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Context: HydroWIRES

In April 2019, the United States (U.S.) Department of Energy's (DOE's) Water Power Technologies Office launched the HydroWIRES initiative to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources as well as reliability and resiliency enhancements.

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. While increasing deployment of variable renewables such as wind and solar have enabled low-cost, clean energy in many regions in the United States, it also creates a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy, but also a source of large-scale flexibility and a force multiplier for other renewable power-generation sources. Realizing this potential requires innovation in several areas: incorporating new operations into planning and licensing decisions, predicting new operations and management patterns and costs to prevent unplanned outages, and designing new turbines and control systems for fast response and frequent ramping while maintaining high efficiency.

HydroWIRES is distinguished in its close engagement with the DOE national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio as well as broader DOE and national laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES initiative are designed to benefit hydropower owners and operators, independent system operators/regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

More information about HydroWIRES is available at https://energy.gov/hydrowires.

Executive Summary

In recent years, the heightened severity of wildfires has significantly increased the necessity for Public Safety Power Shutoff (PSPS) events. These events involve electric utilities preemptively de-energizing portions of power transmission and distribution systems to mitigate the risk of grid-caused fires. Particularly impacting regions like California and other parts of the Western Interconnection, the absence of power delivery during these events poses serious threats to lives, property, and disaster response efforts. As the wildfire threat continues to rise, exploring alternative solutions is crucial to ensure a continuous power supply.

The primary objective of this study is to assess the techno-economic viability of hydropower resources with supplementary investments, including microgrid controllers, storage solutions, load banks, additional generation like diesel generators, communication links, and transmission infrastructure. The aim is to enable these systems to operate autonomously (in islanded mode) and ensure grid resiliency during and after wildfire events. The project seeks to establish a comprehensive framework for setting up hydropower-based microgrids, from risk estimation to final investment decisions. These microgrids can provide critical support during emergencies and offer additional grid stability and revenue opportunities during regular operations and other system contingencies.

In this project, we developed a framework for wildfire resilience (herein referred to as WREST) to perform step-by-step analyses of wildfire impact on power systems and hydropower site characterization for designing resilient microgrids. The primary components of the wildfire resilience framework are as follows:

a. **Wildfire Threat and Impact on Power Systems**—Wildfire risk metrics are translated to power system contingencies, outages, and potential landed grid operations. The impact assessment uses historical and simulated future wildfire risk based on different climate conditions. Details about this modeling and approach are provided in the following chapter.

b. **Hydropower Site Characterization**—The feasibility of hydropower resources to operate in islanded mode following wildfire outages/PSPS events are analyzed—several metrics were identified to quantify the feasibility of hydropower for microgrid operations,

c. **Microgrid Design Specifications** —Based on the wildfire impact assessment and hydro site characterization, a list of use cases where hydro-based microgrids would be possible to set up is identified. Various metrics are also identified to evaluate the techno-economic performance of the identified hydro-based microgrid use cases.

d. **Impact Analyses**—We assess the performance of the hydro-based microgrids based on power systems performance as well as economic evaluation of investment decisions needed to satisfy the wildfire-related contingencies as well as normal grids operations.

The results of the WREST framework can be used to inform contingency studies that identify contingency violations, potential island formations, and load losses. We carried out an example contingency scenario where the top 10 most probable line outages were selected for a small region of WECC in the year 2030 using the Powerworld Simulator software. This scenario allowed us to determine the number of islands and number of line outages that led to the formation of a particular island, number of buses in the island, load (MW), existing generation and their types, and whether the island had a solved power flow. These results can identify load centers in proximity to existing generation and at risk of isolation due to wildfires, which can be identified as feasible case studies for microgrid investments. Furthermore, at-risk substations can be mapped back to 50 km grid cells using the geospatial visualization tool to estimate the vulnerability of impacted communities to loss of electric service and for informing the microgrid investment decision-making process.

Socioeconomic factors may also be considered when identifying potential sites for hydro-based microgrids. Here, we use available datasets to identify vulnerable populations at risk of wildfire-induced grid outages that have proximity to potential hydropower resources.

The report outlines a comprehensive framework for conducting a step-by-step techno-economic evaluation of hydropower-based microgrid solutions aimed at bolstering grid resilience during wildfire-induced transmission outages. This framework encompasses the development of a sophisticated tool capable of translating wildfire risk metrics into power system transmission outages, leveraging both historical data and predictive models to enhance accuracy and effectiveness. Additionally, a suite of metrics has been meticulously curated to assess the feasibility of hydropower resources operating in islanded mode following wildfire-related disruptions.

These foundational elements serve as the cornerstone for identifying and evaluating potential use cases for hydro-based microgrids within the context of grid resiliency. To further elucidate the applicability and efficacy of this approach, detailed techno-economic assessments were conducted at four distinct sites. The first two cases delved into the inherent grid capabilities of hydropower resources, shedding light on their potential to mitigate transmission outages during wildfire events. Conversely, the latter two cases scrutinized the techno-economic ramifications of deploying hydro-based microgrids, necessitating additional investments to justify their implementation under normal operating conditions.

Amidst escalating occurrences of extreme weather phenomena such as heatwaves and wildfires, this study presents a pioneering concept: the integration of hydro-based microgrids as a means of furnishing grid resiliency to customers, particularly critical infrastructure facilities. Looking ahead, a forward-looking agenda aimed at exploring the feasibility of mobile microgrid operations utilizing shared resources and equipment, which will be explored in a future study. This innovative approach holds promise in facilitating rapid deployment to targeted sites based on wildfire propagation patterns and prediction modeling, thereby augmenting the adaptability and efficacy of microgrid systems in response to evolving wildfire scenarios.

In summary, this report represents a significant advancement in the realm of grid resiliency and disaster preparedness, offering a comprehensive framework and toolset for evaluating the viability and potential impact of hydropower-based microgrid solutions in mitigating the adverse effects of wildfire-induced transmission outages. Through continued exploration and innovation, these findings hold the promise of fostering greater resilience and reliability within our energy infrastructure amidst an increasingly volatile environmental landscape.

Acronyms and Abbreviations

BESS	Battery Energy Storage System
CCSM4	Community Climate System Model 4
CDC	Centers For Disease Control and Prevention’s
CIESIN	Center For International Earth Science Information Network
CMIP5	Coupled Model Inter-Comparison Project 5
EMS	Energy Management System
ERC	Energy Release Component
FERC	Federal Energy Regulatory Commission
FOD	Fire Occurrence Dataset
GDP	Gross Domestic Product
HRD	Hydropower Resilience Database
INL	Idaho National Laboratory
LCOE	Levelized Cost of Energy
MACA	Multivariate Adapted Constructed Analogs
MVA	Megavolt-Amperes
MW	Megawatt
MWh	Megawatt-Hour
NASA	National Aeronautics and Space Administration
NERC	North American Electric Reliability Corporation
NFDRS	National Fire Danger Rating System
NID	National Inventory of Dams
NOAA	National Oceanic and Atmospheric Administration
ORNL	Oak Ridge National Laboratory
PNNL	Pacific Northwest National Laboratory
PSPS	Public Safety Power Shutoff
PSSE	Power System Simulation for Engineering
PV	Photovoltaic
RCP	Representative Concentration Pathway
SOC	State Of Charge
SVI	Social Vulnerability Index
USACE	US Army Corps of Engineers
USGS	United States Geological Survey
WECC	Western Electrical Coordinating Council
WI	Western Interconnection

WREST	Wildfires Risk Evaluation of The System
WPTO	Water Power Technologies Office

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1 Introduction

In recent years, the heightened severity of wildfires has significantly increased the necessity for Public Safety Power Shutoff (PSPS) events. These events involve electric utilities preemptively de-energizing portions of power transmission and distribution systems to mitigate the risk of grid-caused fires. Particularly impacting regions like California and other parts of the Western Interconnection (WI), the absence of power delivery during these events poses serious threats to lives, property, and disaster response efforts. As the wildfire threat continues to rise, it's crucial to explore alternative solutions to ensure a continuous power supply.

Distributed energy resources, such as hydropower in Northern California and the Pacific Northwest region, offer a promising avenue for reliably serving electricity consumers during wildfire events in vulnerable regions susceptible to power shutdowns from PSPS. Leveraging existing hydropower generation in microgrid setups could potentially outperform other alternatives like burying transmission lines or implementing fireproofing strategies, both in terms of effectiveness and cost-efficiency. Moreover, the additional electricity market revenues generated by these microgrids during normal operations could alleviate the financial burdens associated with necessary upgrades. The overall modeling approach is depicted in Figure 1-1, showing the flow of information. The input datasets are processed by the WREST framework and visualization tool to evaluate probabilities of transmission line outages.

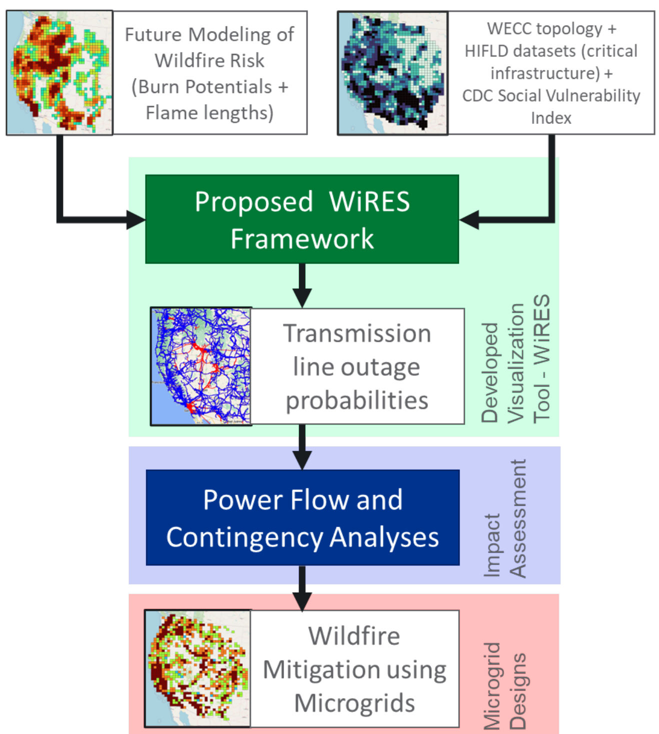


Figure 1-1: The main components of the hydropower based microgrid wildfire resiliency project.

The primary objective of this study is to assess the techno-economic viability of hydropower resources with supplementary investments, including microgrid controllers, storage solutions, load banks, additional generation like diesel generators, communication links, and transmission infrastructure. The aim is to enable these systems to operate autonomously (in islanded mode) and ensure grid resiliency during and after wildfire events. The project seeks to establish a comprehensive framework for setting up hydropower-based microgrids, from risk estimation to final investment decisions. These microgrids can provide critical support during emergencies and offer additional grid stability and revenue opportunities during regular operations and other system contingencies.

In this project, we developed a framework for wildfire resilience to perform step-by-step analyses of wildfire impact on power systems and hydropower site characterization for designing resilient microgrids. Figure 1-2 show the overarching architecture of the wildfire resilience framework. The primary components of the wildfire resilience framework are as follows:

a. **Wildfire Threat and Impact on Power Systems**—Wildfire risk metrics are translated to power system contingencies, outages, and potential landed grid operations. The impact assessment uses historical and simulated future wildfire risk based on different climate conditions. Details about this modeling and approach are provided in the following chapter.

b. **Hydropower Site Characterization**—The feasibility of hydropower resources to operate in islanded mode following wildfire outages/PSPS events are analyzed—several metrics were identified to quantify the feasibility of hydropower for microgrid operations,

c. **Microgrid Design Specifications**—Based on the wildfire impact assessment and hydro site characterization, a list of use cases where hydro-based microgrids would be possible to set up is identified. Various metrics are also identified to evaluate the techno-economic performance of the identified hydro-based microgrid use cases.

d. **Impact Analyses**—We assess the performance of the hydro-based microgrids based on power systems performance as well as economic evaluation of investment decisions needed to satisfy the wildfire-related contingencies as well as normal grids operations.

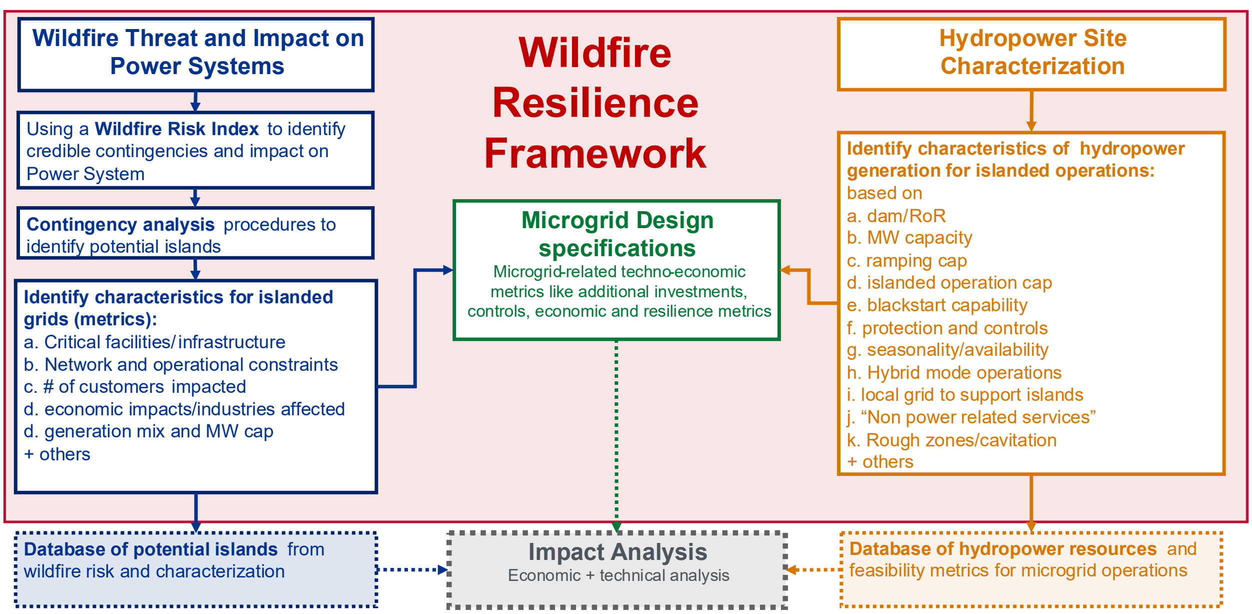


Figure 1-2: The wildfire resilience framework using hydropower-based microgrids.

Hydropower plants play a crucial role in responding to extreme grid events, owing to their agility to change their power generation. Besides supporting the real power needs of the grid, they are well suited to provide voltage response and reactive power support, inertial response, primary frequency response, and spinning reserve. Leveraging the energy stored in the form of water stored behind the dam or in the reservoir, they can provide electricity to critical loads during long grid outages. Hydropower plants are also an excellent resource for black start restoration.

Despite their effectiveness during extreme events, they are highly dependent on the availability of water resources. The drier and drought conditions, when wildfires are most prominent, also constrain the ability of hydropower plants to produce power. The possibility of using hydropower resources in microgrids could be affected by various factors including plant design and physical attributes, hydrology, regulatory requirements with water bodies and electrical grids as well as existing contractual obligations with relevant utilities and consumer bodies. It is important to analyze all these attributes of a hydropower plant before deciding on deploying them in microgrids.

Therefore, as a part of this project, we developed a framework to characterize hydropower plants to understand their suitability in operating in microgrids. As a part of this framework, the hydropower resilience database (HRD) is developed collecting information from various existing resources. A set of metrics are proposed to analyze the ability of hydropower plants to support essential microgrid functions. The hydropower characterization framework and hydropower resilience database are discussed in detail in our previous publications (Poudel et al., 2023, Gautam et al., 2023). In this report, we provide an overview of the developed framework and database and show impact assessment studies using these resources to evaluate the role of several use case wildfire-resilient microgrids built with hydropower plants as a source of resilience during wildfire outages.

2 Wildfire Threat and Impact on Power Systems

As part of the study presented in this report, we acquired and summarized a suite of available geospatial data layers to characterize the study's socioeconomic and biophysical properties. To standardize data across spatial resolutions and data types, we also established a regular 50 km x 50 km grid over the Western Electrical Coordinating Council (WECC) region and extracted data metrics for each grid cell. Data include information on critical infrastructure from the U.S. Department of Homeland Security's Homeland Infrastructure Foundation Level Data[1], information on existing hydropower and non-powered dams[2], current (2020) wildfire risks from the U.S. Forest Service[3], information on population[4], social vulnerability[5] and economic output[6]. A full list of data features and their respective sources are provided in Table 2-1.

Table 2-1: Summary of socioeconomic and biophysical datasets used in WREST.

Dataset	Description/Metric
Hospitals	Count
EMS Stations	Count
Law Enforcement Stations	Count
Social Vulnerability Index	Mean value
Wildfire Burn Potential	Mean, maximum, and minimum
Wildfire Flame Length Probability	Max. probability by height class
Population	Count and density
Transmission Lines	Total megawatt flow and count
Transmission Line Length - AC	Length of lines within cell (total and by voltage class)
Transmission lines length - DC	Length of lines within cell (total)
Substations	Count (total and by voltage class)
Hydropower Dams	Count and Total Discharge
Non-powered Dam Potential	Count and Total Hydraulic Head
Gross Domestic Product	Areal-weighted county GDP, 2019
Net Load	Net load, 2030
2030 WECC Planning Case	Power system model

The input datasets are processed by a performance-based risk evaluation framework (Chalishazar et al 2023). The framework translates probabilities of wildfire severity and chance of ignition for a given 50 km by 50 km grid cell in the WECC region into a risk of outage for a transmission line overlapping that cell using a Bayesian network. The outage risk calculations can be used to select high-risk transmission lines for contingency analyses.

[1] https://hifld-geoplatform.opendata.arcgis.com/
[2] https://nid.sec.usace.army.mil/#/
[3] https://www.fs.usda.gov/rds/archive/Catalog/RDS-2016-0034-2
[4] https://beta.sedac.ciesin.columbia.edu/data/set/gpw-v4-data-quality-indicators
[5] https://www.atsdr.cdc.gov/placeandhealth/svi/index.html
[6] https://www.bea.gov/data/gdp/gdp-county-metro-and-other-areas

2.1 Future Wildfire Risk Assessment

Wildfire risk can be summarized using historical data. However, the factors contributing to risk vary year-to-year, and the distribution of high-risk areas may trend differently in the future. Wildfire risk is largely driven by topography, fuel type and abundance, ignition sources, and climate conditions. Topography is mostly static, comprised of geological features like slope, elevation, and aspect. Fuel type and abundance changes are complex and tied to climate and forest management and policy decisions. Ignitions sources are not well studied and dependent on human and biophysical factors (Chen and Jin, 2022), which are uncertain in the future. Our work focuses on changes in climate and the resulting impacts to risk that may be possible. Future climate is commonly modeled using representative concentration pathways (RCPs), a set of scenarios that represent increases in radiative forcing (van Vuuren et al., 2011).

We focused on climate for future wildfire risk estimation targeting the year 2060. We used the Community Climate System Model 4 (CCSM4) (Gent et al., 2011) which followed the Coupled Model Inter-Comparison Project 5 (CMIP5) protocol (Taylor et al., 2012), with spatial downscaling by the Multivariate Adapted Constructed Analogs (MACA) method (Abatzoglou et al., 2012) to 1/12th of a degree (4 km at the equator). The Representative Concentration Pathway (RCP) scenarios representing 4.5 and 8.5 W/m^2 increases in radiative forcing compared to pre-industrial levels, RCP4.5 and RCP8.5, were selected to represent stabilization, leading to moderate forcing, and high emissions without intervention, leading to high forcing, respectively (van Vuuren et al., 2011).

The energy release component (ERC) is an index that represents the available energy per unit area within the flaming front at the head of a fire (NFDRS, 2023) and high ERC values are associated with increased large fire (>100 acre) risk. The daily area-weighted mean of ERC values per 50-km grid was calculated using CCSM4 data. We then used a historical fire occurrence dataset (FOD) (Short, 2022) and 4 km gridded historical meteorology, gridMET (Abatzoglou, 2013), to produce a logistic function relating the daily ERC value to the chance of a large fire ignition per 50-km grid. The CCSM4 data was split into two periods for each RCP scenario. The baseline period was 1950–2005 and future period was 2045–2075, meant to represent 2060 conditions. We averaged each period over the day of year, then took the day which had the maximum of a 45-day rolling average ERC value to represent the day of peak wildfire season. The peak-season ERC value was input to the logistic function to represent the average risk of a large wildfire igniting within a 50-km grid cell on the day of peak wildfire risk for each period.

Figure 2-1 shows the results of the future wildfire risk analysis. Historically, large wildfires have the highest frequency in the Central Valley and Greater Los Angeles in California, southern Idaho, and the eastern Cascades of Washington and northern Oregon (Figure 2-1d). The RCP 4.5 and 8.5 scenarios both show a modest increase in the risk of a large-fire ignition at peak wildfire season (10–50%) in the Rocky Mountain region of Utah and Wyoming, and the Cascades in northern Oregon. The greatest increase in risk (50–203%) was in the northwestern Rocky Mountain region of Montana and Idaho, and the northern Cascades in Washington (Figure 2-1a and Figure 2-1b). Comparing the RCP 8.5 to the RCP 4.5 scenario risk, there is lesser risk in the Basin and Range region of central and northern Nevada (-10–22%), while the Rocky Mountain region of northern Idaho and the Great Plains region of northern Montana have a modest increase in risk (10–39%) (Figure 2-1c). Our future wildfire risk results represent a single realization of future climate, and thus, are not in any way a forecast. However, we show that future climate may result in shifts in wildfire risk, including areas that were relatively lower risk historically.

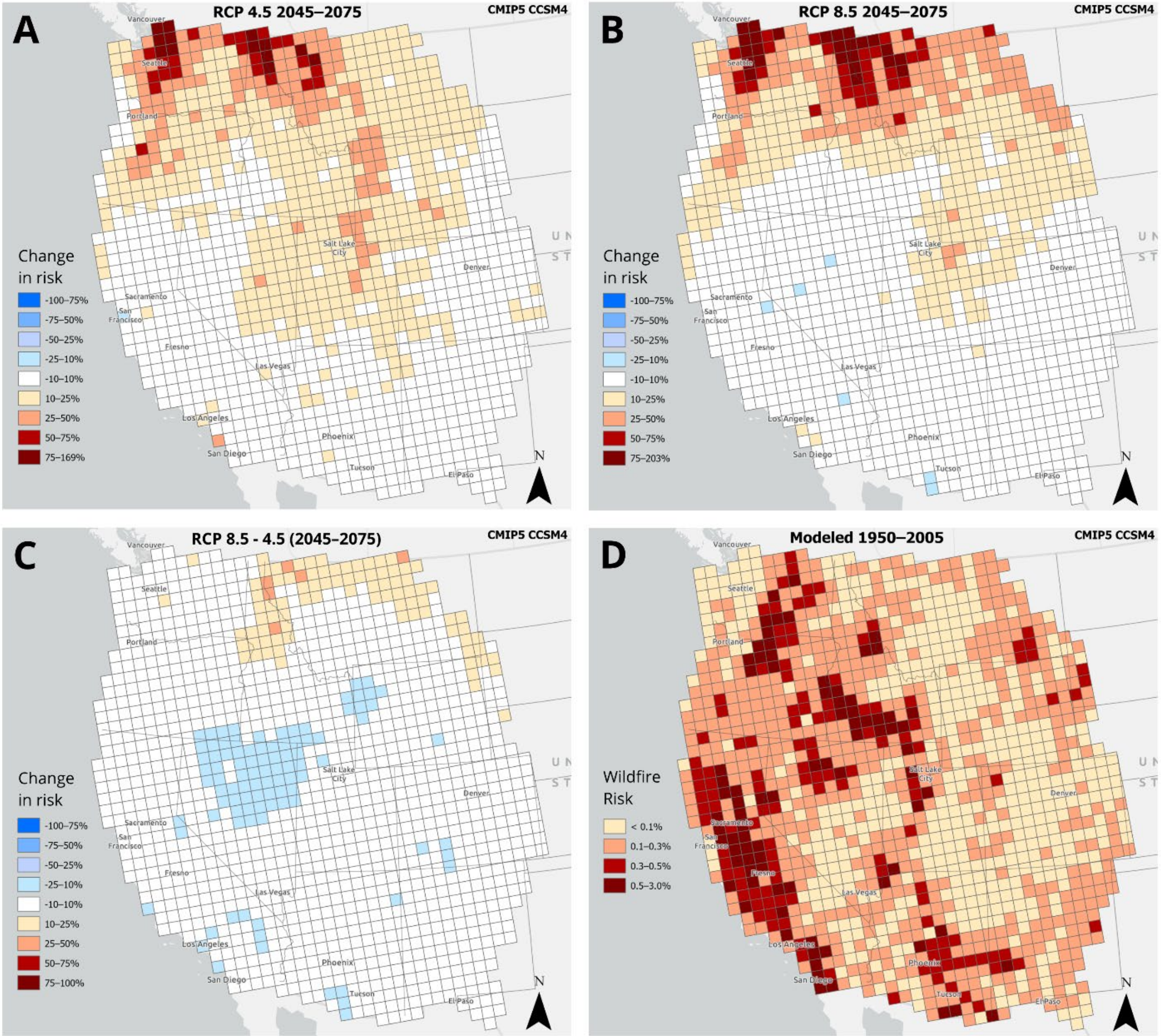


Figure 2-1: A comparison in modeled wildfire risk, represented by the average chance of a large wildfire ignition on the day of peak wildfire season, using CCSM4 data. (A) The change in risk comparing 2045–2075 to 1950–2005 using the Representative Concentration Pathway (RCP) 4.5 scenario. (B) The change in risk comparing 2045–2075 to 1950–2005 using the RCP8.5 scenario. (C) The change in risk for 2045–2075 comparing RCP8.5 to RCP4.5. (D) The modeled risk for the baseline period, 1950–2005.

