Technoeconomic Studies for the Banner Mountain Energy Storage Project

Valuation Framework Test Case Study

December 2022

ANL-22/88

Foreword

This project was funded by the United States Department of Energy's (DOE's) Water Power Technologies Office (WPTO) under its HydroWIRES initiative and carried out by a collaborative consisting of five DOE National Laboratories led by Argonne National Laboratory (Argonne). In addition to Argonne, the project team members included Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory.

The project team collaborated with Absaroka Energy and Rye Development/Copenhagen Infrastructure Partners, whose proposed pumped storage hydropower (PSH) projects (Banner Mountain by Absaroka Energy and Goldendale by Rye Development and Copenhagen Infrastructure Partners) were selected by DOE/WPTO through the Notice of Opportunity for Technical Assistance process. For these two projects, the project team conducted various technoeconomic studies to assess the value of their potential services and contributions to the grid.

A Technical Advisory Group (TAG) was established to provide advice and recommendations to the project team. The TAG included experts from grid operating organizations, utility companies that own and operate PSH plants, PSH developers, equipment manufacturers, consulting companies, industry research organizations, regulatory agencies, and other stakeholders. The following experts participated in the project as members of the TAG:

1. Denis Bergeron (Maine Public Utilities Commission)
2. Norman Bishop (Knight Piesold)
3. Brent Buffington (Southern California Edison)
4. Wei Dang (Puget Sound Energy)
5. Peter Donalek (Stantec)
6. Christine Ericson (Illinois Commerce Commission)
7. Donald Erpenbeck (Stantec)
8. Robert Fick (Los Angeles Department of Water and Power)
9. Scott Flake (Scott Flake Consulting)
10. Levi Gilbert (Pacific Gas & Electric)
11. Edward Hansen (Pacific Gas & Electric)
12. Elaine Hart (Portland General Electric)
13. Udi Helman (Helman Analytics)
14. Michael Manwaring (McMillen Jacobs Associates)
15. Jay Mearns (Pacific Gas & Electric)
16. Denis Obiang (Los Angeles Department of Water and Power)
17. Aidan Tuohy (Electric Power Research Institute)
18. Bruno Trouille (Mott McDonald)
19. Robert Williams (Puget Sound Energy)

In addition to the TAG, the Project Team actively engaged with the hydropower industry and held workshops and seminars at key industry events, such as the National Hydropower Association's Water Power Week and at the HydroVision International conference. The main purpose of these events was to disseminate the information on the development of a valuation framework for PSH projects and obtain feedback from the industry. A key objective was for the PSH valuation framework developed during this project to be publicly available for use by the hydropower industry and stakeholders.

In engaging the hydropower industry and stakeholders, the project team closely collaborated with the National Association of Regulatory Utility Commissioners (NARUC). NARUC also provided technical support and assisted the project team in organizing the industry outreach events, workshops and webinars, as well as in coordinating and facilitating the interactions with the TAG.

Acknowledgments

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The project team would like to express their sincere gratitude to the DOE's WPTO for recognizing the need for this type of research and for funding this effort. Alejandro Moreno, Timothy Welch, Samuel Bockenhauer, Kathryn Jackson, Patrick Soltis, and others at WPTO were instrumental in guiding and supporting the project team and coordinating the interactions with the hydropower industry throughout the project. Special thanks go to Samuel Bockenhauer for his extraordinary management and coordination of the project within the HydroWIRES Initiative.

The project team closely collaborated with the Absaroka Energy, LLC, the developer of the Banner Mountain pumped storage hydropower (PSH) project; and with the Copenhagen Infrastructure Partners and Rye Development, developers of the Goldendale Energy Storage Project. The collaboration with these industry partners and their consultants was outstanding throughout the project. We would like to express our gratitude to all members of the Banner Mountain and Goldendale teams, especially to Eli Bailey, Rhett Hurless, Daniel Lloyd, Matt Pevarnik, and Antoine St-Hilaire on the Banner Mountain team, and to Nathan Sandvig, Erik Steimle, Ushakar Jha, Rick Miller, Carl Mannheim, Michael Rooney, and others on the Goldendale team.

The project team would also like to thank the members of the Technical Advisory Group consisting of 19 industry and regulatory experts for their time and effort in reviewing the project materials and reports, as well as for providing extremely useful guidance and advice for the development of the PSH valuation framework. Their experience and expertise were invaluable for this project and for the development of the *PSH Valuation Guidebook*.

HydroWIRES

In April 2019, WPTO launched the HydroWIRES Initiative to understand, enable, and improve hydropower and 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.

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[1] Hydropower and Water Innovation for a Resilient Electricity System ("HydroWIRES").

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 U.S. regions, it has also created 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: understanding value drivers for hydropower under evolving system conditions, describing flexible capabilities and associated tradeoffs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

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.

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Valuation Framework Test Case Study

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Executive Summary

ES.1 Objectives

As an energy storage technology, pumped storage hydropower (PSH) supports multiple aspects of power system operations. However, determining the value of PSH plants and their many services and contributions to the system is challenging. There is a general understanding that PSH resources provide many services and benefits for the operation of power systems; however, estimating the value of these services—especially the monetary value of some of those services—has been a challenge. The objective of this research program, funded by the U.S. Department of Energy's (DOE's) Water Power Technologies Office (WPTO), is to advance the state of the art in assessing the value of PSH plants and their contributions to the power system.

The specific goals of this project are to: (1) develop comprehensive and transparent valuation guidance that will support consistent valuation assessments and comparisons of PSH projects or project design alternatives, (2) test the PSH valuation guidance and its underlying methodology by applying it to two selected PSH projects, and (3) transfer and disseminate the PSH valuation guidance to the hydropower industry, PSH developers, and other stakeholders. This report presents the results of the technoeconomic studies conducted for one of the two selected PSH projects, the Banner Mountain Storage Project (BMSP).

This report is a companion to the *PSH Valuation Guidebook* ("the Guidebook").[1] The purpose of this companion report is to provide Guidebook users an example of how the project team applied the PSH valuation methodology in a test case for a proposed PSH project. The key objectives of this test case study were to (1) test the valuation methodology and valuation process that was developed for the Guidebook, and (2) provide examples to Guidebook users of how the project team applied different analytical approaches to assess the value of various PSH services and contributions to the power system.

ES.2 *PSH Valuation Guidebook* and Technoeconomic Studies

To accomplish the goals and objectives of this project, as illustrated in Figure ES-1, the project team first developed PSH valuation guidance that accounted for a full range of PSH services and contributions to the grid. This framework was published in the *PSH Valuation Guidebook* in 2021. The team then applied the valuation guidance to two proposed PSH projects that were competitively selected by DOE/WPTO through a Notice of Opportunity for Technical Assistance (NOTA): the BMSP (Absaroka Energy, LLC) and the Goldendale Energy Storage Project (Copenhagen Infrastructure Partners and Rye Development, LLC). The project team engaged with the NOTA selectees and performed technoeconomic studies to assess different aspects of

[1] Koritarov, V., P. Balducci, T. Levin, M. Christian, J. Kwon, C. Milostan, Q. Ploussard, M. Padhee, Y. Tian, T. Mosier, S.M.S. Alam, R. Bhattarai, M. Mohanpurkar, G. Stark, D. Bain, M. Craig, B. Hadjerioua, P. O'Connor, S. Mukherjee, K. Stewart, X. Ke, and M. Weimar, 2021, *Pumped Storage Hydropower Valuation Guidebook: A Cost-Benefit and Decision Analysis Valuation Framework*. 2021. U.S. Department of Energy, Water Power Technologies Office, March. Available at: https://www.energy.gov/eere/water/pumped-storage-hydropower-valuation-guidebook-cost-benefit-and-decision-analysis. DOI: 10.2172/1770766.

value for these two projects. These analyses also served as real-world test cases for the proposed PSH valuation framework. Based on the experience gained during the technoeconomic and valuation studies, the project team revised and improved the valuation guidance before its public release for use by hydropower industry and stakeholders.

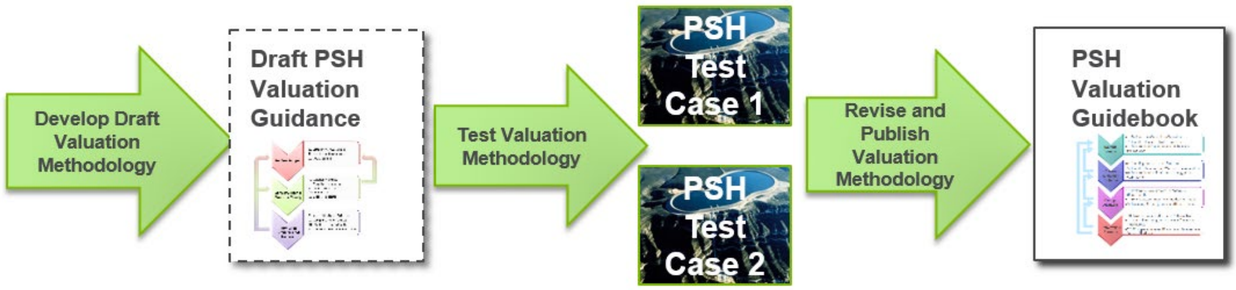


Figure ES-1 Key Project Activities

ES.3 Banner Mountain Storage Project

The BMSP is located at the northern end of the Laramie Mountain Range, in Converse County, Wyoming, 13 miles southeast of Casper, Wyoming. The project design incorporates the topographical features of Banner Mountain, which sits at an elevation of approximately 7,300 feet. The closed-loop PSH facility evaluated in this study would consist of two new reservoirs with approximately 1,175 feet in elevation difference, each with the capacity to store 4,000 acre-feet of water. The penstock would terminate at a powerhouse built adjacent to the lower reservoir, containing the pump and turbine units.

The BMSP could be a key enabler of vast future variable renewable energy deployments in the region, which will be necessary to comply with high renewable portfolio standards in California (100% by 2045), Oregon (100% by 2040), and Washington (100% by 2045).[1] The California Public Utilities Commission also issued an order in 2020 requiring that utilities procure an additional 1 GW of long-duration energy storage by 2026.[2]

The BMSP would have a Quaternary configuration consisting of three unit pairs. Each pair would include a pump and a turbine with a dedicated 134-MW motor and a 134-MW generator. The total power and energy capacities of the BMSP would be 400 MW and 3,400 MWh, respectively. The capital cost for the BMSP is estimated to be $1.12 billion, with a project construction period of 5 years. An additional 5 years will be required to complete all licensing and permitting activities.

[1] National Conference of State Legislatures, "State Renewable Portfolio Standards and Goals." [Online]. Available at: https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

[2] California Public Utilities Commission, 2020, "Rulemaking 16-02-007: 2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning," San Francisco, CA.

ES.4 Technical Approach

Because the BMSP would be a large-scale PSH plant with a 400-MW capacity and would not be located in a structured market, we used system-based capacity expansion, production cost, and transmission system planning models to simulate the price-influencing effects of BMSP operations throughout the Western Electricity Coordinating Council (WECC) region. Benefits are evaluated throughout this report from two perspectives: system and owner-operator. Table ES-1 presents the technical approaches used to assess the value of each use case identified for the system and owner-operator analyses. Key differences between the system and owner-operator perspectives are that (1) a service must be monetized to accrue to the owner-operator, thus leaving out voltage support and most transmission benefits, and (2) the value of energy differs with system benefits measured through reductions in energy costs and owner-operator benefits measured through potential market revenue.

Table ES-1 Technical Approaches Used to Assess Services from System and Owner-Operator Perspectives

Service	System	Owner-Operator
Capacity	AURORA power system expansion model used to simulate generation expansion and retirement throughout the entire WECC from 2019 through 2038. System-oriented approach used to simulate value of capacity as a service in the Rocky Mountain Reserve Group from the perspective of a neutral planner.	Same as that used for system analysis.
Generation Costs / Arbitrage	PLEXOS production cost model (PCM) used with optimization driven by system benefits and value derived from WECC-wide reductions in energy generation costs.	PLEXOS used with optimization driven by system benefits, but value based on relevant prices (e.g., locational marginal price, or LMP, for arbitrage).
Spinning Reserve and Frequency Regulation	PLEXOS used with ancillary services co-optimized with energy service and value derived by comparing WECC-wide ancillary service costs with and without the BMSP.	Same as that used for system analysis.
Black Start	Because the BMSP is not located within a structured market, black start was modeled using the cost-of-service approach. The specific cost-of-service format applied in this analysis is based on the one published for the Pennsylvania–Jersey–Maryland (PJM) interconnect.	Same as that used for system analysis.
Voltage Support	Power System Simulator for Engineers (PSSE) transmission system planning model used to perform simulation and evaluate the impact of the BMSP on system stability using several metrics (e.g., critical clearing time and level of contingency withstood, rate of change of frequency and frequency nadir/zenith for a given event, arresting period rebound period, voltage sag and voltage recovery). Voltage support value based on the reactive power tariffs and payments published by the New York Independent System Operator, Independent System Operator—New England, and PJM.	No value to owner-operator due to the absence of revenue mechanisms.

Service	System	Owner-Operator
Primary Frequency Response	PSSE transmission system planning model used to perform simulation and evaluate the impact of the BMSP on system stability using several metrics (e.g., critical clearing time and level of contingency withstood, rate of change of frequency and frequency nadir/zenith for a given event, arresting period rebound period, voltage sag and voltage recovery). Value of primary frequency response based on known contract pricing between the California Independent System Operator and the Bonneville Power Administration for frequency response services.	Same as that used for system analysis.
Transmission Congestion Relief	PCM runs establish dispatch and PSSE used in coordination with alternating-current optimal power flow (ACOPF) formulation in General Algebraic Modeling System to model transmission impacts and determine reduction in congestion component of LMPs.	Positive externality to system but not monetized benefit.
Transmission Deferral	ACOPF model used to alleviate congestion along targeted lines.	Positive externality to system but not monetized benefit.

AURORA modeling was used to define WECC-wide generation portfolios for several scenarios in future years 2028 and 2038. PLEXOS, using these generation portfolios as inputs to the PCM process, was then used to co-optimize system operations to minimize energy generation and ancillary service costs throughout the WECC. These costs were estimated with and without the availability of Banner Mountain PSH, with the difference in costs being used to define value. For the owner-operator analysis, operations were still optimized for system benefits, but the value of energy arbitrage was estimated based on LMPs evident when the PSH unit was charging (purchasing energy) and discharging (selling energy) while accounting for round-trip efficiency losses.

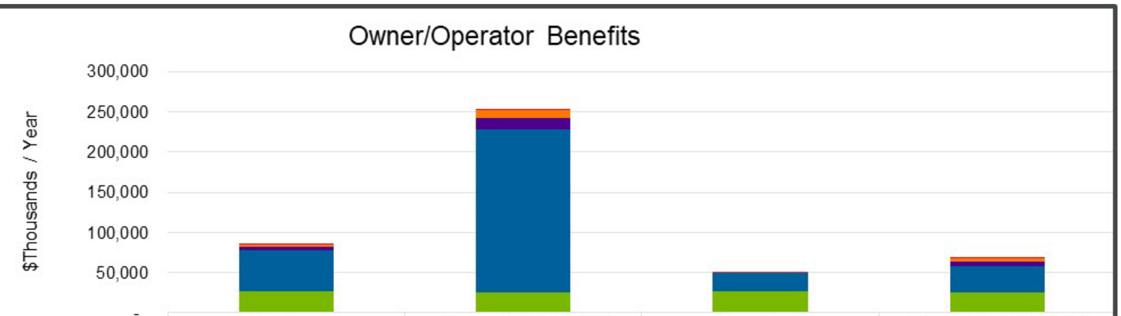
Black start, voltage support, and primary frequency response values were estimated using the PSH capacity remaining after co-optimizing for energy and ancillary services, while transmission benefits were estimated assuming that any benefits accrued as a byproduct or positive externality of plant operations. That is, transmission services are not prioritized in the co-optimization procedures, but the system benefits associated with the transmission congestion component of regionwide LMPs or the deferral of transmission investments can be quantified. Note that the voltage support and transmission benefits register no monetized value to the owner-operator due to an absence of direct market or non-market funding mechanisms.

ES.5 Results of the Financial Analysis

For this test case, we evaluated multiple scenarios while varying key parameters related to discount rates, cost/value growth rates, tax rates, renewable penetration, economic life of the PSH unit, and market structure. Four base scenarios were defined: real-time (RT) baseline, RT high renewables, day-ahead (DA) baseline, and DA high renewables. All sensitivity analyses are compared against the RT baseline scenario. Cost-benefit analysis (CBA) was used to define the economic value of each use case over the economic time horizon of the project and to compare the value of each alternative evaluated in common across all use cases. These values were then compared against all capital, operations and maintenance (O&M), insurance, and tax costs over the CBA period to evaluate the financial performance of the BMSP from system and owner-operator perspectives. A CBA was conducted to calculate several performance metrics, including net present value (NPV), payback period, benefit-cost ratio (BCR), and internal rate of return (IRR).

Figure ES-2 presents the annual co-optimized value of services accruing from an owner-operator perspective for the four base scenarios. Annual estimated revenue under the owner-operator scenario ranges from $50.9 million (DA, baseline), or $127/kW-year, to $253.3 million (RT, high renewables), or $633/kW-year. The vast majority of revenue is tied to capacity and energy services (90% of RT base case). The RT and high renewable cases yield much higher values to the owner-operator. Unserved energy, voltage regulation, and all transmission services yield no revenue because there are no financial mechanisms to monetize the value of these services.

Banner Mountain is more profitable in the owner/operator-focused analysis largely because arbitrage—which is calculated using local LMPs—produces much higher value captured in the form of revenue. The RT scenarios produce positive returns on investment ranging from $191 million (RT baseline) to $2.5 billion (RT high renewables). BCRs for the RT baseline and RT high renewables scenarios are 1.24 and 4.41, respectively. A BCR of 1.0 means project benefits are equal to costs. A BCR of 1.24 means that for everyone dollar invested in the project, we would expect $1.24 in financial returns. Both the DA baseline and DA high renewables scenarios fail to produce positive returns on investment with BCRs registering at 0.56 and 0.91, respectively. Under the RT high renewables case, the IRR is 22.4% and the payback period is 11 years. The RT baseline case produces an IRR of 8.6% and the payback period is 31 years.



	RT - Baseline	RT - High Renewables	DA - Baseline	DA - High Renewables
Unserved Energy	-	-	-	-
Transmission Congestion Relief	-	-	-	-
Transmission Deferral	-	-	-	-
Voltage Regulation	-	-	-	-
Primary Frequency	960	960	960	960
Black Start	152	152	152	152
Frequency Regulation	3,761	10,750	600	4,501
Spin	4,124	13,014	481	5,606
Generation/Arbitrage	51,210	203,350	22,560	32,640
Capacity	26,184	25,100	26,184	25,100

Figure ES-2 Annual Owner-Operator Value of Services Provided by the Banner Mountain PSH Plant

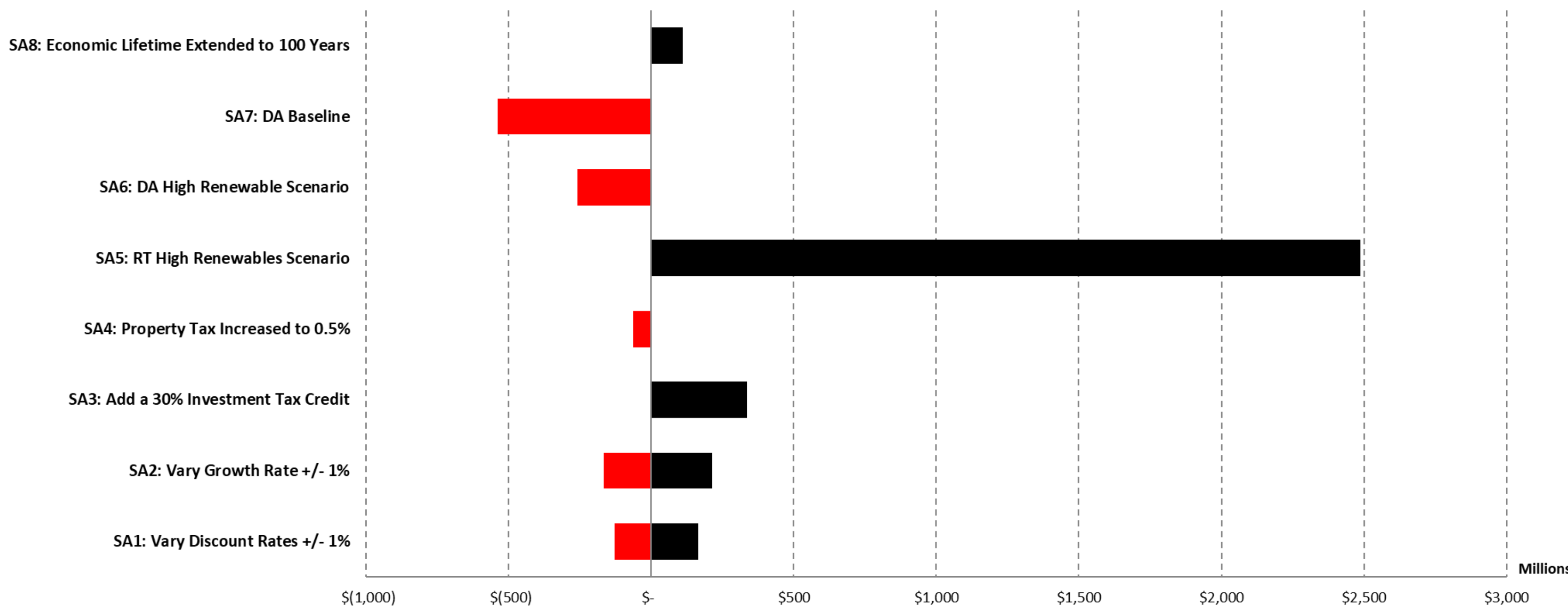
When evaluated from a system perspective, costs exceed the value of services provided to the electrical grid in three of the four scenarios with NPV metrics (mid-year method) ranging from -$149 million (DA, high renewables) to -$523 million (DA, baseline). Among these scenarios, BCRs range from 0.33 to 0.81, and IRRs range from 1.9% to 5.6%. Thus, additional support through investment tax credits or other incentives would be required to yield positive economic returns. Under the RT high renewables scenario, the NPV (mid-year method) is positive at $301 million. The RT high renewables scenario produces a BCR of 1.38 and an IRR of 9.4%. Discounted payback periods are not measured for the three scenarios with negative returns; however, for the RT high renewables scenario, the discounted payback period is 23 years.

