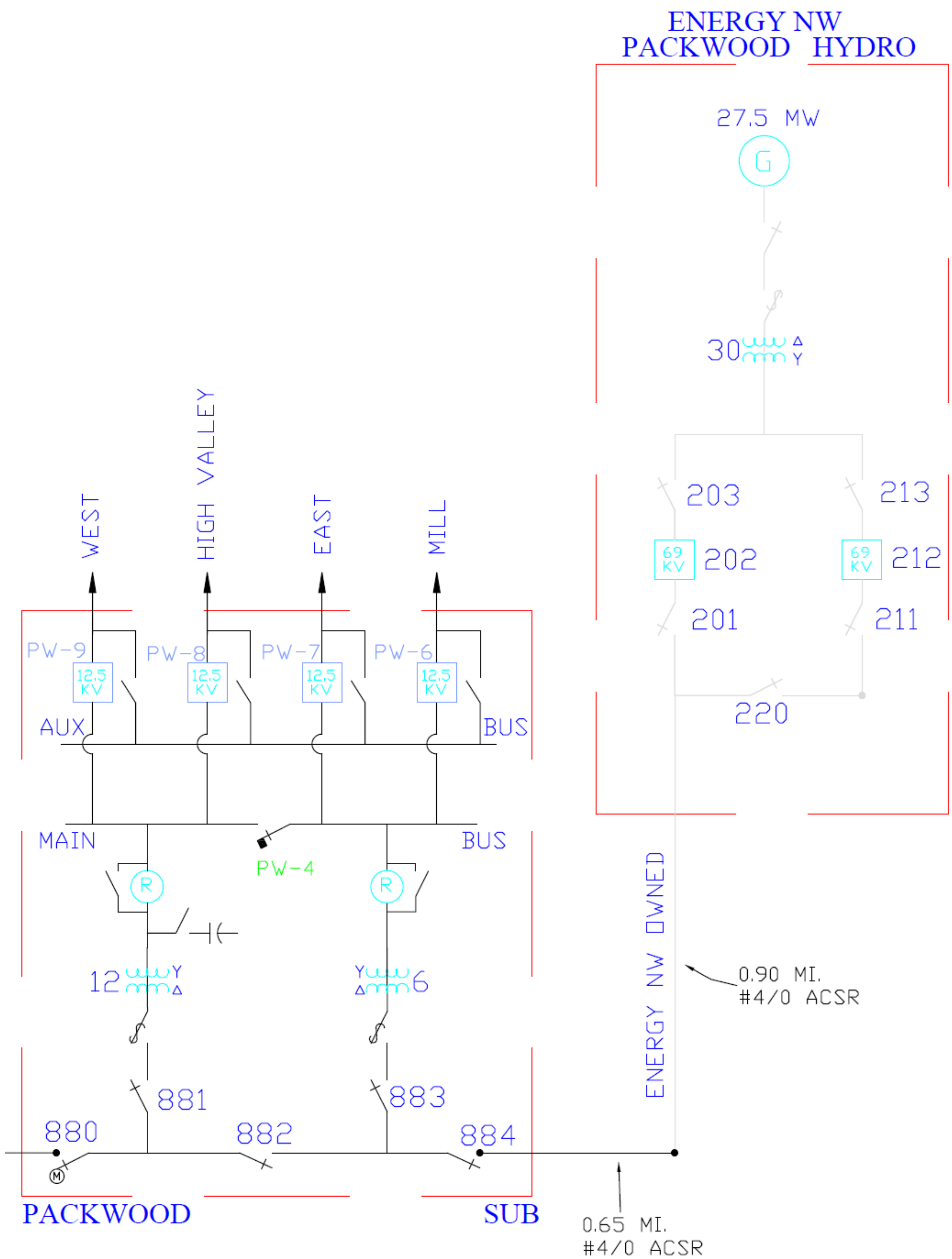

Figure 5.2. A one-line diagram of the Packwood substation

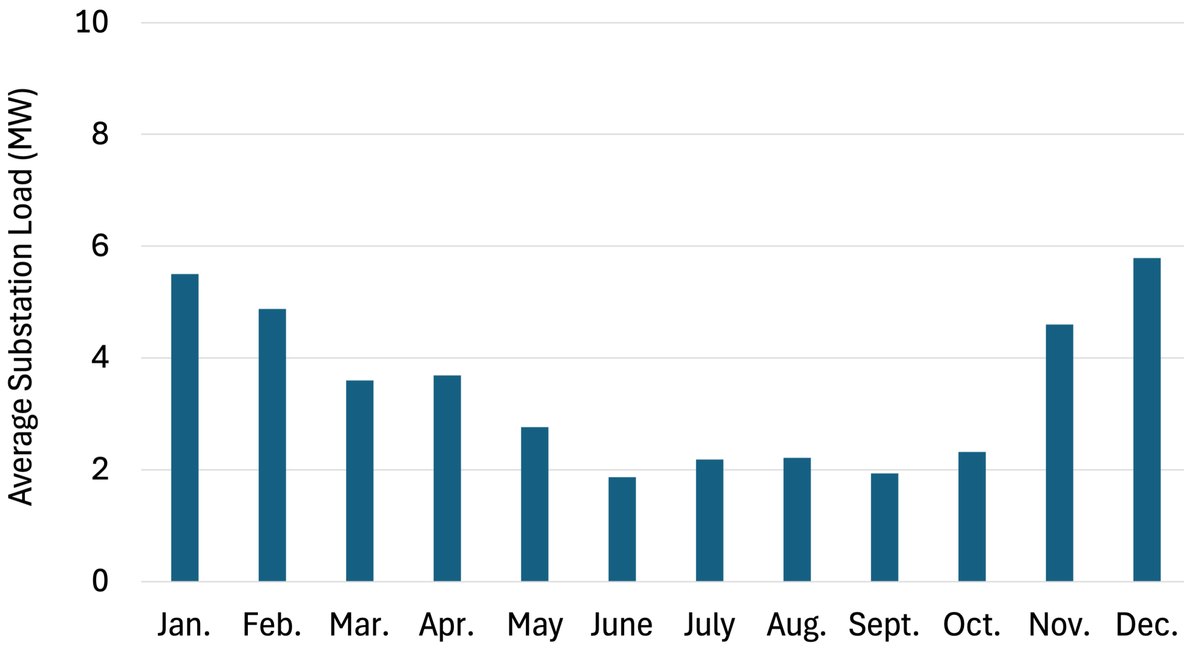

Figure 5.3. Monthly average system load at the Packwood substation for 2022

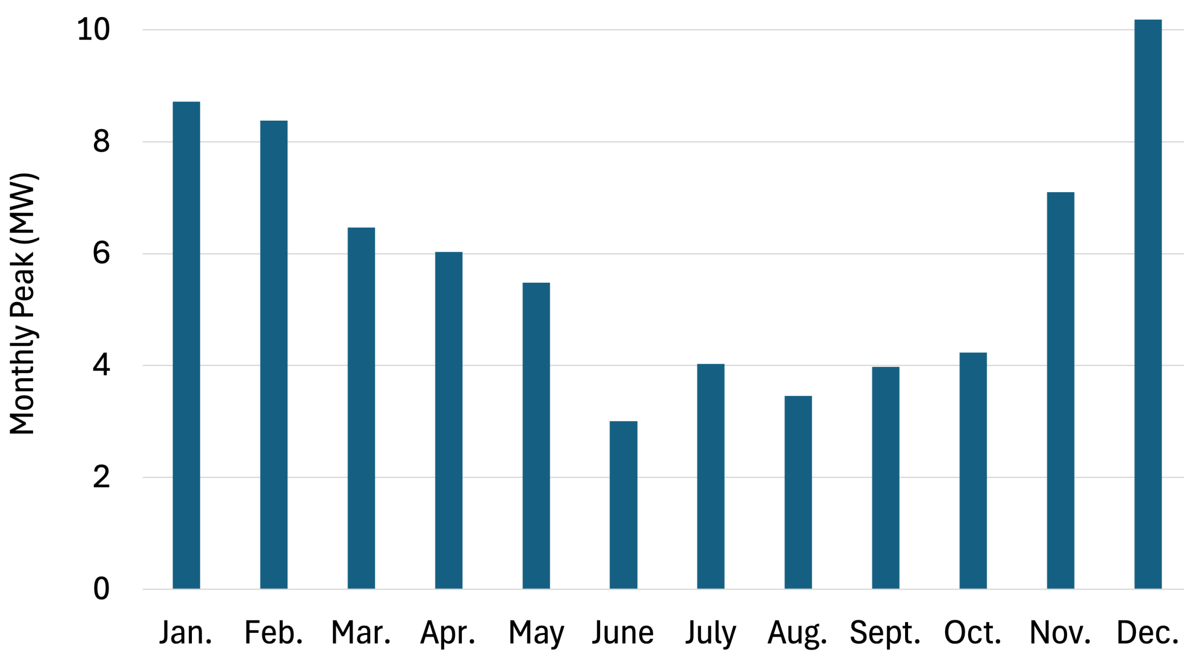

Figure 5.4. Monthly peaks at the Packwood substation for 2022

5.2.1 Existing Substation Load

LCPUD has shared with us their hourly load profiles at the Packwood substation spanning from 2014 to 2023. As a representative example, Figures 5.3 and 5.4 illustrate the average monthly substation load and the corresponding monthly peaks (in MW) for the year 2022. Both figures reveal a clear seasonal pattern. The Packwood substation typically experiences higher system loads in winter (November through February), while the loads remain relatively low during the rest of the year. In 2022, for instance, the average load during winter months exceeded 5 MW, with the monthly peak loads surpassing 8 MW. In contrast, for the remainder of the year, the average load generally stayed below 4 MW, and the monthly peaks remained under 6 MW.

5.2.2 Historical Outage Events

We also received records of LCPUD's historical outage events at the Packwood substation covering a multi-year period from 2017 to 2024. To provide a clearer overview, we summarize in Table 5.2 key statistics for the events that could cause microgrid isolation. As shown, these events concentrate in the years 2019 to 2023. The Packwood substation typically experiences between 1 and 6 isolation outage incidents annually, with an average outage duration ranging from 2 to 11 hours. This data provides a sufficient basis for conducting a resilience analysis to evaluate how much the proposed microgrid could enhance survivability and service continuity for LCPUD during grid disruptions.