2.1.1 Performance-based Tool

Geospatial data layers, including information on critical infrastructure, current wildfire risks, population, social vulnerability, and economic output were summarized over 50km x 50km grid cells across the Western Electrical Coordinating Council (WECC) region. The input datasets are processed by the WREST framework and visualization tool to evaluate probabilities of transmission line outages. WREST uses a four-step deductive process including wildfire severity, response, damage, and loss (Figure 2-2) to evaluate the probability of outage due to wildfire or PSPS for every transmission line in the WECC region. These line loss probabilities inform the development of probable line outage scenarios, which are then analyzed using power flow and contingency analysis tools to assess the impact on the grid.

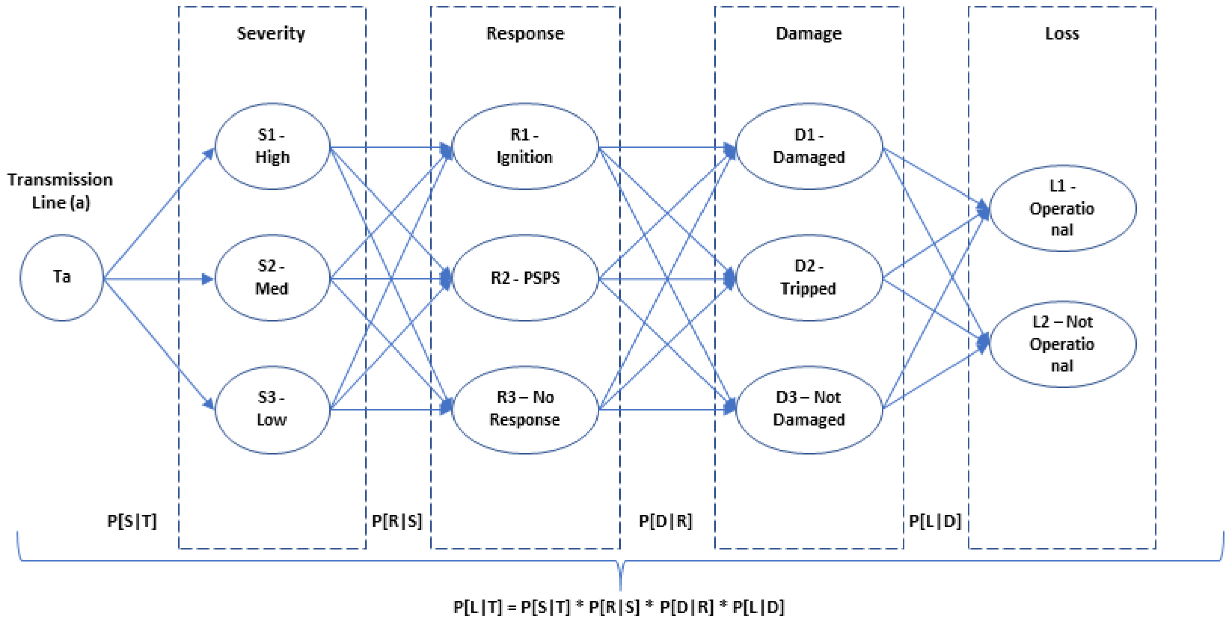


Figure 2-2: Graphical representation of the four-step deductive process of the WREST framework.

The nodes in Figure 2-2 illustrate the independent events possible at each risk modeling stage, and P[L|T] is the composite probability of a transmission line loss. The nodes are connected by conditional probabilities indicating the likelihood of the event in the current layer if the event in the prior layer occurred. Some conditional probabilities would be based on statistical data that may be difficult to obtain, such as the frequency of PSPS occurring for lines in a grid cell where a fire occurs. In this case, intuitive assumptions are made, such as the assumption that if fire ignition in a grid cell occurs, then a line in that grid cell will be damaged or tripped.

The WREST framework (Figure 2-3) is used to produce the transmission line layers for the visualization tool in a multi-step process.

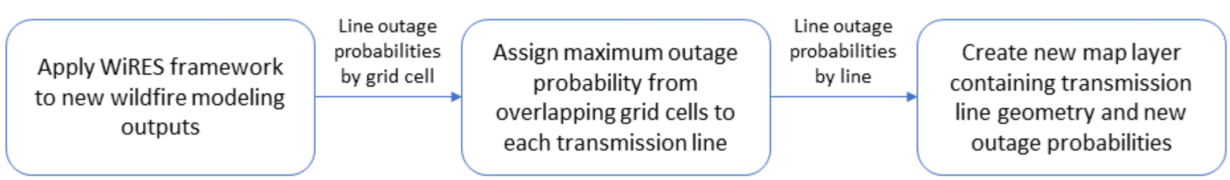


Figure 2-3: Multi-step process to create new transmission line layers.

The following section discusses the development of the visualization tool, which integrates the transmission line data from the performance-based tool as well as additional geospatial data to produce inputs to wildfire impact analyses.

2.2 WREST Framework and Visualization Tool

We built an interactive tool to enable the dynamic exploration of nonoperational lines resulting from wildfire and associated risks (Figure 2-4). This tool allows users to adjust the threshold for outage probabilities calculated using the methods outlined above. Lines that exceed the threshold are determined to be high risk by considering that a fire in one part of a line would render the full line nonoperational. This allows users to visually identify potential islands or areas where capacity of the electric service may be dramatically reduced due to a fire occurrence. Users can then assess the implications of power loss in different regions based on the biophysical and socioeconomic properties of the selected grid cell.

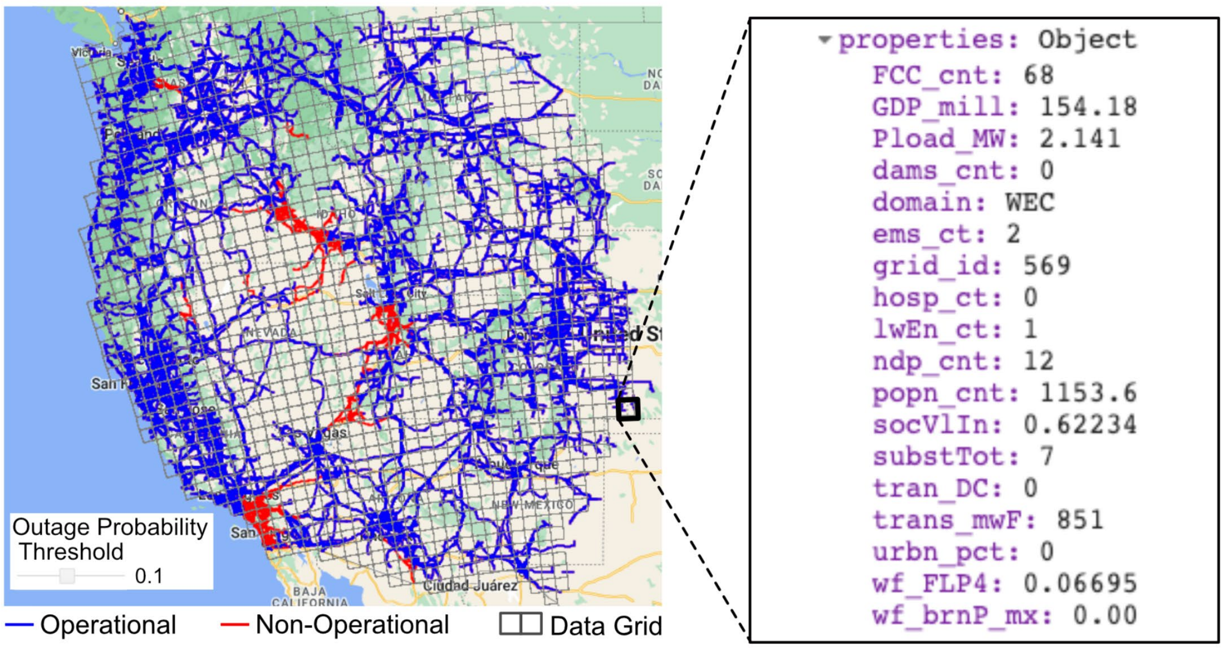


Figure 2-4: Demonstration of the initial version of the interactive visualization tool. Users can adjust the outage probability threshold, which sets all lines with outage probabilities above the specified threshold to nonoperational status.

A later iteration of the tool was development in the Python programming language using an open-source platform for developing web-based data applications (Figure 2-5). The platform enabled several features, which helped facilitate user interactions including:

- Filtering transmission lines by owner, risk level, and other attributes.
- Hovering and clicking on map features (including grid cells, lines, and dams) to obtain key attributes.
- Exporting attributes of high-risk lines in CSV as well as other formats compatible with Powerworld and Siemens PSSE.
- Exporting attributes of grid cells and dams co-located with high-risk lines.
- Comparison of line outage risk produced by analysis of historic and future (predicted) fire occurrence data.

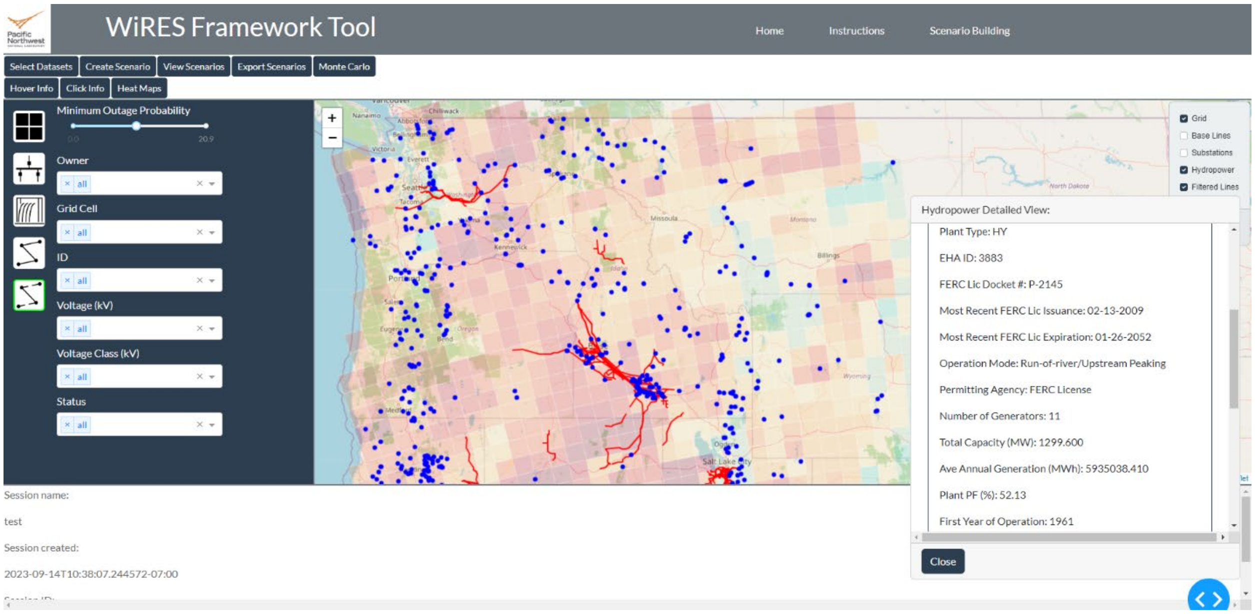


Figure 2-5: Main view of the latest version of the interactive tool. Transmission line filters are available on the left. Users can see location of lines and dams on the map pane in the center. Feature property pop-ups display on the right.

These features allow efficient generation of inputs to more in-depth impact analyses, including specific line outage scenarios for contingency analysis. Furthermore, dams that reside in grids with high SVI and are near high-risk lines can be identified as candidates for hydro-based microgrids.

The tool integrates the historical and future wildfire modeling outputs by making multiple transmission line datasets available to view simultaneously. Each dataset contains outage probabilities derived from different wildfire modeling time frames (historical and future) and climate projections (RCP 4.5 and RCP 8.5).

2.3 Summary and Key Takeaways

The results of the WREST framework can be used to inform contingency studies that identify contingency violations, potential island formations, and load losses. We carried out an example contingency scenario where the top 10 most probable line outages were selected for a small region of WECC in the year 2030 using the Powerworld Simulator software. This scenario allowed us to determine the number of islands and number of line outages that led to the formation of a particular island, number of buses in the island, load (MW), existing generation and their types, and whether the island had a solved power flow. These results can identify load centers in proximity to existing generation and at risk of isolation due to wildfires, which can be identified as feasible case studies for microgrid investments. Furthermore, at-risk substations can be mapped back to 50 km grid cells using the geospatial visualization tool to estimate the vulnerability of impacted communities to loss of electric service and for informing the microgrid investment decision-making process.

3 Hydropower Characterization

3.1 Hydropower Characterization Framework

Hydropower's capabilities to provide valued grid services, and the factors influencing how these capabilities can vary unit-to-unit and plant-to-plant and can be qualitatively and quantitatively different. Therefore, it is important to understand the attributes of each hydropower plant prior to making decisions on building microgrid structure using them.

The physical designs of hydropower plants influence their ability to provide ancillary services like black start, regulation reserve, and spinning reserve. Despite constituting only 10% of overall US generating capacity, hydropower plants contribute to 40% of units providing black start. Their flexibility is vital for microgrid operations, especially considering the low inertia of microgrid systems. The physical characteristics, turbine types, and availability of flexible controls are crucial factors for evaluating their suitability.

Hydropower plants play a critical role in supporting grid services, potentially limiting their focus on building microgrids for nearby communities. Market priorities and profitability considerations, especially for privately owned plants, might lead them to participate in grid markets rather than prioritizing microgrid support.

Hydropower plants often operate in a cascaded series within the same river basin, where the flow to plants in upper reservoirs directly affects those in lower reservoirs. Understanding this cascading impact is essential for managing the overall efficiency and performance of hydropower resources in a river basin. At the same time, the same water body may also be providing non-power services like flood control or irrigation. Water requirements for upstream and downstream users e.g., agricultural, recreational, environmental, and other needs impact mandatory flow requirements from dams in addition to habitats the water body may be supporting. It is important to understand how the non-power and environmental aspects are impacted when hydropower plants operate in microgrids.

How much water and when it is available directly impacts the power generation of hydropower plants. In some seasons, hydropower plants may have to deal with floods while in some others drought. Drought has impact on annual hydropower generation, for example a positive correlation between annual generation and annual precipitation has been observed (Turner et al., 2022). But such correlation is not concurrent across the Western US hydro fleet, thanks to the diversity of weather conditions. Frequency of hydropower generation curtailment due to drought conditions is lower in the spring season (mostly due to the reservoir refill from snowmelt). A monthly wildfire risk profile overlaid with drought driven hydropower generation curtailment frequency can thus inform on available generation capacity from a hydropower for microgrid formation during wildfire. It is important to consider drought characteristics in addition to precipitation and streamflow profiles for sustainable hydro-based microgrids amidst evolving operating conditions.

These aspects of hydropower plants, ranging from physical characteristics to hydrological to environmental considerations, collectively shape the role and challenges faced by hydropower plants, providing a comprehensive view for informed decision-making in areas such as microgrid planning and resilience strategies. As a first step of the hydropower characterization framework, we assemble and analyze various technical and regulatory attributes of hydropower plants relevant to microgrid operation. The datasets collected are summarized in Table 3-1 along with the reference to datasource. The hydropower resilience database (HRD) developed in this project is explained in detail in Section 3.2.

Table 3-1: Datasets collected to build hydropower resilience database to evaluate hydropower plant characteristics relevant to resilient microgrid operation. Most of these are obtained from publicly available resources including Hydrosource database developed by Oak Ridge National Laboratory (ORNL), and National Inventory of Dams (NID) by United States Army Corps of Engineers (USACE). The power plant and grid information are sourced from stability cases of Western Regional Coordinating Council (WECC) system.

Characteristics	Datasets	Datasource
Physical and Design	(a) Plant size and location, (b) electrical characteristics (generator power & energy ratings, capability curve, and excitation system), (c) mechanical characteristics (rotating mass inertia and damping, (d) control characteristics (servomotor response time, actuation delay, controller gains and ramping limits) (e) reservoir size and design, and (f) turbine type.	ORNL Hydrosource, NID, WECC Stability Case
Operational	(a) Hydrological characteristics (water head level, water inflow and outflow, and drought characteristics), (b) mode of operation (e.g., run-of-the-river, baseload, peaking, or cascaded hydro operation unit), and (c) non-power applications (e.g., flood control, irrigation, drinking water, and recreational activities).	ORNL Hydrosource, NID
Development Stage	(a) Status (Operating, planned, under construction or under maintenance), (b) License (e.g., Reclamation, FERC license, USACE)	ORNL Hydrosource
Stakeholders	(a) Plant ownership, (b) dam ownership, (c) utility entity, (d) transmission ownership, and (e) prospective microgrid load centre	ORNL Hydrosource, NID, WREST
Environmental	Endangered species	NID, NOAA Fisheries
Market and Regulatory	(a) NERC region, (b) balancing authority, and (b) water regulatory	ORNL Hydrosource, NID, WECC Stability Case

Now, to evaluate hydropower plants for building wildfire-resilient microgrids, these characteristics need to be translated into quantitative metrics. Therefore, in the second step, we introduce a set of nine metrics that determine the suitability and performance of hydropower plants for microgrid operation. Among these, the first metric (i.e., microgrid formation) serves as an initial technical and regulatory screening to identify if a hydropower plant is suitable for a microgrid. This first metric helps in quick screening of hydropower plants most suitable for wildfire-resilient microgrids across the US. The next four metrics—reactive power, inertial response, ramping capability, and storage capacity—are quantified plant capabilities necessary for microgrid operation. These metrics provide understanding of the strengths and weaknesses of each hydropower facility to provide specific microgrid functions. The last four metrics—seamless islanding, seamless reconnection, black start, and sustained operation—are performance metrics that are dependent on the previous four capability metrics. These metrics are quantified through power system evaluation of hydropower plants under potential microgrid configuration. The dependency of these metrics on different characteristics and their relevance in different stages during wildfire resilience events is shown in Figure 3-1.

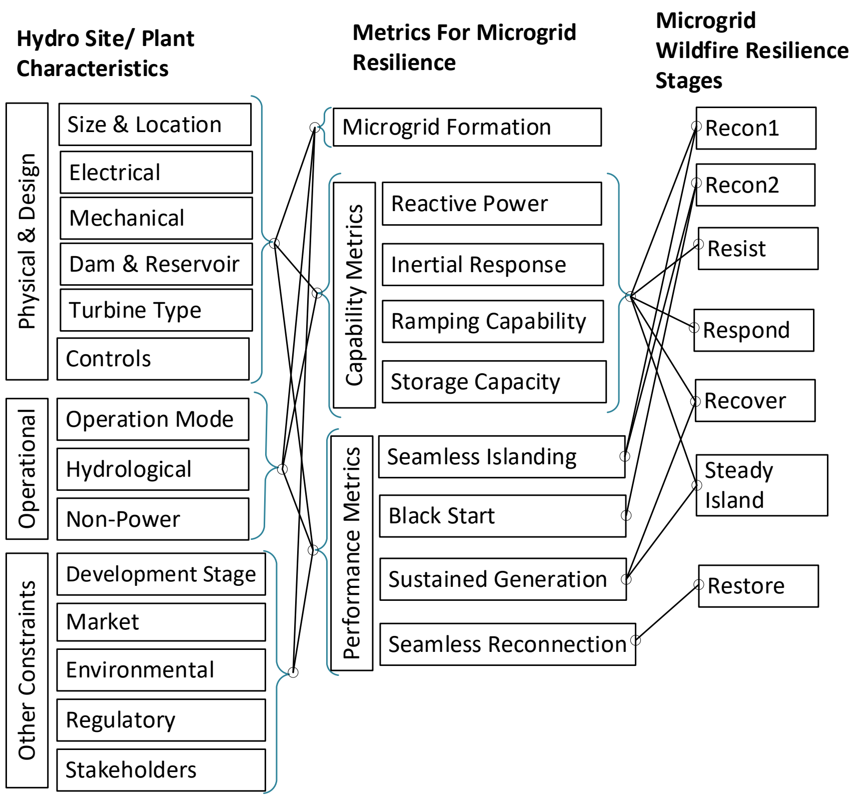


Figure 3-1: The hydropower characterization framework showing the translation of hydropower plant characteristics into the nine microgrid evaluation metrics and their relevance to different wildfire resilience epochs.

Each evaluation metric is described below.

1. **Microgrid Formation:** This metric provides the initial qualitative screening of hydropower plants in terms of their suitability for building wildfire resilient microgrids based on technical and regulatory constraints. In microgrids, hydropower assets will operate prioritizing energy and resilience needs of local community which may not be financially attractive for the asset owners. This may require non-optimal operation of hydropower plants from an economic point of view to maintain dynamic and long-term flexibility reserves in favor of meeting resilience requirements of local loads for any potential events. Existing contractual obligations of hydropower assets with transmission owner and the utility may pose barriers even if hydropower plants are well placed to build wildfire resilient microgrids. The size of hydropower facility is an important factor to consider alongside the number of units and the operating type. Large hydropower plants are not typically suited for wildfire resilient microgrids which are mostly smaller islands formed due to wildfires. Having multiple units in a single plant will support the operational resiliency and economic operation and to maintain the resilience reserve when wildfire occurrence is most probable. In microgrid operations, hydropower plants are required to provide operational flexibility. Therefore, peaking plants with experience and control setups for flexibility service are more favorable than the baseload plants. Hydropower plants with storage and impoundment are more suitable than run-of-river or the canal/conduit systems.

2. **Reactive Power:** Reactive power capability is dependent on the generator electrical characteristics including the type of excitation system and generator capability curve rather than the plant site characteristics. Reactive power is essential to maintain microgrid voltage at a standard level and to provide electricity flow to end users. In grid connected mode, hydropower plants are typically required to provide reactive power to maintain the voltage at their terminal. Reactive power can be controlled more quickly than active power using an excitation system driving the magnetic field of the generator. Therefore, the operational planning in the recon (reconnection) stages is not as stringent as active power. However, there should be sufficient reactive power reserve to maintain voltage performance in islanded operations. If the reactive power from hydropower resource is not sufficient, additional reactive compensation devices should be installed in planning stages. Hydropower plants are known to have significant reactive power capability that helps maintain voltage stability during extreme events. Hydropower's ability to provide reactive power is like other conventional generation resources. However, conventional resources, especially baseload steam turbines (coal) and nuclear plants, operate close to their rated power capacities, which leaves little room to provide reactive power. Hydropower resources (and natural gas-fired plants) generally operate at less than full capacity, which allows them to provide more reactive power support when needed. Simulation results for the Western Interconnection show that hydropower units are a major source of reactive power support under all seasonal, loading, and water availability conditions.

3. **Inertial Response:** The conventional synchronous generators inherently provide inertia due to rotating mass whereas the inverter-based resources can also emulate the inertial response by fast control of their power, commonly known as synthetic inertia (Denholm et al., 2020). The inertial capability of a power generator is represented with inertia constants which represents the stored rotational energy per unit of the capacity of power plant. The inertial response is an important capability to arrest frequency excursions and overshoot immediately following the disturbance to maintain dynamic stability of the microgrids. In islanded microgrid operation before the restoration, the microgrid is more vulnerable to voltage and frequency disturbances as there are few resources to provide inertial response. Hydropower plants typically have lower rotational inertia than other thermal plants including combustion turbines, combined cycle plants, gas turbine, coal-fired plants, and nuclear power plants. Typically run-of-the-river and hydro with reservoir have inertia, whereas in pumped storage hydro it depends on the technology applied to the system. If in case the inertial response of hydropower plant is not sufficient, it could be enhanced by adding synchronous condensers, synchronous renewable energy or inverter based synthetic inertia.