The economic results are more positive in the RT runs because in RT, baseload and intermediate generation are limited in their ability to start and ramp; consequently, there is an increase in the use of higher cost, flexible peaking units being used to address the forecast errors related to wind, load, and solar. As these costs increased, the production cost reductions due to Banner Mountain operations also increased. The production cost benefits of Banner Mountain also increase with the high renewable scenario, in part due to the flexibility and balancing ability of the additional PSH units.

The system analysis yields lower BCRs also because it explores the benefits of the BMSP across the entire western United States. The analysis compares the system with versus without the BMSP, with value derived from avoided startup and fuel costs of other units that would have otherwise been employed to address system needs. Because the scale is so large, it affords maximum flexibility in the system response, thus dampening the impacts and system value of BMSP services. For both the system and owner-operator focused analysis, the study also does not account for more location-specific value that might be negotiated with utilities and other electric service providers in the region and monetized using power purchase agreements. Absent these insights, this analysis may not fully capture the full revenue potential of the BMSP.

We evaluated the sensitivity of the results with respect to changes in a number of key assumptions and parameters. These scenarios and their impacts are outlined in this section as compared to the system and owner-operator RT base cases. The following adjustments to the assumptions were made: (1) vary discount rate by ±1%, (2) vary cost and revenue escalation rates by ±1%, (3) add 30% investment tax credit, (4) property tax rates increased to 0.5%, (5) compare to RT high renewable energy case, (6) compare to DA high renewable energy case, (7) compare to DA baseline case, and (8) extend economic lifetime to 100 years.

The results of each sensitivity analysis for the owner-operator analysis are presented in Figure ES-3. Note that the table below the figure presents the corresponding values numerically. As shown, five of the eight evaluated scenarios yield either entirely or mostly positive impacts on the financial results when compared to the RT base case. The effects of extending the economic lifetime of the PSH plant and increasing the property tax rate to 0.5% are not significant. Due to the long life of the PSH plant, a 1-percentage-point increase in the cost/value escalation rate or reducing the discount rate by one percentage point would have a moderate impact on financial results, yielding higher PV benefits of roughly $214 million and $164 million, respectively. Reducing the cost/value growth rate by 1 percentage point and increasing the discount rate by 1 percentage point reduces the NPV (mid-year method) by $167 million and $128 million, respectively.



	SA1: Vary Discount Rates +/- 1%	SA2: Vary Growth Rate +/- 1%	SA3: Add a 30% Investment Tax Credit	SA4: Property Tax Increased to 0.5%	SA5: RT High Renewables Scenario	SA6: DA High Renewable Scenario	SA7: DA Baseline	SA8: Economic Lifetime Extended to 100 Years
Low	$(127,897,093)	$(167,229,182)		$(62,390,590)		$(259,639,884)	$(540,140,263)	
High	$163,829,088	$213,557,658	$336,000,000		$2,486,403,406			$110,293,789

Figure ES-3 Sensitivity Analysis Results (Owner-Operator Analysis)

As noted previously, high renewable energy scenarios yield higher revenue while DA scenarios reduce value compared to the equivalent RT scenarios. The most significantly positive scenario is RT high renewables, which increases the NPV by roughly $2.5 billion. The 30% ITC improves the NPV of the BMSP investment by $336 million. The results of the sensitivity analyses performed for the system analysis are nearly identical to those of the owner-operator analysis but differ in terms of magnitude.

Although the financial results presented here mostly show negative returns for the system analysis, it is important to note that the BMSP will produce several *non-energy benefits*, serving as a key enabler of vast future variable renewable energy deployments in the region. This conclusion is supported by the results of the PLEXOS analysis, which found that the BMSP would avoid renewable curtailments ranging from 186 to 479 GWh annually. The BMSP produces tremendous environmental benefits in terms of reduced emissions. The results based on values produced by the PCM yield carbon reductions of 636,443 and 262,002 tCO_2 per year for coal and natural gas, respectively.

ES.6 Intended Audience and Users

Although this test case study may be of interest to a variety of stakeholders, it is primarily intended to provide a practical example to analysts who would like to apply the valuation framework and perform the valuation process described in the Guidebook. This companion report provides an illustrative example of how the valuation methodologies presented in the Guidebook can be applied to evaluate an actual PSH project. It illustrates how the project team used different analytical approaches to assess the values of various PSH services and contributions to the grid, and how these results were used as inputs into the valuation framework and for the PSH valuation analysis. As noted above, the purpose of this test case study was to (1) test the valuation framework and valuation process described in the Guidebook, and (2) provide Guidebook users with an illustrative example how to apply the Guidebook for valuation of their PSH projects.

ES.7 Methodology Limitations

Analysts should be aware of the limitations of the proposed valuation methodology. The key limitations for the practical applications of the proposed PSH valuation process include the complexity of the analysis and various uncertainties. Because PSH projects are typically of larger size (e.g., several hundred megawatts total capacity), they inevitably have an impact on power system operations and production costs, as well as on the market clearing prices in organized wholesale markets. Therefore, a price-influencer approach was used to study the BMSP. The research team performed a system analysis, which simulates the operation of the entire system and captures the influence of the PSH project on system operations and prices. To properly perform system analysis and capture the interactions between the PSH project and the power system in which it operates, detailed modeling and simulations of system operations were performed using multiple computer models and tools. This presents a significant analytical burden for the application of the valuation process, because the system analysis requires modeling and simulation of multiple potential future scenarios and using different models to address various PSH services and contributions. It also requires the analysts to have access to sophisticated modeling tools and be trained in their use. Finally, a modeling flow or design must be established to integrate the results between models to ensure internal consistency of results and avoid double counting of benefits. The case studies for the Banner Mountain and Goldendale projects provide a good example of the system analysis approach and illustrate its complexities when dealing with the valuation of PSH projects of larger size.

Another key limitation of the valuation process is the uncertainty related to the values of PSH services and contributions over time. PSH plants are projects with a very long lifetime (50–100 years) and attempting to estimate any value over such a long time inevitably involves huge uncertainties. Even if a shorter time period (e.g., 20–30 years) is selected for the cost-benefit analysis, it is still very challenging to estimate project value streams over such a long period. The evolving power systems, new generation, demand-side technologies, and rapidly changing generation mix all contribute to these uncertainties. The scenario analyses and sensitivity studies to key parameters may help the analyst capture some of the possible future developments, but many uncertainties will still remain.

Despite these and other limitations of the valuation process, the valuation framework and methodology presented in the Guidebook and applied to evaluate the BMSP is still very useful in estimating the potential value of a PSH project, because it provides valuable information to decision makers. Of course, as system conditions change, the valuation analysis occasionally may need to be updated to reflect the new developments and information that was not previously available.

ES.8 PSH Valuation Tool

Considering the complexities of the PSH valuation analysis, the project team has developed an online PSH Valuation Tool, which can be accessed at www.pshvt.egs.anl.gov/tool. The tool can help users navigate the valuation process presented in the Guidebook. The development of the PSH Valuation Tool was funded by DOE/WPTO, and the tool is publicly available. It employs a decision tree structure to guide users through the steps of the PSH valuation process, and it tells them which activities and what types of analyses should be performed at each step.

The PSH Valuation Tool can perform a price-taker valuation analysis using an embedded model. For the system analysis (i.e., price-influencer analysis), the tool gives the user two paths to choose from: (1) it can describe at certain points in the decision tree how the user could apply external models to perform system simulations and return the results in order to continue the valuation process, or (2) it allows the user access to an embedded system model that can perform valuation assessments from a price-influencer perspective. The tool has an embedded multi-criteria decision analysis tool and a back-end benefit–cost analysis tool.

ES.9 Project Team

This project was funded by the DOE's WPTO and carried out under the framework of WPTO's HydroWIRES Initiative by a collaborative project team consisting of five national laboratories. The project was led by Argonne National Laboratory, and included Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest

National Laboratory. In addition, the project team collaborated with the Absaroka Energy and Rye Development/Copenhagen Infrastructure Partners teams, the developers of the two proposed PSH projects that were analyzed during the study. The project team also closely collaborated with a technical advisory group that included prominent experts from the hydropower industry, grid operators, regulatory agencies, and other stakeholders.

Acronyms and Abbreviations

The following are acronyms and abbreviations (including units of measure) used in this document.

AC	alternating current
ACOPF	alternating-current optimal power flow
AGC	automatic generation control
AMI	advanced metering infrastructure
AS	ancillary services
ATB	annual technology baseline
BA	balancing authority
BAU	business as usual
BCR	benefit–cost ratio
BMSP	Banner Mountain Storage Project
BOS	balance of system
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CBA	cost-benefit analysis
CC	combined-cycle natural gas
CCT	critical clearing time
CEC	California Energy Commission
CMPP	California–Mexico Planning Pool
COI	center of inertia
CONE	cost of new entry
CPUC	California Public Utilities Commission
DA	day ahead
DC	direct current
DFIM	doubly fed induction machine
DOE	U.S. Department of Energy
EFOR	equivalent forced outage rate
EIA	Energy Information Administration
EIM	energy imbalance market
EPRI	Electric Power Research Institute
ES	energy storage
ESS	energy storage system
FERC	Federal Energy Regulatory Commission
FTE	full-time employee
GADS	Generating Availability Data System

GAMS	General Algebraic Modeling System
GE	General Electric Company
GHG	greenhouse gas
GMLC	Grid Modernization Laboratory Consortium
GW	gigawatt(s)
GWh	gigawatt hour(s)
HDR	Henningson, Durham, and Richardson
HMA	Hunter Management Area
HSC	hydraulic short-circuit
ICE	interruption cost estimate
IMPLAN	Impact Analysis For Planning
INL	Idaho National Laboratory
IPP	independent power producer
IRP	integrated resource planning
IRR	internal rate of return
ISO	independent system operator
ISO-NE	Independent System Operator—New England
kW	kilowatt(s)
kWh	kilowatt hour(s)
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LMP	locational marginal price
LOLE	loss-of-load expectation
LOLP	loss-of-load probability
MCDA	multi-criteria decision analysis
MISO	Midcontinent Independent System Operator
MVAr	mega volt ampere reactive
MW	megawatt(s)
MWh	megawatt hour(s)
NERC	North American Electric Reliability Corporation
NGO	non-governmental organization
NOTA	notice of opportunity for technical assistance
NPV	net present value
NREL	National Renewable Energy Laboratory
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
O&M	operations and maintenance
OASIS	Open Access Same-time Information System

O-W-I	Oregon–Washington–Idaho
PCM	production cost model
PF	power flow
PJM	Pennsylvania–New Jersey–Maryland
PMAT	Pumped Storage Hydropower Market Analysis Tool
PNNL	Pacific Northwest National Laboratory
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
PPA	power purchase agreement
PRM	planning reserve margin
PSE	Puget Sound Energy
PSH	pumped storage hydropower
PSSE	Power System Simulator for Engineers
PUC	public utilities commission
PV	present value
RA	resource adequacy
REC	renewable energy credit
RMRG	Rocky Mountain Reserve Group
ROCOF	rate of change of frequency
RT	real time
RTE	round-trip efficiency
RTO	regional transmission organization
SOC	state of charge
TEPPC	Transmission Expansion Planning Policy Committee
UCAP	unforced capacity
VO&M	variable operations and maintenance
VRE	variable renewable energy
WECC	Western Electricity Coordinating Council
WIH	Walk-in Hunting
WPTO	Water Power Technologies Office

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1.0 Introduction

The role and value of pumped storage hydropower (PSH) resources in an evolving electricity grid are increasingly important. The flexible nature of these resources allows them to supply the full range of necessary grid services. PSH can also be used to store excess variable generation, reduce the curtailments of variable renewables, and support the integration of these resources into the power grid. To ensure PSH continues to play a role in the nation's evolving grid, there is a need to better understand the values and benefits PSH projects provide to the grid, in addition to technoeconomic analyses of potential PSH sites, improved quantification and valuation of PSH operational flexibility, analyses into new potential market structures, and understanding the effects of flexible operation on plant components.

This report is a companion to the *PSH Valuation Guidebook* (Koritarov et al., 2021). The purpose of this companion report is to provide Guidebook users an example of how the project team applied the PSH valuation methodology in a test case for an actual PSH project. The key objectives of this test case study were to (1) test the valuation methodology and valuation process that was developed for the Guidebook, and (2) provide examples to Guidebook users of how the project team applied different analytical approaches to assess the value of various PSH services and contributions to the power system.

1.1 Project Purpose and Context

The primary purpose of the PSH valuation project was to advance the state of the art in assessing the value of PSH plants and their contributions to the power system. The specific goals of this project were to: (1) develop comprehensive and transparent valuation guidance that would support consistent valuation assessments and comparisons of PSH projects or project design alternatives, (2) test the PSH valuation guidance and its underlying methodology by applying it to two selected PSH projects, and (3) transfer and disseminate the PSH valuation guidance to the hydropower industry, PSH developers, and other stakeholders.

The valuation framework developed during the PSH valuation project was tested by performing a valuation analysis for two PSH projects located at sites with a high penetration of variable renewable generation. The two sites for valuation analysis were selected by the U.S. Department of Energy's (DOE's) Water Power Technologies Office (WPTO) through a Notice of Opportunity for Technical Assistance (NOTA) process. Prior to issuing the NOTA, a Request for Information was issued by DOE/WPTO to obtain inputs from the hydropower industry, PSH developers, and other stakeholders. Two proposed new closed-loop PSH projects were selected by DOE/WPTO for valuation analysis:

- Banner Mountain PSH Project (Absaroka Energy, LLC), and
- Goldendale Energy Storage Project, or GESP (Copenhagen Infrastructure Partners and Rye Development, LLC).

Almost a dozen technoeconomic studies were performed for the selected PSH sites to assess various PSH services and contributions that these projects may be able to provide to the grid, and to estimate the value of those services. The results and assessments for value streams that were obtained through technoeconomic studies served as inputs into the valuation framework to test the process for obtaining an overall assessment of the economic value of these two PSH projects. This report represents one of two companion technical reports with the purpose of providing illustrative case studies for the application of valuation methodologies and analyses presented in the Guidebook.

1.2 Methodological Approach

The project team performed several technoeconomic studies to analyze and evaluate various benefits that the Banner Mountain Storage Project (BMSP) may be able to provide to the grid. The types of services and contributions to the grid that were examined included:

- Value of bulk power capacity and energy arbitrage,
- Value of PSH ancillary services,
- Power system stability benefits,
- Reduction of system production costs,
- PSH transmission benefits, and
- PSH non-energy benefits.

In addition, the project team performed a historical market analysis to assess the upper bounds of revenue streams and to investigate potential impacts of new market rules and structures.

AURORA modeling was used to define Western Electricity Coordinating Council (WECC)–wide generation portfolios for several scenarios in the years 2028 and 2038. PLEXOS, using these generation portfolios as inputs to the production cost modeling (PCM) process, was then used to co-optimize system operations to minimize energy generation and ancillary service costs throughout the WECC. These costs were estimated with and without the availability of Banner Mountain PSH, and the differences in costs were used to define value.

For the owner-operator analysis, operations were still optimized for system benefits, but the value of energy arbitrage was estimated based on local locational marginal prices (LMPs) evident when the PSH unit was charging (purchasing energy) and discharging (selling energy) while accounting for round-trip efficiency (RTE) losses.

Black start, voltage support, and primary frequency response values were estimated using the PSH capacity remaining after co-optimizing for energy and ancillary services, while transmission benefits were estimated assuming that any benefits accrued as a byproduct or positive externality of plant operations. That is, transmission services are not prioritized in the co-optimization procedures, but the system benefits associated with the transmission congestion component of regionwide LMPs or the deferral of transmission investments can be quantified. Note that the voltage support and transmission benefits register no monetized value to the owner-operator due to an absence of direct market or non-market funding mechanisms. Much more detail regarding these approaches is provided in Sections 7 and 8.

Cost-benefit analysis (CBA) was used to define the economic value of each use case over the economic time horizon of the project and to compare the value of each alternative evaluated in common across all use cases. These values were then compared against all capital, operations and maintenance (O&M), insurance, and tax costs over the CBA period to evaluate the financial performance of the BMSP from system and owner-operator perspectives. A CBA was conducted to calculate several performance metrics, including net present value (NPV), payback period, and internal rate of return (IRR). Finally, several sensitivity analyses were conducted to evaluate the impact of variable renewable energy (VRE) penetration, discount rates, cost and value escalation rates, and tax implications on study results.

1.3 Main Project Outcomes

The *PSH Valuation Guidebook* established an objective and comprehensive valuation framework for PSH plants to provide a consistent and repeatable method to assess the value PSH technology brings to the power grid. Although most grid operators and utility experts agree that PSH plays a key role in supporting safe, reliable, and economical grid operations, it is difficult to assess the full value of all PSH services and contributions to the grid. The inability to estimate the full value of certain PSH services, especially those known as system-wide (or portfolio) contributions, makes it difficult to assess the total benefits of PSH for the system and provide appropriate compensation to PSH owners and operators.

This technoeconomic study demonstrates the feasibility of applying the broad taxonomy of value established in the *PSH Valuation Guidebook* to an individual project. In so doing, it represents a big step forward in understanding the true value this technology brings to the grid, thus removing one of the obstacles faced by PSH operators and developers.

1.4 Organization of the Report

Section 2 provides an overview of the BMSP. Section 3 presents the findings of a power market analysis used to assess potential revenue streams for various market services based on existing market conditions. Section 4 provides an overview of the PSH valuation framework and describes in detail a 15-step valuation process. Section 5 defines the scope of the BMSP, which addresses the first four steps of the valuation process. Section 6 addresses the fifth and sixth steps in the valuation process by developing valuation criteria for analysis. Section 7 presents an overview of the analysis design. Section 8 provides extensive technical detail on the methods and approaches used to assess, quantify, and estimate the value of different PSH services and contributions to the grid by the BMSP. Section 8 includes the findings of the CBA, results of a risk assessment, and reporting of key findings. Section 9, the final section, presents conclusions and recommendations.

The report also includes three appendices that will be useful to the reader. Appendix A presents the worksheet used to obtain the data required to complete valuation steps 1–4. Appendix B presents the worksheet used to complete valuation steps 5–6. Appendix C provides a comprehensive glossary of valuation terms.

1.5 Reference

Koritarov, V., P. Balducci, T. Levin, M. Christian, J. Kwon, C. Milostan, Q. Ploussard, M. Padhee, Y. Tian, T. Mosier, S.M.S. Alam, R. Bhattarai, M. Mohanpurkar, G. Stark, D. Bain, M. Craig, B. Hadjerioua, P. O'Connor, S. Mukherjee, K. Stewart, X. Ke, and M. Weimar, 2021, *Pumped Storage Hydropower Valuation Guidebook: A Cost-Benefit and Decision Analysis Valuation Framework*. 2021. U.S. Department of Energy, Water Power Technologies Office, March. Available at: https://www.energy.gov/eere/water/pumped-storage-hydropower-valuation-guidebook-cost-benefit-and-decision-analysis. DOI: 10.2172/1770766

2.0 Overview of the Banner Mountain Storage Project

2.1 Banner Mountain Storage Project Overview

The BMSP is located at the northern end of the Laramie Mountain Range, in Converse County, Wyoming, 13 miles southeast of Casper, Wyoming (population 59,628). The project site is illustrated in Figure 2-1. The project design incorporates the topographical features of Banner Mountain, which sits at an elevation of approximately 7,300 feet. The BMSP is located on a privately owned greenfield site. The closed-loop PSH facility will consist of two new reservoirs with approximately 1,175 feet in elevation difference, each with the capacity to store 4,000 acre-feet of water. The penstock will terminate at a powerhouse built adjacent to the lower reservoir containing the pump and turbine units. The BMSP could be a key enabler of vast future VRE deployments in the region, which will be necessary to comply with high renewable portfolio standards (RPS) in California (100% by 2045), Oregon (100% by 2040), and Washington (100% by 2045) (National Conference of State Legislatures 2022).