Table 5.2. Historical outage statistics for LCPUD

Year	Number of Outage Events	Minimum Dur. (h)	Maximum Dur. (h)	Average Dur. (h)	Median Dur. (h)	Average Load (MW)	Peak Load (MW)
2019	3	1	10	4.33	2	1.64	5.47
2020	1	2	2	2	2	1.9	2.79
2021	6	1	8	3.67	2.5	1.37	7.89
2022	2	3	19	11	11	0.27	2.18
2023	1	2	2	2	2	0.83	0.86
Total	13	1	19	4.69	2	1.03	7.89

5.3 PV and BESS Techno-economic Characteristics

5.3.1 Economic Parameters and Assumptions

In this study, the economic life of the PSSM project is assumed to be 25 years and the discount rate is assumed to be 4%. Additionally, the inflation rate for both energy cost and annual O&M cost is assumed to be 5%.

5.3.2 BESS Parameters

We incorporated the BESS testing results and measured performance (Crawford et al., 2022) into the economic assessment. The key parameters of the linear BESS models are summarized as follows. According to the original proposal, the BESS size proposed by EN and LCPUD is 1 MW with a 4-hour duration. It will serve as a baseline for our initial techno-economic analysis.

Consequently, for the first stage of analysis, we select the BESS rated power as 1 MW. The BESS is designed with 4 MWh of total usable energy. Within the recommended 10 – 90% SOC, the allowed daily discharged energy is limited to 4 MWh according to the capacity maintenance agreement for 25 years. To guarantee this, we constrained the BESS to operate between 10% and 90% SOC with no more than 4 MWh of discharged energy each day. The BESS round-trip efficiency is 87.6%, with the same charge and discharge efficiencies, i.e., $\eta^+ = \eta^- =$ 93.6%.