4. **Ramping Capability:** Immediately following islanding, the hydropower plant may need go through large operational ramps to adjust to new load condition. In microgrid operation, it will have to respond to local disturbances that can breach the regulations and specified voltage and frequency constraints. Ramping operations are necessary during start-up, shutdown and any other power output changes and can be driven by open-loop or closed-loop governor controls. Ramping capability is essential for both primary and secondary control and is one of the primary factors in deciding the frequency response of the system alongside inertia. Large frequency excursions and overshooting can occur if the ramping capability is not adequate leading to under-frequency load shedding and over-frequency generation and load trips. Besides control and valve actuation delays of hydro governors, the power ramping of hydropower plant is constrained by the flow ramping capability affected by many factors including river geomorphology, river users, types of aquatic life present, differences in ramping up versus ramping down, river lag time, natural flow attenuation, flow regime, and natural flow changes (Knight Piésold Consulting, 2005). The turbine type also has an impact on ramping

capability (Hell, 2017). Abrupt operation of turbine valve can create large pressure change which can exceed the pipeline's structural capability to withstand pressure differential. These pressure changes, which are known as hydraulic transients or "waterhammer", are directly proportional to the speed of closure of the valve and the corresponding change in flow rate (Knight Piésold Consulting, 2005). If flow is stopped too quickly, the resulting waterhammer pressure can exceed the design strength of the penstock material and burst the pipe. Ramping can also biologically impact the aquatic ecosystem. For example, excessive up-ramping rates can lead to riverbed scouring and depositing at gravel and sand bars, where eggs and alevins are present. Juvenile fish can also be physically flushed downstream due to increased flow velocities. Despite this constraint, the maximum permissible rate of closure from an engineering design perspective is typically much faster than the ramping rates tolerated by the aquatic resources and recreation users of a creek.

5. **Storage Capacity:** Having energy storage capacity is important in providing resilient power to microgrid during wildfire outages. The storage capacity is most relevant during long-duration outages. In normal grid-connected operation, the operating decisions should also consider the level of water (energy stored) to ensure energy availability during outages. Based on the predicted probability of occurrence wildfire occurrence at a given time, proactive decisions can be made to reduce the water uses in electricity generation (while still grid-connected) or other non-power usage to maintain the sufficient level of water in dams or reservoirs. For pumped storage hydro, proactive decisions can be made to pump water to the upper reservoir to maintain adequate storage capacity. In islanded operation, the stored energy needs to be optimally utilized to meet critical demand. This requires optimization of operation prioritizing the critical loads and curtailing non-critical loads considering potential uncertainty and delays in grid restoration.

6. **Seamless Transition (Islanding and Reconnection):** In this discussion we merge both seamless islanding and reconnection as seamless transition. The capability to seamlessly transition between islanded and grid connected mode is an important attribute for microgrids. In seamless transition, microgrid connect and disconnect from a larger grid accomplished without resulting in voltage and frequency transients that exceed the standard requirements. The islanding can be planned and unplanned, whereas the reconnection is always planned. In planned islanding, the microgrid typically has time to identify the control sequence and new operational setpoints to execute efficient transition. If wildfire events are initiated outside the grid or far from the microgrid, there is typically some time to make decision for microgrid transition. Based on the prediction of wildfire propagation, microgrid may make proactive decisions to isolate themselves from the grid in favor of improving resilience to local communities. In case of unplanned islanding, the microgrid or the distribution system is disconnected from the rest of the transmission system due to automatic activation of switchgear devices or due to wildfire-related transmission outages. This happens if wildfire originates from the transmission line connecting microgrid to the rest of the system or if the preemptive transmission switching as a part of PSPS strategy switching isolates the microgrid from the grid. Planned transitions are mostly seamless and effectively unnoticeable from the perspective of loads. In the case of planned seamless transition, power system voltage and frequency may fluctuate briefly, but outages are typically avoided.

7. **Black Start:** Hydropower plants require low energy for self-starting. Readily available conversion of stored energy and low station power requirements make them well-suited for black start restoration of a microgrid. Black start using hydropower plants would require understanding of their inertial and ramping capabilities to understand the load stepping that can be done to design the cranking path. The

low inertia means the large load step may lead to excessive frequency excursion in a plant. Batteries or supercapacitors can support hydropower plants for black start.

8. **Sustained Operation:** Sustained operation measures the ability of hydropower plants to support critical loads during long outages. The hydropower plant will need to manage its water resource over a long duration, as well as provide primary response to frequency and voltage disturbances that could arise. Storage capacity is one of the crucial capabilities for sustained operation. Hydropower plants also need strategies to prioritize loads and execute load shedding strategies evaluating potential generation capacity considering the water inflow and stored as well as predicting scenarios ahead of time. Effective energy management strategies are crucial for microgrids.

3.2 Hydropower Resilience Database and Visualization

The HRD integrates data from ORNL HydroSource, NID by the US Army Corps of Engineers (USACE), and the US Western Grid Stability Base Cases. ORNL HydroSource includes information about hydropower projects including the size of the facility, location, number of units, owners and regulatory bodies and operating type. NID provides extensive information about dams including dam size and dimensions, and primary and secondary purposes supported by the dam. These two resources lack specific details crucial for microgrid operations, such as generator electrical and mechanical parameters of hydropower plants and grid interconnection specifics which are available in the US Western Grid Stability Base Cases. Combining these databases into the HRD offers a holistic view of hydropower plants' characteristics, to evaluate potential hydro-based resilient microgrids to support affected communities during extreme events like wildfires.

In this project, we primarily focused on four wildfire-prone states in the US: California, Oregon, Washington, and Idaho. We analyzed 740 hydropower plants across these states. Figure 3-2 depicts the distribution of these plants in terms of size, number of units, and operational mode.

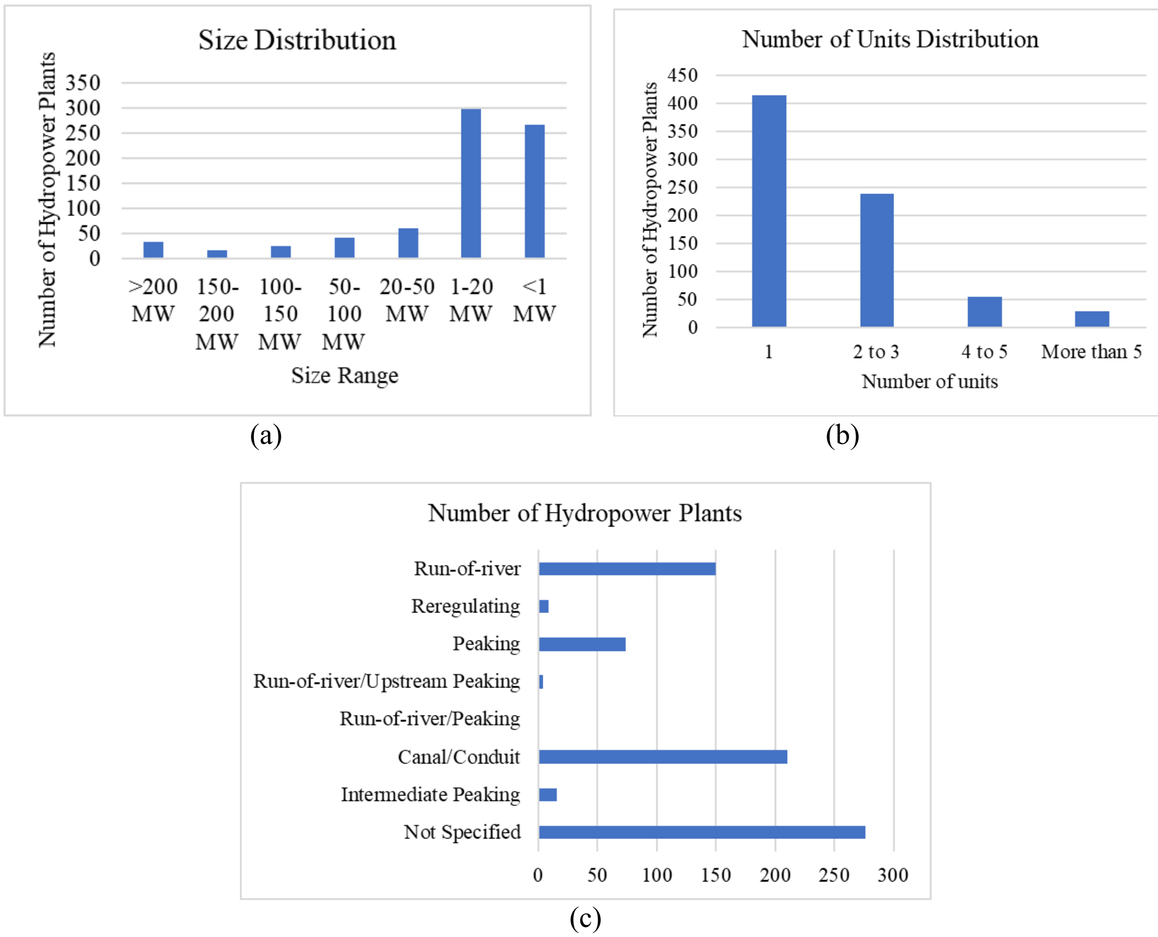


Figure 3-2: Distribution of various characteristics of hydropower plants in California, Oregon, Washington, and Idaho states for initial screening. (a) size of the plant, (b) number of units, and (c) mode of operation (Gautam et al., 2023).

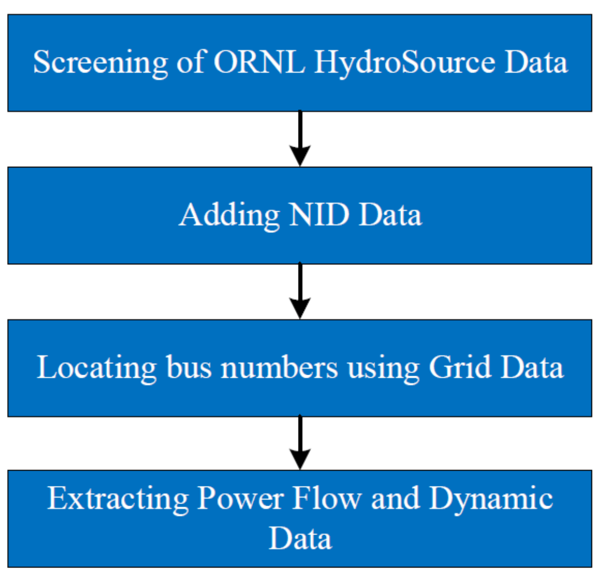


Figure 3-3: Steps for HRD development (Gautam et al., 2023).

Figure 3-3 illustrates the steps involved in HRD development. Firstly, data is screened from HydroSource, filtering plants based on specific criteria like capacity, number of units, and plant types. Subsequently, NID data is integrated, enriching the database with information about dam dimensions and hydrological data. The next step involves identifying bus numbers using the US Western Grid Stability Base Cases and incorporating extracted PSS/E power flow and dynamic data from PSS/E (.dyr) into HRD, offering insights into electrical and mechanical characteristics of the generation resource.

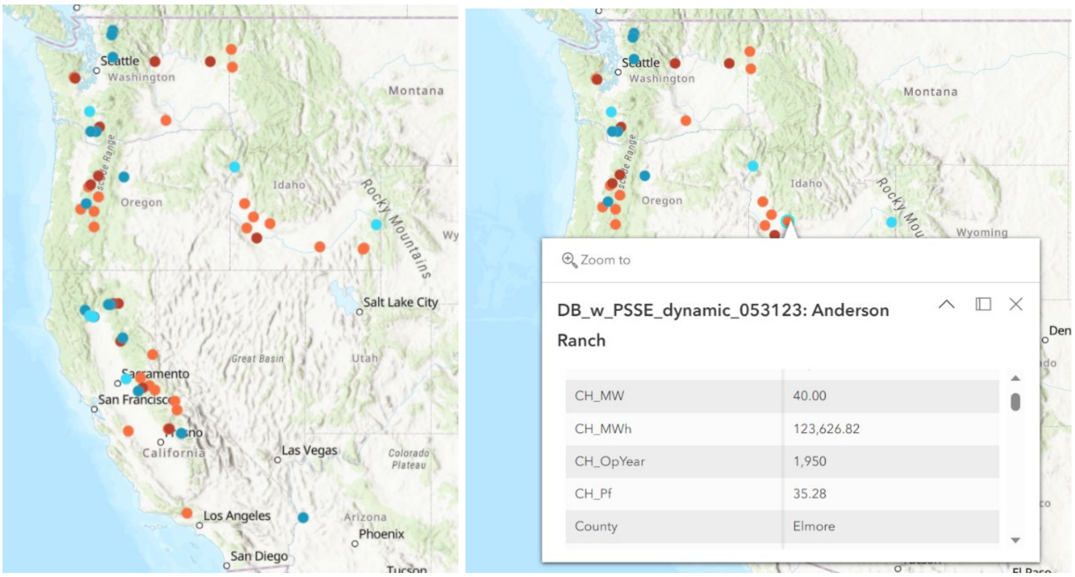


Figure 3-4: Interactive map of hydropower plants using ArcGIS platform (Gautam et al., 2023).

Figure 3-4 shows an interactive map visualized using the ArcGIS platform. Each distinct dot on the map represents a hydropower plant. Upon hovering over a dot, a pop-up window appears, showing detailed information and key parameters for the corresponding hydropower plant. This information encompasses the plant's name, location, hydropower capacity, type, number of generating units, dam storage capacity, bus number, Base kV, voltage and reactive power limits, Base MVA, among others. Users can apply filters and query the database. This functionality aids in identifying clusters of hydropower plants with desirable attributes, like high capacity and storage capability, ideal for microgrid development. The interactive nature of this visualization allows users to gain insights into each hydropower plant's essential attributes and capabilities.

Utilizing HRD, the microgrid formation and four capability metrics (see Figure 3-5) are scored. The scores are integrated as a part of the database. Figure 3-5 compares the score for four hydropower plants located in Idaho region. More detail on the scoring approach is available in (Gautam et al., 2023).

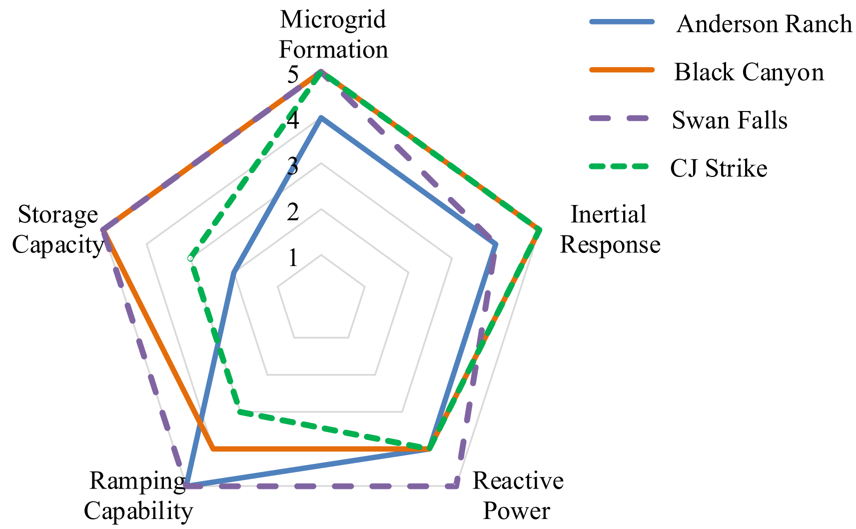


Figure 3-5: Metric scoring for hydropower plants in Idaho region [Metric scores from 1 to 5, with 5 indicating high suitability for resilient microgrids and 1 indicating low suitability] (Gautam et al., 2023).

Evaluating characterization metrics not only allows utilities to identify hydropower plants with the greatest potential for microgrid formation but also helps in comprehending their ability to fulfil essential microgrid functions. As previously discussed, certain hydropower plants might excel in one category while being weaker in another. This analysis also pinpoints areas of weakness where microgrid planners can invest in to enhance the suitability of a hydropower plant for microgrid formation.

3.3 Summary and Key Takeaways

In the proposed hydropower characterization framework, hydropower site and plant attributes are analyzed to evaluate nine metrics quantifying the suitability and performance of hydropower facilities in microgrids. The HRD provides enhanced insights into each hydropower facility and includes the first five of nine metrics that reveal strengths and weaknesses of hydropower plants to provide essential microgrid functions. In the next section, the developed framework and database are used to evaluate several potential hydro-based microgrid use cases identified in regions vulnerable to wildfire.

4 Hydropower Based Microgrid Impact Assessment

For the integration task, the teams at PNNL and INL are exchanging datasets and information to merge the two frameworks for wildfire impact assessment and hydro site characterization.

4.1 Power Systems Impact Assessment

The wildfire burn potential generated through WREST framework and the database of hydropower plant resources pre-screened in HRD are integrated to find the communities with right profile hydro resources in the vicinity and susceptible to wildfire events. Four use cases are identified to explore the full range of analysis from power system evaluation to technoeconomic assessment. Potential microgrid based on Hills Creek hydro located in Oregan and Chelan Lake hydro located in Washington have strong hydropower resource with large reservoir capacity and therefore selected for operation performance evaluation. Micrigrids based on Boise River Diversion hydro in Idaho and Snoqualmie river hydropower plant in Washington need additional generation capacity to support nearby load centers, and therefore, considered for the technoeconomic impact assessment. These four use cases offer a wide range of attributes ranging from the location of microgrid, wildfire potential, availability and strength of hydropower resource and the operating type of the hydropower facility. This helps in building example evaluation cases for different potential wildfire-resilient microgrids.

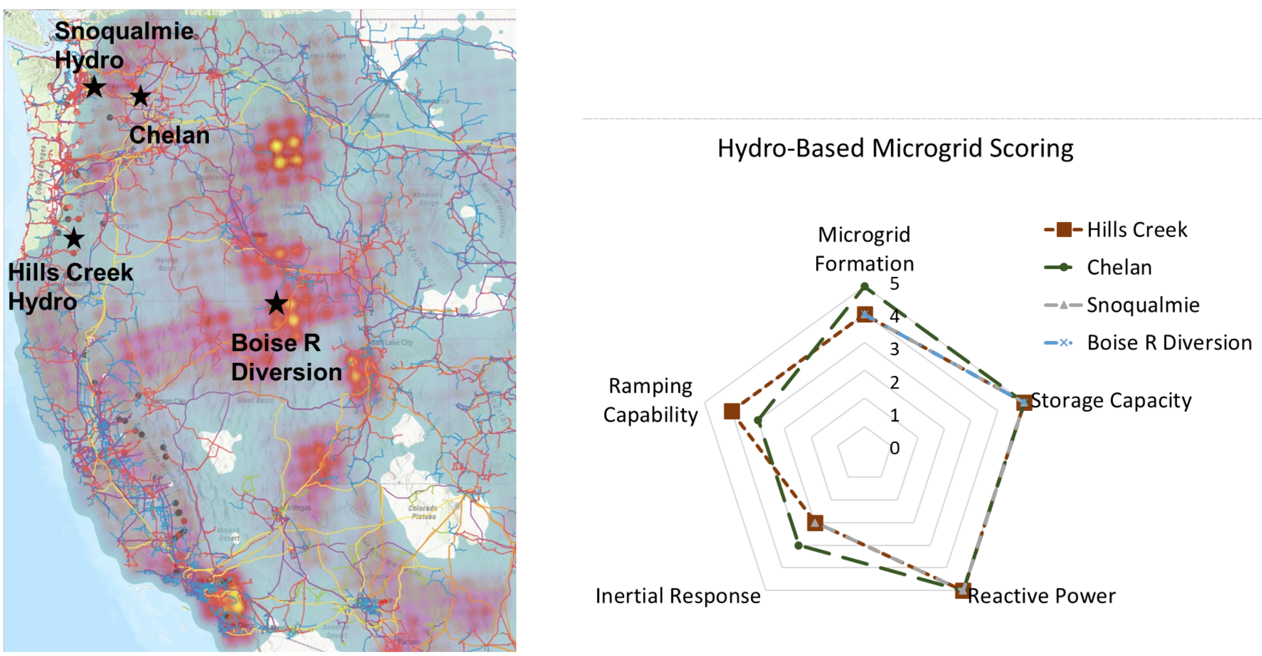


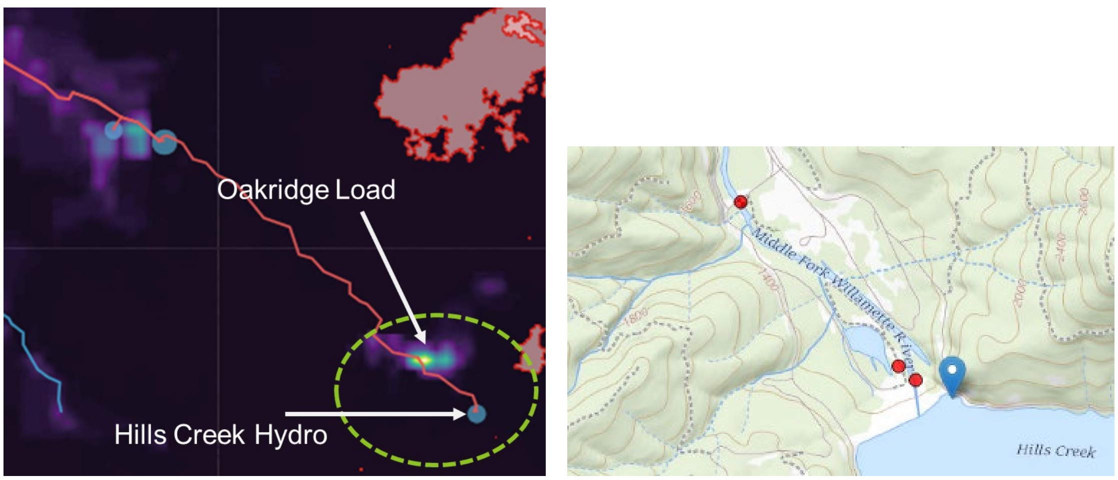
Figure 4-1: The four hydropower plant use cases selected for impact analysis. The burn potential obtained from the WREST framework based on historical and future wildfire potential is integrated with hydropower resource database from HRD. Five of the nine microgrid evaluation metrics are scored for these four hydropower plants.

Figure 4-1 compares microgrid scores for the selected four hydropower plants. The HRD includes essential data for Hills Creek and Chelan Lake hydropower plants for evaluating microgrid formation and four capability metrics. However, due to the absence of turbine-governor information of Snoqualmie hydropower plant, we were not able to score its ramping capability. Similarly, no power system information was available for Boise River Diversion hydropower plant in WECC database to score reactive power, inertial response and ramping capability metrics. This indicates that there are some additional gaps in existing hydro resources that need to be resolved to complete the HRD.

4.1.1 Power System Impact Assessment Use Case 1: Hills Creek hydropower and City of Oakridge in the state of Oregon

4.1.1.1 Scenario Modeling and Assumptions

The first use case involves Hills Creek hydropower plant in Lane County, Oregon. The facility has a generating capacity of 30 MW across 2 units and a substantial storage capacity of 234,300 acre-feet. This facility plays an important role in supporting the energy needs of the city of Oakridge with a peak load of 10.1 MW. Notably, the Hills Creek plant has showcased its robustness during critical events, successfully executing a black start during the winter storm of February/March 2019 (Brosig et al., 2022). This demonstration provided uninterrupted support to the entire Oakridge load for over five days, emphasizing its reliability during adverse weather conditions. These successful demonstrations highlight the plant's resilience and reliability, laying a foundation for further analysis within the wildfire resilience microgrid framework.



(a) (b)

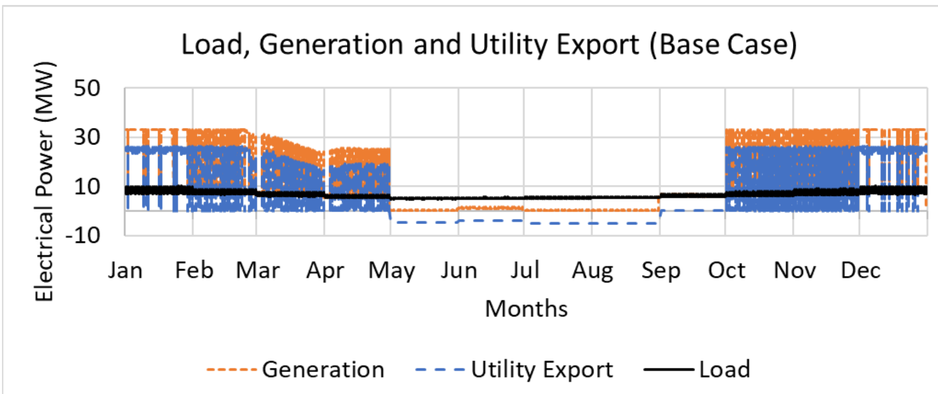
Figure 4-2: (a) Proposed microgrid with Hills Creek hydropower plant and Oakridge load center. The city of Oakridge was in the vicinity of several wildfires in the past although not directly islanded by one. (b) USGS stream gauging locations near Hills Creek hydro. The tailwater flow measurement at Hills Creek dam (USGS# 14145110) is considered as flow available for power production.