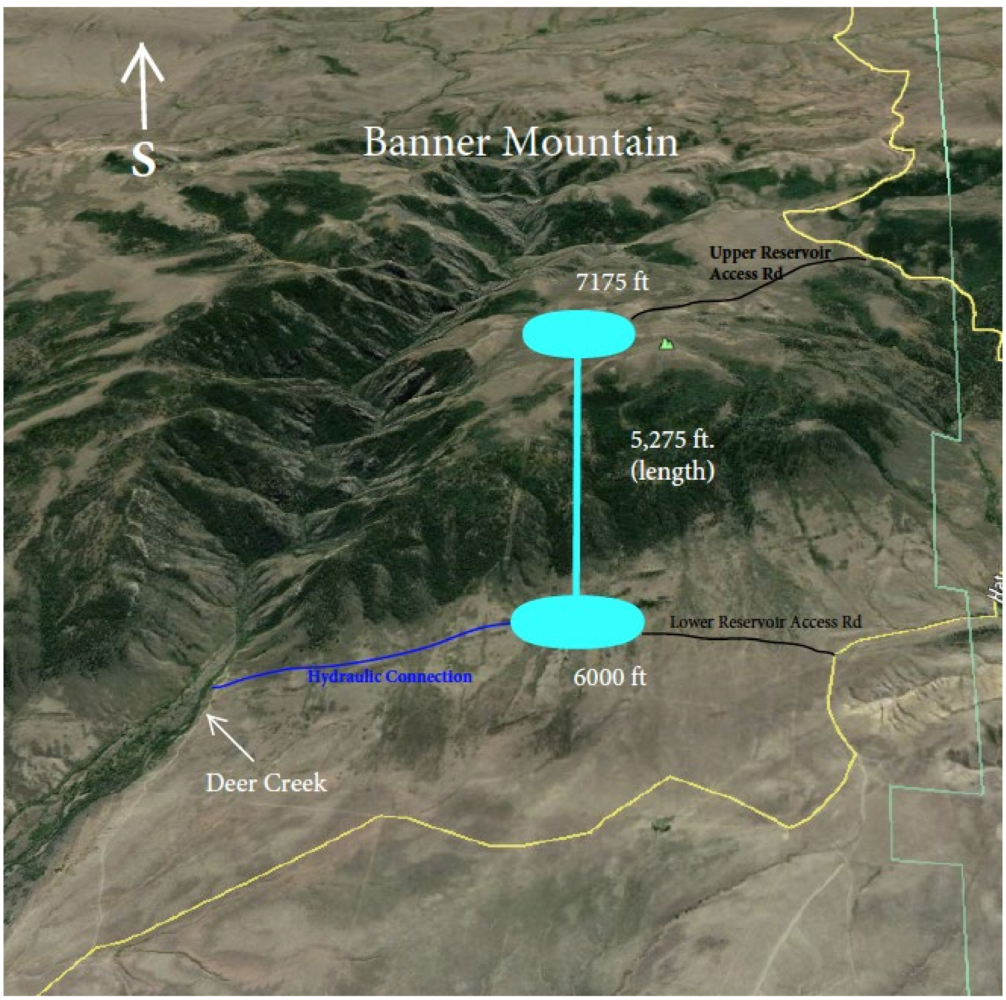

Figure 2-1 Banner Mountain Energy Storage Project Location

The BMSP will have a Quaternary configuration consisting of three-unit pairs. Each pair will include a pump and a turbine with a dedicated 134-MW motor and a 134-MW generator, respectively. The total power and energy capacities of the BMSP will be 400 MW and 3,400 MWh, respectively. Other operational characteristics include 1,175 feet of head, 20 MW/second ramp rates, and 83% RTE. The capital cost for the BMSP is estimated to be $1.12 billion, with a project construction period of 5 years. An addition 5 years are required to complete all licensing and permitting activities.

2.2 References

National Conference of State Legislatures, 2022, “State Renewable Portfolio Standards and Goals.” Available at: https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

3.0 Historical Market Analysis

3.1 Overview of the Power Market Analysis

This chapter provides the power market analysis results conducted by Argonne for the BMSP. The goal of the power market analysis is to assess potential revenue streams for various market services and products and to investigate new market rules and structures. The power market analysis accomplishes the following tasks:

- Review market rules and treatment of PSH in existing U.S. electricity markets;
- Review new trends and developments in market structure and rules;
- Analyze historical price for energy, capacity, and ancillary services (AS); and
- Assess potential revenue streams for various market services or products.

The BMSP has access to multiple market participation options, including the wholesale electricity market operated by the California Independent System Operator (CAISO), the western energy imbalance market (EIM), and a local balancing authority (BA) in the Pacific Northwest (PNW) region. The power market analysis considers the three options, as summarized in Table 3-1.

Table 3-1 Market Participation Options Considered in the Market Analysis

Service	CAISO	Local BA	
		EIM Participating	EIM Non-Participating
Capacity	Non-market-based resource adequacy framework	Bilateral contract	Bilateral contract
Energy	DA and RT dispatch and settlement by CAISO	Base schedule by BA; intra-hour dispatch and settlement by CAISO	Dispatch and settlement by a BA
AS	Regulation up/down, spinning reserve, non-spinning reserve	Flexible ramp product (EIM); AS procured by BA	AS procured by a BA

The rest of the chapter is organized as follows. First, in Section 3.2, we review market rules and PSH treatment in CAISO and investigate new trends and developments in market design. In Section 3.3, we report the historical market analysis results. Section 1.4 provides conclusions of the power market analysis.

3.2 Market Rules and Treatment of PSH in Wholesale Electricity Markets

3.2.1 Overview

There are seven U.S. wholesale electricity markets operated by independent system operators (ISOs) and regional transmission organizations (RTOs). Each competitive wholesale market typically has markets for energy and selected AS—and in some cases capacity—with its own unique product definitions and market rules. ISOs and RTOs operate energy and AS markets to maintain system reliability by continually balancing instantaneous generation and load. This is achieved through a combination of generation scheduling and AS deployment.

Generation scheduling includes a unit commitment to ensure that the appropriate units are active and available to generate and economic dispatch to ensure that electricity is provided by the units that are available at the lowest possible cost. AS provide operating reserve capacity that is available over various timeframes to help compensate for fluctuations caused by forecasting errors, short-term variability in load, and VRE, or loss of generation or transmission elements.

ISOs and RTOs operate sequential markets from day ahead (DA) to real time (RT) with different time resolutions. In addition, some ISOs and RTOs have centralized capacity markets to ensure that sufficient capacity is available, at the right locations, to serve forecasted demand plus planning reserve margins (PRMs).[1] The capacity markets create long-term revenue streams that are more stable for generation units, helping to make a new project financeable and preventing existing units from retiring. A more detailed review of capacity markets appears in Beyers et al. (2018).

In principle, PSH can participate in all wholesale electricity markets. In Section 3.2.2, we review the existing market participation models for PSH in the wholesale electricity market operated by CAISO in which the BMSP can participate. In Section 3.2.3, we briefly review the new trends and market participation model developments, focusing on the relevance of recent FERC orders to PSH, including FERC Order 841.

3.2.2 Existing Market Participation Rules of PSH in CAISO

In this section, we first review the existing market participation models, rules, and protocols for PSH in the energy and AS markets operated by CAISO. CAISO has a distinct participation model for PSH, called the "Pumped Storage Hydro Unit model," which allows the PSH units to provide all capacity, energy, and AS (CAISO 2015). PSH units can bid into the market or self-schedule, in which case CAISO will validate their scheduling for feasibility.

CAISO requires PSH units to submit individual bids for generation and pumping in the same market interval. PSH resources submit three bid components for pumping mode: shutdown cost, pumping level, and pumping cost. In addition, the resources submit three bid components for generating mode: start-up cost, megawatt operating point, and energy bid component (CAISO 2019a). PSH plant operators must anticipate market conditions in advance and reflect their preferred mode of operation in the bidding parameters to maximize profit. After PSH resources submit individual bids for generation and pumping, the CAISO's market optimization engine processes the bids as one bid curve to determine the most economical dispatch while reflecting their operating characteristics (Counsel for the CAISO Corporation 2018; CAISO 2019b). CAISO determines the commitment status of PSH while avoiding conflicting dispatch signals for

[1] ISO-NE, MISO, NYISO, and PJM operate centralized capacity markets. In CAISO and SPP, load-serving entities are mandated to procure capacity requirements without a centralized capacity market. ERCOT does not operate a centralized capacity market and relies on a so-called "energy-only" market to achieve an adequate supply of generation (i.e., through reliance on scarcity pricing to provide incentives for investments in generation capacity).

pumping and generating in CAISO's DA integrated forward market, residual unit commitment,[1] and RT market (CAISO 2018a). CAISO models the pumping mode of PSH as participating load, which is equal to the curtailable demand. The commitment for a PSH unit operating in generating mode is determined in the same way other conventional generators are determined (CAISO 2018a).

CAISO procures five types of AS: regulation up, regulation down, spinning reserve, non-spinning reserve, and flexible ramping products.[2] The ISO allows PSH units to provide AS considering the multistage resource configuration of the plant. PSH units can set the wholesale market clearing prices (i.e., LMPs), as seller and buyer in CAISO's markets. CAISO also allows PSH units to manage their own state of charge (SOC) while also offering a SOC management in the market optimization process as an option. Last, PSH units are eligible to receive bid cost recovery (or make-whole payments) (CAISO 2018a).

Although CAISO does not operate a centralized capacity market, CAISO ensures sufficient generation capacity to serve load reliably using the resource adequacy (RA) program. CAISO requires that any resource providing RA capacity to CAISO through the RA program to offer that capacity into the CAISO markets. CAISO also has a "bid insertion" rule that allows CAISO to use a generated bid in the DA market if an RA resource does not provide its full RA capacity. In such a case, CAISO also inserts a self-schedule for the resource in the RT market to match its DA award. In the recent RA enhancements straw proposal, CAISO proposed a DA must offer obligation along with minor updates to the rules for specific resource types (CAISO 2020a).

3.2.3 New Trends and Market Participation Model Developments in CAISO

The recent increase in penetration of VRE resources has changed the operational profile of PSH in CAISO. The California Energy Commission (CEC) reported that, in recent years, the PSH plants participating in CAISO markets had been called upon to operate in pumping mode to resolve over-generation events during the daytime, whereas traditionally these PSH plants only operated under generation mode during the day and pumping mode overnight (Doughty et al., 2016). This new operating paradigm for PSH was also reported in the 2017 Hydropower Market Report (Uria-Martinez et al., 2018). This is illustrated in Figure 3-1, which shows the increased daytime pumping mode operations of the Helms PSH project from 2012 to 2017 along with the changes in the CAISO net load curve.

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1 A DA market clears bid-in demand, which could be different than the demand forecast. In order to ensure reliable system operation, CAISO executes a residual unit commitment process that commits additional generating resources beyond the DA market schedules if this is required to meet the demand forecast.

2 The flexi-ramp product was recently introduced to provide more flexibility in RT operations. The reserved capacity is available in RT to address deviations in the forecasts of load and VRE.

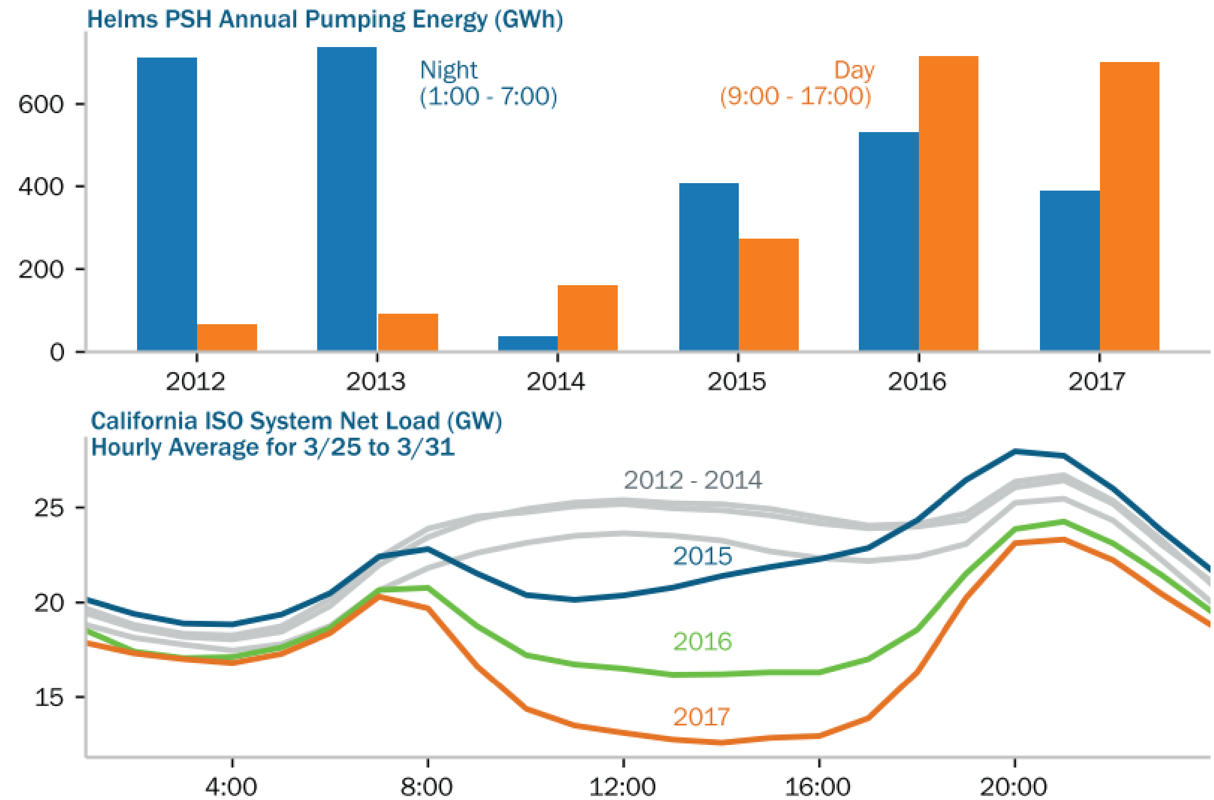

Figure 3-1 Comparison of the Annual Helms PSH Pumping Energy Consumption during the Day (orange bars) and Night (blue bars), and the CAISO Net Load (bottom; Uria-Martinez et al., 2018)

In addition to the new operating paradigms of PSH, market participation models are also evolving in some regions with oversight from the Federal Energy Regulatory Commission (FERC). In recent years, FERC has issued several orders to improve the valuation of services provided by energy storage, including PSH, and to facilitate their market participation in the wholesale electricity markets.[1]

For instance, FERC Orders 755 and 784, issued in 2011 and 2013, respectively, aimed to enhance how AS provided by energy storage are compensated. In particular, the orders required ISO/RTOs to implement a performance-based payment scheme in their frequency regulation markets, as comprehensively reviewed by Xu et al. (2016). In addition, FERC enacted FERC Order 792 in 2013, which introduced new small-generator interconnection standards for distributed energy resources, including energy storage, up to 20 MW in capacity (Database of State Incentives for Renewables and Efficiency, 2016). Moreover, FERC Order 1000, issued in 2011, created an opportunity for energy storage resources to be included in the regional

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[1] ISO/RTOs that are under FERC regulatory jurisdiction are mandated to implement FERC orders in their tariffs for electricity market operations. Note that the ERCOT market is not under FERC regulatory jurisdiction. The ERCOT system is solely located in the state of Texas with very limited interconnections to surrounding areas (Greenfield, 2017).

transmission planning process as alternative transmission solutions and receive a cost-based rate treatment (FERC 2020a).

Most recently, FERC issued FERC Order 841 in 2018 (FERC, 2020b). The objective of FERC Order 841 is to remove barriers to the participation of energy storage in the wholesale capacity, energy, and AS markets and to ensure that market rules for these resources are just and reasonable. The order requires ISOs/RTOs to establish a participation model for ES, which recognizes the physical and operational characteristics of these unique grid resources, along with appropriate metering and accounting practices. According to the order, the energy storage participation model must meet several requirements, including the following, which are relevant to PSH (FERC, 2020b):

- Ensure that energy storage resources can provide all the services, including capacity, energy, and AS, they are technically capable of providing.
- Ensure that energy storage resources can be dispatched and can set wholesale market clearing price as both a wholesale seller and buyer.
- Account for the physical and operational characteristics of energy storage resources through bidding parameters or other means.
- Execute energy storage wholesale transactions at the wholesale LMP.
- Enable energy storage resource to receive make-whole payments.[1]
- Allow energy storage resources to self-manage their SOC.

Prior to FERC Order 841, CAISO began its Energy Storage and Distributed Energy Resource initiative in 2015. In 2017, CAISO published a market rule enhancement proposal called “ES and distributed energy resource phase 3,” to lower barriers and enhance the abilities for energy storage and distribution-connected resources to fully participate in the CAISO markets (CAISO, 2018b). In the compliance filing to FERC, CAISO states that its existing tariff and participation models for non-generator resources, PSH units, and demand response providers already comply with most of the requirements in FERC Order 841 (Counsel for the CAISO Corporation, 2018). Therefore, CAISO will not develop a new market participation model for energy storage to comply with FERC Order 841.

Although we do not anticipate any immediate changes in the existing market participation for PSH or an introduction of a new market participation model for energy storage in CAISO, the ongoing transformation of the power grid requires the ISO to continuously evolve its market design and rules. For instance, CAISO recently proposed introducing an imbalance reserve product into the DA market. The imbalance reserve product is an extension of the existing flexible ramp product, which is currently procured in the RT market only. In addition, CAISO

[1] In some cases, revenues from energy and reserve markets do not cover the total operating costs of individual power plants, including start-up and no-load costs. In such cases, ISOs/RTOs provide so-called “make-whole” payments (i.e., side payments in addition to the regular market revenues), to ensure that the plant receives sufficient revenue to cover its full operating costs.

proposed a reliability energy product and reliability capacity in the DA market to replace the existing residual unit commitment process (CAISO, 2020b).

3.3 Historical Market Analysis

3.3.1 Overview

The historical market analysis assesses the monetized value of the BMSP in providing capacity, energy, and AS. As the name of the analysis suggests, the historical market analysis answers how much net revenue the BMSP could have earned in the historical markets. It is important to note that this analysis is not intended to be interpreted as a forecast of likely revenue streams and market conditions in the future.

Several prior studies have proposed different ways to assess potential revenue streams. In general, there are two approaches: price influencer and price taker. The price-influencer approach assumes that a PSH plant under consideration influences market prices; therefore, this approach requires power system production cost simulation models to determine market prices. This approach is typically used with PSH assessments due to the associated larger power and energy capacities. Alternatively, one can use a concept of price quota curve to predict market prices as introduced in Arteaga and Zareipour (2019). In this study, we adopt a price-taker approach, which is widely used because of its simplicity. The price-taker approach is based on historical market prices and assumes that the operation of a PSH plant under consideration will not change market prices. Therefore, this approach provides the best possible income (i.e., the upper bound of the possible profit of a PSH plant, for a given set of market prices, assuming perfect foresight).

3.3.2 Valuation Methodology

We use the Pumped Storage Hydropower Market Analysis Tool (PMAT) developed by Argonne (Kwon et al. 2021). PMAT is an optimization model that determines the optimal market participation strategy based on potential revenue streams from providing various grid services. It is a price-taker model that assumes perfect foresight, and the simulation is performed based on given market prices. The modeled grid services include capacity, energy, and AS, which include regulation-up, regulation-down, spinning, and non-spinning reserves. PMAT performs a time-coupled co-optimization of capacity, energy, and AS scheduling to determine the optimal market participation strategy that maximizes net revenue.

PMAT has a two-stage approach, as presented in Figure 3-2. In stage 1, the model finds the optimal capacity participation for each unit of a PSH plant based on capacity prices and hourly energy prices only. Thus, in stage 1, PMAT will not capture the energy arbitrage opportunity from a finer time resolution (e.g., 5 minutes in RT). For instance, PMAT finds the optimal capacity participation in CAISO and PNW for three units of the BMSP. The capacity participation decision in stage 1 is considered a capacity obligation to each market in stage 2. That is, in stage 2, the model performs a time-coupled co-optimization to schedule the provision of energy and AS in DA and RT markets subject to the capacity participation decision made in stage 1. The participation in EIM is determined in stage 2 because EIM is an energy-only market, except for the flexible ramping product, which is not modeled in this analysis. The participation in EIM is subject to the capacity participation in PNW (i.e., only a portion of capacity participating in PNW can participate in EIM). The benefit of applying this two-stage approach includes reduced computational complexity and a reflection of realistic market participation practices where the capacity participation decision is made in advance with limited information.

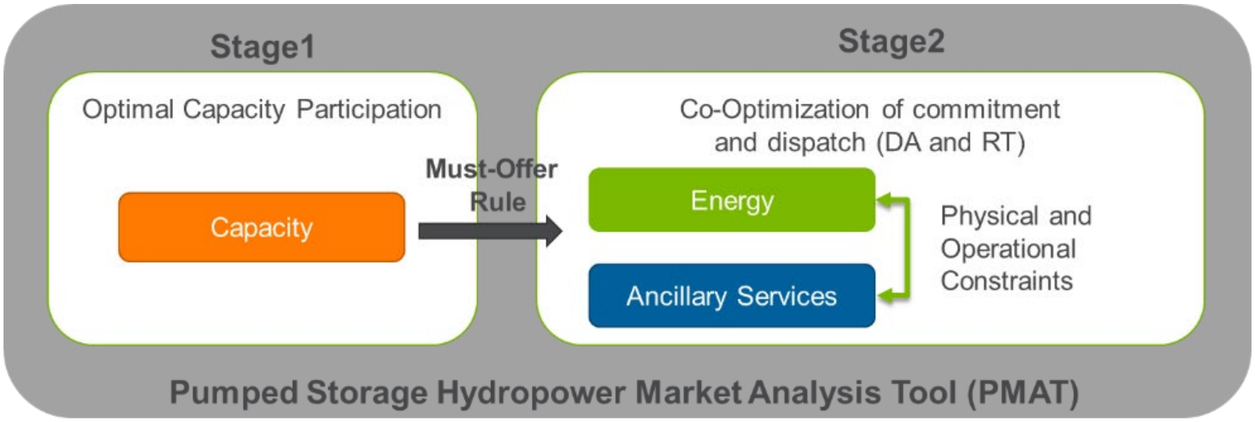


Figure 3-2 Two-stage Approach of PMAT

PMAT includes a detailed representation of the physical and operational constraints of a closed-loop PSH plant. Figure 3-3 presents an overview of the PSH modeling in PMAT. The PSH modeling captures the changes in the upper reservoir water level due to water discharge for generation and water pumping. The model also considers upper reservoir headroom reserve for AS provision in pumping mode and upper reservoir water reserve for AS provision in generating mode. Other constraints include penstock constraints that prevent simultaneous pumping and generation, inter-temporal ramping constraints, and constraints for unit commitment conditions.