5.3.3 PV Parameters

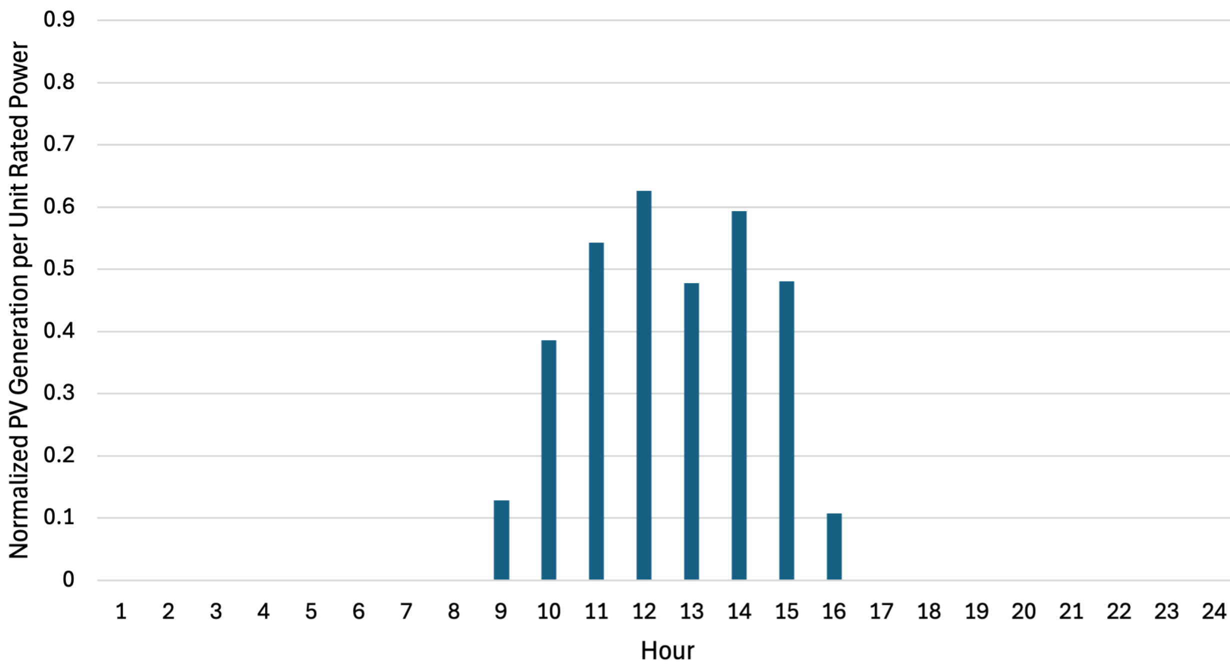

Figure 5.5. PV generation at Packwood on a typical winter day

The AC power rating of the solar panel was originally designed as 1.6 MW for this PSSM project. Locational normalized PV generation profiles are generated for Packwood using the `pvlib` library (Holmgren et al., 2018), which is a community-supported tool for simulating the performance of PV systems. The required input parameters of `pvlib` include PV module and inverter parameters, PV installation parameters, as well as parameters that depend on weather conditions. The parameters such as hourly clear sky global horizontal irradiance, direct normal irradiance, ambient temperature, and wind speed are generated using a stochastic model with historical weather data from National Solar Radiation Database (Wilcox, 2012) as inputs.

The PV generation at Packwood on a typical winter day (January 16) and a typical summer day (July 16) is shown in Figures 5.5 and 5.6, respectively, where the vertical axis represents a normalized generation per unit rated power of the PV system. From these two figures, we can observe that the PV generation is available between 9 a.m. and 4 p.m. in winter, and between 6 a.m. and 8 p.m. in summer. The peak PV output occurs around 12 – 1 p.m. for both seasons. According to `pvlib` simulation, the average hourly PV generation is 0.24 MWh and about 2,080 MWh annually.