The plant is modeled using data from the HRD. The steady state model is built in Xendeee as a hydro with reservoir model. This model leverages dam dimensions essential for comprehending the plant's water storage capabilities. The tailwater flow measurements at Hills Creek dam were used as inflow available for power production. To account for seasonal variations, we simulate heavy and light load scenarios for winter, summer, and spring using time-series load data generated from PSS/E stability cases. A dynamic evaluation case is also built in PSSE.

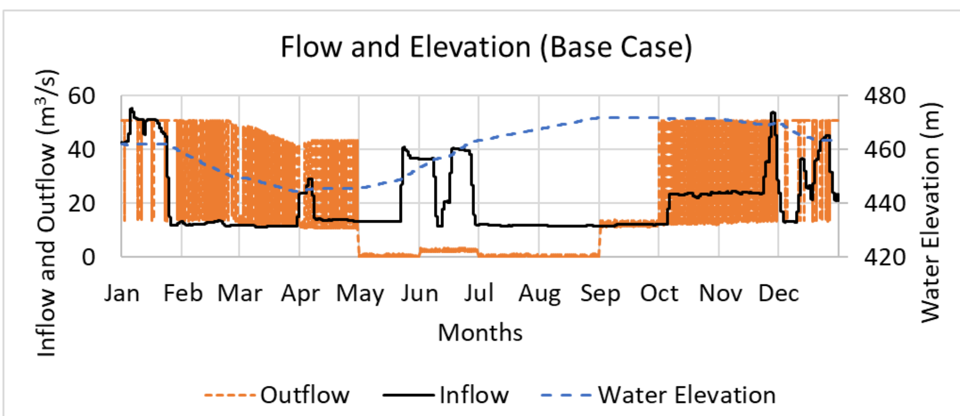
4.1.1.2 Steady State Evaluation

Base Case Dispatch Results

First, the system is run without grid outage to establish base case dispatch results. A detailed quasi-steady-state analysis was conducted utilizing the Xendee platform. The primary focus of this assessment centered on optimizing the plant's water elevation to enhance the efficient utilization of its water resources. Based on the optimization result, the microgrid imports electricity between May and September. During this period, the reservoir underwent refilling, aimed at improving the efficiency of electricity production. As a result of this, the assessment indicated a net import of 14.12 GWh along with a net export of 68.25 GWh. This base case analysis offers insights into the plant's operational strategies, emphasizing its capability to effectively optimize electricity production within the microgrid environment by managing imports and exports.



(a)

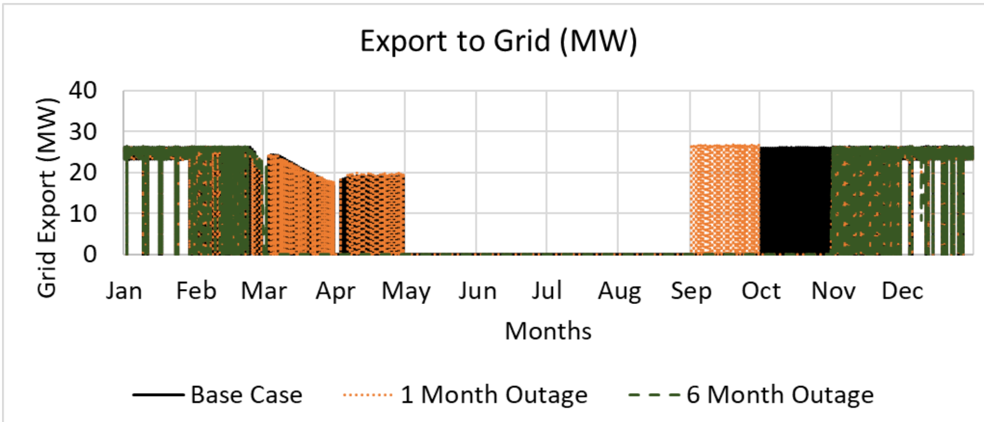


(b)

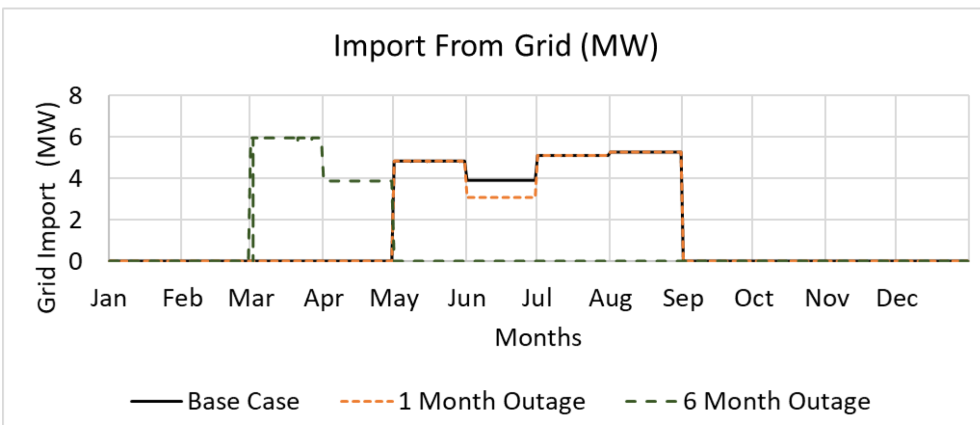
Figure 4-3: Base case dispatch results (a) load, generation and grid exchange, (b) hydro reservoir inflow, outflow, and water elevation.

Dispatch Results for Long Duration Outages

The microgrid was found to be able to operate on the island for extended long outages up to six months. The results for two significant outage durations are included: a month-long outage spanning the entirety of October and an extensive six-month outage from May to November. The month-long outage showed minimal impact on power imports from the utility, with a slight decrease observed in electricity imported during June. Moving to the six-month outage scenario, the Hills Creek hydropower plant remarkably sustained support for the entire Oakridge load without encountering any operational issues. Notably, during this extended period, shifts were observed in the electricity import patterns, particularly between March and May, indicating the plant's adaptability to manage sustained operation throughout prolonged outages without requiring modifications. This resilient performance highlights the plant's capability to ensure sustained operation, crucial for prolonged outage scenarios.



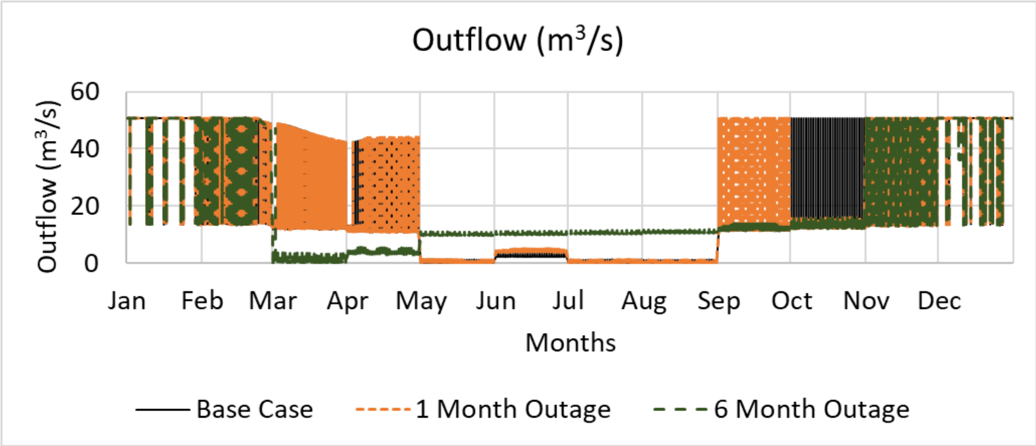
(a)



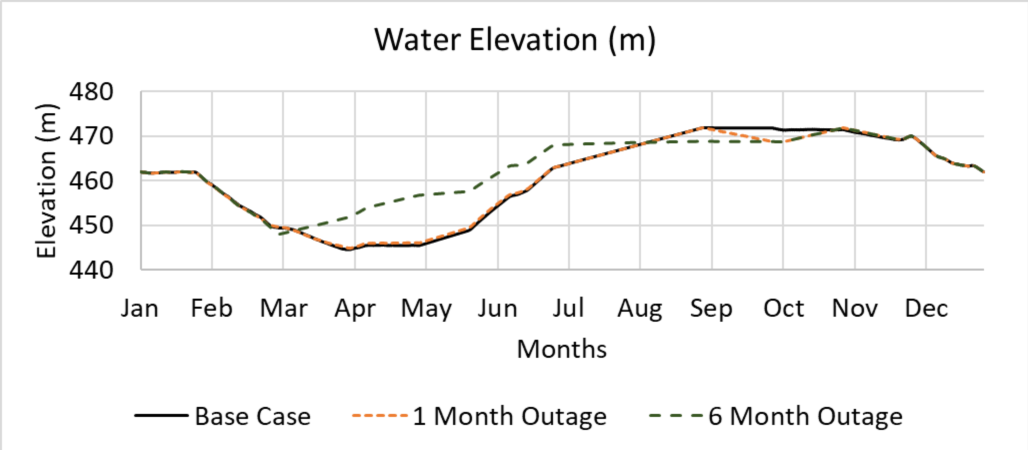
(b)

Figure 4-4: Power exchange with grid considering 1 month and 6-month outages (a) electricity export, (b) electricity import.

Additionally, we analyzed the outflow and water elevation during these outages, comparing them with the baseline scenario. In normal operating conditions without outages, the plant utilizes flow primarily from January to May and between October to December. However, during the month-long October outage, the plant altered its electricity export, shifting it to September instead of October, aligning its operations with local load demands in October. In the case of the six-month outage, the plant adjusted its export patterns, following local load demands during the outage and ceasing exports in March to preserve water resources for the impending outage starting in May. These adaptive strategies highlight the plant's flexibility in adjusting its operations to meet local demand and preserve water resources during extended outage periods.



(a)



(b)

Figure 4-5: Comparing hydropower plant dispatch results for 1 month and 6-month outages with base case (a) turbine outflow, (b) water elevation.

Importantly, the assessment affirmed the Hills Creek hydropower plant's resilience and capacity to endure long-term outages owing to its sufficient inflow and reservoir capacity. Throughout the outage duration, the plant could be optimized to produce electricity to meet local load demands, ensuring continuity in power supply. Upon reconnection to the grid, the plant operated intermittently, optimizing power production to maximize revenue from electricity sales while efficiently managing resources, as shown in Figure 4-6. These findings highlight the plant's adaptability in addressing sustained outage scenarios while ensuring operational efficiency and revenue optimization.

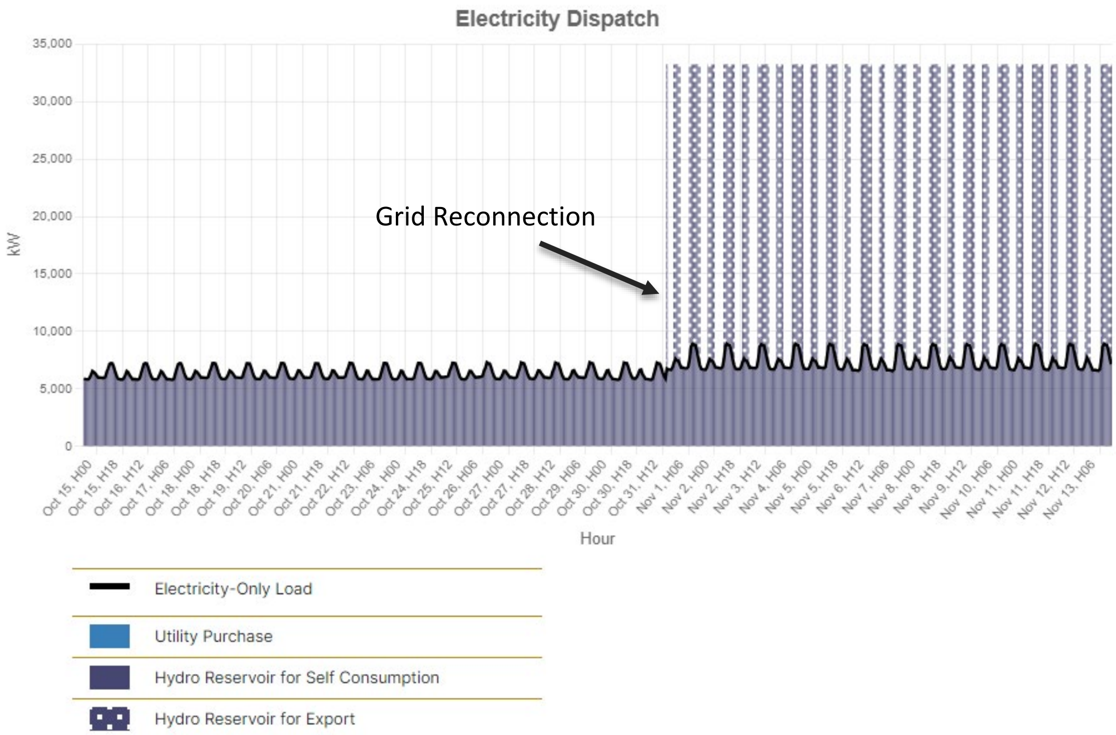


Figure 4-6: Hydropower plant electricity production before and after grid reconnection.

4.1.1.3 Dynamic Response Evaluation

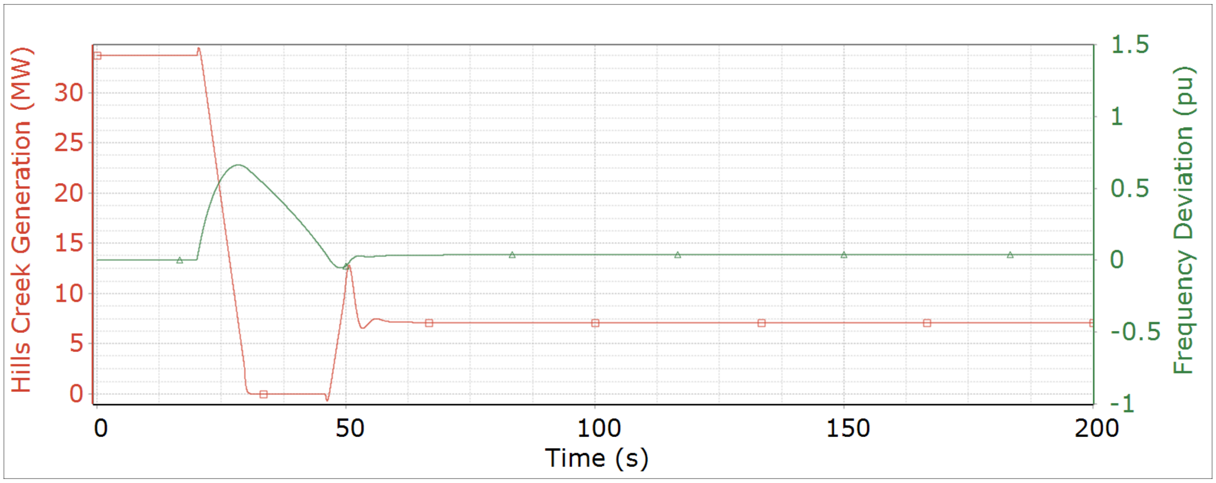
Hills Creek demonstrated a strong ability to support steady state operation for long outages and did not require investment in additional generation resources. In this section, we analyze potential dynamic scenarios to understand the plant's ability to navigate through them to ensure stable operation. Using the hydropower resilience database, we created power flow (.raw) and dynamic simulation (.dyr) case files for PSS/E, which include power flow information of transmission nodes, distribution lines, transformers, and generators, as well as dynamic parameter for generator, exciter, and turbine governor system. These scenarios listed in Table 4-1 are the extreme cases of time-series dispatch selected from the steady state analysis.

Table 4-1: Scenarios considered for Hills Creek hydro dynamic evaluation.

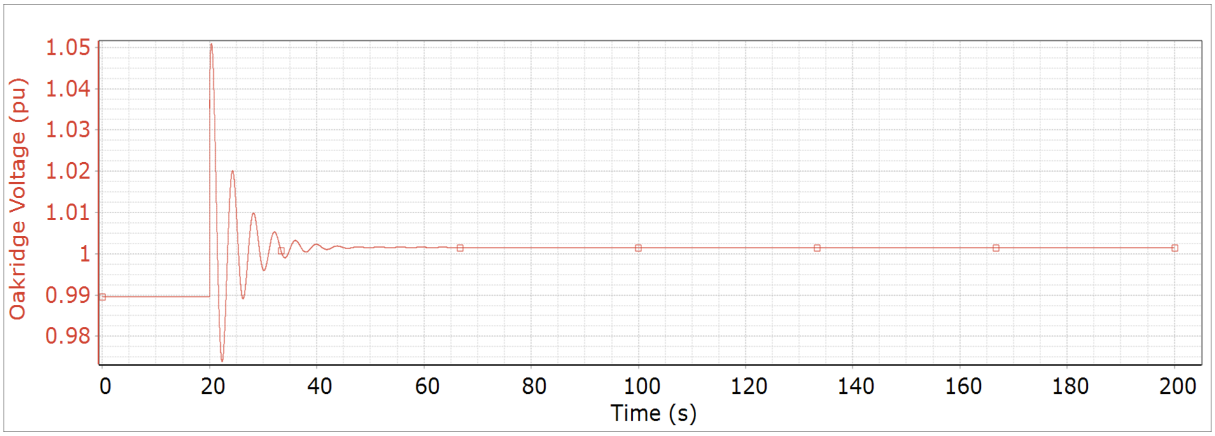
Scenarios	Description	Simulation Time	Generation (MW)	Load (MW)	Export (MW)	Current Flow (m3/s)	Hydraulic head (m)
S1	Maximum grid export	Nov 25, 4 PM	33.21	6.90	26.31	50.74	89.966
S2	Maximum grid import	Aug 01, 12 AM	0.03	5.30	-5.27	0.05	88.386
S3	Maximum load	Dec 1, 6 PM	33.21	9.93	23.28	50.75	90.526
S4	Moment of islanding	May 01, 12 AM	0.02	4.85	-4.83	0.04	66.256

Seamless Islanding

For seamless islanding, the system is modeled in a droop control mode. First, scenario S1 is selected which is the instant when the grid export was maximum. Assuming the system islands abruptly, the hydropower plant will have to quickly reduce its power output from 33.21 MW to 6.9 MW to meet the load of city of Oakridge. As seen in Figure 4-7(a), such step change will lead to large frequency overshot, and generator power output drops to zero. It should be noted that the simulation captures extreme transients with no restriction from the generator protection settings. Standard protection settings would trip-off the generators and cause blackout to the city of Oakridge instead of seamless islanding. Although the generation is shown to be recovering after the transition in the simulation, the power plant would shut down following the transient and instead initiate black start sequence. Figure 4-7(b) shows the voltage at Oakridge load dispatch center during this islanding process. Although there is a voltage fluctuation during this transient, the maximum deviation stays within ±5%.



(a)



(b)

Figure 4-7: Dynamic frequency and voltage response of Hills Creek hydro to largest step load decrease while islanding during maximum grid export.

The second scenario (S2) is the case with maximum electricity import which happens on May 01, 12 AM. At the instant of islanding, the hydropower plant was not producing any power, and the Oakridge demand was met by importing electricity from the grid. Islanding in this situation would mean Hills Creek ramp its power output to meet the Oakridge load. Figure 4-8 shows the generation and frequency deviation for scenario 2. The microgrid with Hills Creek hydro units and the Oakridge load could island but result in large frequency excursion of 0.057 pu (or 3.45 Hz). The transient settles with steady state frequency error of 0.48 Hz. While the settling frequency deviation is within the acceptable range for a microgrid, the large excursion seen for this transient means the protection systems are likely to be triggered for this scenario as well.

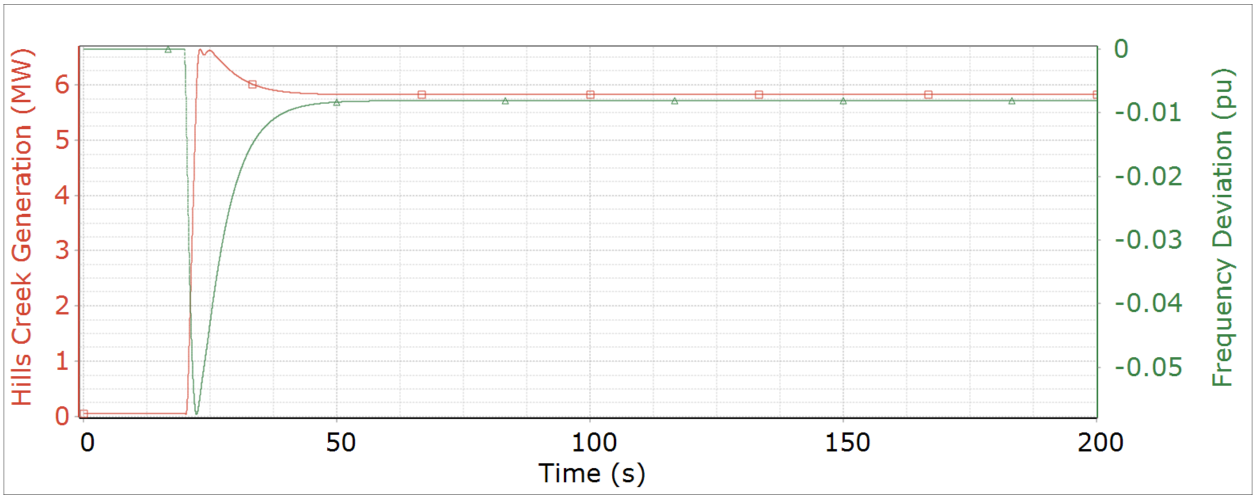


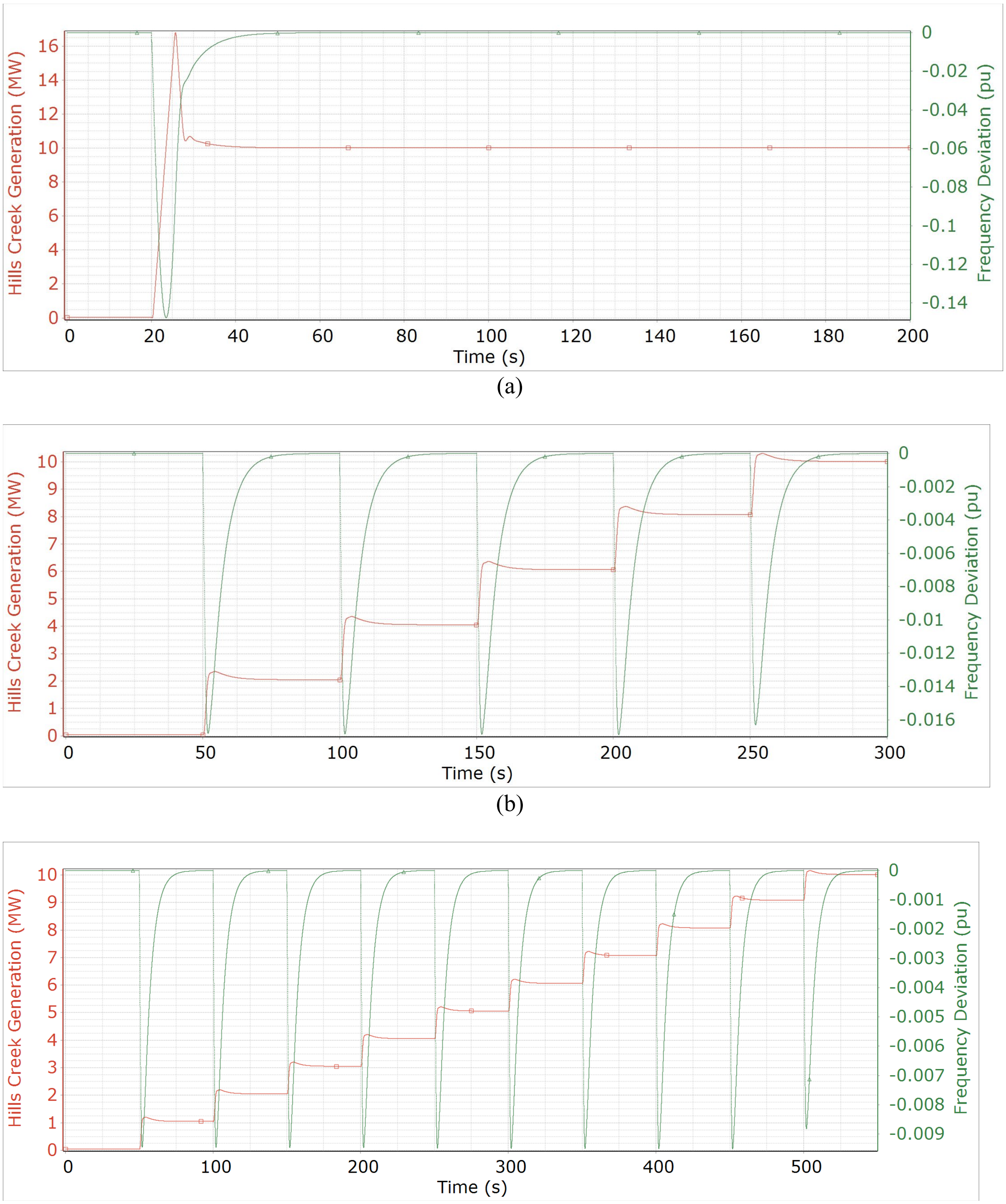
Figure 4-8: Dynamic frequency response of Hills Creek hydro to largest step load increase while islanding during maximum grid import.