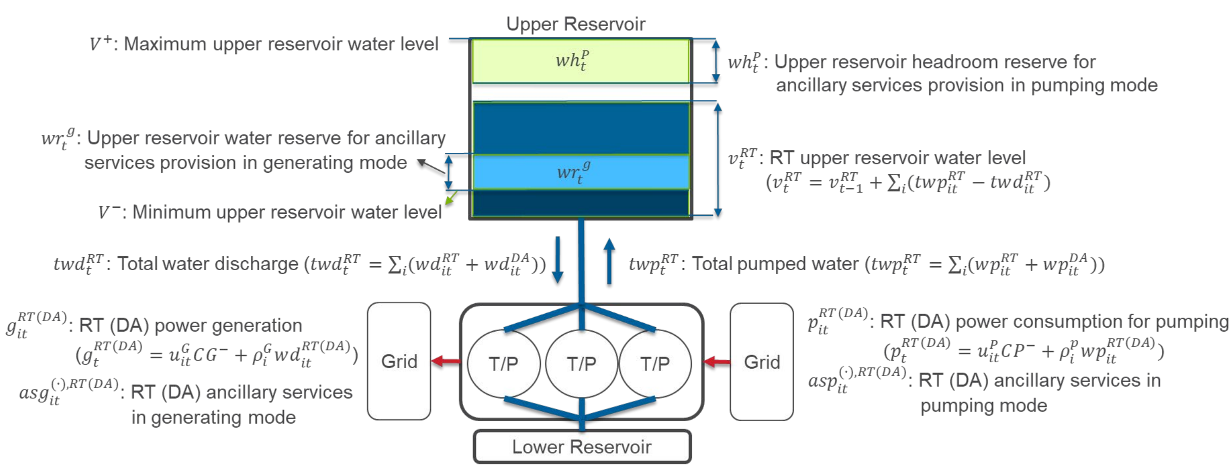


Figure 3-3 Overview of PSH Modeling in PMAT

In addition, PMAT models the operation of a PSH plant with a hydraulic short-circuit (HSC) technology, which is schematically presented in Figure 3-4. PMAT uses binary decision variables to account for the multiple operating modes, including generation, pumping, and HSC.

This way, PMAT can capture the continuous operation, from maximum power consumption to maximum power generation, of a PSH plant, as presented in the input/output curve in Figure 3-5.

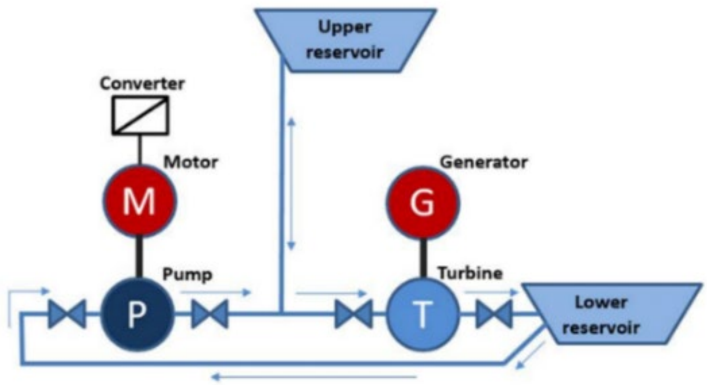


Figure 3-4 Schematic Representation of a PSH Unit with HSC

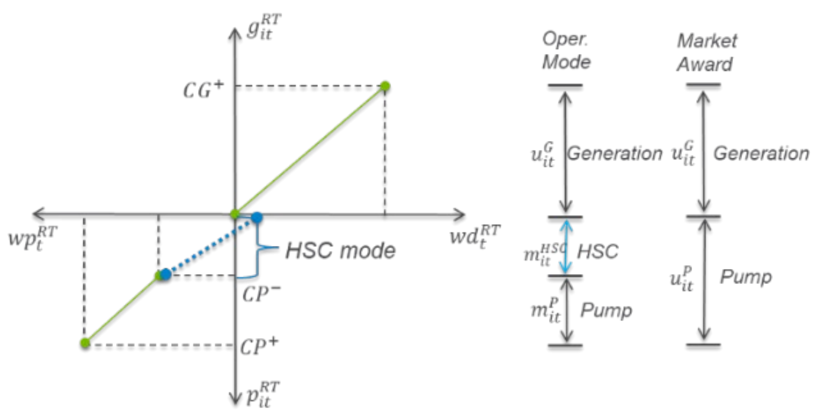


Figure 3-5 Input/Output Curve for a PSH Unit with HSC

3.3.3 Analysis Design

3.3.3.1 Baseline Case

The baseline case of the historical market analysis is based on historical prices from 2017 to 2019. Table 3-2 presents the general analysis design parameters. Although the BMSP has access to the three market participation options, as summarized in Table 3-1, we only consider CAISO and PNW in the baseline case because the RT price data in the PNW is limited. We investigate the impact of RT prices in the sensitivity analysis. As mentioned in Section 3.3.2, we apply different model settings in stages 1 and 2 of PMAT to limit the provision of certain grid services at each stage. Table 3-3 summarizes the modeled grid services in the baseline case. In stage 1, the model determines the optimal annual capacity participation in CASIO and the PNW based on the capacity prices and the hourly market prices for energy. In stage 2, the model determines the optimal PSH scheduling subject to the capacity obligation determined in stage 1, while considering the hourly market prices for energy and AS. Finally, we use the detailed project information provided by the Banner Mountain project team in this analysis. The project information includes capacity, fixed and variable costs, RTE, energy conversion rate, and other plant specifications.

Table 3-2 General Analysis Design Parameters

Key Parameter	Assumptions/Potential Values
Planning Design	• Years: 2017–2019 • Number of markets: 2 (CAISO, PNW) • Market products: capacity, energy, AS (spinning, non-spinning, regulation up/down) • AS market share: 10%
Time Resolution	• Time resolution of the DA market: 60 minutes • Time resolution of the RT market: 5 minutes

Table 3-3 Modeled Grid Services in PMAT

Stage	Market	Capacity	Energy	AS
Stage 1	CAISO	Yes (annual)	DA (hourly)	N/A
	PNW	Yes (annual)	DA (hourly)	N/A
Stage 2	CAISO	Fixed	DA (hourly)	DA (hourly)
	PNW	Fixed	DA (hourly)	DA (hourly)

We also introduce a simple market share concept to limit the total provision of each AS product by the market size and predetermined market share to consider relatively small AS market size and to prevent the unrealistic provision of AS services. The considered AS market sizes in CAISO are obtained from CAISO (2019c) and based on the average hourly AS imports in 2018. However, there is limited information available to the public regarding AS market size in the PNW. Therefore, we assume an AS market size of a local BA. We select Puget Sound Energy (PSE) as a local BA because we use the AS prices generated by PSE in this study. The AS market size of PSE is assumed by proportionally scaling down CAISO's AS market size based on the peak loads in 2018 without considering any import limits. Table 3-4 summarizes the modeled AS market sizes in CAISO and the PNW. We assume a 10% market share in the baseline case.

Table 3-4 AS Market Size in CAISO and the PNW, in Megawatts

AS Product	CAISO		PNW
	Procurement Requirement	Average Hourly Import in 2018	
Regulation up	310	80	34
Regulation down	400	10	44
Spinning	980	180	107
Non-spinning	980	30	107

3.3.3.2 Data Needs and Sources

As mentioned in Section 3.3.3.1, the historical market analysis is performed using historical prices for capacity, energy, and AS from 2017 to 2019. Table 3-5 details the data and sources used in this study. The market prices in CAISO are obtained from CAISO's Open Access Same-time Information System (OASIS), and the annual RA reports from the California Public Utilities Commission (CPUC; Chow and Brant, 2019; Brant et al., 2019).

In CASIO, we select the pricing node in CAISO that has the shortest distance from the BMSP. For the PNW, we use the Mid-Columbia Index, obtained from Powerdex. We also use an estimated capacity value in the PNW. The estimated capacity value is obtained from the power purchase agreement (PPA) signed in 2018 between the Los Angeles Department of Water and Power (LADWP) and PacifiCorp for the Milford Wind Corridor Phase I and II Projects. The PPA includes a capacity charge of $1.77/kW-month. Last, we use the value of AS in the PNW based on the AS marginal costs obtained from a production cost simulation conducted by PSE using the commercial tool PLEXOS and shared by the PNNL project team.

Table 3-5 Summary of the Data and Sources Used in the Historical Market Analysis

Market Product	Market	Data Source	Type	Zone/Pricing Node	Year
Capacity	CAISO	CPUC's annual RA reports (2017, 2018)	Monthly weighted average RA capacity prices	CAISO NP26	2017–2019
	PNW	PPA signed in 2018 between LADWP (seller) and PacifiCorp (buyer) for the Milford Wind Corridor Phase I and II Projects	Capacity charge ($/kW-Month)	N/A	2018–2019
Energy	CAISO	CAISO (OASIS)	DA, RT	DAVEJOHN_NODE4	2017–2019
	PNW	Powerdex	DA	Mid-Columbia	2017–2019
	EIM	CAISO (OASIS)	RT	ELAP_PACE-APND	2017–2019
AS	CAISO	CAISO (OASIS)	DA, RT	AS_CAISO_EXP, AS_NP26_EXP	2017–2019
	PNW	PSE	DA	Mid-Columbia	2019

3.3.3.3 Scenarios and Assumptions

In addition to the baseline case, we also consider several additional sensitivity scenarios, as detailed in Table 3-6. The baseline case only considers DA prices. Therefore, in the CAISO + RT scenario, we investigate the impact of RT prices on the revenue streams. Note that we only model CAISO in the CAISO + RT scenario because RT price data in the PNW is insufficient. We exclude the CAISO option in the PNW Only and PNW + EIM scenarios to examine different market participation settings. Last, in the PPA scenario, we analyze the impact a PPA between the BMSP and a local BA would have on the revenue stream.

Table 3-6 Sensitivity Scenarios Considered in the Power Market Analysis

Scenario ID	Market Participation	Capacity Prices in CAISO	Capacity Value in PNW	Energy/AS Prices
Baseline	CAISO, PNW	CPUC 2018 report	PPA between LADWP and PacifiCorp	DA
CAISO + RT	CAISO	CPUC 2018 report	N/A	DA, RT
PNW Only	PNW	N/A	PPA between LADWP and PacifiCorp	DA
PNW + EIM	PNW, EIM	N/A	PPA between LADWP and PacifiCorp	DA, RT(EIM)
PPA	CAISO, PNW (PPA)	CPUC 2018 report	2020 IRP report of AVISTA	DA

3.3.4 Analysis Results

3.3.4.1 Historical Prices for Energy, Capacity, and AS

We first review historical prices for capacity, energy, and AS because these are the primary drivers of the market participation strategy and the estimated revenue streams. Figure 3-6 compares the capacity prices and values used in the historical market analysis. The capacity value in PNW is lower than the average capacity prices in CAISO reported in the CPUC reports.

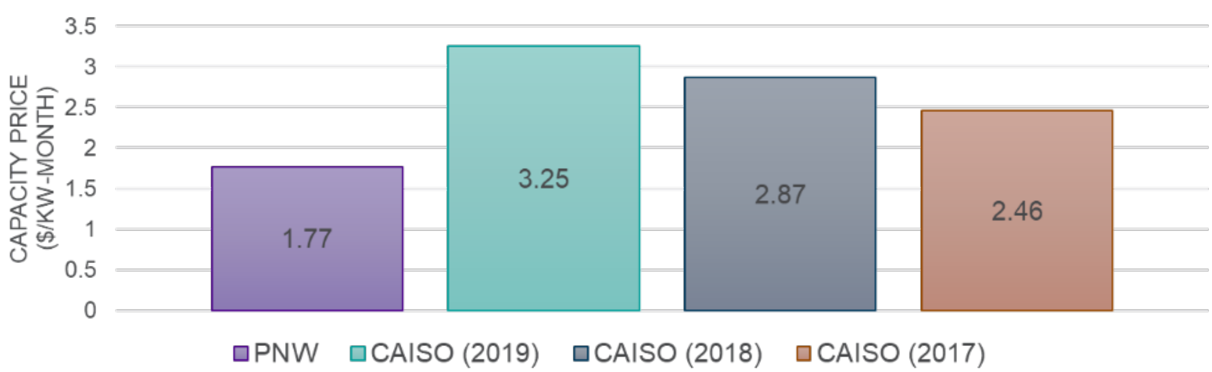


Figure 3-6 Comparison of the Capacity Prices Used in the Historical Market Analysis

Next, we examine the historical energy prices. Figures 3-7 through 3-9 compare the historical energy prices in 2017, 2018, and 2019, respectively. The DA energy prices in CAISO and the PNW show the highest volatility in 2018 and the lowest volatility in 2019. The 2019 DA energy prices in CAISO are notably more stable than other years. The DA energy prices in CAISO are also generally higher than the prices in the PNW. The DA energy prices show the 2017 and 2018 season peak occurring in the summer; however, the 2019 energy prices peak in February and March.

As expected, the RT energy prices in CAISO and EIM clearly show higher volatility than DA energy prices. The RT price volatility changes over the years are relatively modest compared to the DA price volatility. The most notable change in the RT prices is the reduced negative RT energy prices in 2018 and 2019.

Figure 3-10 compares the distributions of the DA energy prices in CAISO and PNW with and without outliers. Similarly, Figure 3-11 compares the RT energy prices' distributions in CAISO and EIM with and without outliers.

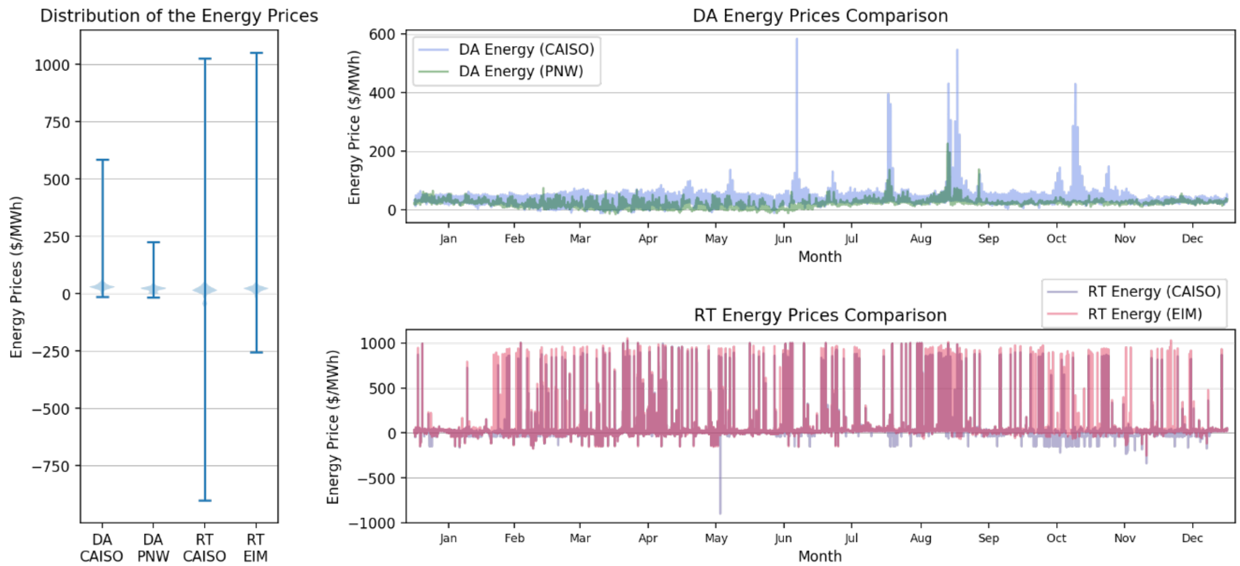


Figure 3-7 Comparison of Energy Prices in 2017

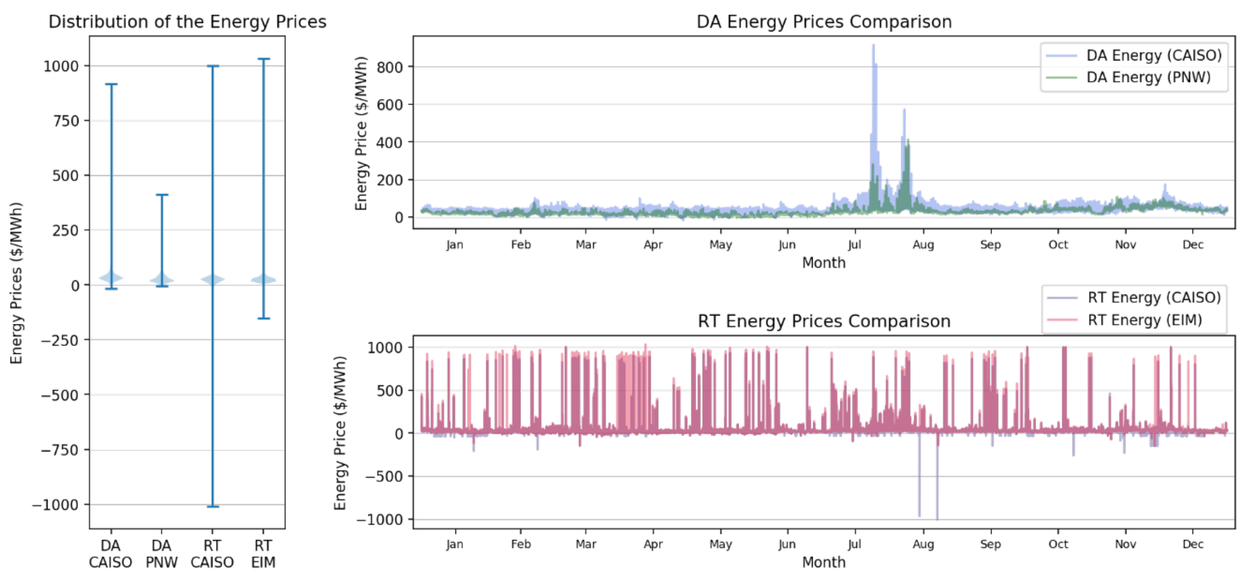


Figure 3-8 Comparison of Energy Prices in 2018

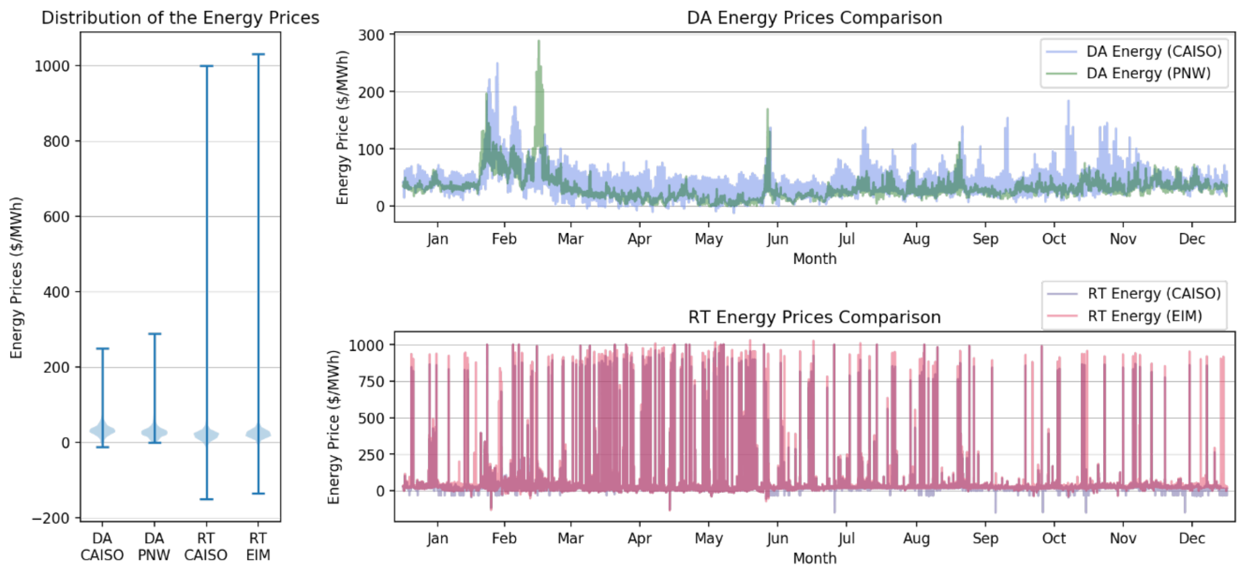


Figure 3-9 Comparison of Energy Prices in 2019

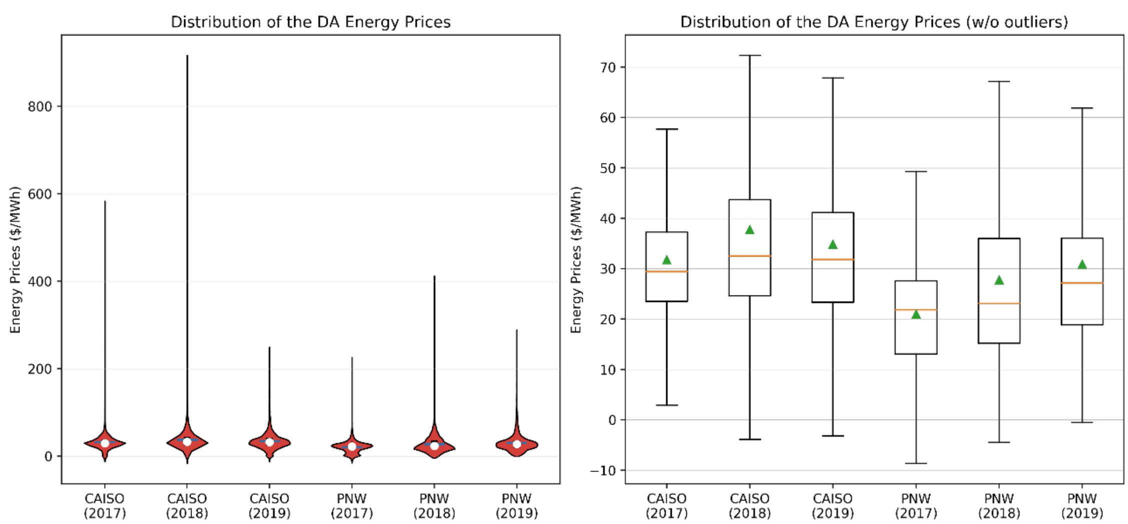


Figure 3-10 Comparison of DA Energy Price Distributions With (left) and Without (right) Outliers

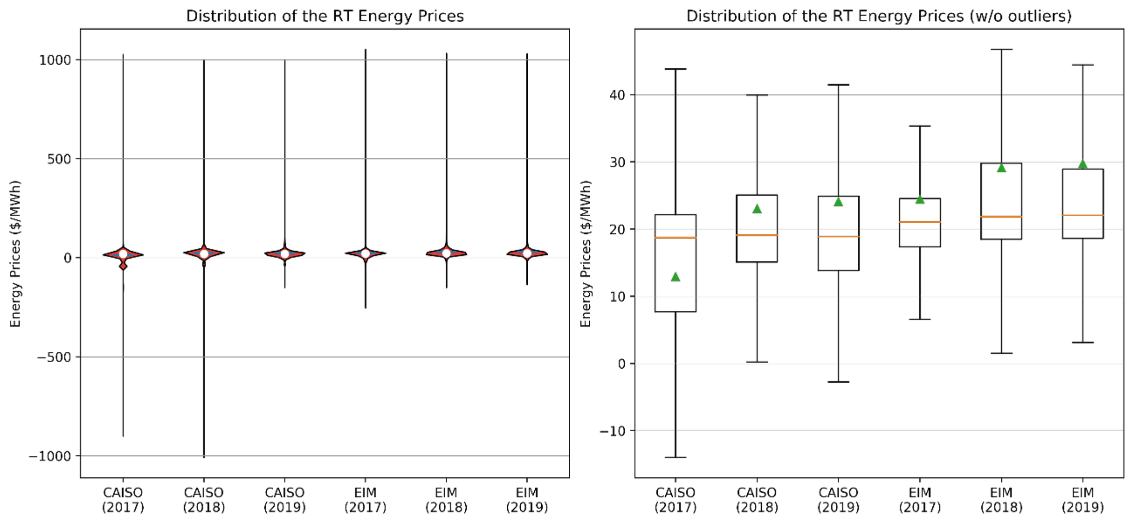


Figure 3-11 Comparison of RT Energy Price Distributions With (left) and Without (right) Outliers

Finally, we review the historical AS prices from 2017 to 2019. Figures 3-12 through 3-14 compare AS prices in 2017, 2018, and 2019, respectively. The simulated AS prices in the PNW show lower price volatility than the AS prices in CAISO. This is because the simulated AS prices from production cost simulations do not capture scarcity events; therefore, the simulated AS prices show fewer AS price spikes in terms of both frequency and amount. Like the energy prices, the DA AS prices show the season peak in the summers of 2017 and 2018; however, the 2019 DA prices peak in February and March.