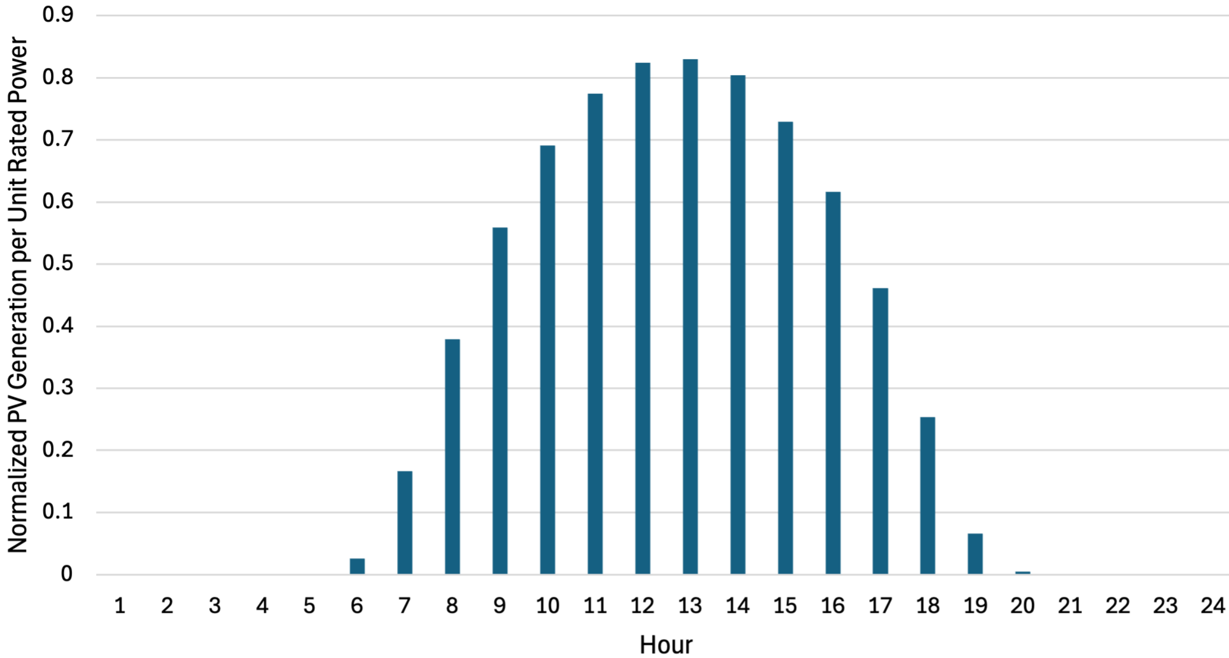

Figure 5.6. PV generation at Packwood on a typical summer day

5.3.4 Costs Associated with PV and BESS

In this work, the capital costs of PV and BESS are estimated using EN's Horn Rapids Project (Ma et al., 2022) as a reference. Specifically, the cost of the 1 MW/4 MWh BESS is estimated at $3.4 million, which includes EN's labor and overhead, legal support, Small Generator Interconnection Application fees, engineering, archaeological surveys, State Environmental Policy Act compliance, owner's engineering services, PNNL analytics, site infrastructure, and the BESS engineering, procurement, and construction contract. This BESS cost also covers construction, warranty, equipment, and BPA interconnection. The cost of the 1.6 MWac PV is estimated at $2.1 million, bringing the total cost of the proposed system to approximately $5.5 million.

Additionally, microgrid project and controller costs have been reviewed and summarized in (Giraldez et al., 2018). Cost variations depend on the type of distributed energy resources, market segments (e.g., campus, commercial, community, or utility), and the complexity of control systems. The average cost of microgrid controllers for energy storage and PV systems with load management capabilities is approximately $162,000 per MW. This equates to roughly $422,000 for a system that includes a 1 MW BESS and a 1.6 MWac PV installation. In addition, (Giraldez et al., 2018) also benchmarks the cost of microgrid controllers as a percentage of the total project cost, identifying a median value equivalent to 7%. Based on this percentage, the additional cost for microgrid controllers can be estimated at $385,000 for the proposed system. For simplicity, this study assumes that the additional cost for enabling microgrid capabilities is around $400,000.

CHAPTER 6

Assessment Results

In this chapter, we customize the mathematical modeling and valuation methods developed in Chapter 4 to evaluate LCPUD and EN's benefits using the dataset collected in Chapter 5. The chapter is organized into three sections. The first two sections evaluate the economic benefits of LCPUD and EN, respectively, based on the PV and BESS sizes that were planned in their original proposal. The final section presents the results of the optimal battery sizing, along with the corresponding techno-economic assessment.

This project primarily focuses on Packwood Hydro, but the optimization model and analytical framework developed can be broadly applied to other comparable systems. The model captures key characteristics common to hydropower systems, such as the interplay between water flow and hydroelectric generation, ramping and mileage constraints, lake level management, and the integration of PV and BESS operations. However, it is important to note that the findings and conclusions derived from this study may not directly translate to other projects. Accurate application to different cases requires in-depth consideration of specific system designs, operational parameters, and comprehensive data on market conditions and weather patterns to ensure the validity and reliability of the results.

6.1 Benefits for LCPUD

As outlined in Chapter 3.1, if LCPUD owns the PV and BESS, it can establish a local microgrid to effectively manage peak demand and improve system resilience at the Packwood substation.

6.1.1 Peak Demand Management

In grid-connected mode, the microgrid integrates the 1 MW/4 MWh BESS, 1.6 MWac PV, and a 14% share of hydropower generation from Packwood Hydro to manage LCPUD's peak load at the Packwood substation. For evaluation, we solve problem $\mathbf{P}_{\mathrm{LC}}$ developed in Chapter 4.3.1.1, without considering system outage events. The monthly peak reduction, along with comparisons between the native and net loads at the Packwood substation, is shown in Figure 6.1.

During high-demand winter months, as we may observe from Figure 6.1, the peak demand management can reduce load peaks by approximately 50%. In comparison, during low-demand summer months, the microgrid's own power generation can fully meet demand, resulting in zero peaks. Even in August, when the hydro generation is offline for maintenance, the PV and BESS continue to effectively reduce peak demand. This capability to manage peak demand minimizes reliance on external grid power during periods of peak demand or supply shortages, avoiding additional costs for LCPUD.