The other two scenarios have similar responses for seamless islanding case. Scenario S3 will have a similar response as S1 with slightly lesser frequency overshoot, as the hydropower plant switches from 33.21 MW to 9.93 MW instead of 6.9 MW. Similarly, S4 will have a similar response to S2 with slightly smaller frequency drop as the load is lower than S3.

This analysis clearly indicates that the Hills Creek hydropower plant is less likely to be able to seamlessly island under these extreme scenarios and may need to opt for black start.

Black Start

Black starting the entire load of Oakridge would lead to large transients like seamless islanding for scenario 3. Figure 4-9(a) shows the response with Hills Creek trying to take up entire load of Oakridge at once from the cold start. Although the settling frequency is back to 0 Hz, frequency excursion up to 8.88 Hz means the protection system will likely trigger and the plant will fail to black start. Because the plant will have opportunity to decide the step increments of the load or cranking path, the black start can be executed in a more controlled manner. In addition to that, with generators black starting the hydropower plants can switch from droop-controlled mode to isochronous mode to provide better dynamic response. Figure 4-9(b) and (c) show the response with a 2 MW and 1 MW load step increase, respectively. The maximum frequency excursion seen for a 2 MW step is 1.02 Hz and the black start process is completed within 300 s. For 1 MW step load increase, the maximum frequency excursion is 0.54 Hz and the black start completes in 550 s.



(a)

(b)

(c)

Figure 4-9: Black starting Oakridge load when it is at its peak (a) Full load at once, (b) 2 MW load stepping, and (3) 1 MW load stepping.

The analysis shows that with proper control strategy, the Hills Creek hydropower plant will be able to black start the maximum potential load of the city of Oakridge.

4.1.1.4 Key Takeaways

The Hills Creek hydropower plant demonstrated strong capability to form microgrid to support Oakridge load during wildfire outages in the state of Oregon. The scoring of the wildfire-resilience microgrid metrics for Hills Creek hydro is shown in Figure 4-10. In terms of microgrid formation, it scores 4 out of 5. One point is deducted because the primary purpose of the dam is flood control which could restrict the operation of the hydropower plant for microgrid operation. In terms of storage capacity and reactive power response, it demonstrates strong capability scoring 5 out of 5. Ramping capability is found adequate with a 4 out of 5 score. Inertial response which is scored relative to other hydropower plants considered in HRD in terms of inertia constant is scored 2 out of 5. This indicates the need for fast acting assets such as batteries and supercapacitors to support the inertial response of the system.

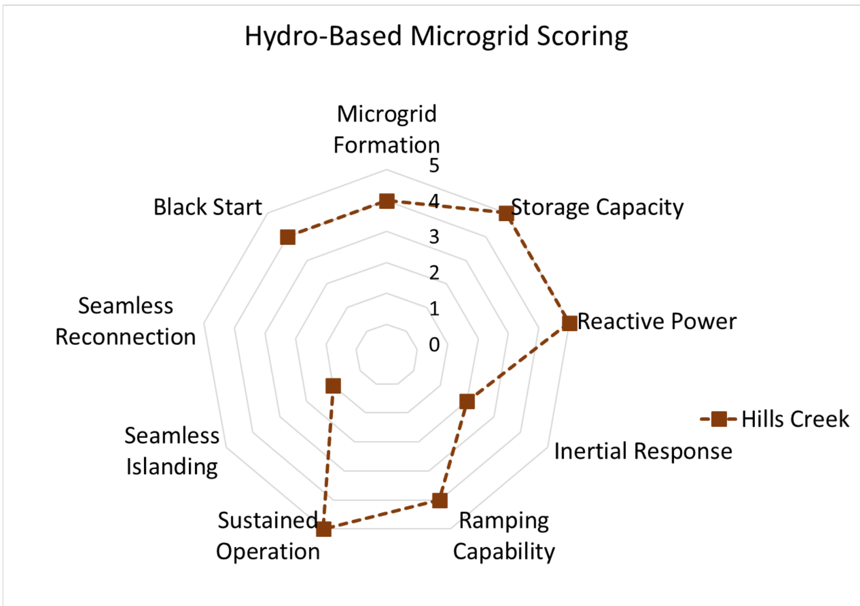


Figure 4-10: Metric scores for Hills Creek hydropower plant. Additional analysis and testing necessary to score seamless reconnection.

In terms of performance metrics, Hills Creek excelled in sustained operation category and was able to support entire load of Oakridge during long wildfire outages of up to 6 months, and therefore is scored 5 out of 5. In terms of seamless islanding, Hills creek failed to switch between grid connected to islanded mode in possible extreme cases of generation-load imbalance, and therefore scores 1 out of 5. However, it was able to black start the maximum possible load of Oakridge with minimal frequency and voltage transients with predefined cranking path with load step increments between 1-2 MW. Therefore, it is scored 4 out of 5 in black start category. The seamless reconnection performance depends primarily on grid reconnection strategy, associated control system components and human factors. It needs to be scored based on performance during real operation.

4.1.2 Power System Impact Assessment Use Case 2: Chelan Lake Hydropower in Washington State and Small Communities

4.1.2.1 Scenario Modeling and Assumptions

The Chelan Lake hydropower plant in WA state, generating 59.2 MW across two units can support four communities in microgrid. Those four communities include Chelan district, Union Valley, Manson, and Wapato with total annual peak load of 77.64 MW. The assessment methodology adopted in this case study relies on various data sources and modeling techniques to evaluate the operations and resilience of this plant. We model the plant's reservoir using data from the NID, integrating it into the Xendee platform to construct a hydro reservoir model. This model leverages dam dimensions essential for comprehending the plant's water storage capabilities.

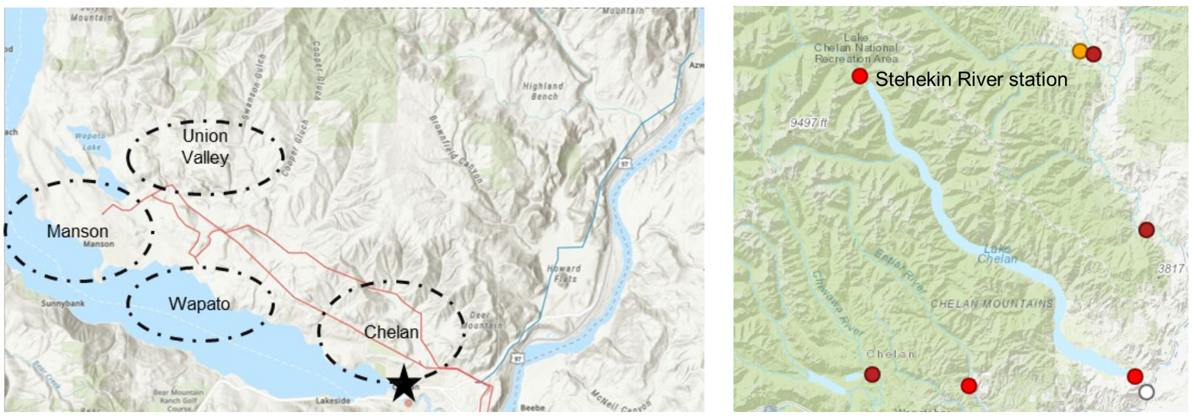
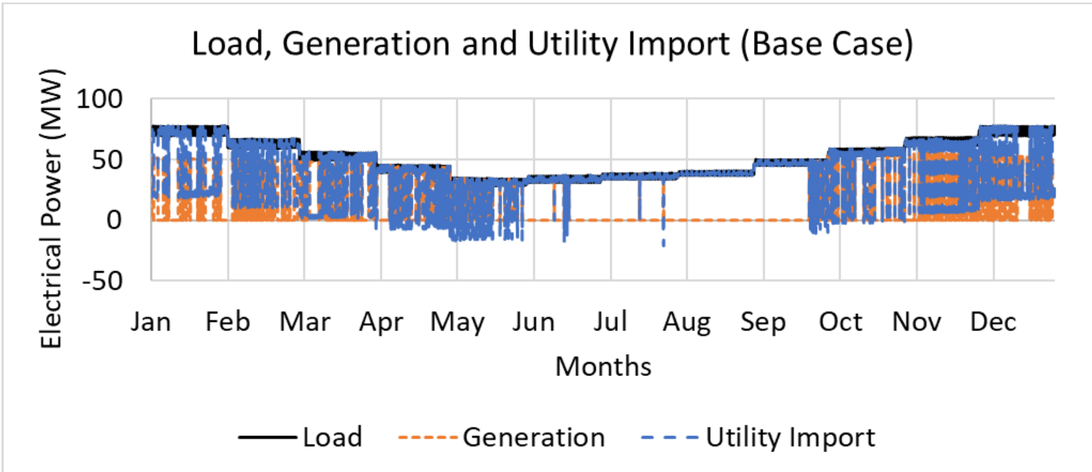


Figure 4-11: (a) Chelan hydropower plant supporting Chelan district, Union Valley, Manson, and Wapato load centers. and Oakridge load center (b) USGS stream gauging locations near Chelan Lake. Flow measurement from tailwater of the reservoir as the inflow available for power production.

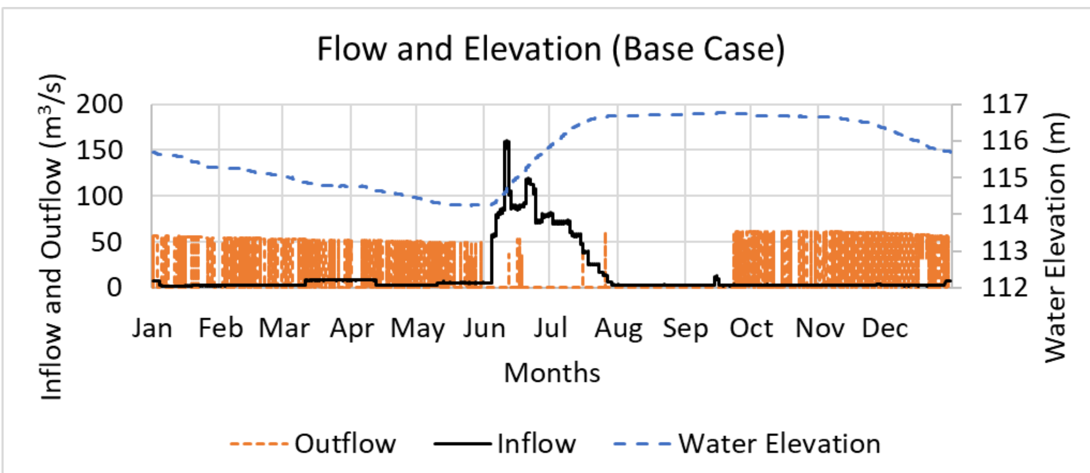
Furthermore, leveraging USGS data, we develop an inflow model that captures temporal variations in water inflow patterns. Notably, the Stehekin River contributes 65% of the total water to Lake Chelan. To account for seasonal variations, we simulate heavy and light load scenarios for winter, summer, and spring using time-series load data generated from PSS/E stability cases. Two key gauging stations are in close proximity, specifically the Stehekin River gauging station (USGS# 12451000) located upsteam of Lake Chelan and Chelan River gauging station (USGS# 12452500) positioned downstream. Our study utilizes data from the Chelan River station, representing the regulated outflow from the hydropower plant.

4.1.2.2 Steady State Evaluation

In the steady state evaluation, our analysis focuses on the Chelan hydropower plant's operations under normal conditions, like the approach taken for the Hills Creek assessment. This evaluation considers the base case scenario without accounting for any outages. The peak load demand occurs during December and January, reaching approximately 70 MW. However, during October, the peak load demand was around 60 MW, nearly aligning with the plant's maximum generation capacity of 59.2 MW when operating at rated flow with both units. Notably, the plant is optimized to both import and export energy, demonstrating a net import of 340.99 GWh and a net export of 4.76 GWh. Figure 4-12 provides the dispatch results for the base case without outage.



(a)



(b)

Figure 4-12: Base case dispatch results for the proposed microgrid (a) load, generation, and grid import, and (b) flow and elevation.

Long-term outage scenarios were simulated to assess the plant's resilience during disruptive events. A 15-day outage simulation unveiled a partial unmet energy demand in the latter days of the outage due to a decline in power output resultant from the decreased reservoir elevation, as shown in Figure 4-13. However, the analysis demonstrated the plant's capability to manage multi-day outages lasting up to 7 days in October through optimized operational strategies, ensuring the reservoir maintains its full elevation prior to the outage. Notably, the primary issue during such scenarios wasn't the scarcity of energy but rather the deficiency in power output, despite adequate water stored in the reservoir. This decrease in power output resulted in a total unmet energy of 15100.4 kWh, emphasizing the need for increased power output to effectively meet the total demand during such long-duration outages.

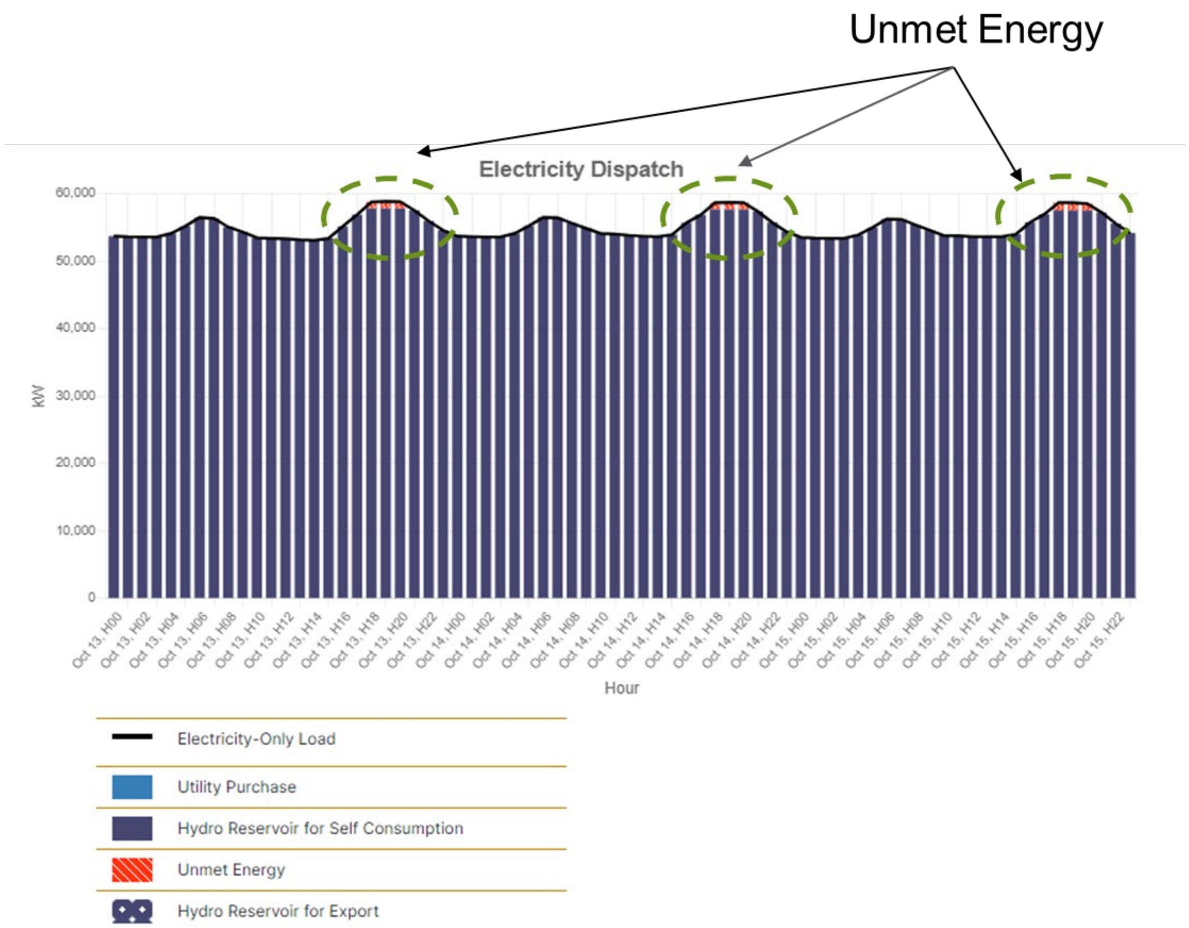


Figure 4-13: Unmet energy during last 3 days of 15-day outage.

4.1.2.3 Proposed Solutions and Analysis

Two distinct strategies are explored to mitigate the power deficit observed during the long-term outage scenarios for the Chelan hydropower plant.

Addition of Battery Energy Storage System (Solution 1)

The first proposed solution involves the integration of a Battery Energy Storage System (BESS) with an initial capacity of 32 MWh which is optimized using Xendee to meet the 15-day resilience requirements. This system is primarily aimed at optimizing operational efficiency and meeting energy demands throughout a 15-day outage occurring in October. However, a limitation is noted as this BESS capacity can't fully meet the energy demand in a prolonged 30-day outage scenario. To adequately address this longer outage duration, the BESS capacity needed a substantial increase to 125.6 MWh. Despite this limitation, the solution appears economically feasible for managing a 15-day outage.

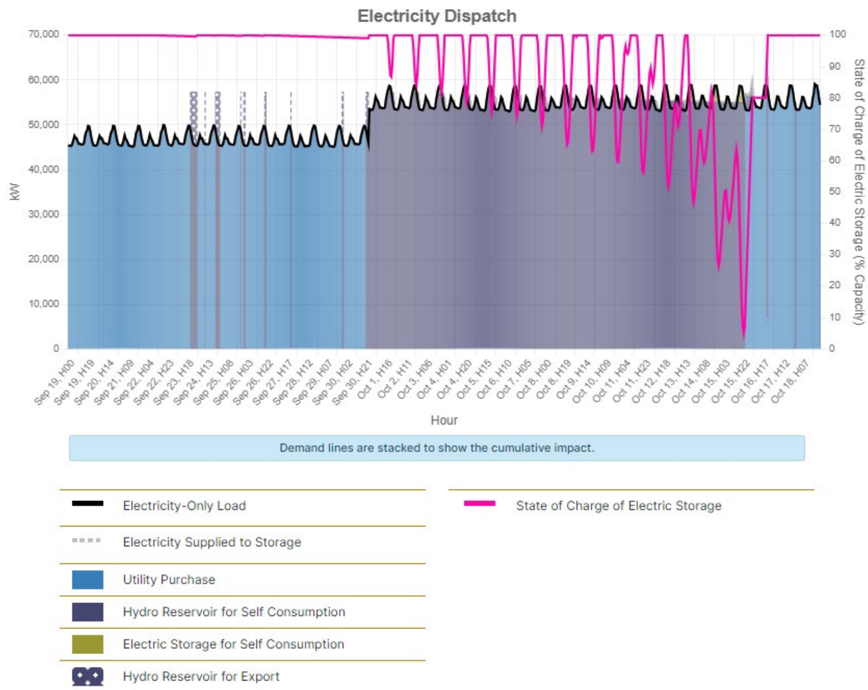


Figure 4-14: Dispatch results for days before, during and after 15-day grid outage with new 32 MWh BESS. Battery goes through deep power cycles during the outage.

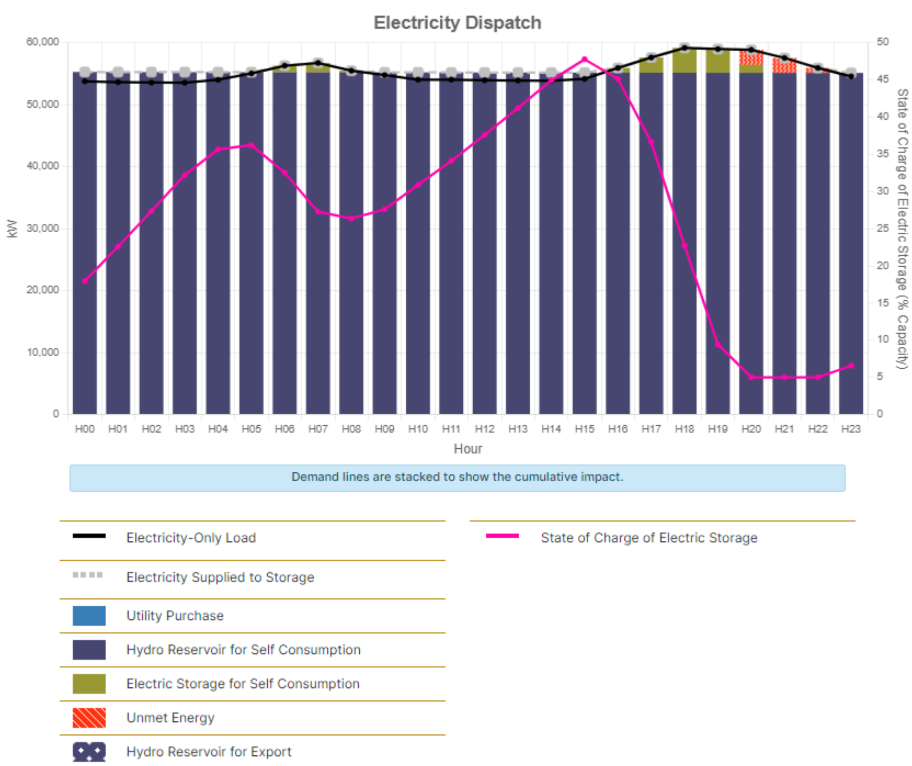


Figure 4-15: Unmet energy observed in last day of 30-day outage. To support 30-day outage, BESS of 125.6 MWh is required.

Additional Hydropower Unit (Solution 2)

In Solution 2, the addition of an identical turbine-generator unit is proposed, adding a capacity of 29.6 MW, to the Chelan hydropower plant. This strategy aims to alleviate the power shortage challenge during outages by significantly enhancing the plant's overall generation capacity. The analysis indicated that, provided the penstock could supply adequate discharge for the new unit, it would effectively fulfill energy demands for outage periods lasting up to a month. However, the economic viability and cost-effectiveness of this solution should be evaluated against the expected outage frequency and duration.

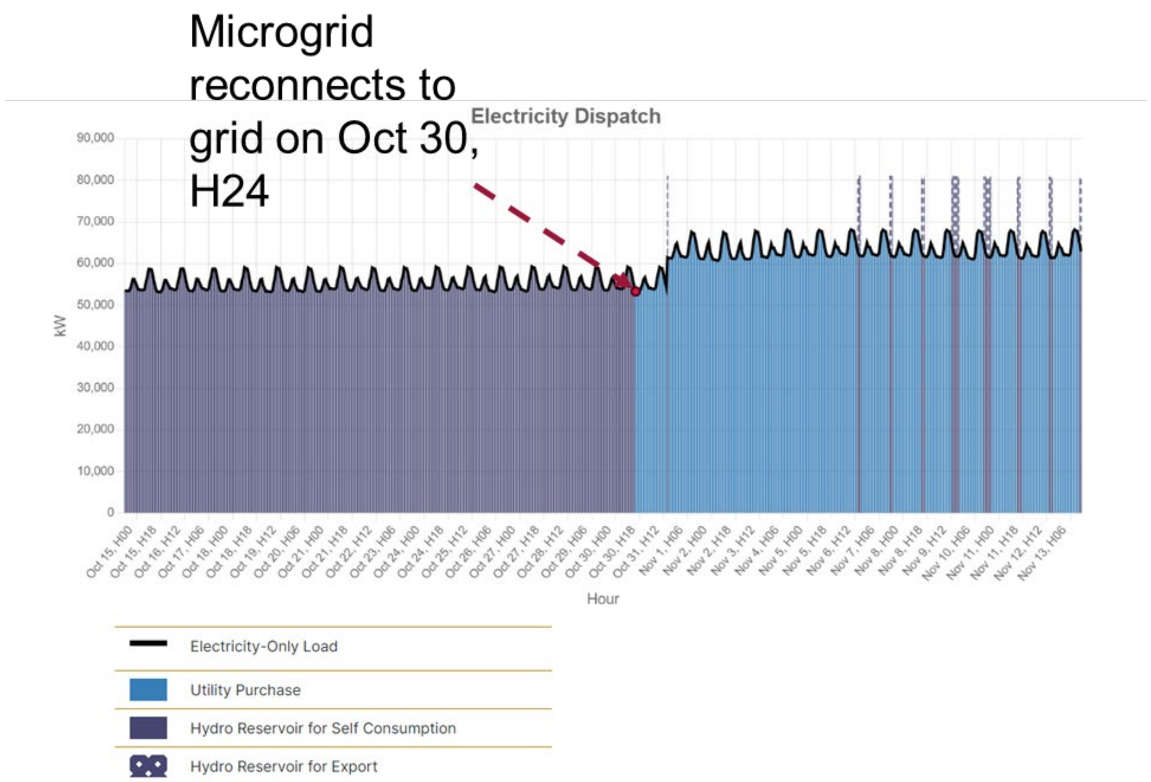


Figure 4-16: Dispatch results during and after outage with additional third hydropower unit.