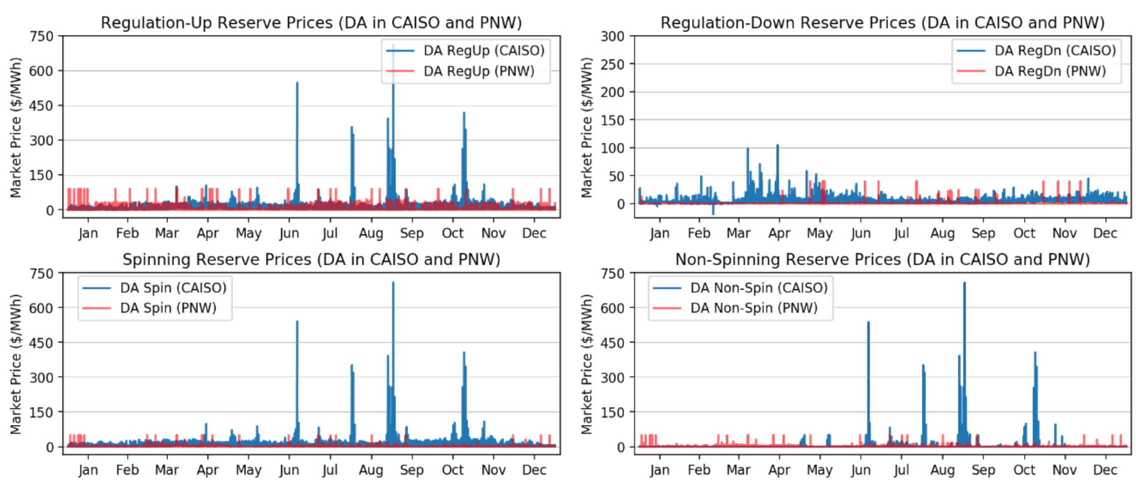


Figure 3-12 Comparison of AS Prices in 2017

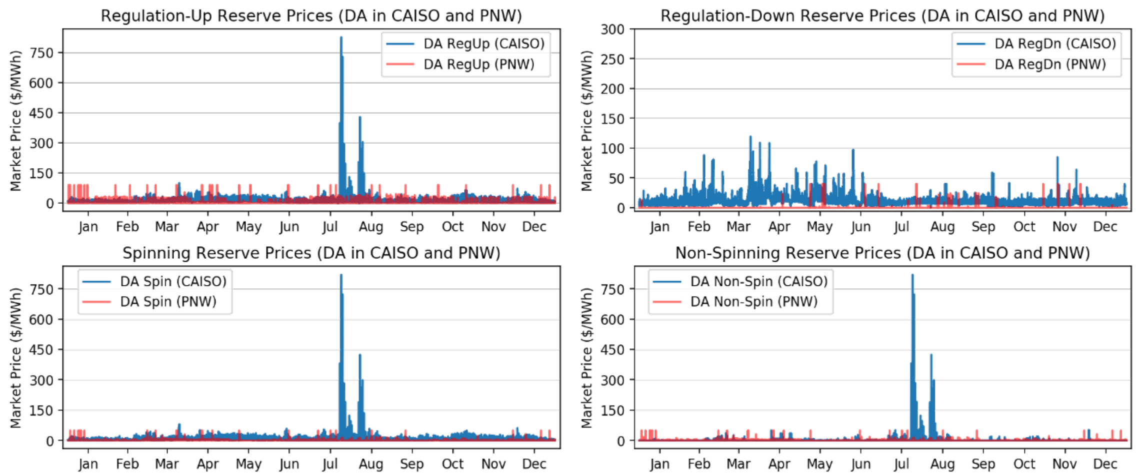


Figure 3-13 Comparison of AS Prices in 2018

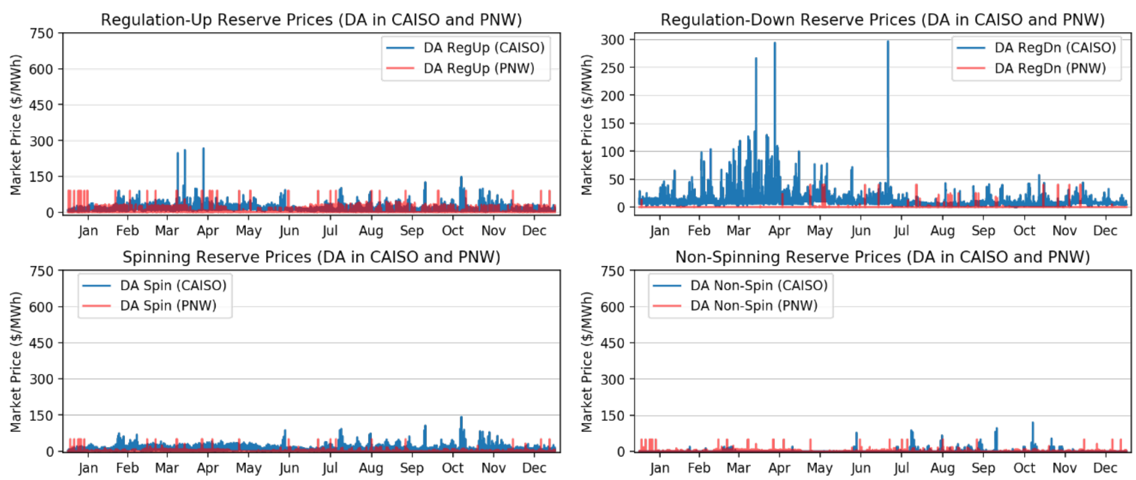


Figure 3-14 Comparison of AS Prices in 2019

3.3.4.2 Baseline Historical Market Analysis Results

In this section, we review the results from the baseline case of the historical market analysis. Figure 3-15 compares the annual service provision by the BMSP project (left panel) and the net revenue received by the BMSP project from providing each grid service (right panel). The estimated annual net revenue of the BMSP project is between $92.6 and $105.4/kW-year. All three units participate in CAISO in the baseline case. This indicates that the net gain from CAISO is higher than the net gain from the PNW. The revenue from energy arbitrage covers the most significant share of the total net revenue.

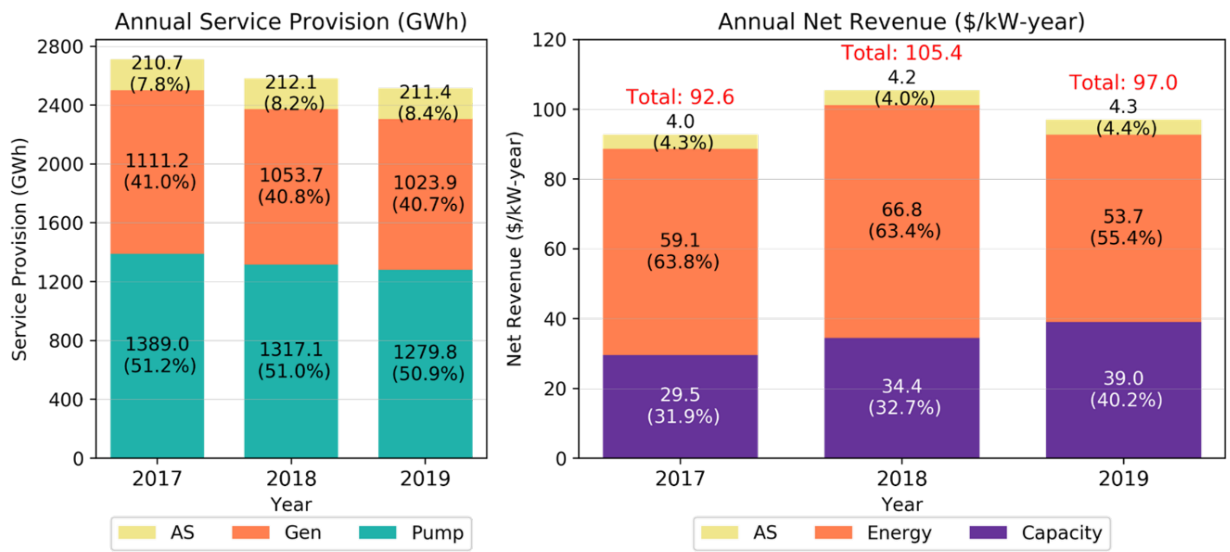


Figure 3-15 Annual Grid Service Provision (left) and Net Revenue per Grid Serve (right) in the Baseline Case

3.3.4.3 Sensitivity Studies

This section provides sensitivity analysis results. As mentioned in Section 3.3.3.3, we have four sensitivity scenarios based on different market participation settings. Figure 3-16 compares the annual net revenues in 2017–2019 when RT prices are considered. The CAISO + RT case shows that the consideration of RT prices in the co-optimization in PMAT provides higher annual net revenue than the baseline case. We also observe a declining trend in the total net revenue in CAISO when considering historical DA and RT prices from 2018 and 2019, primarily because the RT prices became more stable with less volatility and fewer spikes over time. This means that the PSH plant would have less opportunity for energy arbitrage if prices were aligned with historical outcomes from 2018 and 2019.

The baseline case results show that all three units of the BMSP participate in CAISO because of co-optimization. Therefore, we exclude the CAISO option in the PNW Only and PNW + EIM scenarios. Figure 3-17 compares the annual net revenues in 2019 between the baseline case and the sensitivity scenarios that exclude the CAISO participation option. The PNW Only case shows much lower annual net revenue than the baseline case. The consideration of EIM, which is an RT market, provides higher annual net revenue than the PNW Only case; however, the estimated net revenue is still lower than the net revenue of the CAISO + RT case.

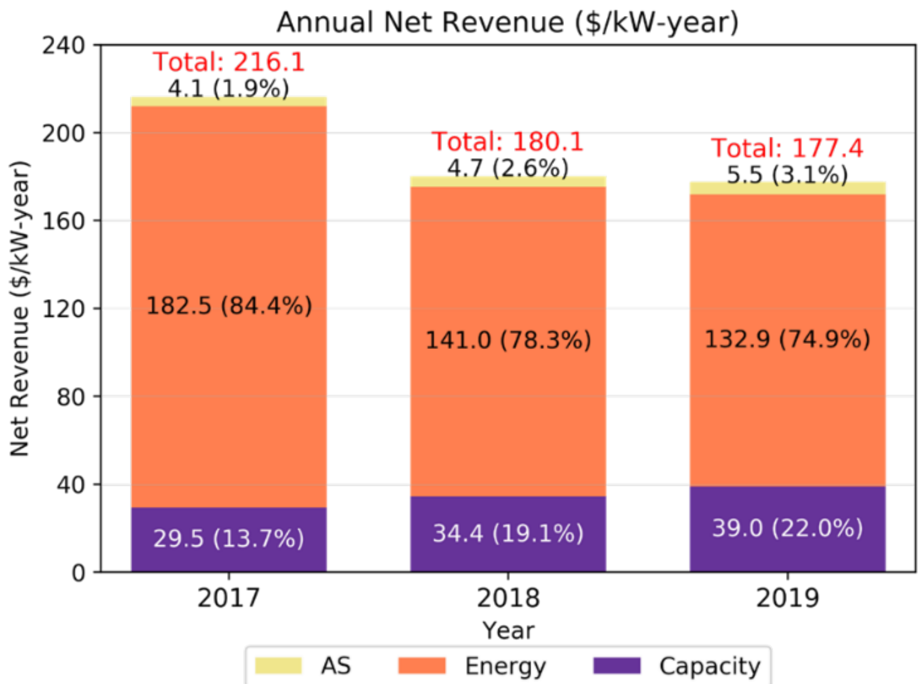


Figure 3-16 Comparison of Annual Net Revenue from 2017 to 2019 when RT Prices Are Considered

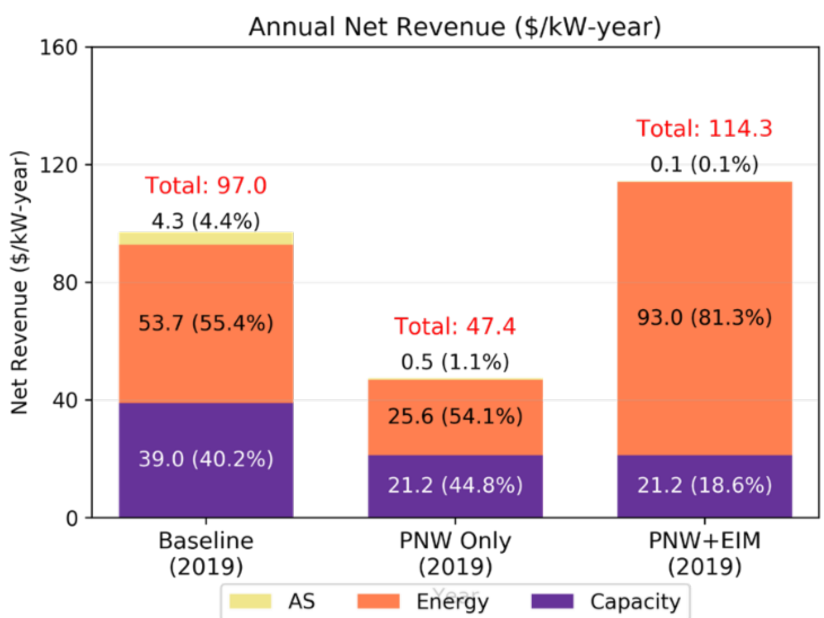
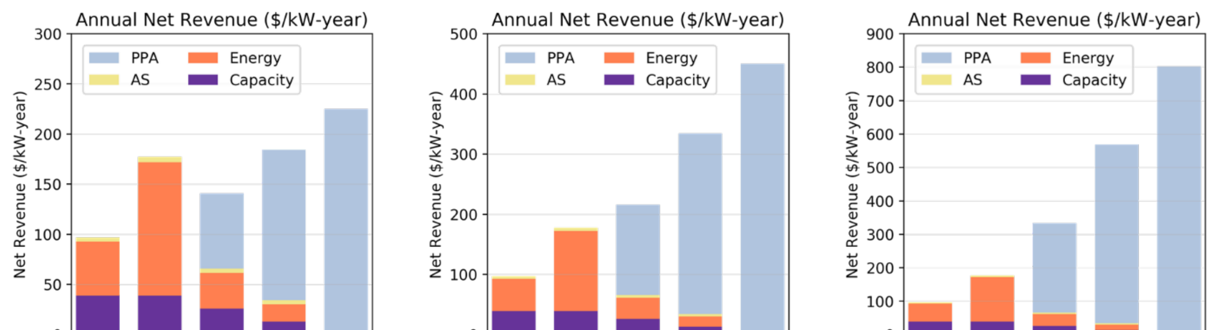


Figure 3-17 Comparison of Annual Net Revenue in 2019 Between the Baseline Case and the Sensitivity Scenarios That Exclude the CAISO Participation Option

Finally, we analyze the impact of a PPA between the BMSP and a local BA on the revenue streams. The PPA pricing data was obtained from the 2020 electric integrated resource plan (IRP) of Avista that considers two PPA pricing options with fixed payments for PSH: $22.28/kW-month and $12.50/kW-month (Avista 2020). In addition, we add a PPA pricing of $6.25/kW-month to the analysis.

Considering the size of the BMSP, we further introduce three sub-scenarios based on the number of units that have a PPA contract. The PPA-1 sub-scenario assumes that only one unit has a PPA contract with a local BA. In this case, we assume that the other two units are participating in CAISO. Similarly, the PPA-2 sub-scenario assumes that two units have PPA contracts. All three units have PPA contracts in the PPA-3 sub-scenario.

Figure 3-18 compares the annual net revenues with the three PPA pricing options. The PPA options with fixed payments provide significantly higher revenue compared to other market participation options. Even the lowest PPA pricing (i.e., $6.25/kW-month) outperforms the baseline case regardless of the number of units with a PPA contract.



	Baseline	CAISO +RT	PPA-1 (low)	PPA-2 (low)	PPA-3 (low)
AS	4.3	5.5	4.3	4.3	0.0
Energy	53.7	132.9	35.4	17.0	0.0
Capacity	39.0	39.0	26.0	13.0	0.0
PPA	0.0	0.0	75.0	150.0	225.0
Total	97.0	177.4	140.7	184.3	225.0

	Baseline	CAISO +RT	PPA-1 (mid)	PPA-2 (mid)	PPA-3 (mid)
AS	4.3	5.5	4.3	4.3	0.0
Energy	53.7	132.9	35.4	17.0	0.0
Capacity	39.0	39.0	26.0	13.0	0.0
PPA	0.0	0.0	150.0	300.0	450.0
Total	97.0	177.4	215.7	334.32	450.0

	Baseline	CAISO +RT	PPA-1 (high)	PPA-2 (high)	PPA-3 (high)
AS	4.3	5.5	4.3	4.3	0.0
Energy	53.7	132.9	35.4	17.0	0.0
Capacity	39.0	39.0	26.0	13.0	0.0
PPA	0.0	0.0	267.4	534.7	802.1
Total	97.0	177.4	333.1	569.0	802.1

Figure 3-18 Comparison of Annual Net Revenue with Low (left), Medium (middle), and High (right) PPA Pricing

3.3.5 Summary of Results

In the historical market analysis, we estimate the monetized value of the Banner Mountain PSH project in providing capacity, energy, and AS considering a combination of multiple market participation options. The historical market analysis answers how much net revenue the Banner Mountain project could have been earned in the historical markets. The historical market analysis uses a price-taker approach; therefore, it provides the best possible income, in other words, the upper bound of the possible profit of the Banner Mountain project for a given set of market prices assuming perfect foresight. It is important to note that our analysis with perfect foresight can significantly overestimate actual revenues. Therefore, the results should be interpreted cautiously.

The historical market analysis results of the baseline case show the annual net revenue of the Banner Mountain PSH project between $92.6/kW-year and $105.4/kW-year. Note that we use the historical hourly prices from 2017 to 2019 in the baseline case. In addition to the baseline case, we conduct a sensitivity analysis with four scenarios with different market participation settings. All three units are participating in CAISO in the baseline case because of the low capacity value and energy arbitrage opportunity in the PNW. The sensitivity analysis with the consideration of RT prices shows additional energy arbitrage revenue, as expected. We also observe lower total net revenues in CAISO in the later years because the RT market price profiles are stable, with less volatility and spikes. This means that the PSH plant would have less opportunity for energy arbitrage under these conditions, which covers the most significant share of the total net revenue. Last, the sensitivity analysis with PPA options shows a substantial increase in the annual net revenue, even with the lowest PPA pricing option considered in the study.

3.4 Conclusions

In this chapter, we report the power market analysis results conducted for the Banner Mountain PSH project. The power market analysis includes (1) a review of market rules and treatment of PSH in CAISO, (2) a review of new trends and development in market structure and rules, (3) an analysis of historical prices for energy, capacity, and AS, and (4) an assessment of potential revenue streams.

The review of the existing market participation model for PSH in CAISO shows that the Pumped Storage Hydro Unit Model in CAISO allows PSH to provide all capacity, energy, and AS services to the markets. Other ISO/RTO markets in the United States are currently introducing new market participation models for ES in response to FERC Order 841; however, CAISO will not develop a new market participation model for ES because its existing tariff and participation models already comply with the requirements in FERC Order 841. Therefore, we do not anticipate any immediate changes in the market participation model for PSH in CAISO. However, the market design and structure will evolve continuously due to the ongoing transformation of the power grid.

Our historical market analysis estimates the monetized value of the Banner Mountain PSH project between $92.6/kW-year and $105.4/kW-year based on historical hourly prices from 2017 to 2019. The monetized value reflects how much net revenue the Banner Mountain project could have earned in the historical markets by providing capacity, energy, and AS with a combination of multiple market participation options in CAISO, PNW, and EIM. The sensitivity analysis highlights how a PPA between the Banner Mountain PSH project and a local BA in the PNW could have a significant impact on the revenue stream. The results show that even the lowest PPA pricing option considered in our study (i.e., $6.25/kW-month) provides a monetized value between $140.7/kW-year and $255.0/kW-year.