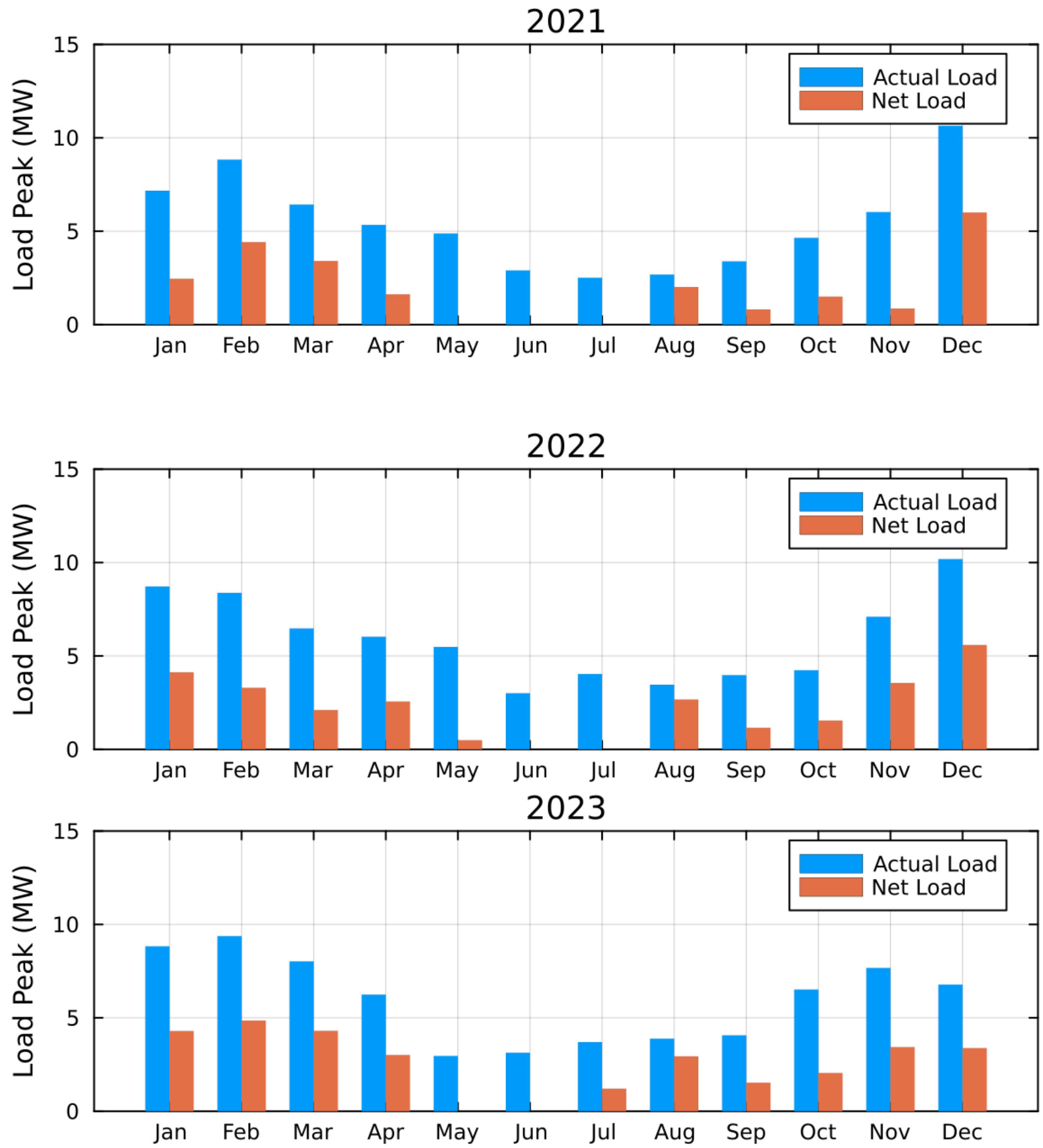

Figure 6.1. Packwood substation's monthly peak reduction from 2021 to 2023

6.1.2 Resilience Enhancement

We further evaluate the microgrid's capability to withstand the Packwood substation's historical outage events (detailed in Chapter 5.2.2). During each outage event, the microgrid will operate in islanding mode. The load is supplied by the 1 MW/4 MWh BESS, 1.6 MWac PV, and full hydropower generation. The lake water level and BESS SOC from the optimal dispatch solution of the peak load management are used as initial conditions for each outage analysis. The initial states correspond to the conditions in the optimal dispatch solution at the starting time of each outage event. The results of these resilience analyses are summarized in Table 6.1, with details for each outage event provided in Table 6.2. With full hydro generation support, the microgrid could successfully endure all nine outage events that occurred between 2021 and 2023, even during high-demand winter periods. During isolated outage scenarios, the 27.5 MW nameplate capacity of Packwood Hydro is more than sufficient to meet the local demand at the Packwood substation.

Table 6.1. Resilience enhancement with PSSM during historical outage events

Year	Number of Outage Events	Survived Events	Survivability	Total Outage Duration (h)	Served Hours (h)	Served Time Ratio
2021	6	6	100%	22	22	100%
2022	2	2	100%	22	22	100%
2023	1	1	100%	2	2	100%

Table 6.2. Detailed resilience analysis for each outage event

Starting Time	Total Outage Duration (h)	Survived (Yes / No)	Served Hours	Total System Load (MWh)	Unserved Load (MWh)
2021-02-13T00:00:00	1	Yes	1	7.89	0
2021-09-18T12:00:00	8	Yes	8	3.35	0
2021-09-27T04:00:00	3	Yes	3	1.40	0
2021-09-30T13:00:00	2	Yes	2	3.38	0
2021-12-26T11:00:00	6	Yes	6	7.18	0
2021-12-27T12:00:00	2	Yes	2	6.93	0
2022-06-16T04:00:00	3	Yes	3	3.15	0
2022-07-19T14:00:00	19	Yes	19	2.24	0
2023-05-15T23:00:00	2	Yes	2	0.86	0

Fortunately, no historical outage events have been recorded in August, the month when the Packwood Hydro facility undergoes annual maintenance. To evaluate the microgrid's ability to withstand outages in August without hydro generation, we simulated 100 outages every year, each with randomly selected start times and durations of 5 hours. The results are summarized below in Table 6.3. As we can see, the microgrid was only able to successfully endure 4 outage events in 2021 and failed to survive any outages in 2022 or 2023. To improve resilience during extreme events, such as outages in August, increasing the capacity of the BESS or PV system may be necessary.

6.2 Benefits for EN

Conversely, if EN owns the PV and BESS, integrating them with Packwood Hydro will enable more efficient dispatch through strategic energy arbitrage, maximizing EN's annual economic returns. The BESS can also enhance operational flexibility by ensuring consistent and stable output levels, which helps minimize wear and tear on the mechanical components of the hydro

Table 6.3. Resilience analysis with synthetic outage events in August

Year	Number of Outage Events	Survived Events	Survivability	Total Outage Duration (h)	Served Hours (h)	Served Time Ratio
2021	100	4	4.00%	500	74	14.80%
2022	100	0	0.00%	500	1	0.20%
2023	100	0	0.00%	500	2	0.40%

facility. Additionally, the BESS improves system resilience by providing black start capability, allowing the hydropower plant to restart independently without relying on the existing diesel generator.

6.2.1 Energy Arbitrage

The economic benefits of energy arbitrage is evaluated by solving the optimal dispatch problem $\mathbf{P}_{\mathrm{EN}}$ formulated in Chapter 4.3.1.2. Table 6.4 presents the annual revenue under four scenarios:

- Observed historical dispatch;
- Optimal dispatch without PV or BESS;
- Optimal dispatch with BESS only;
- Optimal dispatch with both PV and BESS.

Also, the annual revenue improvements achieved and total electricity generation in these optimal dispatch scenarios are summarized in Tables 6.5 and 6.6. In Table 6.5, the row entitled “Revenue Increase by Optimal Dispatch” compares the two rows “Optimal Dispatch w/o PV or BESS” and “Observed Historical Dispatch” in Table 6.4. The last two rows compare the corresponding rows with “Optimal Dispatch w/o PV or BESS” in Table 6.4, respectively, showing additional benefits from the deployment of PV and BESS devices.