Comparison of Proposed Solutions

Both solutions offer distinct avenues to address the operational challenges observed during outage scenarios at the Chelan hydropower plant. While the addition of BESS (Solution 1) presents a viable short-term solution for shorter outages, Solution 2's incorporation of an additional turbine-generator unit demonstrates potential for addressing longer-term outage challenges. The choice between these solutions hinges on a comprehensive evaluation considering economic feasibility, operational efficiency, and the anticipated outage scenarios, ensuring a strategic decision aligning with the plant's operational requirements and long-term resilience goals. Broadly, the two solutions can be compared in terms of two key aspects: infrastructure upgrade and outage duration compatibility.

In terms of the infrastructure upgrade, Solution 1, requiring the installation of a BESS, may have a lower upfront infrastructure impact compared to constructing a new turbine-generator unit. The BESS installation might require less immediate capital expenditure and potentially entail minimal modification to the existing infrastructure, presenting an advantage in terms of upfront infrastructure impact. Conversely, Solution 2, focusing on the construction and integration of an additional turbine-generator unit, poses a substantial requirement for infrastructure enhancement. The addition of this unit necessitates considerable capital expenditure and infrastructure modification, impacting various components such as the dam, water channel, and penstock. This solution entails a more extensive and potentially costly upgrade to the plant's infrastructure, which could involve longer implementation timelines and higher initial investments.

In terms of the outage duration compatibility, Solution 1, with initial BESS capacity, seems economically viable and effective in managing a 15-day outage scenario. However, its limitation surfaces when faced with an extended 30-day outage without an increase in BESS capacity, indicating a need for expansion to meet prolonged outage demands. In contrast, Solution 2, incorporating the additional turbine-generator unit, demonstrates compatibility for more extended outage scenarios, specifically a one-month duration. The increased generation capacity facilitated by this solution enables sustained support over a more extended period, catering to prolonged outage situations effectively.

4.1.2.4 Dynamic Response Evaluation

Similar to what we did for Hills Creek hydro, we identified dynamic simulation scenarios for Chelan Lake hydro based on the results of steady-state analysis. Table 4-2 lists the extreme case scenarios considered for the dynamic analysis focusing on the capability of Chelan hydro to seamlessly island or black start. In the case of the Chelan Lake hydro, two investment dynamic cases in addition to the base case when no investment is considered a part of load is assumed to be curtailed.

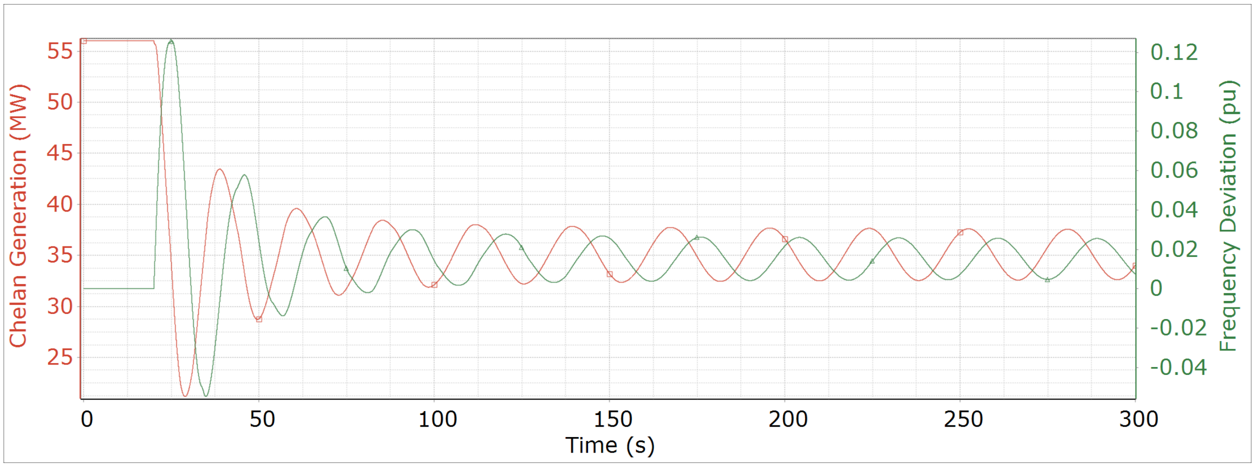
Table 4-2: Scenarios considered for Chelan hydro microgrid dynamic evaluation.

Scenarios	Description	Simulation Time	Generation (MW)	Load (MW)	Export (MW)	Current Flow (m3/s)	Hydraulic head (m)
S1	Maximum Grid Export	July 26, 10 AM	55.61	34.70	20.91	60.81	113.66
S2	Maximum Grid Import	Dec 01, 8 PM	0.00	77.28	-77.28	0	113.34
S3	Maximum Load	Dec 01, 8 PM	0.00	77.28	-77.28	0	113.34
S4	Moment of Islanding	Oct 01, 12 AM	55.89	53.47	2.42	61.09	113.73

4.1.2.5 Without Investment

Seamless Islanding

For seamless islanding, we first consider scenario 1 without investment and without correcting the control settings. The Hills creek generation will have to reduce its power generation by 20.91 MW which it was exporting to the grid. Such a transition led to large frequency deviation with peak up to 7.56 Hz as seen in Figure 4-17(a). In addition to that, the hydropower plant was oscillating with sustained frequency oscillations of peak 1.56 Hz. Similarly, the voltage response measured at the generator terminal as well as at the remote end at Wapato Valley load dispatch (plotted in Figure 4-17(b)) node shows large, sustained oscillation going up to 1.1 pu. These large frequency deviations and sustained oscillations mean that the hydro units will trip off due to voltage and frequency protection and unable to seamlessly island.



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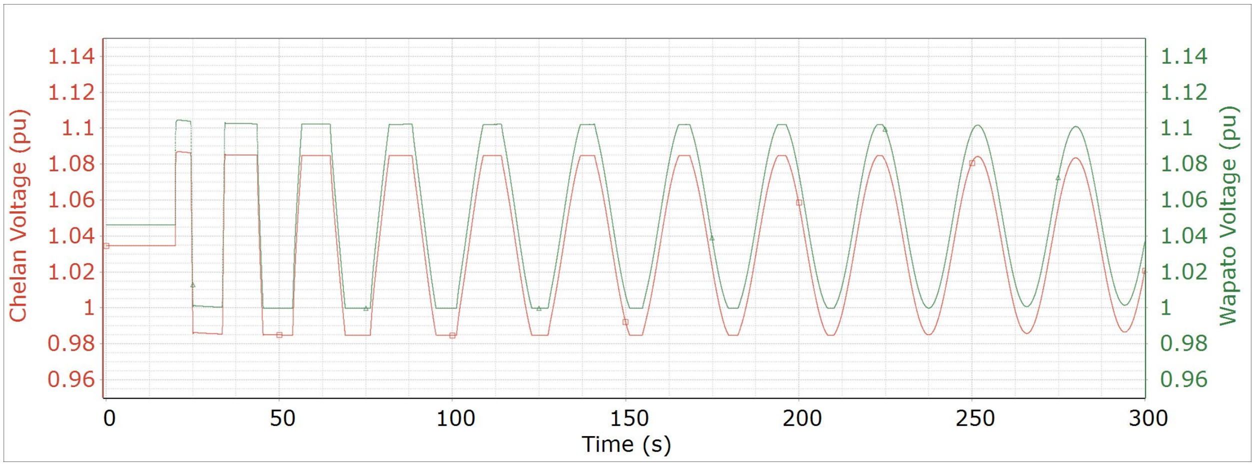


(b)

Figure 4-17: Dynamic frequency and voltage response of Chelan hydro to largest step load decrease while islanding during maximum grid export.

To mitigate the oscillations, we adjusted the control of the governor control and re-ran the scenario. With new control settings, the sustained frequency and voltage oscillations were mitigated but the frequency deviation was still more than 0.12 pu (7.2 Hz), as shown in Figure 4-18. The system won't be able to seamlessly island for S1 even after controller tuning. This clearly means that the hydropower plant as it is, is not equipped to seamlessly island the entire load of the microgrid which includes Chelan district, Union Valley, Manson, and Wapato load centers under extreme conditions.

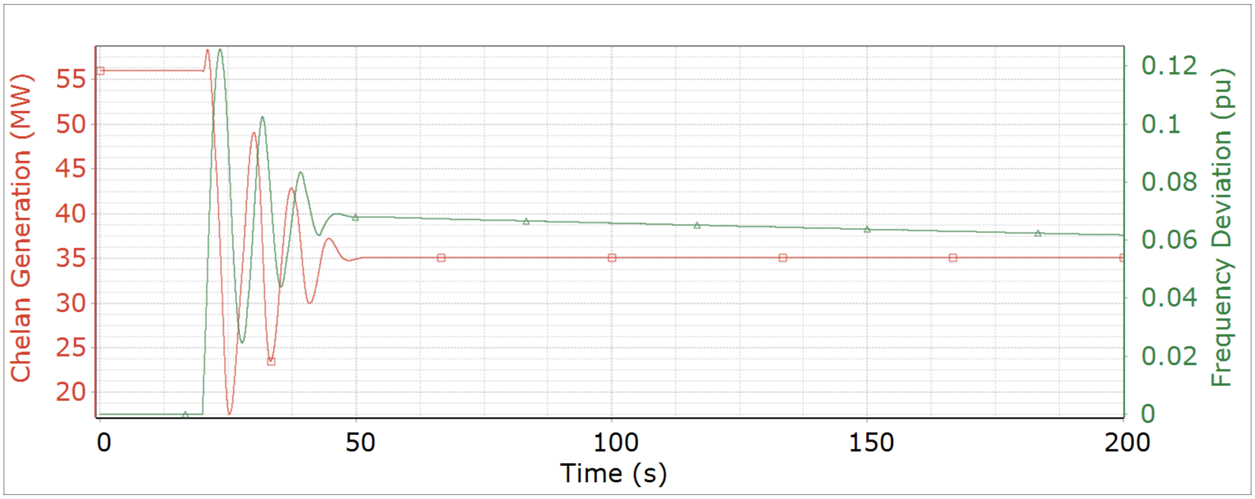
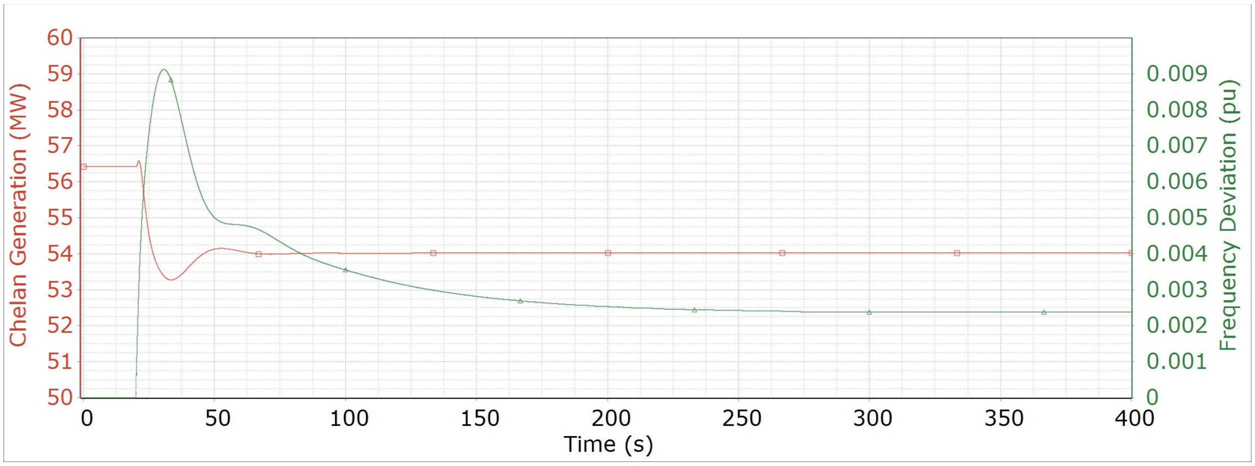


Figure 4-18: Frequency response of Chelan hydro in response to large step load decrease with new control settings. The oscillations are reduced, but the frequency deviation is still very high.

The maximum grid imports and maximum load period scenarios (S2 and S3) occurred on Dec 01, 8 PM. During this period, Chelan hydro was not producing any electricity and the load demand is met by buying electricity from the grid. Since this scenario will be similar to black start, we analyzed S4 instead which is the instant of islanding.

In S4, the microgrid load is met in its entirety by Chelan Lake hydro and also export 2.42 MW to the grid. Seamlessly islanding for S4 means, the hydropower plant will have to reduce its power output by 2.42 MW which it was exporting to the grid. Although smaller change compared to the size of the plant, it still leads to frequency overshoot of up to 0.009 pu (or 0.54 Hz) and settle with frequency deviation of 0.002 pu (or 0.12 Hz), as shown in Figure 4-19. Under this scenario, the Chelan hydropower plant will be able to seamlessly island.



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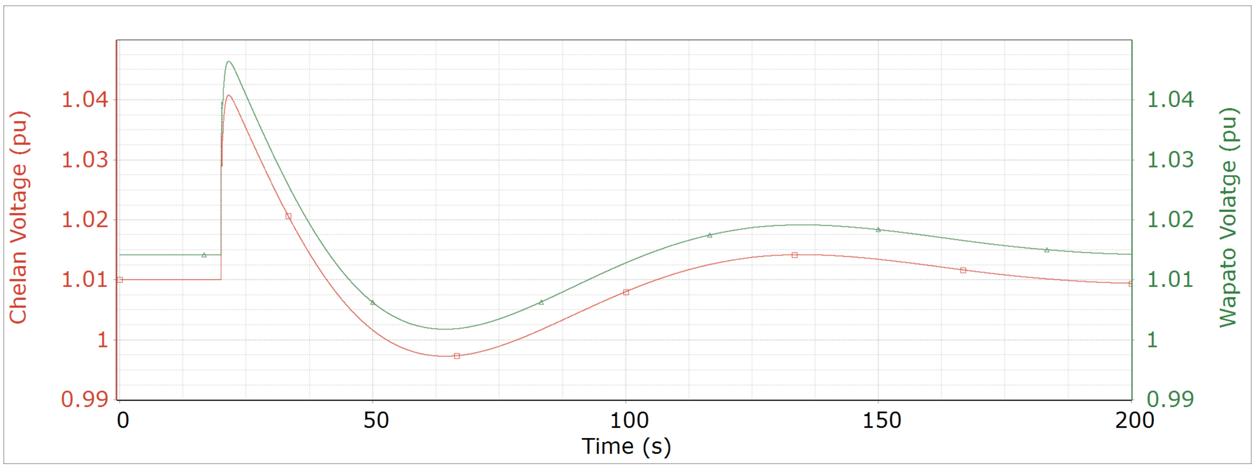


(b)

Figure 4-19: Dynamic frequency response of Chelan hydro to step load increase while islanding during the moment of islanding considered in timeseries dispatch simulation. Although the step decrease is just 2.42 MW, it results in a considerable frequency deviation of 0.54 Hz.

Black Start:

To analyze black start capability, we considered S3 with maximum loading condition. The hydropower plants will not be able to support the entire 77.28 MW load. Therefore, a portion of microgrid load is curtailed, with final load following black start at 56.3 MW. We assume the curtailed load is proportionally distributed over the four load centers based on the peak load. For black start, we considered the plant switches to isochronous mode instead of droop control mode.

First, we tried black starting the system with 5 MW generation steps. Extremely large frequency excursions (around 0.06 pu or 3.6 Hz) were seen for the first load stepping, as shown in Figure 4-20. The subsequent load stepping results in smaller frequency deviation but the peak is still around 0.04 pu (2.4 Hz). Similar fluctuations were seen in the voltage response. Such deviations would immediately trigger system voltage and frequency protection settings and the system will not be able to black start.

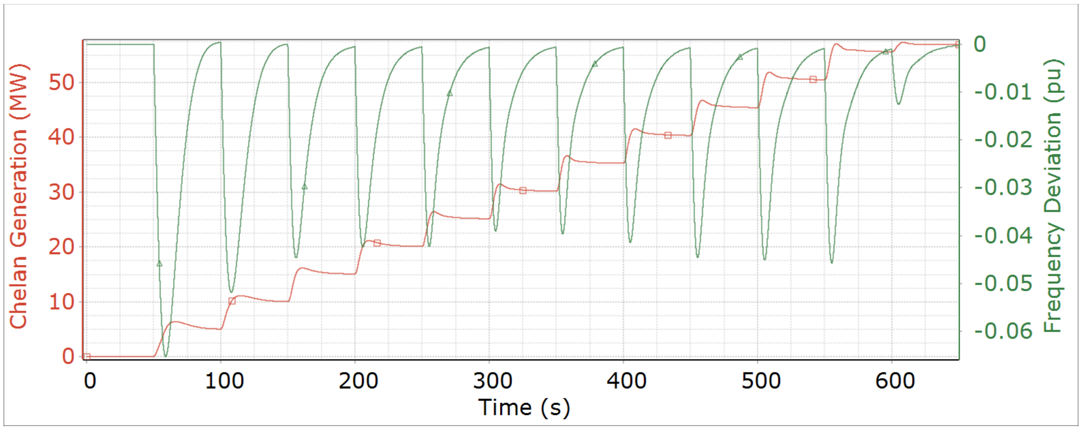


Figure 4-20: Black start with 5 MW load stepping results in large frequency deviations of up to 3.6 Hz.

We decreased the step size to 2 MW, 1MW and up to 0.5 MW. The first 1000 s for each case is shown and compared in Figure 4-21. Although frequency response improves with 2 MW step size, it still leads to large frequency excursions of close to 1.5 Hz peak. This will likely trigger frequency protection relays and trip off the hydropower units, thus, failing to black start. For load step sizes of 1 MW or 0.5 MW, the frequency deviations are well within 1 Hz. Thus, the system will be able to black start for 1 Mw or below load steps.

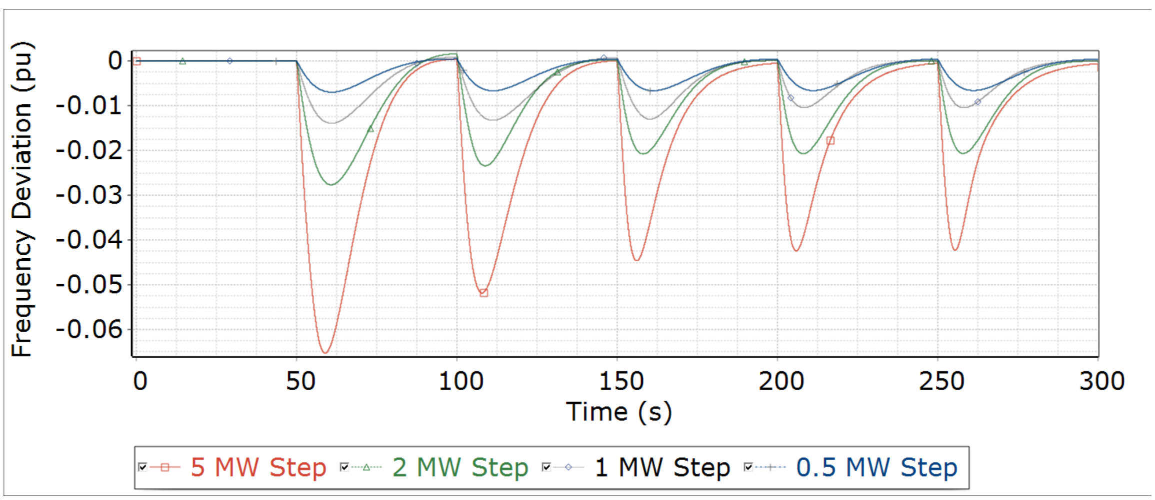


Figure 4-21: Comparing frequency deviation for black start with load stepping of 5 MW, 2 MW, 1 MW and 0.5 MW.

With Investment

Two investment options were considered for steady-state analysis. The first option involved adding a new battery storage sized 32 MWh. A 3.3 h rating is considered with maximum power capacity of 10 MW. The second investment option included adding a new hydropower turbine generator unit to the Chelan Lake hydropower plant. Figure 4-22 shows the seamless islanding under S1 with maximum export. Implementing either solution will significantly improve the frequency response. However, the frequency deviation seen for the investment cases are also very high and likely to trigger system frequency protection trip settings.

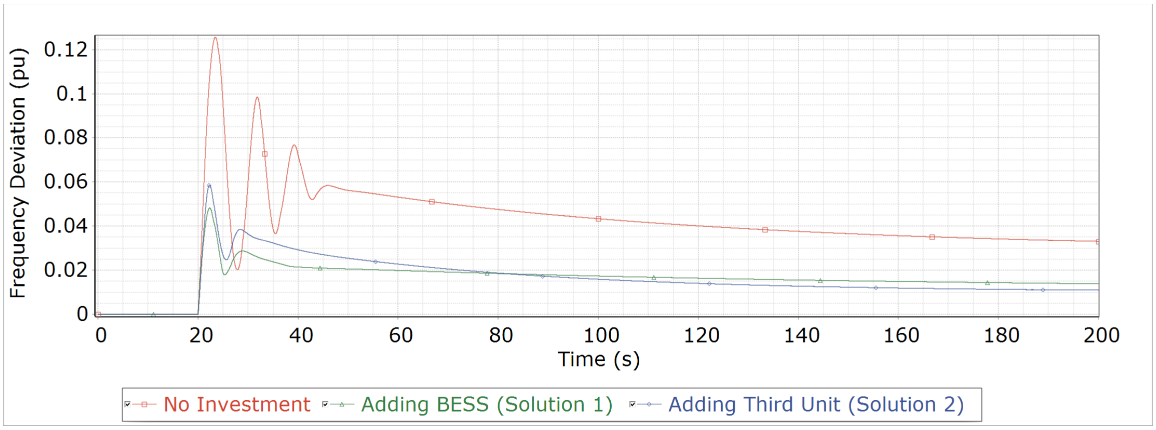
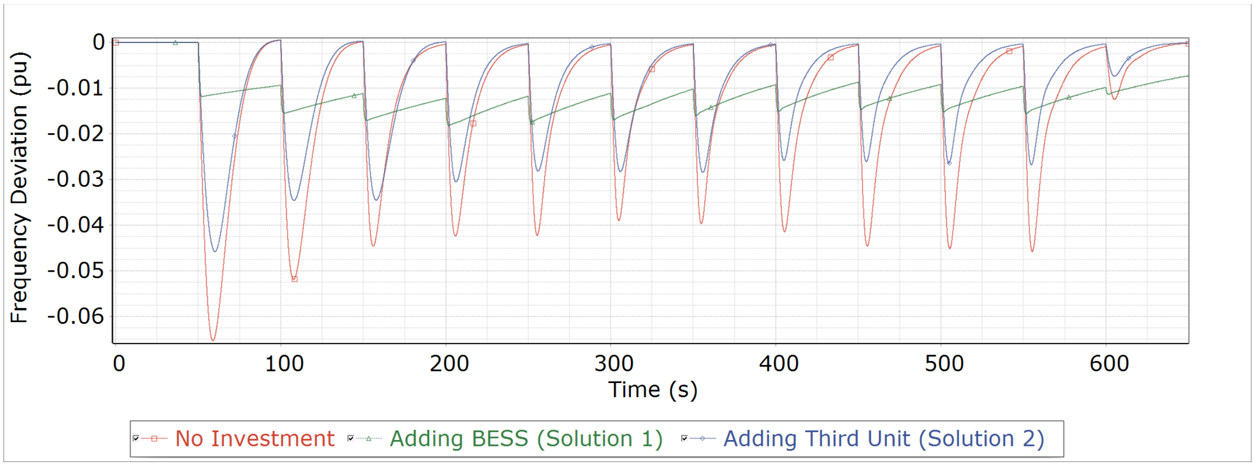


Figure 4-22: Dynamic frequency response of Chelan hydro to largest step load decrease while islanding during maximum grid export considering two proposed solutions.