3.4.1 References

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4.0 Overview of the Valuation Process

The proposed valuation process for PSH projects includes 15 steps, as illustrated in Figure 4-1. Each step involves certain actions, considerations, or analyses that need to be performed as part of the overall valuation process. The steps are arranged in four groups, based on the types of activities being performed.

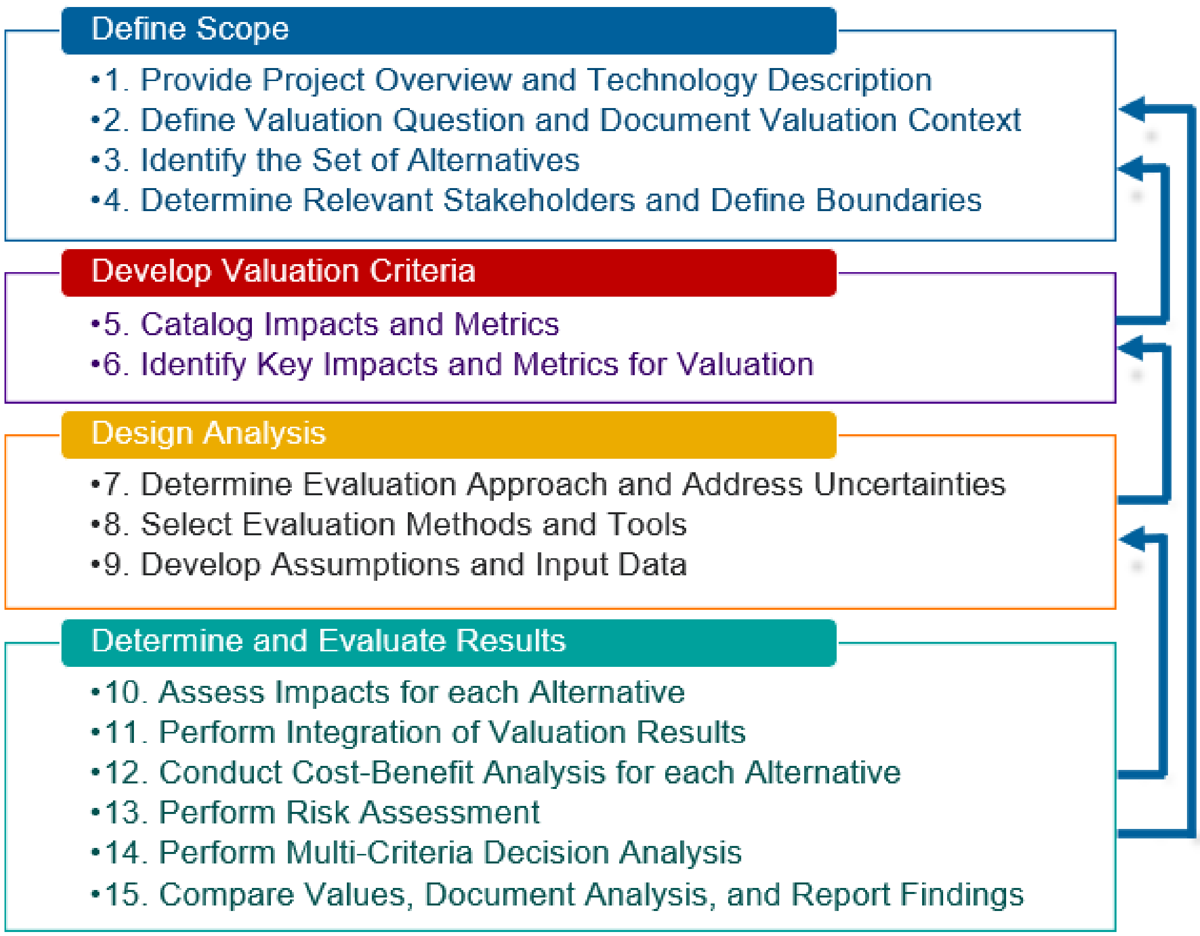

Figure 4-1 Key Steps in PSH Valuation Process

The following exercise is meant to guide the analyst through a practical application of the valuation process. The goal is to go through each step and perform the necessary actions required or recommended for that step. By going through the valuation process systematically, the analyst ensures that no actions or considerations were forgotten or not given due diligence. Not all of the actions may be applicable or necessary to perform for a particular PSH project being evaluated, but this step-by-step valuation process will ensure that all recommended actions and analyses receive proper consideration before determining whether they are needed or not.

The steps of the PSH valuation process are presented in Sections 5 through 7. As guidance to the analyst, a general description of the step and its key actions and objectives are presented first, followed by the space reserved for specific inputs for the BMSP.

5.0 Define the Scope of the Analysis

The first four steps of the valuation process involve providing a brief overview of the PSH project under consideration, describing its technology, formulating the valuation question by considering the valuation context and purpose, identifying the set of alternatives or alternative solutions, determining all relevant stakeholders, and defining the boundaries of the analysis.

5.1 Step 1: Provide Project Overview and Technology Description

A brief project overview should describe the PSH project or sub-project—including its key parameters and characteristics—and identify its owners and/or operators (for existing projects) or developers (for new projects). Relevant technical information should also be provided. The project overview narrative should typically include, but should not be limited to, the types of information found in Table 5-1. See Appendix B for the form used to acquire the information presented in Steps 1–4.

Table 5-1 Project Characteristics and Parameter Summary

Characteristic	Summary
Name of Project	Banner Mountain Pumped Storage Hydro Project
Project Location	14 miles south of Glenrock, WY – Converse County
Lead Organization	Absaroka Energy, LLC
Other Project Participants	None
Project Manager	Carl Borgquist
Project Size and Number of Units	400 MW total: 3×134 MW
In-Service Date	2028
Project Type	Closed-loop pumped storage hydro
Technology Type	Quaternary
Technical and Operational Characteristics	3,400 MWh storage, 1,175 feet of head, 20 MW/second ramp rates, 83% roundtrip efficiency, -400 to 400 MW operational range
Other Relevant Project Information	Estimated capital cost of $1.12 billion

The project overview should also include any other relevant project information or data that is deemed necessary to understand the PSH project and its characteristics. For example, if an upgrade or conversion (e.g., from fixed-speed to adjustable-speed technology) of an existing PSH project is being considered, the project overview should provide enough details to describe the proposed upgrade or conversion.

5.2 Step 2: Define the Valuation Question and Document the Valuation Context

The valuation question should be defined with careful consideration of the valuation context, purpose, and objectives. Proper formulation of the valuation question is essential for the successful application of the valuation process. In formulating the valuation question, it is important to understand both which entity or organization is asking the question (e.g., project owner or developer, market operator, regulatory agency) and what perspective(s) will be used in the valuation assessment (e.g., value to PSH owner/operator, to PSH developer, to utility, to ratepayers, to society as a whole), because this affects the assessment and types of relevant value streams used in the assessment.

Valuation context and purpose play key roles in formulating the valuation question. Many different factors should be considered to properly understand and establish valuation context. For example, does the PSH project currently exist? Is it operational or is it a proposed new facility? What are the regulatory and market environment, relevant policy incentives or disincentives, potential environmental issues, and other relevant considerations?

There are also numerous potential factors that affect the valuation purpose. Examples include the owner or operator of an existing PSH project wanting to assess its full value to the grid or to decide whether to invest in a project upgrade. Similarly, a PSH developer may want to determine whether to invest into the proposed new PSH project or not, or a PSH developer may want to determine which of the several potential project designs is likely to provide the highest value. The questions addressed in this study are bolded in Table 5-2. These questions were defined by Absaroka Energy in consultation with the project team.

Table 5-2 Purposes for a PSH Valuation Assessment

Existing PSH Project	Proposed New PSH Project
• Assess the value of the project; this valuation analysis can be conducted for different perspectives (e.g., project owner/operator, market operator, utility, regulatory agency) • Assess the value of a proposed project power upgrade or rehabilitation • Assess the value of technology change (e.g., conversion from fixed-speed to adjustable-speed units) • Compare the project value to that of some other project (e.g., another PSH project or a competing technology)	• **Assess the economic value of the project over a 50-year economic life to inform the investment decision-making process** • **Determine the value from system and owner-operator perspective** • Assess the values of different project design configurations • Compare the project value to that of an alternative project or investment • **Demonstrate how value changes under scenarios with high VREs** • Scale the power/energy capacities in order to maximize the return on investment based on the landscape of economic opportunities

The outcome of Step 2 should be a concise valuation question that considers the purpose and context of the valuation process, including the primary perspective that the valuation should be constructed around, the purpose of the decision, the timeframe and temporal resolution of the question, the performer of the valuation analysis, and the valuation process budget and milestones.

5.3 Step 3: Identify the Set of Alternatives

Identification of alternatives is closely related to the valuation question and the understanding of the valuation purpose and context, so often they can be performed in parallel. A properly formulated valuation question and a holistic understanding of the valuation purpose and context are essential for properly identifying potential alternatives.

Depending on the valuation question, the number of alternatives can range significantly, from just a few to a wide range of options. For example, if the valuation seeks to inform the investment decision-maker whether to build the project or not, there are only two alternatives. Alternatively, if the valuation seeks to answer the question of which project alternative provides the highest value, the number of alternatives is equal to the number of project options being considered, including a “do nothing” alternative.

There are also potentially many different types of alternatives, depending on the project options and potential actions or decisions that can be taken. For example, many different project design alternatives (e.g., the total project capacity, number of units, or energy storage size and duration) may be considered for a proposed new PSH project. In addition, project alternatives can potentially include other technologies that could provide services similar to those PSH plants provide.

In principle, the set of alternatives should include a baseline alternative to serve as a reference point for the comparison of alternatives. This baseline alternative is typically defined as the business-as-usual (BAU) scenario, which assumes current practices will continue in the future or will follow an already known or predefined scenario (e.g., expected technology evolution, known changes in regulatory frameworks).

The outcome of this step should be a comprehensive set of alternatives for the valuation analysis. The alternatives considered for the BMSP are as follows:

1. Do not develop the BMSP.
2. Build the 3 × 134-MW BMSP.
3. Develop other technologies (battery, gas) for new flexible capacity resources.

The valuation study presented in this report considered Alternatives 1 and 2 above.

5.4 Step 4: Determine Relevant Stakeholders and Define Boundaries

The purpose of this step is to identify stakeholders who will or might be affected by the considered project, determine boundaries of project impacts, and plan relevant stakeholder engagement. The activities within this step are closely related to those in Steps 2 and 3, and sometimes need to be performed in parallel. For example, it may be important to identify relevant stakeholders in order to identify the full set of alternatives that should be considered during the valuation study. In addition, the valuation question itself may sometimes need to be revised to include the perspectives and potential impacts on all relevant stakeholders who have been identified in Step 4.

5.4.1 Defining Stakeholders

The selection of relevant stakeholders is highly dependent on the purpose of the valuation study, type of valuation question, and the entity or decision maker (identified in Step 2) performing the valuation analysis.

Identifying all relevant stakeholders is key to a successful valuation process, because different stakeholders provide correspondingly different perspectives and thereby better encapsulate value. Depending on the perspective of the valuation question or the decision maker, not all the stakeholders need to be included in the valuation study, because the appropriate scope of perspectives is case dependent. For example, if an independent PSH developer is performing a valuation of a proposed merchant PSH project to determine whether to build it or not, the list of relevant stakeholders may not include the end-users of electricity (ratepayers) or broader society, because it is not essential to gather their perspectives to make a decision. On the other hand, if a public utility commission is approving the PSH project, the perspective of ratepayers and corresponding impacts on electricity rates may be of highest importance. Literature provides a robust series of case examples that can be leveraged to assess stakeholder inclusion; however, note that each analysis is case dependent and therefore care should be taken when developing the scope.

Table 5-3 defines the relevant stakeholders identified for the BMSP. It also defines the reason each group is a stakeholder and the type of authority each holds.

Table 5-3 Banner Mountain PSH Project Stakeholders

Stakeholder/Organization	Why Is It Relevant? (Provide a Brief Rationale)	Type of Stakeholder Authority (e.g., decision, jurisdictional) or Impact (e.g., advisory, market)
Ratepayers	Purchase of PSH by a utility ultimately affects the cost of electricity for ratepayers	Electricity rate impact
Potential Offtakers	Project customers	Market impact
Wyoming Public Service Commission	Regulatory body	Regulatory authority
State of Wyoming	Governance body	Regulatory authority
California ISO	ISO and western EIM	Market impact
GE Renewable Energy	Potential equipment manufacturer	Advisory and project design impact
Converse County Commissioners	Governance body	Regulatory authority
Wyoming Consumer Council	Regulatory body	Regulatory authority
FERC	Regulatory body	Regulatory authority

5.4.2 Defining Boundaries

Selection of relevant stakeholders can be facilitated by determining the applicable boundaries first. Typically, there are two main types of boundaries that should be considered: (1) decision boundaries, and (2) jurisdictional boundaries.

Decision boundaries identify relevant stakeholders whose perspectives may have an impact on the decision making. Jurisdictional boundaries further refine the stakeholder selection process by identifying which stakeholders have jurisdictional or other authority. For example, jurisdictional boundaries help identify municipal, state, and federal authorities, as well as relevant utility, ISO/RTO, or electricity market authorities.

5.4.3 Stakeholder Engagement

Once the relevant stakeholders have been identified, a stakeholder engagement plan should be prepared. The level of collaboration with different stakeholders may vary, depending on the relative impact of their perspectives for the valuation process. It is recommended to engage with major stakeholders at the very beginning of the valuation study to facilitate the process and assist in developing a consensus on the valuation procedure. Several stakeholders can be included in the advisory board for the study, while others can be informed about the valuation process through regular workshops, seminars, discussion meetings, and review processes. The purpose of stakeholder engagement is twofold: to keep the stakeholders informed about the valuation process and to obtain inputs and feedback from stakeholders on their specific perspectives and concerns, which may need to be addressed during the valuation process. The key benefit of successful stakeholder engagement is that it increases the transparency of the valuation process and enhances the understanding and acceptance of valuation results.

The outcomes of Step 4 include the identification of relevant stakeholders, their respective areas of interest, and the proposed means to engage with stakeholders during the valuation process. Table 5-4 presents an overview of previous and planned stakeholder engagements.

Table 5-4 Stakeholder Engagement for the Banner Mountain PSH Project

Stakeholder/Organization	Engagement Actions Already Performed (e.g., what, when, goals achieved)	Planned Engagement Actions, If Any (e.g., what, when, objectives)
Ratepayers	No contact thus far	Public forums that will include ratepayers
Potential Offtakers	Introduction to project ongoing	Periodic presentations to keep them informed of our progress
Wyoming Public Service Commission	No contact thus far	Frequent presentations to keep them informed of our progress
State of Wyoming	Initial discussions	Frequent presentations to keep them informed of our progress
California ISO	No contact thus far	Periodic presentations to keep them informed of our progress
General Electric	Made them aware of our project in December 2019	Initial meeting to discuss if they are interested in or able to provide equipment
Converse County Commissioners	No contact thus far	Frequent presentations to keep them informed of our progress
Wyoming Consumer Council	No contact thus far	Frequent presentations to keep them informed of our progress
FERC	Issued a preliminary permit in May 2018	Frequent contact throughout the permit application process

6.0 Develop Valuation Criteria

The purposes of Steps 5 and 6 are to catalog all PSH impacts and identify those that are most relevant for the valuation of the PSH project being considered. In addition to impacts, this includes identifying the metrics that can be used to measure those impacts, and their costs and benefits. Some impacts are measured in monetary units and their costs and benefits are easily monetized; however, some other impacts are measured in physical or other units that are not easily monetized.

Figure 6-1 illustrates relationships and terminology for PSH project services, impacts, metrics, and costs and benefits. The process starts with identifying the project functions (services or use cases), their applications in the power system, measures of their impacts using appropriate metrics, and monetizing the impacts to derive costs and benefits. Figure 6-1 was adapted form EPRI (2015).

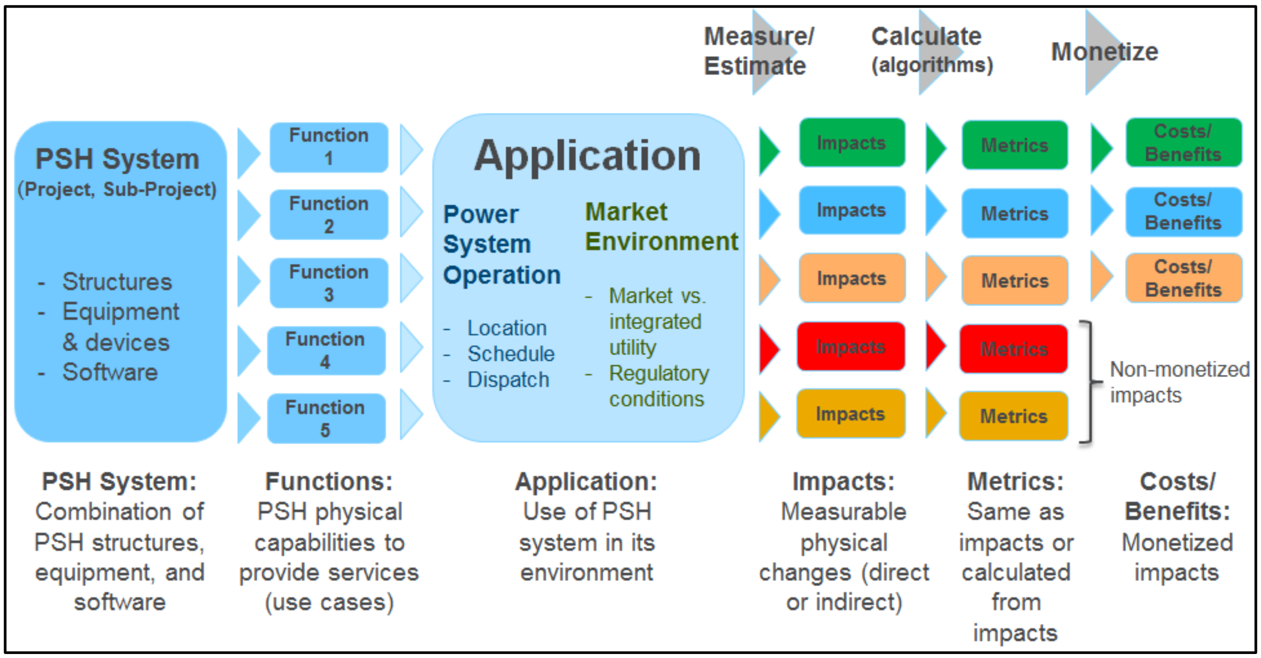

Figure 6-1 Terminology and Relationships Connecting PSH Services, Impacts, Metrics, and Benefits

6.1 Step 5: Catalog Impacts and Metrics

PSH plants are highly versatile and can provide many grid services and other benefits to the power system. In addition to so-called energy (or power) services, some of the impacts of PSH plants operations may go beyond the power system and can have wider societal effects. Typical examples of these wider societal impacts are the creation of jobs, economic development, water management services, environmental impacts, and security impacts. In principle, both energy and non-energy impacts should be included in the list of impacts relevant for the valuation analysis of the PSH project being analyzed.

In addition, note that both the energy and non-energy categories can include certain impacts that can be monetized and others that are very difficult or impossible to explicitly monetize. Although the monetized impacts can be used directly in the CBA, the non-monetized attributes can still be used in the valuation process as components of the multi-criteria decision analysis (MCDA). The MCDA (or multi-criteria decision analysis) is described in Step 14 and can be used for the valuation of alternatives that are described by both monetized and non-monetized impacts.

6.1.1 Impacts

A list of PSH services and impacts that are typically associated with a large grid-scale PSH project is provided in Table 6-1, which also presents the types of metrics that are typically used for assessing services or impacts. Note that the valuation approaches in Section 8 provide specific metrics that can be used to assess different services or impacts.

Table 6-1 Potential Services and Impacts for Inclusion in Valuation Studies

Stakeholder/ Beneficiary	Cost/Benefit Category	Service or Impact	Typical Metrics Used to Describe Services/Impacts
PSH Owner or Operator	Bulk energy services	• Electricity price arbitrage • Bulk power capacity	Physical and monetary units
	Ancillary services	• Regulation • Spinning reserve • Non-spinning reserve • Supplemental reserve • Voltage support • Black start service	Physical and monetary units
Power System	Power system stability	• Inertial response • Governor response	Physical and qualitative units
		Flexibility (e.g., ramping and load following)	Physical, qualitative, and monetary units
	Power system reliability and resilience	Reduced sustained power outages and restoration costs	Physical and qualitative units
	Power system indirect benefits	Reduced electricity generation cost	Monetary units
		• Reduced cycling and ramping (wear and tear costs) of thermal units • Reduced curtailments of variable generation	Physical and monetary units
	Transmission infrastructure benefits	Transmission upgrade deferral	Physical and monetary units
		Transmission congestion relief	Monetary units

Stakeholder/ Beneficiary	Cost/Benefit Category	Service or Impact	Typical Metrics Used to Describe Services/Impacts
Societal Costs and Benefits	Non-energy services	• Water management services • Socioeconomic benefits (e.g., jobs, economic development, recreation) • Environmental and health impacts	Physical, qualitative, and monetary units
	Security benefits	• Fuel availability, savings, and diversification • Major blackouts avoided	Physical, qualitative, and monetary units

Naturally, not every PSH project can provide, will be able to provide, or will be operated in such a manner as to provide all of these services. The services provided depend on the PSH technology (e.g., fixed-speed, adjustable-speed, or ternary units), plant design and technical performance characteristics, operational and environmental constraints, project size, location, and role in the system (e.g., large grid-scale PSH project versus small-scale PSH project), market environment (e.g., traditional regulated versus competitive market), and many other factors. For example, a list of services and impacts typically associated with a small-scale PSH project are shown in Table 6-2.