We can observe from Table 6.5 that optimally dispatching the hydropower generation without incorporating PV or BESS can increase annual revenue of the station by $1.175 million to $2.385 million, representing a 35% to over 50% improvement compared to historical dispatch practices. While the optimal dispatch assumes perfect foresight over the course of a year, the results underscore a substantial potential for revenue enhancement through dispatch optimization. Moreover, integrating PV and BESS further boosts revenue by an additional $121,000 to $175,000, emphasizing the added economic values these technologies bring to the system.

A comparison of the first two rows in Table 6.6 reveals that the optimal dispatch generates more energy in 2021 but less energy in 2022 and 2023. This observation indicates that the additional revenue from optimal dispatch is not necessarily driven by higher electricity generation. Instead, it results from strategically timing the power output to align with favorable market conditions. This is further highlighted when BESS is integrated into the system. While BESS itself does not generate power and incurs energy losses during charging and discharging, its ability to store electricity during periods of low prices and release it during high-price periods leads to increased revenue. Notably, the total system output decreases when BESS is included. Finally, the addition of a 1.6 MWac PV system increases overall power generation, which directly contributes to higher revenue.

Table 6.4. Annual revenue with different dispatch solutions

	Annual Revenue		
	2021	**2022**	**2023**
Observed Historical Dispatch	$3,276,000	$4,401,000	$3,207,000
Optimal Dispatch w/o PV or BESS	$4,450,000	$6,785,000	$4,905,000
Optimal Dispatch w/ BESS	$4,484,000	$6,836,000	$4,956,000
Optimal Dispatch w/ PV and BESS	$4,572,000	$6,961,000	$5,075,000

Table 6.5. Annual revenue improvement by optimization with PV and BESS

	Annual Revenue Improvement		
	2021	**2022**	**2023**
Revenue Increase by Optimal Dispatch	$1,175,000	$2,385,000	$1,699,000
Additional Revenue Increase by BESS Only	$33,000	$50,000	$51,000
Additional Revenue Increase by PV and BESS	$121,000	$175,000	$169,000

Table 6.6. Annual electricity generation with different dispatch solutions

	Total Generation (MWh)		
	2021	**2022**	**2023**
Observed Historical Dispatch	88,201	87,657	60,513
Optimal Dispatch w/o BESS or PV	89,684	82,294	59,215
Optimal Dispatch w/ BESS	89,482	82,086	59,007
Optimal Dispatch w/ BESS and PV	91,562	84,166	61,087

Based on the last row of Table 6.5, let us take the additional revenue of $169,000 generated in year 2023 as a representative median value for the revenue resulting from the integration of PV and BESS. Given that the total cost of PV and BESS is estimated to be approximately $5.5 million (see Section 5.3.4), the corresponding payback period for this project is 32.5 years. This analysis suggests that relying solely on PV and BESS pairing with Packwood Hydro for energy arbitrage may not be a cost-effective strategy from EN's perspective.

This energy arbitrage study presents a low-risk, high-reward opportunity for EN and the Packwood Hydro Participant utilities, even without deploying a BESS or PV. To achieve the increase in revenue, PNNL will develop an actionable strategy for power dispatch that works in a forward-looking manner rather than assuming perfect foresight over a year. This requires capabilities to predict future power pricing and water inflow to the lake. To implement this strategy, EN would need to upgrade the current SCADA system to automate power ramping and eliminate manual adjustments by Packwood operators.

6.2.2 Wear and Tear Reduction

As discussed in Chapter 4.2.2.1, a parameter γ can be used as a weighting factor to penalize the hydro turbine's operational mileage, helping EN strike a balance between the economic gains from energy arbitrage and the wear and tear of the hydro facility. Table 6.7 presents the annual revenue and total mileage over the year with various γ values.

As the value of mileage penalty increases, we conclude that both annual revenue and total mileage decrease. Table 6.8 below further summarizes these reductions in comparison to the no-penalty scenario. Setting the mileage penalty parameter at $100/MW reduces total mileage by 9.1 to 12.1 GW, at the cost of a decrease in annual revenue of $172,000 to $235,000. Increasing the penalty to $500/MW further reduces mileage by approximately 1 GW but results in an additional loss of $213,000 to $299,000 in annual revenue. In summary, higher penalty values yield only marginal mileage reductions, while the associated revenue losses remain significant. Hence, selecting a mileage penalty of $100/MW is an appropriate choice to balance economic benefits and wear and tear reduction.

Table 6.7. Annual revenue and turbine mileage with different mileage penalties

	Annual Revenue			Annual Mileage (MW)		
Mileage Penalty ($/MW)	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**
None	$4,572,000	$6,961,000	$5,075,000	12,691	13,777	11,119
100	$4,400,000	$6,725,000	$4,878,000	1,423	1,672	1,972
500	$4,187,000	$6,471,000	$4,579,000	447	610	512
1000	$4,077,000	$6,303,000	$4,461,000	292	372	362

Table 6.8. Annual revenue and mileage reduction with different mileage penalties

	Annual Revenue Reduction			Mileage Reduction (MW)		
Mileage Penalty ($/MW)	**2021**	**2022**	**2023**	**2021**	**2022**	**2023**
100	$172,000	$235,000	$197,000	11,268	12,104	9,146
500	$385,000	$490,000	$496,000	12,244	13,166	10,607
1000	$495,000	$657,000	$614,000	12,400	13,404	10,757