Figure 4-23(a) shows the frequency response for black start S1 with maximum export for 5 MW stepping. The addition of BESS results in accepted frequency deviation with 1 Hz. Although the additional unit results in better frequency response than the no investment case, the frequency deviations are still large enough to trigger the frequency protection settings. Figure 4-23 (b) shows the voltage response for 5 MW stepping. The addition of new units doesn't result in any significant improvement in voltage response. However, the addition of BESS results in better voltage response with decreased voltage overshoots.



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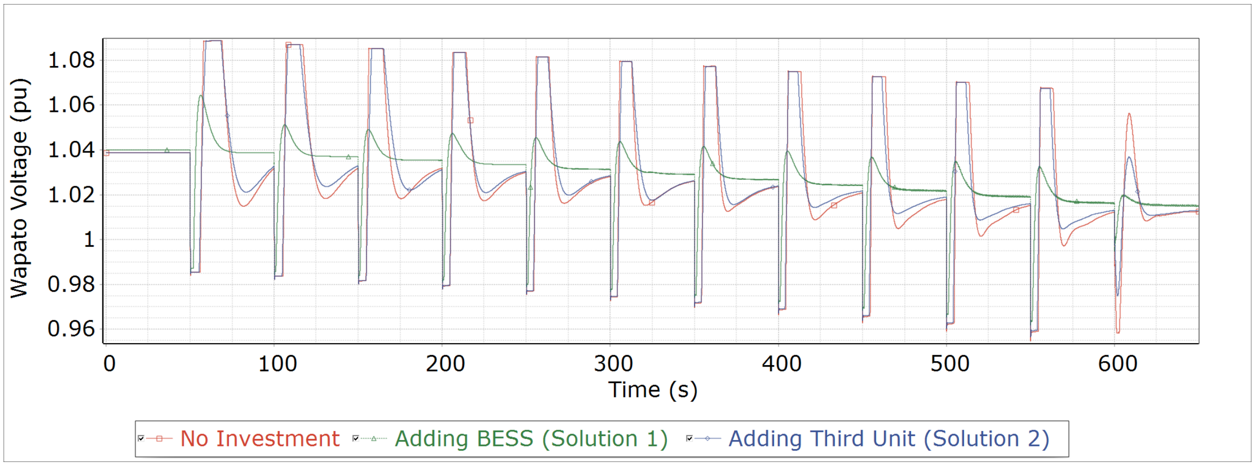

(b)

Figure 4-23: Dynamic frequency and voltage response of Chelan hydro during black start with 5 MW load stepping considering two proposed solutions. Frequency response improves with both. However, the addition of BESS results in better frequency and voltage response. No improvement in voltage response using solution 2.

Figure 4-24 shows the hydropower generation and BESS power output during the black start. Although the load is applied in step fashion, the hydropower generation ramps gradually. The BESS immediately steps up its power generation to support this operation.

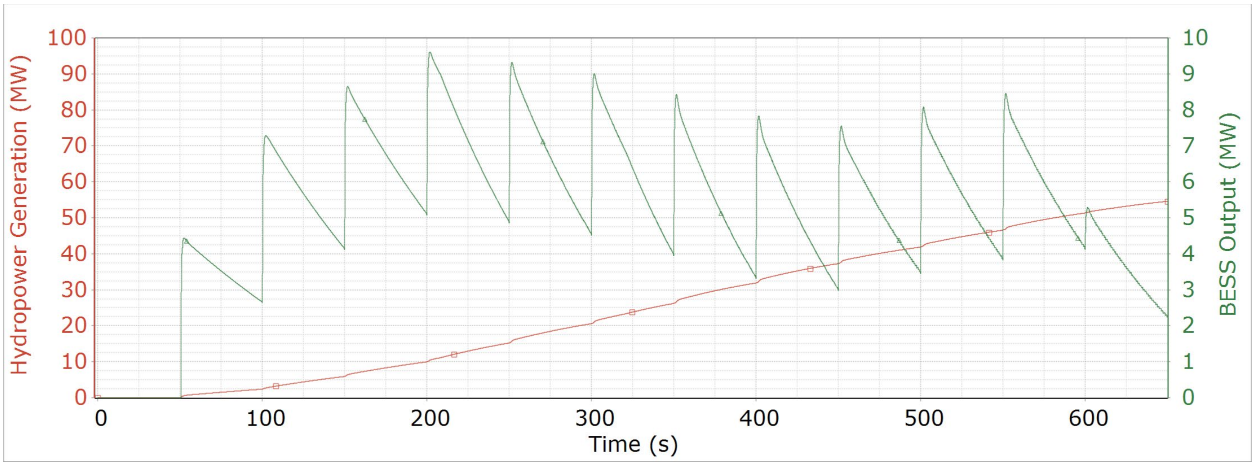

Figure 4-24: Hydropower plant and BESS power output during black start for solution 2.

Figure 4-25 shows the hydropower generation and BESS residual energy and energy used over the black start period considering 32 MWh energy capacity. The BESS is at 75% SOC at the start of black start. Over the course of black start, close to 2.4% of BESS energy was used. This shows that the energy rating of the BESS selected for the steady state operation can provide the microgrid black start.

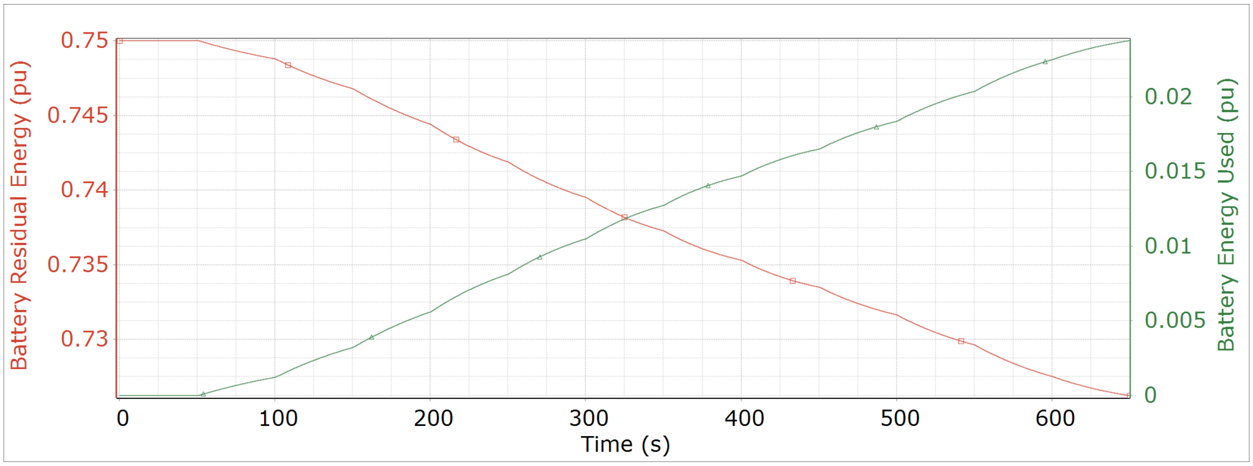

Figure 4-25: BESS residual energy and energy used during black start process considering solution 2.

4.1.2.6 Key Takeaways

The Chelan Lake hydropower plant demonstrated strong ability to form microgrid to support Chelan district, Union Valley, Mansion and Wapato load centers. The scoring of wildfire-resilience microgrid metrics for Chelan Lake hydro is shown in Figure 4-26. In terms of microgrid formation, it scores 5 out of 5, meeting all specified categories. In terms of storage capacity and reactive power response, it demonstrates strong capability scoring 5 out of 5. Inertial response which is scored relative to other hydropower plants considered in HRD in terms of inertia constant is scored 3 out of 5. Similarly, the ramping capability scored based on the ramping time delays and ramping rate limits is also scored 3 out of 5. This indicates the need for fast acting assets such as batteries and supercapacitors to support the inertial and primary frequency response of the microgrid.

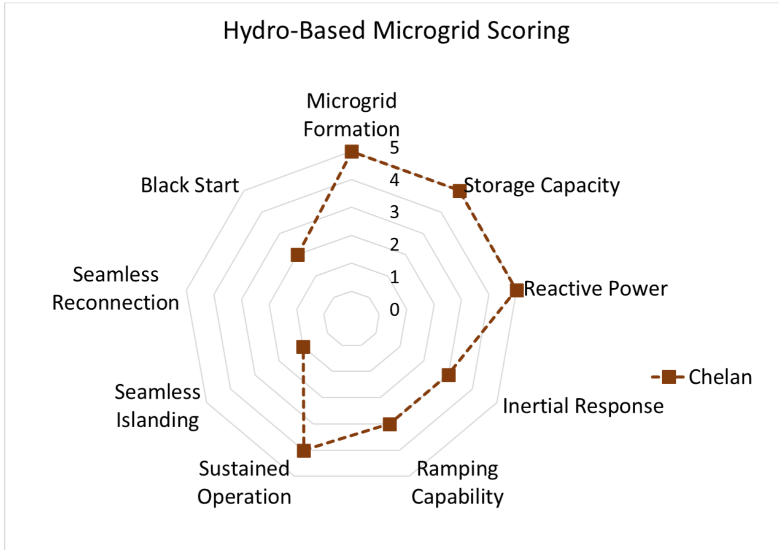

Figure 4-26: Metric scores for Chelan hydropower plant. Additional analysis and testing necessary to score seamless reconnection.

In terms of performance metrics, the hydropower plant was adequate in sustained operation category. Although not able to support the entire load, it is able to meet the majority of load demand in all four load centers. Therefore, it is scored 4 out of 5. In terms of seamless islanding, the hydropower plant failed to switch between grid connected to islanded mode in possible extreme cases of generation-load imbalance. The hydropower plant also fails to seamlessly island for the outage instant considered in the steady state analysis. Therefore, the hydropower plant scores 1 out of 5 in seamless islanding category. By itself, it was not able to black was for 5 MW and 2 MW step sizes but showed adequate frequency response with 1 MW or 0.5 MW load step sizes. However, considering the final load it has to black start, those are very small load steps. Therefore, it is scored 2 out of 5 in black start category. With new investment, it showed adequate frequency performance during black start, particularly when battery energy storage is considered. Regarding seamless reconnection, the microgrid performance depends on grid reconnection strategy, associated control system components and human factors. It needs to be scored based on performance during real plant operation.

4.2 Techno-Economic Impact Assessment

Once the future wildfire risk is evaluated for a given region, candidate hydropower resources are selected to be used as a part of a microgrid for resilience during wildfire events. There are two operational scenarios: normal operation (Figure 4-27). In the first scenario, the candidate hydropower resource is considered a part of the normal utility supply. In the second scenario, during wildfire event/outage operation, the hydropower resource creates a microgrid with energy storage and other supplemental generation, and the utility supply is disconnected. Both scenarios may consider the same or different energy and demand tariffs.

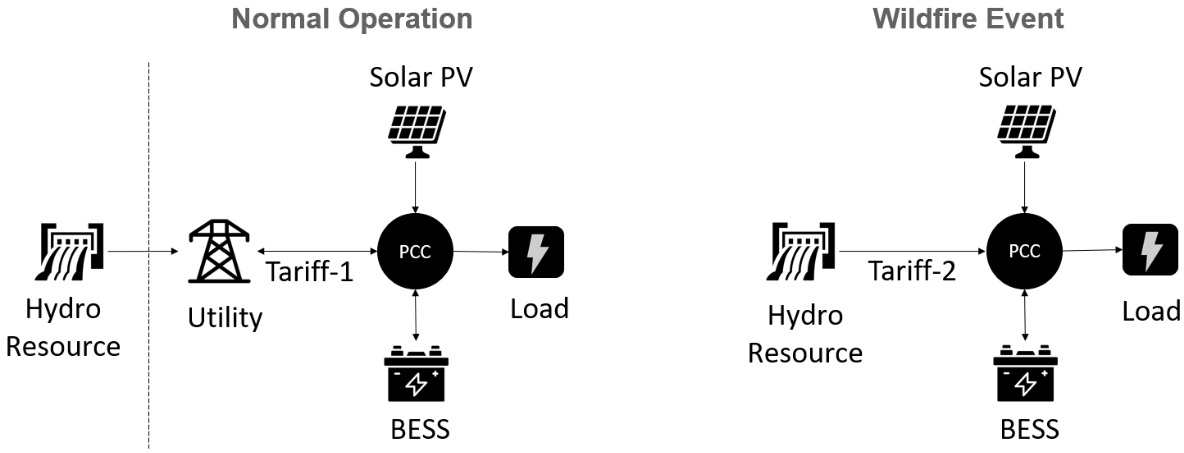

Figure 4-27: Operational scenarios for normal and wildfire event for a hydro-based microgrid.

4.2.1 Techno-Economic Use Case 1: Undisclosed Site and Local Communities

4.2.1.1 Scenario Modeling and Assumptions

For the purpose of the Use Case 3 study illustrated in this section, a hydropower plant is selected in the Idaho region which has historically had a high risk for wildfires. The available hydro capacity is 2.8 MW and the peak load for the local region to be served is 6 MW. Xendee, a GAMS-based microgrid decision tool is used for the techno-economic analysis to determine the required battery capacity, PV capacity, and possibly additional hydro capacity to ride through a wildfire outage period of two weeks. Different cases considered in this work are differentiated by whether additional hydro capacity can be installed or not, and the minimum size of the hydro plant.

4.2.1.2 Techno-Economic Evaluation

The dispatch plots in Figure 4-28, Figure 4-29 , Figure 4-30, and Figure 4-31 show the 24-hr dispatch plots for various cases where there is curtailment of excess hydro during periods of low load, as well as the deployment of battery storage when the available hydro dispatch capacity is exceeded by the load. Additional hydro capacity installation is constrained for Scenario 1 but allowed for Scenario 2a and Scenario 2b. All the cases show substantial energy charge and demand charge savings, given the resources that have been optimized to ride through wildfire are available to be dispatched during normal operation periods as well. Hence, in addition to providing resilience, these supplemental resources also provide grid services and value stacking.

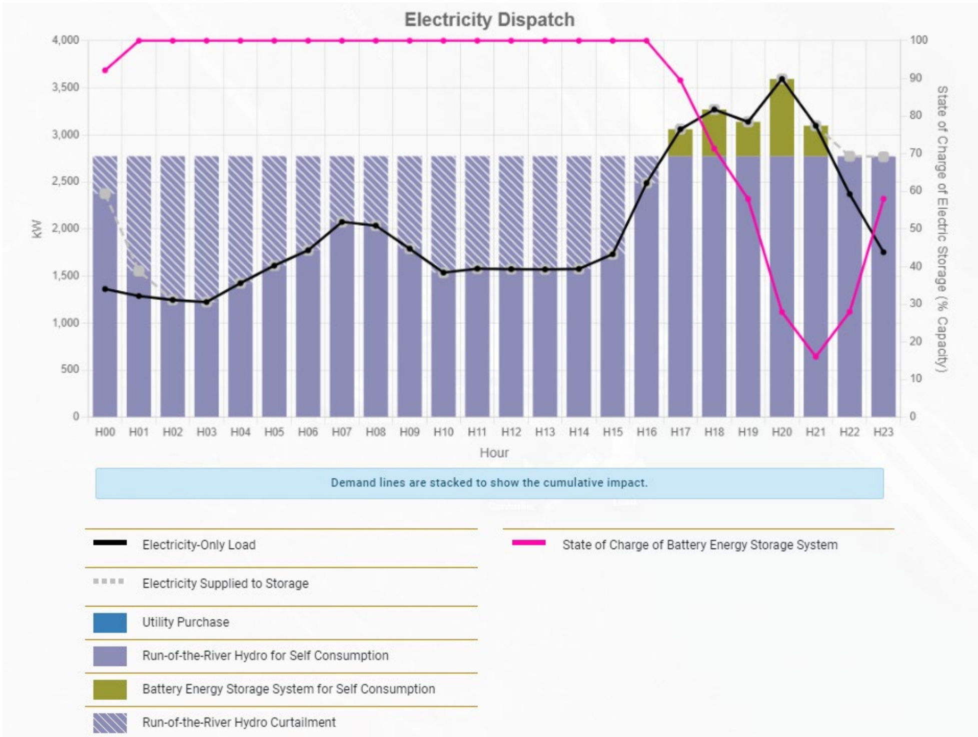

Figure 4-28: Use case Site 3, Scenario 1 24-hr outage operation.

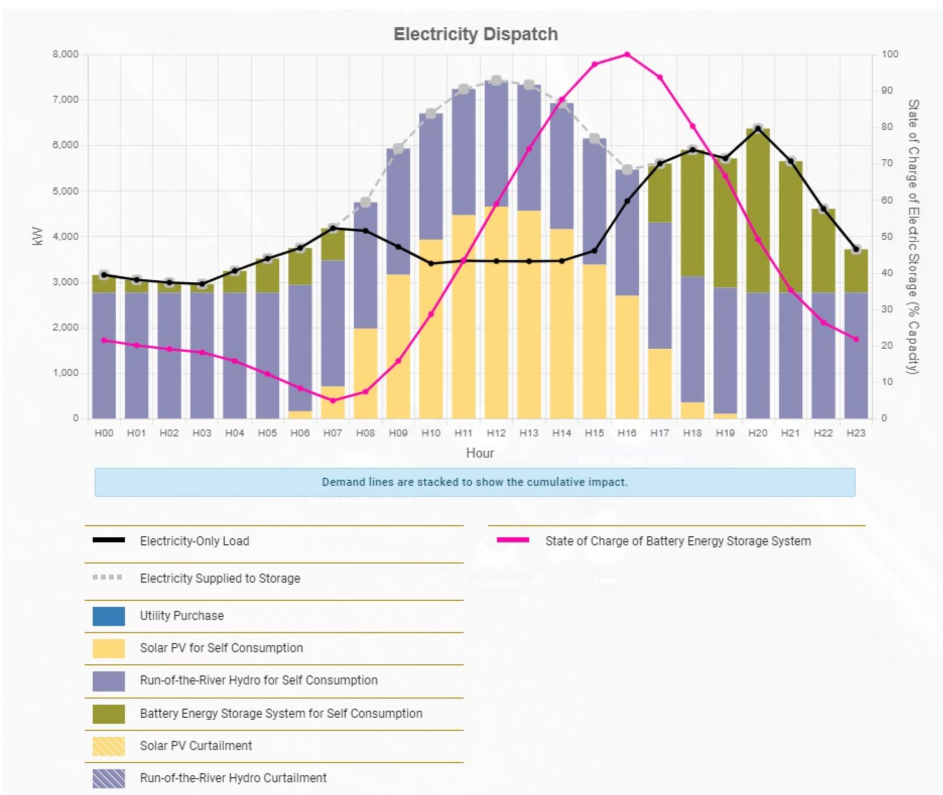

Figure 4-29: Use case Site 3, Scenario 2 24-hr outage operation.

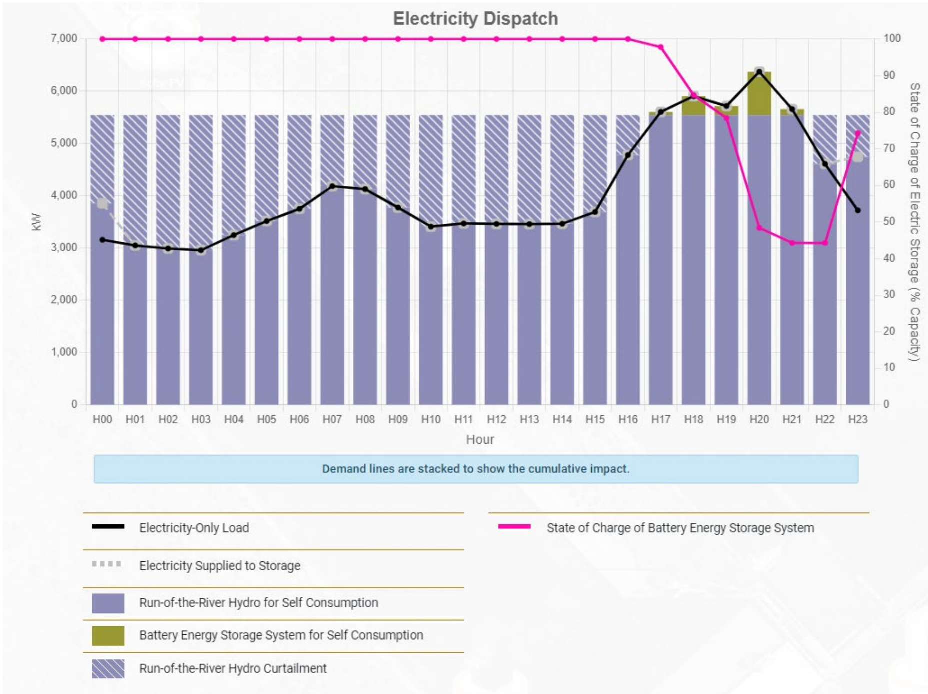

Figure 4-30: Use case Site 3, Scenario 2a 24-hr outage operation.

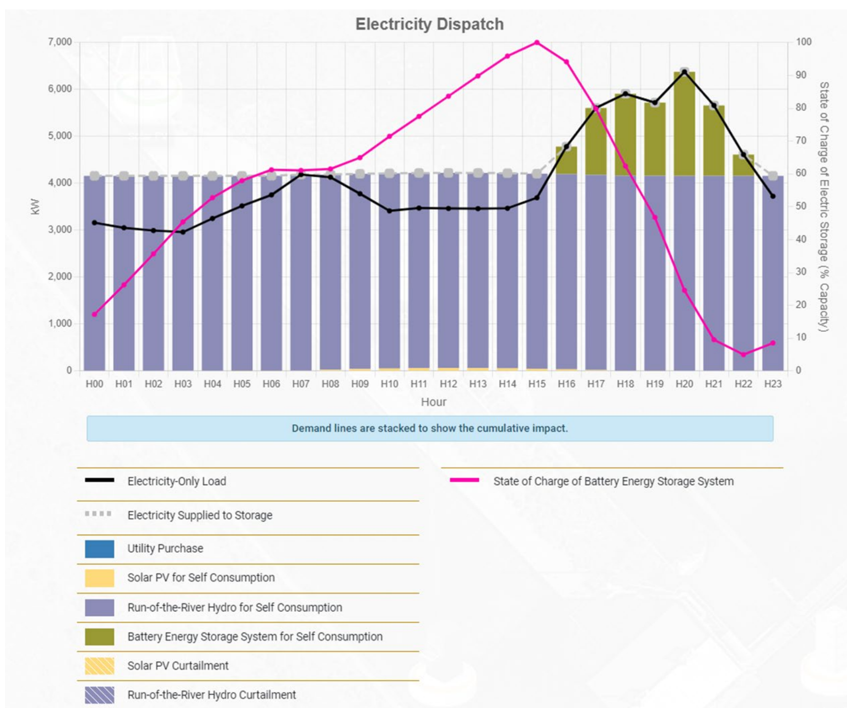

Figure 4-31: Use case Site 3, Scenario 2b 24-hr outage operation.

4.2.1.3 Key Takeaways

Table 4-3 shows some of the key energy and demand charge assumptions for the study, as well as the techno-economic metrics from the optimization. Given that a new energy source of a substantial capacity is added in all the cases, there are annual energy charge savings on top of demand charge savings that result from peak shaving using the battery. Based on the installation costs considered, we see that a mix of hydro, PV, and battery storage is the most ideal solution with the lowest upfront investment cost, shortest break-even period, and the highest savings. This section presented a use case on the feasibility of harnessing grid resilience from hydropower resources during wildfire-induced outages operating in islanded microgrid mode.

Table 4-3: Key assumptions and techno-economic metrics for Site 3.

		Site 3, Case 2	Site 3, Case 2a	Site 3, Case 2b
Inputs/ Assumptions	**Peak Load**	6 MW		
	Energy Charge	$0.086/kWh up to 2000kWh, $0.0981/kWh above 2000kWh		
	Demand Charge	$10/kW	$10/kW	$10/kW
	Existing Hydro	2.8 MW (1 unit of 2.8 MW)	2.8 MW (1 unit of 2.8 MW)	2.8 MW (2 units of 1.4 MW)
Optimized Decisions	**New Hydro**	-	2.8 MW (1 unit)	1.4 MW (1 unit)
	New PV	6.69 MW	-	90.7 kW
	New Battery	23 MWh	3.04 MWh	11.1 MWh
Techno-Economic Metrics	**Energy Charge Reduction per year**	$531,000	$611,000	$610,000
	Demand Charge Reduction per year	$299,000	$327,000	$324,000
	Simple Project Break-Even	>20 years	11 years	10 years
	Load Served LCOE	$0.0501/kWh	$0.0474/kWh	$0.0443/kWh
	Investment Cost (upfront)	$15.2 million	$9.6 million	$8.5 million

4.2.2 Techno-Economic Use Case 2: Hydropower plants in Snoqualmie, WA and local communities

4.2.2.1 Scenario Modeling and Assumptions

For the purpose of the Use Case study illustrated in this section, a hydropower plant is selected in Washington's Snoqualmie region which has historically had a high risk for wildfires. The available hydro capacity is 14 MW and 39.2 MW for Plants 1 and 2 respectively, for a total of 53.2 MW. Four nearby load centers are chosen, with a peak demand of 17 MW, 12 MW, 11.2 MW and 1 MW respectively. Xendee decision tool is again used for the techno-economic analysis to determine the required battery capacity, PV capacity, and possibly additional hydro capacity to ride through a wildfire outage period of two weeks. The different cases and modelling assumptions for this Use Case are differentiated from Use Case 3, in that for this site, we try to focus only on the wildfire event and size the system adequately to serve our selected loads in case of a PSPS event. To achieve this, we take the following steps in our optimization:

1. Run time series optimization for only hydro plants, constraining new battery and new PV to zero.
2. Identify days in July-Aug-Sept where hydro generation is lower than load and select a 2-week window.
3. Reduce hydro generation and the load to zero for the rest of the year.
4. Run time series optimization to find PV, battery and capacity hydro required for the two weeks.
5. Run the optimization again with the load for the entire year with the PV, battery and hydro capacity fixed from the previous step.