Table 6-2 Illustrative List of Services and Impacts of a Small-Scale PSH Project

Stakeholder/ Beneficiary	Cost/Benefit Category	Service or Impact	Typical Metrics Used to Describe Services/Impacts
End User	Customer Energy Management Services	• Time-of-use energy charge management • Demand charge management • Power quality • Power reliability	Physical and monetary units
Utility System	Distribution Infrastructure Services	• Distribution voltage support • Distribution upgrade deferral • Distribution losses • Integration of variable generation	Physical and monetary units
ISO Market	Ancillary Services	• Regulation • Spinning reserve • Non-spinning reserve	Physical and monetary units

For each PSH project analyzed, the analysts should develop a comprehensive list of services and impacts the project can provide. The lists of services and impacts provided in Tables 6-1 and 6-2 are an effective starting point but are by no means exhaustive. Depending on the technoeconomic and operating characteristics of the PSH project being evaluated, its purpose and role in the system, and other factors, the list of its services and impacts may include a combination of items listed in Tables 6-1 and 6-2, as well as other project-related services and impacts not listed in these two tables.

6.1.2 Metrics

In addition to cataloging the services and impacts for the PSH project analyzed, the analysts' task under Step 5 is to also develop a list of appropriate metrics to be used for measuring the impacts. In principle, depending on the type of units, the metrics can be categorized into three broad groups: (1) monetary, (2) physical and numerical, and (3) qualitative.

6.1.2.1 Monetary Metrics

Monetary metrics are used to describe services and impacts that can directly be expressed in monetary units (e.g., U.S. dollars). As such, the costs and benefits of these services and impacts are already monetized and can be directly used to develop cost and benefit value streams for the CBA. Services and impacts that are sold and bought in electricity markets are the easiest to monetize and are defined in terms of market-based revenue. Other services (e.g., transmission congestion relief) may result in cost avoidance that, while monetizable, fails to generate revenue for the developer. These avoided costs are still relevant and worthy of definition. By including them in the valuation process, the analyst can bring the value streams to the attention of regulators and market operators. By doing so, the analyst may assist in removing regulatory and market barriers to PSH deployment in that region.

6.1.2.2 Physical Metrics

Most often, the services and impacts are expressed in physical units. Services and impacts expressed in physical units can sometimes be easily monetized, but sometimes it is very hard or even impossible to explicitly monetize their value. Products or services with an established market can use the relevant market prices to monetize the value stream in question. Note that this "price-taker" approach has analytical implications that must be considered. One example of an easily monetized service that is expressed in physical units is the electricity generation (MWh) or, for PSH plants, the value of energy arbitrage (value of electricity generation minus the cost of pumping). In the case of PSH plants, the quantities of electricity (MWh) produced and consumed during the energy arbitrage are multiplied by the respective prices of electricity ($/MWh) in those time periods to derive the value of energy arbitrage in monetary units ($). On the other hand, some services and impacts can be expressed in physical or numerical units, but it is very hard to monetize them and express their value in monetary units. That is typically the case when there is no market for a particular service or impact (e.g., inertial response), or the value of its benefits is difficult to estimate (e.g., system reliability).

In addition to physical units (i.e., those that have a clear physical meaning and background), certain services or impacts can be expressed in numerical or synthetically derived units. While these units may still describe the physical impacts and services, the units that are used are purely numerical. One example is the PRM, which describes the desired level of available system capacity in excess of projected system peak load. Although both the available capacity and system peak load are expressed in megawatts, the PRM is expressed as a percentage (%). Another example is the commonly used reliability metric LOLP (loss-of-load probability), which is also expressed as a percentage but is derived from the LOLE (loss-of-load expectation) parameter. While LOLP is a purely probabilistic metric, it is derived from the LOLE. LOLE has a physical background, because it describes the target reliability value for long-term expansion planning of power systems. In the United States, the target LOLE value is less than 1 day of outages in 10 years.

6.1.2.3 Qualitative Metrics

Some services or impacts can also be described using qualitative metrics. Typically, qualitative metrics use descriptive units, such as "low," "medium," and "high," or a predefined or constructed scale (e.g., from 0 to 1, or from 0 to 100) to describe the quality or benefit provided by a certain service or impact. Obviously, since the quality or value of services and impacts is judged by experts performing the analysis, this is very subjective. Typical examples of qualitative units are fuel diversity, resilience, and environmental sustainability. Expanding on the first of these, while fuel diversity may not have clearly defined parameters and thresholds, the plant mix and fuel use in the power systems can often be broadly categorized as low, medium, and highly diversified.

The main outcome of Step 5 is a detailed list of all services, impacts, and associated metrics for the PSH project or sub-project that is being evaluated.

6.2 Step 6: Identify Key Impacts and Metrics for Valuation

6.2.1 Key Impacts and Metrics for Valuation

The purpose of this step is to identify key impacts and metrics important for valuing the PSH project or sub-project being analyzed. Starting from the comprehensive list of project services and impacts developed in Step 5, analysts should identify those that will be assessed in the valuation process. The first step is to identify which services are currently provided or may be provided by the PSH project over its lifetime. Then this subset should be examined to determine which services and impacts should be assessed and used in the valuation study. Ideally, all the potential services and impacts should be evaluated; however, that is often impractical in an actual valuation study. Reasons for omitting certain services or impacts include value streams that are negligible, or whose value is difficult to estimate or assess analytically (e.g., the value of inertial response).

Which services and impacts will be assessed in the valuation study also depends on the electricity market structure, PSH business model, operational and environmental constraints, and several other factors. For example, if the PSH project operates in a restructured market environment where energy and ancillary services are procured by the market operator through a competitive bidding process, those value streams and their associated costs and benefits should be assessed and included in the valuation analysis. On the other hand, if the PSH project operates in a traditionally regulated utility environment, where no individual value streams are established for ancillary services, the benefits of the PSH plant operation are still there, but in this case they are usually assessed through the impacts of the PSH plant on the overall system operation (e.g., reduced electricity generation costs, reduced cycling and ramping of thermal units, reduced curtailments of variable generation).

The business model of the existing or planned PSH project should be considered as well. For example, if the PSH project is developed as a merchant plant and has a long-term PPA with a utility, this factor represents one of the most important value streams to be considered in the valuation analysis. If there are potential other value streams in addition to the PPA, those opportunities should also be considered.

Note that the list of key impacts and metrics for valuation should include all important services—both monetized and those that cannot be monetized. Important non-monetized services and impacts should be included if they can be expressed in physical units or in qualitative terms. These can be leveraged in the development of an MCDA to choose among different alternatives described by multiple attributes (e.g., monetized and non-monetized).

The output of this step results in a list that should include all services and impacts that will be evaluated in the valuation study. This list can be prioritized so that higher importance is given to services that are expected to provide higher value streams. This prioritization can be used later to determine the level of detail needed for modeling and analyses that will be performed to assess the value of each of these services.

The selection of the metrics for evaluation will to some extent dictate the analysis methods that need to be applied in the valuation study, so that the relevant metrics can be used to assess PSH services and impacts. The design of the analysis is addressed in the next group of steps.

The list of PSH services and impacts included in this study are presented in Table 6-3, which also identifies the metrics used to describes services/impacts and the priority placed on each metric by the BMSP team. Note that some of the services were not included in the initial set ranked by the BMSP team and, therefore, did not receive a ranking. The priority ranking in this case was developed on a scale from 1 to 5, with 1 being the highest priority. A full list of metrics is also provided in Appendix A of the *PSH Valuation Guidebook* (Koritarov, 2021).

Table 6-3 Services and Impacts Evaluated for the Banner Mountain PSH

Stakeholder/ Beneficiary	Cost/Benefit Category	Service or Impact	Typical Metrics Used to Describe Services/Impacts	Priority
PSH Owner or Operator	Bulk energy services	Electricity price arbitrage	Physical and monetary units	2
		Bulk power capacity	Physical and monetary units	1
	Ancillary services	Regulation	Physical and monetary units	2
		Spinning reserve	Physical and monetary units	3
		Primary frequency response	Physical and monetary units	3
		Black start service	Physical and monetary units	3
Power System	Power system stability	Primary frequency response	Physical and monetary	3
		Voltage support	Physical and monetary	2
		Transient stability	Physical	--
	Power system indirect benefits	Frequency regulation	Physical and monetary	2
		Spinning reserve	Physical and monetary	3
		Reduced electricity generation cost	Physical and monetary	--
		Reduced curtailments of variable generation	Physical	1
	Transmission infrastructure benefits	Transmission upgrade deferral	Physical and monetary	3
		Transmission congestion relief	Physical and monetary	2
Societal Costs and Benefits	Non-energy services	Socioeconomic benefits (e.g., jobs, economic development, recreation)	Physical and monetary units	--
		Environmental and health impacts (emissions)	Physical and monetary	2
	Security benefits	Cost of unserved energy	Physical and monetary units	3

6.2.2 References

Koritarov, V., P. Balducci, T. Levin, M. Christian, J. Kwon, C. Milostan, Q. Ploussard, M. Padhee, Y. Tian, T. Mosier, S.M.S. Alam, R. Bhattarai, M. Mohanpurkar, G. Stark, D. Bain, M. Craig, B. Hadjerioua, P. O'Connor, S. Mukherjee, K. Stewart, X. Ke, and M. Weimar, 2021, *Pumped Storage Hydropower Valuation Guidebook: A Cost-Benefit and Decision Analysis Valuation Framework*. 2021. U.S. Department of Energy, Water Power Technologies Office, March. Available at: https://www.energy.gov/eere/water/pumped-storage-hydropower-valuation-guidebook-cost-benefit-and-decision-analysis. DOI: 10.2172/1770766.

EPRI (Electric Power Research Institute), 2015, *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects: Revision 3*, Palo Alto, CA.

7.0 Design Analysis

With the key impacts and metrics for the valuation analysis identified, Steps 7, 8, and 9 help the analyst to (1) determine an evaluation approach, (2) select evaluation methods and tools, and (3) develop assumptions and input data for the analysis.

7.1 Step 7: Determine Evaluation Approach

Selecting an appropriate evaluation approach depends on the types of impacts and metrics identified in Step 6. The approach should also consider modeling limitations (discussed in Step 8) and data availability (addressed in Step 9), so these three steps are often considered in parallel. There will be several different impacts for which the value streams need to be assessed, each of which may require different evaluation methods and approaches. For example, to estimate the value streams for energy arbitrage and ancillary services in a competitive ISO-operated electricity market, a market analysis may need to be performed.

Two commonly used evaluation approaches for assessing potential market revenues and value streams are the price-taker approach and the system analysis, or price-influencer, approach. The price-taker approach uses an optimization model with fixed price inputs (historical or forecasted) to calculate optimal market revenues; hence, it assumes that the operation of the project does not influence the market clearing prices, which is generally true for relatively small projects (e.g., less than 10 MW or so, depending on the size of the power market). In this case, the price-taker evaluation approach does not require a simulation of electricity market operation, because the revenues can be estimated using historical or forecasted market prices. However, if the PSH project being evaluated is a large, grid-scale project, its operation will likely have a significant influence on market clearing prices. In that case, the system analysis approach requires a simulation of electricity market operation to determine what the market clearing prices would be with the PSH project in operation.

Similarly, if the PSH project being evaluated is in a non-market environment (e.g., vertically integrated utility under traditional cost-of-service regulation), a production cost analysis may need to be performed to estimate its impacts on electricity generation costs, reliability, and other portfolio effects. To estimate some long-term impacts, such as the value of PSH capacity or the value of transmission deferral, the evaluation approach may require an application of the IRP analysis. On the other hand, power flow (PF) modeling and dynamic simulation analysis may be needed to assess the value of short-term impacts, such as fast inertial response and power system stability.

Therefore, several different evaluation methods and approaches may be required to assess the value of the key impacts identified in Step 6. The purpose of this task is to determine the appropriate approaches for the evaluation of various impacts or groups of impacts. The analytical capabilities of the analysts, their access to simulation methods and tools, and data availability should be considered when selecting the appropriate evaluation approaches and level of detail for the valuation analysis. For example, if an electric power utility or a consulting company is performing the valuation study, they may have access to very sophisticated tools and simulation models, as well as detailed data needed for the valuation analysis. On the other hand, if an IPP is performing an in-house valuation analysis, they may need to use simplified, less-detailed analytical approaches because they may be constrained in their access to sophisticated power system modeling tools, data, and time.

Since the BMSP is a large-scale PSH plant with a 400-MW capacity and is not located in a structured market, we used system-based capacity expansion, production cost, and transmission system planning models to simulate the price influencing effects of the BMSP operations throughout the WECC region. Table 7-1 presents the technical approaches used to assess the value of each use case identified for the system and owner-operator analyses in Table 6-1. The societal effects are not highlighted in Table 7-1 because these values were obtained from the PCM results from the energy and ancillary services assessment and a benefit transfer approach that used the economic impact analysis conducted by Highland Economics for the Goldendale PSH project. Detailed methodologies are presented for each service in Section 8.

Table 7-1 Technical Approaches Used to Assess Services from System and Owner-Operator Perspectives

Beneficiary	System	Owner-Operator
Capacity	Power system expansion model used to simulate generation expansion and retirement throughout the entire WECC from 2019 to 2038. System-oriented approach to simulate value of capacity as a service in the Rocky Mountain Reserve Group (RMRG) from the perspective of a neutral planner.	Same as that used for system analysis.
Generation Costs / Arbitrage	PCM used with optimization driven by system benefits and value derived from WECC-wide reductions in energy generation costs.	PCM used with optimization driven by system benefits, but value based on relevant prices (e.g., LMP for arbitrage).
Spin Reserve and Frequency Regulation	PCM used with ancillary services co-optimized with energy service and value derived by comparing WECC-wide ancillary service costs with and without the BMSP.	Same as that used for system analysis.
Black Start	Because the BMSP is not located within a structured market, black start was modeled using the cost-of-service approach. The specific cost-of-service format applied in this analysis is based on the one published for the Pennsylvania–New Jersey–Maryland (PJM) interconnect.	Same as that used for system analysis.
Voltage Support	Transmission system planning model used to perform simulation and evaluate the impact of the BMSP on system stability using several metrics (e.g., critical clearing time [CCT] and level of contingency withstood, rate of change of frequency [ROCOF] and frequency nadir/zenith for a given event, arresting period rebound period, voltage sag and voltage recovery). Voltage support value based on the reactive power tariffs and payments published by New York Independent System Operator (NY-ISO), Independent System Operator-New England (ISO-NE), and PJM. Value of primary frequency response based on known contract pricing between the California Independent System Operator (CAISO) and Bonneville Power Administration (BPA) for frequency response services.	No value to owner-operator due to the absence of revenue mechanisms.

Beneficiary	System	Owner-Operator
Primary Frequency Response	Transmission system planning model used to perform simulation and evaluate the impact of the BMSP on system stability using several metrics (e.g., CCT and level of contingency withstood, ROCOF and frequency nadir/zenith for a given event, arresting period rebound period, voltage sag and voltage recovery). Voltage support value based on the reactive power tariffs and payments published by the NY-ISO, ISO-NE, and PJM. Value of primary frequency response based on known contract pricing between CAISO and BPA for frequency response services.	Same as that used for system analysis.
Transmission Congestion Relief	PCM runs establish dispatch and alternating current optimal power flow (ACOPF) model determined reduction in congestion component of LMPs.	Positive externality to system, but not monetized benefit.
Transmission Deferral	ACOPF program used to alleviate congestion along targeted lines.	Positive externality to system, but not monetized benefit.

7.2 Step 8: Select Evaluation Methods and Tools

Following the choices made in Step 7 regarding appropriate evaluation approaches and how uncertainties will be addressed, the purpose of Step 8 is to select specific methods and tools to assess the values of the key PSH services and impacts identified in Step 6. In principle, the choice of methods and tools is very wide, from a simple spreadsheet analysis to very complex and detailed power system modeling and simulations. Because the level of detail for the valuation analysis of each PSH service or impact was determined in Step 7, the purpose of this step is to select among the available valuation methods and tools the ones that satisfy those requirements. For example, if in Step 7 it was determined that the evaluation approach for energy arbitrage and ancillary services should be based on the analysis of historical market prices, an appropriate spreadsheet tool may satisfy those requirements, and the purpose of this step is to select an available spreadsheet tool that satisfies the methodological and analytical requirements. If such a tool is not readily available, the decision may be to develop one if that is a feasible option.

On the other hand, if the evaluation approach calls for a simulation of the electricity market, then an appropriate market analysis tool should be selected. The selection of the evaluation method can also be illustrated with the following example: Different market analysis tools may use different modeling approaches and simulation algorithms. Some may use marginal electricity generation costs of generating units or user-specified bid prices to calculate market clearing prices, while some may simulate the electricity market bidding process using agent-based modeling and simulation, where bid prices dynamically change during the simulation based on learning and adaptation techniques. Therefore, if the evaluation approach determined in Step 7 calls for a market analysis by simulating electricity market operation, then the analytical method and modeling tool that satisfies those requirements should be selected in this step.

Similar considerations are also valid for the selection of appropriate methods and tools for the valuation and quantification of other PSH impacts and value streams. Obviously, different services and impacts will require different methods and tools for their valuation. Table 7-2 identifies the models/tools used to carry out the methods defined in Table 7-1.

Table 7-2 Models, Tools, and Approaches Used to Assess Services and Impacts

Service	System	Owner-Operator
Capacity	AURORA used to define WECC-wide generation portfolios in 2028 and 2038. System-oriented approach to simulate value of capacity as a service in the RMRG from the perspective of a neutral planner.	Same as that used for system analysis.
Generation Costs / Arbitrage	PLEXOS PCM	PLEXOS PCM
Spin Reserve and Frequency Regulation	PLEXOS PCM	PLEXOS PCM
Black Start	Cost-of-service equation taken from one published for the PJM interconnect.	Same as that used for system analysis.
Voltage Support	PSSE transmission system planning model used to perform dynamic simulation.	No value to owner-operator due to the absence of revenue mechanisms.
Primary Frequency Response	PSSE transmission system planning model used to perform dynamic simulation.	Same as that used for system analysis.
Transmission Congestion Relief	PLEXOS runs establish dispatch and PSSE used in coordination with ACOPF formulation in the General Algebraic Modeling System (GAMS) to model transmission impacts.	Positive externality to system but not monetized benefit.
Transmission Deferral	PLEXOS runs establish dispatch and PSSE used in coordination with ACOPF formulation in GAMS to model transmission impacts.	Positive externality to system but not monetized benefit.

To integrate results and avoid double counting of benefits, we developed a coordination or modeling flow when conducting the technoeconomic studies. AURORA modeling was used to define WECC-wide generation portfolios for several scenarios in future years 2028 and 2038. PLEXOS, using these generation portfolios as inputs to the PCM process, then co-optimized system operations to minimize energy generation and ancillary service costs throughout the WECC. These costs were estimated with and without the availability of Banner Mountain PSH, with the difference in costs being used to define value. For the owner-operator analysis, operations were still optimized for system benefits, but the value of arbitrage was estimated based on local LMPs evident when the PSH unit was charging (purchasing energy) and discharging (selling energy) while accounting for RTE losses.

Black start, voltage support, and primary frequency response values were estimated using the PSH capacity remaining after co-optimizing for energy and ancillary services, while transmission benefits were estimated assuming that any benefits accrued as a byproduct or positive externality of plant operations. That is, transmission services are not prioritized in the co-optimization procedures, but the system benefits associated with the transmission congestion component of regionwide LMPs or the deferral of transmission investments can be quantified. Note that the voltage support and transmission benefits register no monetized value to the owner-operator due to an absence of direct market or non-market funding mechanisms.

7.3 Step 9: Develop Assumptions and Input Data

Using the evaluation methods and tools selected in Steps 7 and 8, in Step 9 we develop detailed assumptions and collect the input data needed for the valuation analyses of alternatives defined in Step 3. As discussed in Step 7, several scenarios may need to be defined and examined for each alternative to address uncertainties. A set of sensitivity studies may also need to be performed for each scenario to gain a better understanding of how certain factors may impact the value of PSH services. Because it is likely that several different tools will be used for the valuation of various PSH impacts and the quantification of associated value streams, different datasets may need to be assembled for different models and tools.

The starting point of Step 9 is to define a set of scenarios that will be explored in the valuation analysis of each alternative. The scenarios can be defined with a set of assumptions about demand growth, variable renewable penetration, the shape of the net load profiles in the future, projections of natural gas prices, and other factors. Each scenario will be defined with a unique set of assumptions. A set of sensitivity studies should also be defined for each scenario. For example, suppose that two scenarios have been defined for the price of natural gas: “low gas prices” and “high gas prices.” In this case, additional insights into the potential impacts of gas prices can be gained through sensitivity studies by varying gas prices above and below the baseline assumption that was used in each of the two scenarios. During this step, a preliminary list of key drivers and factors that are likely to influence the value of PSH services should be prepared. This list can be amended later with additional factors that need to be examined, based on the insights gained during the valuation process. This list may include technical, economic, regulatory, and other factors and constraints.

As mentioned above, Steps 7, 8, and 9 are closely related and often need to be performed in parallel or iteratively. The analyst should revisit the previous steps and reevaluate previous decisions. For example, if a selected methodology requires data at a 5-minute timestep, and only hourly data are available, either the modeling approach needs to be adjusted or 5-minute time-resolution data will need to be obtained.

In summary, the outcome of this step will be a set of scenarios, described by their respective scenario assumptions, for each alternative defined in Step 3. A preliminary list of parameters and key drivers for which sensitivity studies will be performed should also be developed for each scenario. Finally, a set of input data should be prepared for each of the modeling tools that will be used in the valuation analysis.

Table 7-3 describes the scenarios considered in the capacity technoeconomic study. In addition to the base case, we also consider several additional sensitivity scenarios to better understand how the relative impacts of introducing Banner Mountain to the power system change under different conditions. In each sensitivity scenario, we similarly first determine a baseline capacity expansion plan for the entire WECC system. We then conduct a second run while introducing Banner Mountain in 2028 and re-optimizing unit investments and retirements near Banner Mountain. These scenarios do not represent any judgement about the likelihood of outcomes; they are intended to be directionally informative and identify broad system trends caused by changes in these parameters. For each scenario, two cases are run—one without and one with Banner Mountain—producing eight different capacity expansion plans. The PCM evaluation focuses in on the base and AggCarbon scenarios, but also evaluates the implications of DA (1-hour) and RT (5-minute) operations, which results in eight PCM scenarios. The arbitrage assessment employed the same eight scenarios. Finally, from the base case file prepared for the stability valuation assessment, scenarios files were generated for 2028: 2028 heavy summer, 2028 light winter, 2028 heavy summer with high wind, 2028 light winter with high wind, and 2029 heavy spring.