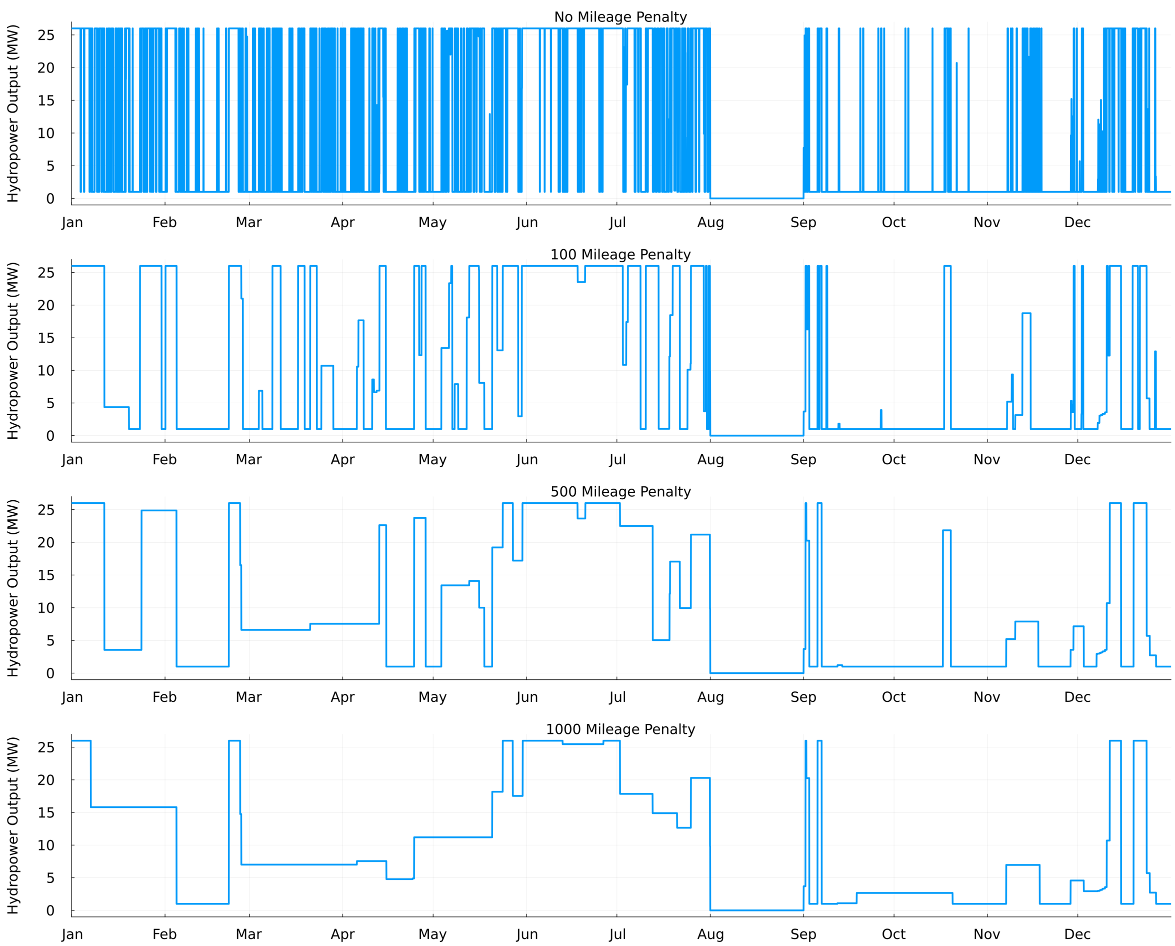

Figure 6.2. Hydropower outputs with different mileage penalties for 2022

To illustrate the impact of the mileage penalty parameter on hydropower dispatch, we select the year 2022 as an example and plot the hydropower output throughout the year with different penalty values in Figure 6.2. When no mileage penalty is applied, as we can observe from the first subplot on the top, the hydropower output fluctuates frequently between its lower and upper limits only to maximize the annual revenue, which may cause significant wear and tear on the facility. In contrast, introducing a mileage penalty drastically reduces output variations, offering better protection for the hydropower equipment.

6.2.3 Black Start Capability

As detailed in Chapter 5.1.5, EN currently utilizes a 125 kW diesel generator to perform black start operations. The whole black start process requires no longer than four hours to complete and consumes up to 0.5 MWh of energy. Therefore, the integrated 1 MW/4 MWh BESS is fully capable of meeting this energy demand, eliminating reliance on the diesel generator for black start support. If necessary, the minimum SOC constraint within the proposed optimization model can also be adjusted to retain sufficient stored energy.

6.3 Optimal BESS Sizing

6.3.1 Sizing from LCPUD's Perspective

To enhance performance and resilience, the BESS can be integrated with the Packwood Hydro facility and solar systems to establish a microgrid. Such an integrated microgrid offers LCPUD a more strategic solution to address peak demand challenges and bolster system resilience at the Packwood substation.

Following our detailed analysis results presented above, the proposed 1 MW/4 MWh BESS has demonstrated significant potential by reducing peak demand at the Packwood substation by approximately 50%. This load reduction could be translated into cost savings, decreased strain on infrastructure, and improved service delivery during high-load periods. Moreover, resilience testing showed that the microgrid configuration could successfully sustain operations during all historical outage events reported for the Packwood substation, enhancing LCPUD's continuous power supply and minimizing disruption.

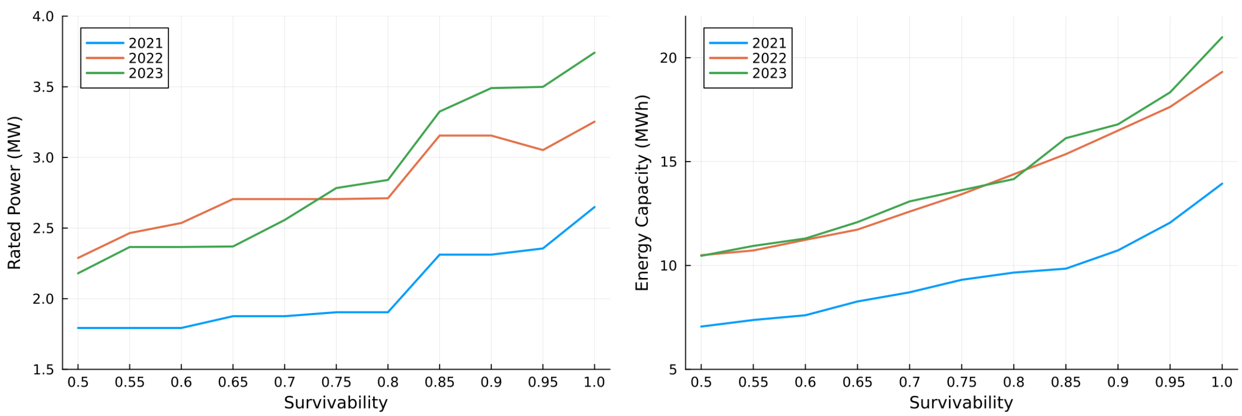

Figure 6.3. Minimum required BESS size to ensure various levels of survivability during outage events in August