4.2.2.2 Techno-Economic Evaluation

Figure 4-32, Figure 4-33, and Figure 4-34 show the 2-week dispatch plots, and Figure 4-35, Figure 4-36, and Figure 4-37 show the 24-hr dispatch plot for those same cases. There is curtailment of excess hydro during periods of low load, as well as the deployment of battery storage when the load exceeds the available hydro dispatch capacity. Additional hydro capacity installation is allowed for all the cases.

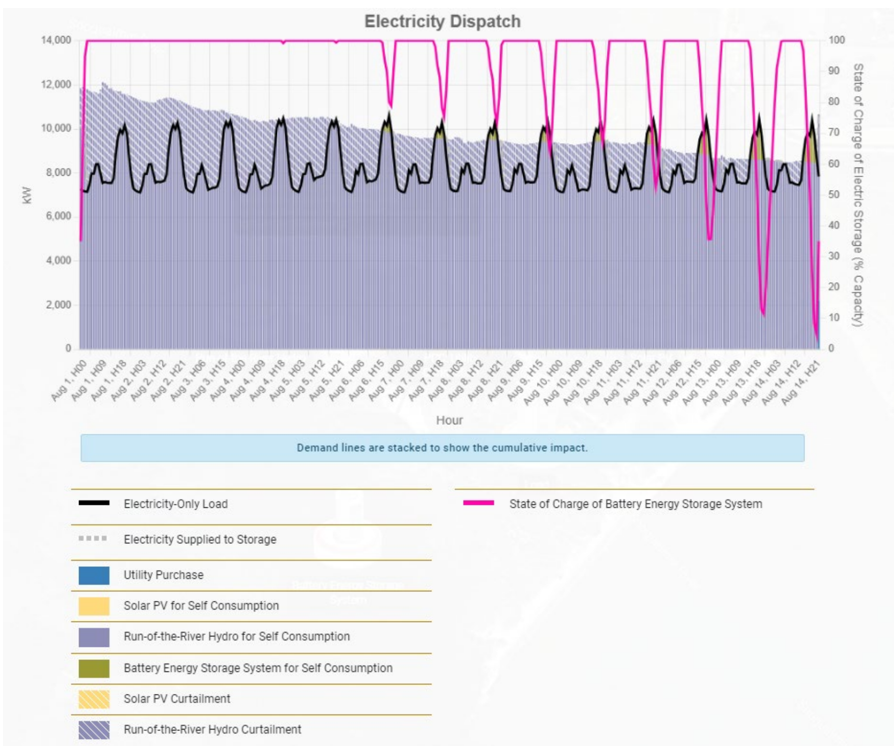

Figure 4-32: Use case Site 4, Scenario 1, 2-week outage operation.

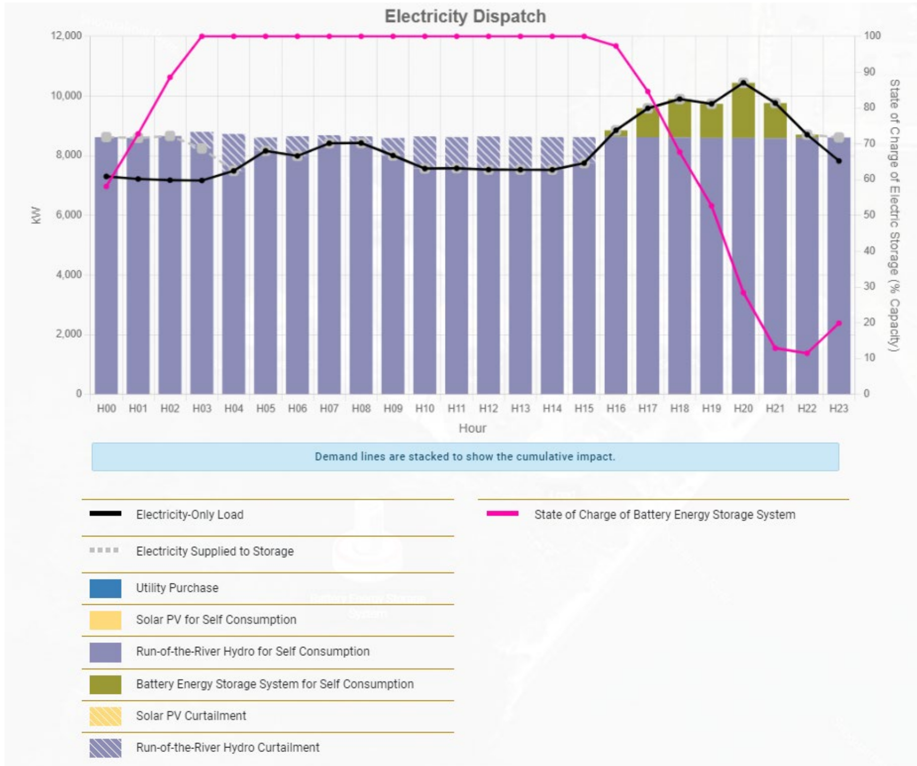

Figure 4-33: Use case Site 4, Scenario 1, 24-hr outage operation.

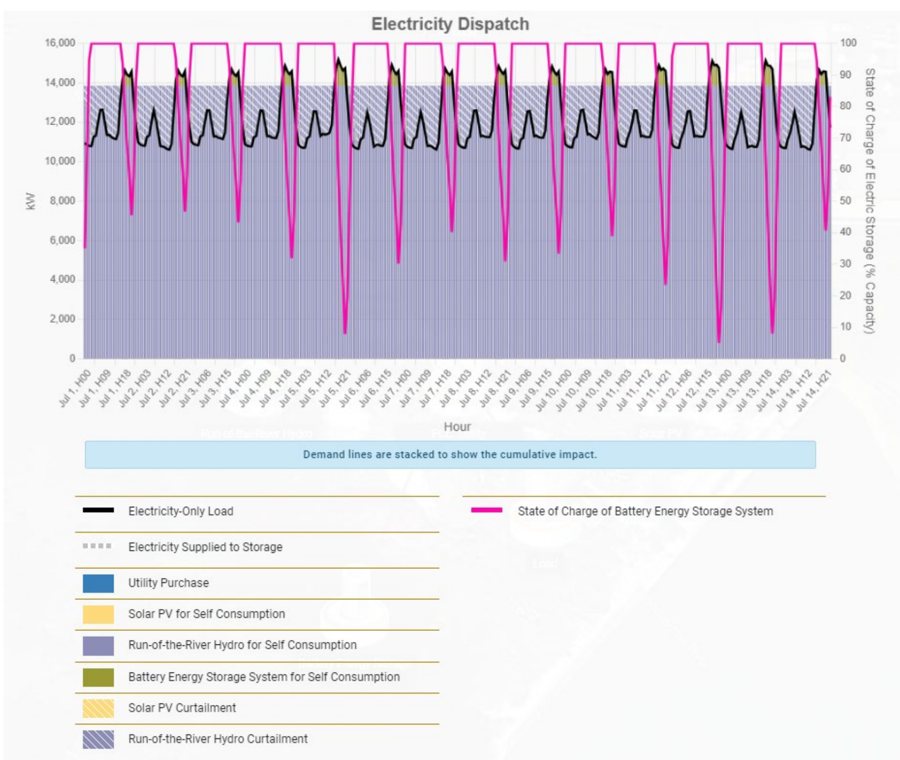

Figure 4-34: Use case Site 4, Scenario 2, 2-week outage operation.

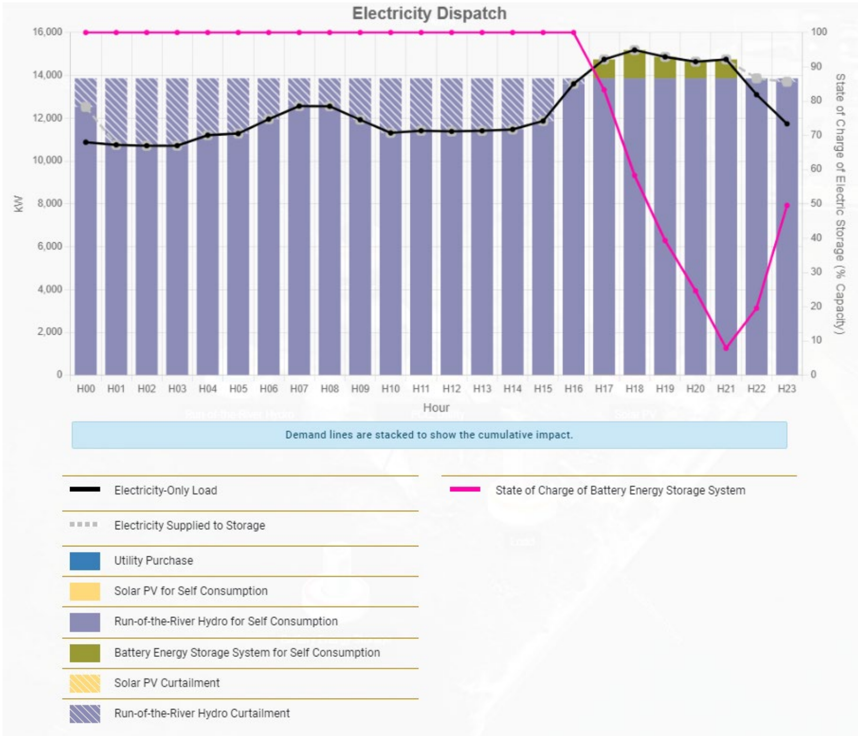

Figure 4-35: Use case Site 4, Scenario 2, 24-hr outage operation.

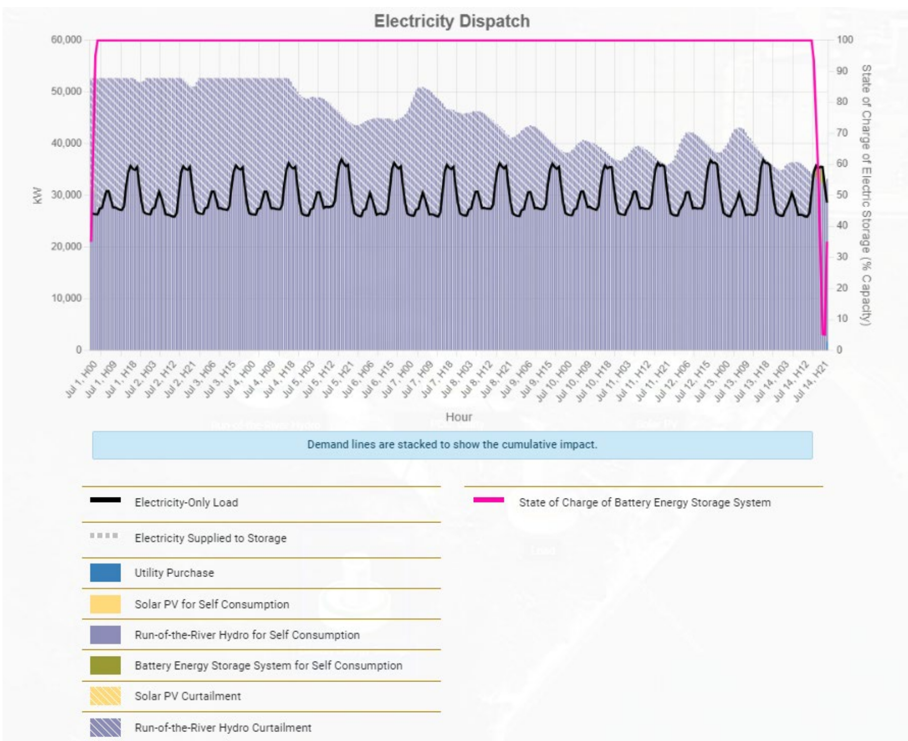

Figure 4-36: Use case Site 4, Scenario 3, 2-week outage operation.

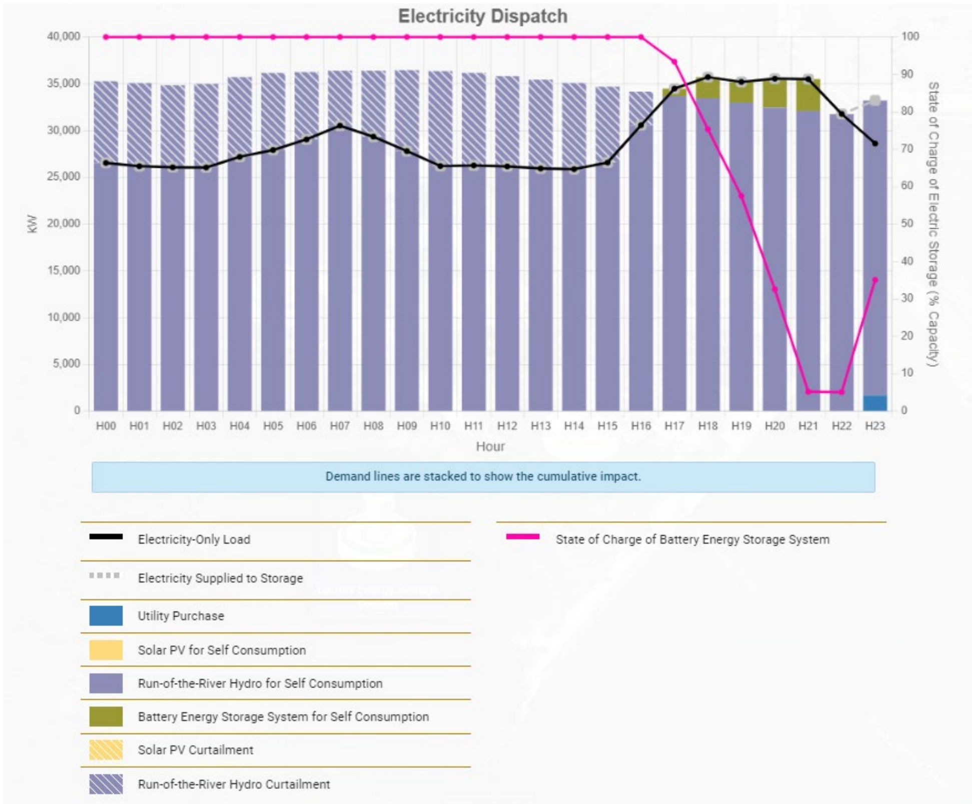

Figure 4-37: Use case Site 4, Scenario 3, 24-hr outage operation.

4.2.2.3 Key Takeaways

Table 4-4 shows some of the key energy and demand charge assumptions for the study, as well as the techno-economic metrics from the optimization.

All the cases for this site show only demand charge savings, and negative energy charge savings. This is because the optimization does not allow any additional hydro to be added, while the added PV capacity is very low. Hence, in the absence of any new substantial energy resources, there are no energy charge savings and the additional charging of battery for use during outages is reflected as a negative energy charge saving. However, the presence of battery resource allows peak shaving during periods of high demand from the grid during non-outage scenarios, which is reflected as demand charge savings. Annually, this is still a net positive in terms of savings. Hence, in addition to providing resilience, these supplemental resources also provide grid services and value stacking. This section presented a use case on the feasibility of harnessing grid resilience from hydropower resources during wildfire-induced outages operating in islanded microgrid mode, where only outage operation is prioritized and investments are not made to additionally curtail demand and energy charges throughout the year.

Table 4-4: Key assumptions and techno-economic metrics for Site 4.

		Site 4, Case 1	Site 4, Case 2	Site 4, Case 3
Inputs/ Assumptions	Peak Load	11.2 MW	17 MW	41.2 MW
	Energy Charge	$0.1225/kWh		
	Demand Charge	$12.58/kW (Oct-Mar), $9.21/kW (Apr-Sept)		
	Existing Hydro	14 MW	14 MW	53.2 MW
Optimized Decisions	New Hydro	-	-	-
	New PV	6.45 kW	4.71 kW	11 kW
	New Battery	8.45 MWh	5.88 MWh	13.8 MWh
Techno-Economic Metrics	Energy Charge Reduction per year	-$54,000	-$22,000	-$65,000
	Demand Charge Reduction per year	$235,000	$199,000	$469,000
	Simple Project Break-Even	18 years	13 years	13 years
	Load Served LCOE	$0.1692/kWh	$0.1581/kWh	$0.1697/kWh
	Investment Cost (upfront)	$3.2 million	$2.2 million	$5.2 million

4.3 Socioeconomic Analysis

4.3.1 Socioeconomic Analysis

Socioeconomic factors may also be considered when identifying potential sites for hydro-based microgrids. Here, we use available datasets to identify vulnerable populations at risk of wildfire-induced grid outages that have proximity to potential hydropower resources.

4.3.1.1 Methodology

To quantify vulnerability across the WECC study area, we use the Centers for Disease Control and Prevention's (CDC) U.S. Social Vulnerability Index (SVI). This dataset was originally produced at the census tract level based on 15 variables encompassing four themes (Socioeconomic, Household Composition & Disability, Minority Status & Language, and Housing Type & Transportation). The index values range between 0 (least vulnerable) to 1 (most vulnerable) based on the percentile among all U.S. census tracts. Here, we use the SVI for 2018, which has been processed to a 1 km standard grid by NASA's Socioeconomic Data and Applications Center (CIESIN 2021). We found the mean SVI value for each 50 50 km^2 cell in our study grid.

To screen for areas with elevated social vulnerability and wildfire risk, we first identified 50 km^2 grid cells that met both two criteria: 1) SVI score greater than 0.6 and 2) intersecting an electrical line with greater than 0.1% probability of non-operation based on the WREST Tool (Figure 4-38). We conducted this analysis for historical fire risk and our projections for 2045-2075. For future projections, we focus only on climate scenario RCP4.5, deemed more realistic than RCP8.5 based on present-day trajectories. Finally, we visually identified which priority grid cells were near known non-powered dams based on the National Inventory of Dams (NID 2015).

4.3.1.2 Results

We found that areas characterized by both higher social vulnerability and risk of wildfire-induced electrical outages were dispersed across the WECC region (Figure 4-38). Present-day priority zones meeting our two criteria were largely concentrated in southwest Idaho, northern Nevada, Utah, Arizona, and southern California. When examining future wildfire risks, all present-day priority zones remained high-priority areas for scenario RCP4.5. We also see an expansion of priority zones under future wildfire risk, most notably in central Washington, Oregon, California, and Nevada (Figure 4-38).

When we compare these priority zones with the current distribution of non-powered dams, we find five central candidate locations for future evaluation (Figure 4-38).

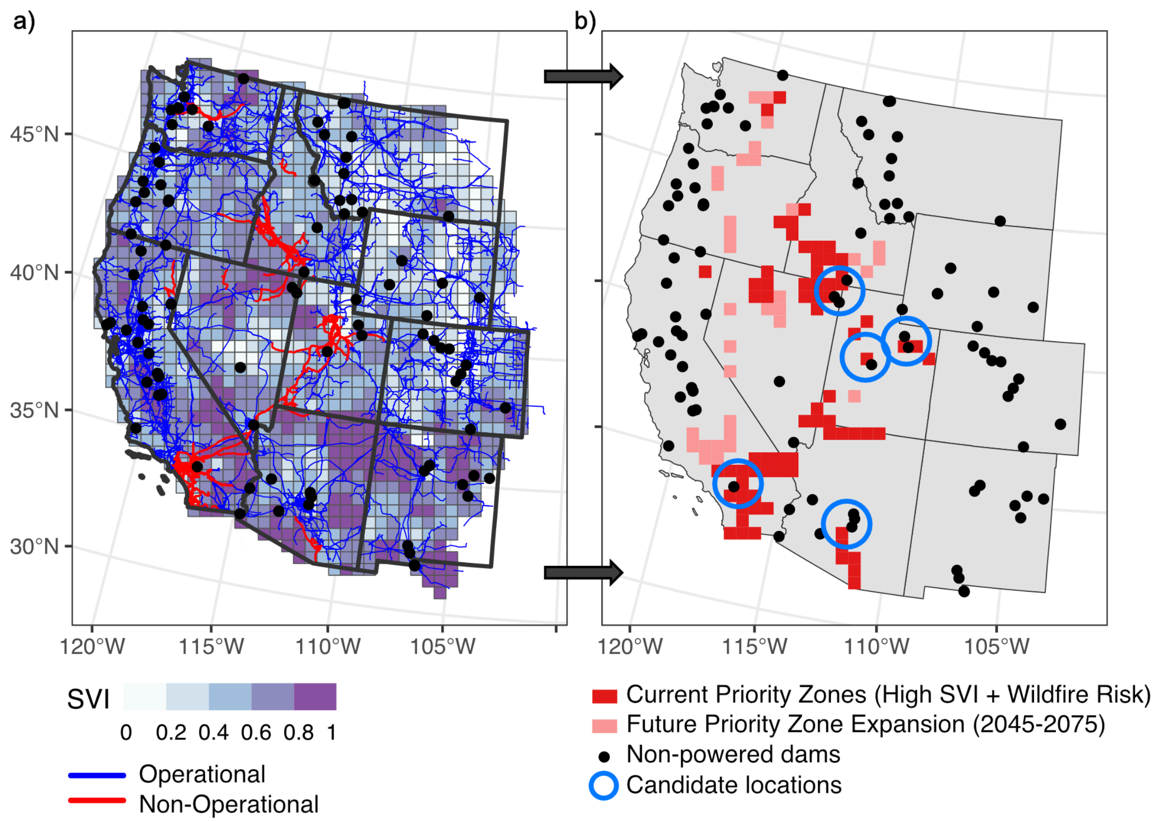

Figure 4-38: Identifying locations with high vulnerability and potential hydropower resources. a) Methodology overview portrayed by a map of non-operational gridlines at 0.1% probability of wildfire outage (red) overlaid on the Social Vulnerability Index (SVI). b) Zones which meet the dual criteria of high social vulnerability (SVI > 0.6) and high wildfire risk (probability of outage > 0.1%) for present-day (red) and future climate (RCP4.5 2045-2075, light red). Note that priority zones only expanded into the future time period, so red indicates priority zones in both time periods.

5 Summary and Future Directions

The report outlines a comprehensive framework for conducting a step-by-step techno-economic evaluation of hydropower-based microgrid solutions aimed at bolstering grid resilience during wildfire-induced transmission outages. This framework encompasses the development of a sophisticated tool capable of translating wildfire risk metrics into power system transmission outages, leveraging both historical data and predictive models to enhance accuracy and effectiveness. Additionally, a suite of metrics has been meticulously curated to assess the feasibility of hydropower resources operating in islanded mode following wildfire-related disruptions.

These foundational elements serve as the cornerstone for identifying and evaluating potential use cases for hydro-based microgrids within the context of grid resiliency. To further elucidate the applicability and efficacy of this approach, detailed techno-economic assessments were conducted at four distinct sites. The first two cases delved into the inherent grid capabilities of hydropower resources, shedding light on their potential to mitigate transmission outages during wildfire events. Conversely, the latter two cases scrutinized the techno-economic ramifications of deploying hydro-based microgrids, necessitating additional investments to justify their implementation under normal operating conditions.

Amidst escalating occurrences of extreme weather phenomena such as heatwaves and wildfires, this study presents a pioneering concept: the integration of hydro-based microgrids as a means of furnishing grid resiliency to customers, particularly critical infrastructure facilities. Looking ahead, a forward-looking agenda aimed at exploring the feasibility of mobile microgrid operations utilizing shared resources and equipment, which will be explored in a future study. This innovative approach holds promise in facilitating rapid deployment to targeted sites based on wildfire propagation patterns and prediction modeling, thereby augmenting the adaptability and efficacy of microgrid systems in response to evolving wildfire scenarios.

In summary, this report represents a significant advancement in the realm of grid resiliency and disaster preparedness, offering a comprehensive framework and toolset for evaluating the viability and potential impact of hydropower-based microgrid solutions in mitigating the adverse effects of wildfire-induced transmission outages. Through continued exploration and innovation, these findings hold the promise of fostering greater resilience and reliability within our energy infrastructure amidst an increasingly volatile environmental landscape.