However, our resilience analysis has identified a specific vulnerability during August, which coincides with the annual maintenance shutdown of the Packwood Hydro facility. During this period, survivability levels are projected to be much lower due to the absence of hydroelectric support. To ensure power supply during contingencies in August, a larger BESS is required. We conduct a preliminary battery sizing study using the same synthetic outage events for resilience analysis in Chapter 6.1.2. Figure 6.3 illustrates the required BESS rated power and energy capacity for survivability levels ranging from 50% to 100%. For this analysis, we assume the BESS is fully charged at the start of each contingency, a condition that is easily achievable before hydro facility maintenance. The results show that maintaining a survivability level above 90% during this critical time frame requires upgrading the battery system to a 3.5 MW/17 MWh configuration, which leads to an approximate capital cost of $7.7 million, according to PNNL's Energy Storage Evaluation Tool (ESET) (https://eset.pnnl.gov/). This enhanced capacity would sufficiently satisfy resilience requirements and provide reliable backup power to meet demand during hydro outages.

In summary, the integration of a microgrid powered by BESS, PV systems, and Packwood Hydro represents a strategic and scalable solution for LCPUD. While the 1 MW/4 MWh BESS offers significant benefits in peak load reduction and outage resilience, transitioning to a larger 3.5 MW/17 MWh system will further ensure optimal performance and survivability even during hydro maintenance periods, ultimately aligning with LCPUD's goals for system resilience.

6.3.2 Sizing from EN's Perspective

As illustrated in Table 6.5, the 1 MW/4 MWh BESS yields an annual additional revenue ranging between $33,000 and $51,000 for EN during 2021 to 2023 through energy arbitrage only. This revenue is generated by strategically charging the BESS during periods of low electricity prices and discharging it during peak-price hours to capture the price differentials.

However, the economics of energy arbitrage alone are insufficient to justify the investment cost. The proposed 1 MW/4 MWh BESS has an approximate capital cost of $3.4 million, which far exceeds the cumulative revenue that can be earned through energy arbitrage over a typical expected lifetime of 10 – 15 years for the battery. Even with favorable market conditions, the return from energy arbitrage revenue alone is projected to fall short of offsetting the initial BESS investment cost.

Furthermore, the results from our optimal BESS sizing analysis suggest that under current market conditions, when sizing the BESS exclusively for benefits derived from energy arbitrage, the optimal BESS size consistently converges to zero. This implies that, based solely on energy arbitrage, there is no cost-effectiveness to install a BESS, as the expected returns would fail to cover both the battery's capital expenditures and operational costs. This outcome underscores the importance of considering additional applications or value streams for BESS installations at EN, such as ancillary services or leveraging government incentives, which could enable a more favorable cost-benefit balance that supports wider-scale adoption.

CHAPTER 7

Conclusions

This report presented a comprehensive techno-economic assessment to evaluate the feasibility and potential benefits of hybridizing the Packwood Hydro facility. This study leverages PNNL's advanced hydropower modeling and analytical tools to analyze various use cases, considering both the perspectives of LCPUD and EN.

Our first assessment focused on addressing Packwood Hydro's tailrace water temperature compliance issues. The proposed PV panel shading strategy alone was proved insufficient in effectively mitigating the elevated tailrace water temperatures. Analysis of the monitored water temperature from the Packwood Lake revealed the fact that temperatures at PLO consistently exceeded the critical threshold of 19.4°C between early July and late August. Contrary to EN's initial assumptions, the primary contributor to elevated water temperatures was identified as the lake itself, rather than solar radiation exposure within the tailrace canal. Thus, future research will explore alternative strategies aimed at addressing this fundamental issue, with a focus on sustainable solutions that ensure long-term compliance with temperature regulations.

From LCPUD's perspective, integrating PV and BESS systems with Packwood Hydro offers significant operational advantages. In grid-connected mode, the microgrid demonstrates notable improvements in peak load management, reducing peak demand by approximately 50% during high-demand winter months and achieving almost full peak reduction during lower-demand summer months. This reduction minimizes LCPUD's reliance on external grid power, enabling significant cost savings and enhanced system flexibility during periods of elevated demand or supply shortages. In islanding mode, the microgrid — leveraging the full generation capacity of Packwood Hydro — proves its resilience to endure all historical outage events recorded at the Packwood substation. However, synthetic outage simulations for August reveal limitations, as the current microgrid configuration struggles to maintain critical services when the hydropower unit is offline due to the annual maintenance. This highlights the need for an enhanced BESS capacity to ensure reliability and support for residents during maintenance periods. Finally, a LCPUD-owned battery asset would solve the black start issue by essentially making sure that the plant never loses grid power, therefore removing the need for a black start procedure.

For EN, the hybridization of Packwood Hydro with BESS also presents substantial revenue growth opportunities. Using PNNL's advanced modeling tool, optimal dispatch strategies were developed, demonstrating the potential to increase EN's annual revenue from energy arbitrage by $1.2 million to $2.4 million — a 35% to over 50% improvement compared to recorded historical operations from years 2021 to 2023. The inclusion of PV and BESS for energy arbitrage further enhances revenue potential, contributing an additional $121,000 to $175,000 annually. Although the optimal dispatch strategy assumes perfect foresight for the entire year, the results underscore the significant value of operational optimization. In addition to maximizing economic benefits, the hydropower model incorporates mileage penalties to reduce the facility's ramping frequency, thereby addressing wear and tear concerns. This could effectively balance financial gains with operational durability, extending the lifespan of the hydropower facility and reducing maintenance costs.

CHAPTER 8

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Pacific Northwest National Laboratory

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99352
1-888-375-PNNL (7665)

www.pnnl.gov