Table 7-3 Scenarios Considered in Capacity Analysis

Scenario	Abbreviation	Description
Baseline	Baseline	Capital costs based on the 2018 NREL annual technology baseline (ATB)
Energy Information Administration (EIA) Capital Costs	EIA	Default AURORA capital costs, based on EIA projections
High Natural Gas Price	HighNG	The Henry Hub natural gas price is 19% greater than Baseline in 2019 and the price difference escalates by an additional 2.5% annually
Aggressive Carbon Reductions	AggCarbon	No new natural gas additions beyond currently planned units; all coal units are retired by 2030 with gradual scale-down

The research team also conducted a set of sensitivity analyses to identify and evaluate potential risks that may impact the value of the project being evaluated. The CBA performed in Step 12 is subject to numerous uncertainties and short- and long-term projections (e.g., fuel price projections, revenue projections made during the valuation process). For this analysis, we evaluated the sensitivity of the results with respect to a few key parameters, varying them as follows:

- Vary discount rate by ±1%
- Vary cost and revenue escalation rates by ±1%
- Add 30% investment tax credit
- Property taxes increased to 0.5%
- Compare to RT high renewable energy case
- Compare to DA high renewable energy case
- Compare to DA baseline case
- Economic lifetime extended to 100 years

These alternatives are compared to the RT baseline case to measure the range of potential impacts on NPV for each sensitivity analysis.

Table 7-4 presents the primary sources of data used to support the technoeconomic studies. The data structure supports the previously discussed modeling flow with output from one service, such as the capacity expansion results developed in AURORA, being used to inform the next (e.g., energy and ancillary service modeling in PLEXOS). The data covered a broad geographic area (WECC), but more granularity was required to support more detailed analysis of areas nearer to the BMSP (e.g., the RMRG). Unit additions and retirements and solar profiles were required to characterize future grid conditions. PSH capacity, performance, transmission connections, and other data required to model BMSP interactions with the grid were also key in supporting the technoeconomic studies.

Table 7-4 Primary Data Used to Assess Services and Impacts

Beneficiary	System Owner-Operator
Capacity	• Base generation portfolio in AURORA, which includes several planned unit additions and retirements based on data from the EIA • Prospective unit additions that are included in the 2019 PacifiCorp IRP • Coal retirements anticipated by the WECC • PSH capacity and performance data from the BMSP project team
• Generation Costs / Arbitrage • Spin Reserve • Frequency Regulation	• 2024 Transmission Expansion Planning Policy Committee (TEPPC) database • Capacity expansion scenarios completed as part of our capacity analysis • Wind and solar profiles, for which we used the Wind Toolkit (Draxl et al., 2015) and the National Solar Radiation Database (Sengupta et al., 2018) • PSH capacity and performance data from the BMSP project team
Black Start	• Hourly labor costs, as prescribed by the PJM (PJM Interconnection, 2019) • PSH capacity and performance data from the BMSP project team
• Voltage Support • Primary Frequency Response	• Base case model in PSSE • Output from PLEXOS model • EIA generation retirement data • PSH capacity and performance data from the BMSP project team
• Transmission Congestion Relief • Transmission Deferral	• 2025 Heavy Summer 1 PTI PSSE case for the PF model • Base PF case, the generator, lines, and loads were revised in the PF case to match the PCM model • PSH plant and connecting transmission line data were obtained from the BMSP project team

7.4 References

Draxl, C., B.M. Hodge, A. Clifton, and J. McCaa, 2015, *Overview and Meteorological Validation of the Wind Integration National Dataset Toolkit*, NREL/TP-5000-61740, 1214985. Available at https://doi.org/10.2172/1214985.

PJM, 2019, *Review of Black Start Formula and Cost Components.*

Sengupta, M., Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby, 2018, “The National Solar Radiation Data Base (NSRDB),” *Renewable and Sustainable Energy Reviews* 89(June): 51–60. Available at https://doi.org/10.1016/j.rser.2018.03.003.

8.0 Determine and Evaluate Results

The valuation methods and tools selected in Step 8 are applied in this step, which includes the analysis of PSH services and impacts and to quantify their corresponding value streams. This step also includes a significant amount of modeling and simulation; the analysis covers all the alternatives identified in Step 3, including all scenarios and sensitivity studies defined in Step 9. Sections 8.1 through 8.7 collectively comprise Step 10; they present an overview, background, methodology, and findings for each use case assessment.

8.1 Capacity Valuation

8.1.1 Overview of the Analysis

This section first reviews the concept of capacity as a grid service and presents a methodology for quantifying the system value of capacity in a given region. To this end, we first apply AURORA, a commercial power system expansion model to simulate generation expansion and retirement throughout the entire WECC from 2019 to through 2038 for a baseline and three sensitivity scenarios. For each scenario, we consider one case where Banner Mountain is not developed, and one case where Banner Mountain is added to the system in 2028. These capacity expansion results inform the additional analyses that are presented throughout this report.

We also conduct more detailed operational modeling for two specific years, 2028 and 2038, and determine an annual capacity valuation in each of five WECC planning pools. The capacity valuation is set by the revenue requirement of the marginal resource in each planning pool, in terms of satisfying the target PRM in that pool. We calculate baseline capacity valuations in the RMRG of $65.46/kW-year in 2028 and $52.53/kW-year in 2038. Across all four considered scenarios, the valuations range from $48.39/kW-year to $66.91/kW-year in 2028 and from $33.87/kW-year to $120.33/kW-year in 2038, all in constant 2019 dollars. We compare these capacity valuations in the RMRG with those in the California–Mexico Planning Pool (CMPP) across all four scenarios in both years examined. The baseline capacity values are lower in the CMPP in both 2028 and 2038; however, valuations are higher under some sensitivity scenarios. Finally, we discuss some challenges involved in modeling future capacity valuations, the inherent uncertainty and variability in realized capacity valuations, and the importance of considering capacity valuations in the context of the other specific market rules, products, and design elements that are present in the system.

8.1.2 Background on Service

The value of capacity as a grid service typically stems from the contribution of a resource to ensuring long-term power system RA and reliability. Resources that provide “capacity” to a power system may be compensated for the value of capacity by agreeing to make themselves available to generate energy when called upon during peak load conditions. If they are called on as a capacity resources, they are separately and additionally compensated for the energy they deliver to the grid. Similarly, they can receive separate and additional revenues for providing reserve capacity in RT operations. The definitions and rules that dictate requirements for capacity provision, and the penalties from failing to meet these requirements, may differ greatly across power systems.

In some sense, capacity can be thought of as a long-term reserve product; by agreeing to make themselves available to provide energy if called upon during future peak conditions, these resources provide planning stability and long-term reliability to the system. This stability has a tangible value. It is, however, important to distinguish the value that a resource provides through capacity as a grid service from the value that it can provide through energy and ancillary services in RT system operations. Therefore the "capacity value" of a resource is not simply equal to the total value that the resource provides to the system. The value from the provision of energy and other grid services must be considered separately, in order to ensure proper accounting and avoid double-counting of value streams.

To quantify capacity contributions, the installed capacity of a resource is typically derated by an equivalent forced outage rate (EFOR) to account for unplanned outages that might prevent the resource from providing energy during peak conditions. Planned outages are not considered in this derating calculation because they can be scheduled during periods of lower demand. The resultant derated capacity fraction (100%, EFOR) may also be referred to as the resource's "peak credit" or "capacity credit," while the resultant derated capacity may be referred to as its "peak capacity" or "unforced capacity" (UCAP). We will use the terms "capacity credit" and "UCAP" throughout this section for consistency.

Determining capacity credits for VRE resources, such as wind and solar, is less straightforward because their reliable contribution to meeting peak load is based on resource availability during peak conditions, which is variable and uncertain. Methods for calculating the capacity credit of wind and solar resources differ throughout U.S. power systems, and the determination of appropriate capacity credits for these resources as system generation portfolios evolve is an active area of research (Byers et al., 2018; Wiser et al., 2017).

Different power systems throughout the United States take different approaches to valuing and potentially compensating capacity as a service. Four of the U.S. wholesale power markets—PJM, NYISO, ISO-NE, and MISO—hold formal competitive auctions that signal their demand for capacity as a standalone service. These markets determine a value of capacity by matching capacity supply curves (an aggregate of offers from participating resources) and capacity demand curves (administratively defined by the market operator) and thereby arriving at a market clearing price. Capacity market rules and definitions can differ across these regions, particularly those related to auction lead times, the formation of capacity demand curves, and the treatment of VRE resources (Byers et al., 2018).

In competitive capacity markets, demand curves are generally established around the concept of cost of new entry (CONE) or net cost of new entry (net CONE) for a reference generation unit, which is typically a gas combustion turbine. CONE represents the annualized costs that a new unit would incur when entering the system, while net CONE further deducts anticipated revenues from participation in energy and ancillary service markets. Therefore, net CONE represents the anticipated revenue requirement of a reference generation unit (i.e., the additional revenue required to ensure that the unit revenues equal its costs in a given year).

Two of the U.S. wholesale markets—CAISO and SPP—impose capacity requirements on load-serving entities and provide some mechanisms for capacity remuneration but do not operate a centralized capacity market. The final U.S. market, ERCOT, does not have a formal mechanism for valuing or compensating capacity as a standalone service. ERCOT instead chooses to rely on price signals in its energy and ancillary services markets to provide appropriate incentives to support long-term RA and reliability.

The remainder of the United States operates under a vertically integrated paradigm where typically a target PRM is established and pursued through centralized planning processes rather than a competitive market framework. These regions therefore may not formally determine a price or value of capacity as a service; however, it may still be possible to infer an implicit valuation based on long-term planning procedures and system conditions.

8.1.3 Valuation Methodology

As is evident from the range of different capacity procurement and valuation approaches currently used throughout the United States, it is difficult to identify a single universal methodology for the valuation of capacity. The specific value of capacity is also intertwined with the valuation or price formation methodologies that are used for other grid services. This is particularly the case in the region surrounding Banner Mountain, where there is no formal capacity valuation framework in place. Resources may receive capacity incentives from vertically integrated utilities in their region to support local RA goals or may alternatively have opportunities to offer capacity into the CAISO system.

We adopt a system-oriented approach for capacity valuation analysis for the BMSP. We first use AURORA, a commercial power system planning and operations tool widely used throughout industry, to simulate the value of capacity as a service in the RMRG from the perspective of a neutral system planner.

Our system-oriented approach to capacity valuation is based on determining the revenue requirement of the marginal resource in terms of satisfying the PRM in the RMRG, where the BMSP is located. The revenue requirement of a resource is defined as the additional revenue that is required to ensure a resource's total revenue equals its costs in a given year; this includes an annualized investment cost. If a resource's revenues exceed its costs in a year, the revenue requirement becomes zero. We apply the concept of resource revenue uniformly throughout the WECC regardless of the market structure in a particular region. Specifically, we determine energy revenues for resources located in vertically integrated regions in the same manner as for those resources located in regions with wholesale markets. In each case, the marginal cost of electricity provision in each transmission zone is determined during each simulated hour (i.e., the incremental cost of serving one additional unit of load in that zone and hour). This marginal cost serves as a proxy for the "energy price" that resources in that region receive for every unit of generation they provide in that hour. This simulates the energy price formation process in a wholesale market, albeit at less detailed and more geographically aggregated level. When energy prices are discussed throughout this section, we are referring to this marginal cost metric as calculated by AURORA.

This resource revenue requirement-based approach to capacity valuation simulates a competitive capacity market clearing process under the assumptions that (1) every unit offers capacity at its true revenue requirement in a given year and (2) the RMRG has a vertical capacity demand curve at its target PRM. Although this approach represents market clearing under a competitive capacity market framework, it still provides valuable insights in systems that are vertically integrated or do not operate a competitive capacity market. The PRM target selected for each pool implies that there is a tangible system value associated with maintaining a certain level of UCAP in the operating pool. In a vertically integrated system this capacity valuation may not be formally calculated or made explicit as a direct payment, but it would still be implicit in a central planning process that selects these units for development and guarantees their cost recovery. As mentioned previously, some vertically integrated utilities may enter into bilateral contracts with resources to secure firm capacity during periods of peak demand. It is not possible to consider the specifics of individual contract negotiations in a system-level capacity expansion analysis; however, these valuations provide a proxy for the revenue streams that resources would require to provide capacity.

We define a vertical capacity demand curves for five operating pools in the WECC based on the target PRM in each pool. Enforcing the target PRM requires that the total UCAP of installed generation resources must be a given percentage greater than the peak load in each year. The default PRMs used in our analysis are presented in Table 8-1. These values are largely based on North American Electric Reliability Corporation's (NERC's) reference reserve margins for each planning region.[1] In practice, these PRM requirements are typically not binding under current conditions, because sufficient capacity is present in the WECC system; however, enforcing these requirements ensures that adequate reserve margins will be maintained in the future. Demand curves in the PJM, NYISO, and ISO-NE capacity markets tend to be downward-sloping and more nuanced than the vertical representation used here. Such curves imply both that there is a limit to the price systems operators are willing to pay for capacity, and that that there is some system value in procuring capacity in excess of a single fixed target. However, in the absence of a clear competitive capacity market framework in the region, we use a vertical curve to represent the fixed PRM approach more commonly used by vertically integrated utilities.

Table 8-1 PRMs for the Five WECC Operating Pools in AURORA

Operating Pool	PRM
Southwest Reserve Sharing Group	15.82%
RMRG	14.14%
NWPP (United States)	16.32%
California–Mexico	16.16%
NWPP (Canada)	11.03%

To define the aggregate supply curve of all resources in the RMRG, we first determine the revenue requirement of each resource in each year. The revenue requirement of resource i (RR_i) is defined as the difference between its revenues and costs in that year as outlined in the equation below. We consider revenues from the provision of energy, calculated as the sum of the product

[1] See https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

of energy generation $G_{i,t}$ in each hourly period and the marginal cost of energy provision in the transmission zone in that hourly period λ_t. Therefore, this approach implicitly assumes that units receive revenues based on hourly pricing mechanisms found in competitive markets as opposed to long-term firm contracts that may be more common in vertically integrated systems. Policy-driven revenue from the provision of renewable generation is also considered as the product of the VRE resource's generation output in a given year $G_{REi,t}$ and the marginal cost of achieving the RPS constraint in the resource's state in that year γ_{RPS}. Considered costs include an annualized investment cost C_{invi}, fixed O&M costs C_{FOMi}, variable O&M costs $C_{VOMi,t}$, and fuel costs $C_{\text{fuel}i,t}$. AURORA does not explicitly model resource-level ancillary service provision, so potential revenues from ancillary services are not considered in this analysis. The inclusion of ancillary services would incorporate an additional revenue stream for some resources and thereby reduce the revenue requirement of these resources, and accordingly the resultant capacity value:

$$RR_i = \left[C_{inv_i} + C_{FOM_i} + \sum_t \left(C_{VOM_{i,t}} + C_{fuel_{i,t}}\right)\right] - \left[\sum_t \left(G_{i,t} \cdot \lambda_t\right) + \sum_t G_{RE_{i,t}} \cdot \gamma_{RPS}\right]$$

In addition to potential revenue from energy generation, we also consider policy-based revenue streams for renewable resources, particularly those stemming from state RPSs. For each state with an RPS an annual renewable energy credit (REC) valuation is determined based on the marginal cost of meeting the RPS constraint in that state in a given year. This REC price is provided to renewable resources in that state for every unit of generation they provide, which ensures that the RPS targets in each state are met when renewable resources may otherwise not have sufficient incentive to enter the system.

As RPS targets increase, REC prices tend to increase as well. This provides another increasing value stream for renewable resources. These revenue requirements are calculated with output data from model runs that simulate plant level-operations and revenues for all 8,760 (or 8,784) hourly periods in each year. This approach provides more detail than the output of the expansion runs, which only consider a representative subset of hourly periods in each year.

All the resources located in the specified operating pool are then ordered according to their revenue requirement, which is normalized by their UCAP. The result is a capacity supply curve for the operating pool in that year. The value of capacity in that year is then determined by the intersection of these supply and demand curves; this valuation approach is presented visually in Section 8.1.5.3.

8.1.4 Analysis

8.1.4.1 Overall Design of Study

We use the commercial power system model AURORA to assist in conducting the system-oriented capacity valuation analysis for the BMSP. The results of this model also provide the long-term capacity expansion plans that serve as the basis for additional valuation analyses outlined in subsequent sections. We model the entire WECC system from 2019 through 2043 for this application; however, results are only presented through 2038. The extended modeling horizon was chosen to ensure that there are no modeling artifacts or edge effects observed in the final target year, 2038. All financials presented throughout this section are presented in constant year-2019 dollars.

AURORA employs an investment heuristic to determine a resultant capacity expansion and retirement plan over the modeling horizon. The model first simulates power system dispatch with the existing generation portfolio, while also considering any planned unit additions or retirements. It then determines all potential new units that would have been profitable when operating in that system and all existing units that were not profitable when operating in that system. Profitability is defined in terms of real levelized lifetime NPV. A subset of these units is then added and removed from the system respectively and dispatch is again simulated. Unit profitability is again determined, and additional units are added or removed in the same fashion, and this iterative process is repeated until there is either convergence on a stable outcome or a maximum number of iterations is achieved. AURORA selects only a subset of the most profitable (unprofitable) units for addition (removal) on any given iteration to help ensure convergence. This approach is used to help maintain computational feasibility when modeling large systems such as the entire WECC where conducting a full least-cost optimization over the entire planning horizon is not computationally practical. The heuristic is outlined in more detail in the flow diagram in Figure 8-1.

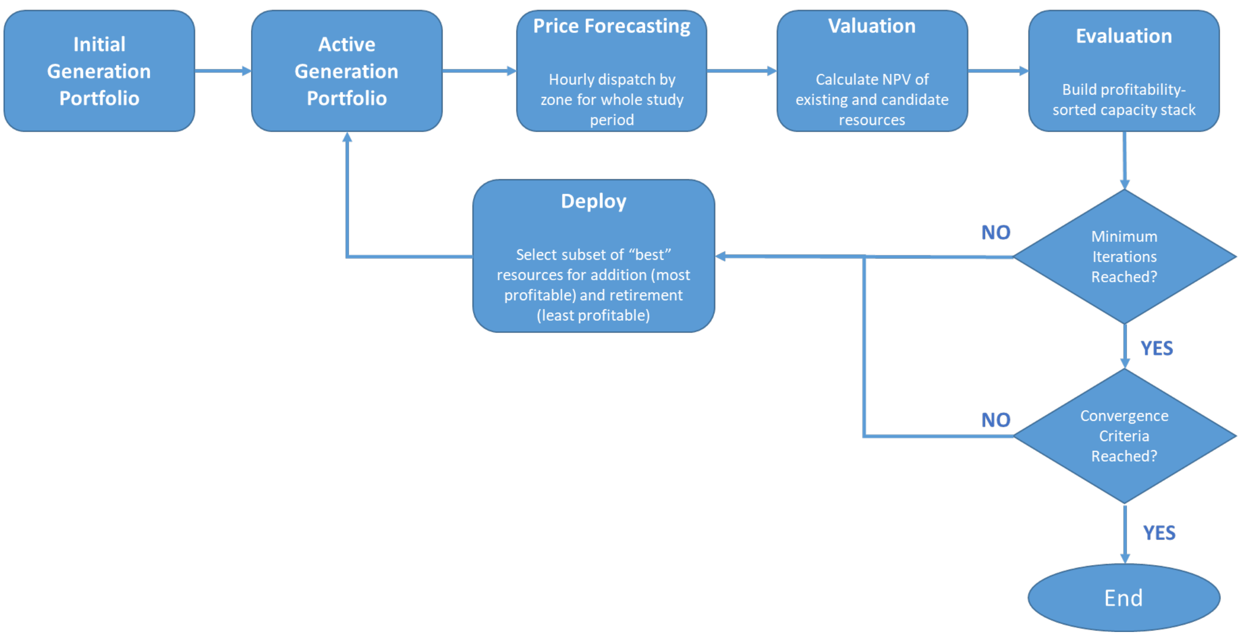

Figure 8-1 Capacity Expansion and Retirement Heuristic Used by AURORA

In an additional effort to maintain manageable computational requirements, the capacity expansion analysis also only considers a subset of time periods over the course of each year when making investment decisions; in our case, the expansion model considers all 24 hours of daily operations but is limited to 2 days per month. AURORA makes appropriate adjustments to ensure peak load conditions are considered and that aggregate outcomes are appropriately scaled up to represent a full year of operations. We then conduct a more detailed operational analysis in two target years, 2028 and 2038, by holding the generation portfolio fixed and simulating all 8,760 or 8,784 hours in the study horizon.

AURORA uses a three-tiered power system topology based on planning pools, transmission zones, and demand areas. Planning pools are used to define a regional target PRM, which in turn dictates an annual UCAP target based on the peak load conditions in the pool. Each planning pool contains one or more transmission zones that are used to represent transmission constraints and network congestion.

Within each transmission zone is one or more demand areas, which are roughly based on balancing authorities; these are used to define hourly demand profiles, and resource siting is also specified at the demand area level. However, it is assumed that there are no transmission constraints between demand areas in the same transmission zone. The zonal topology used to represent the WECC system is shown in Figure 8-2. AURORA does not model physics-based alternating current (AC) or direct current (DC) PFs; rather, aggregated transmission constraints are enforced between each zone on a transactional basis. That is, in any given hour the power transmission between two zones cannot exceed aggregated transmission capacity limits defined for each direction; these limits in megawatts are indicated by the numeric labels on each line between zones in Figure 8-2. Banner Mountain is located in the Wyoming (WY) zone.

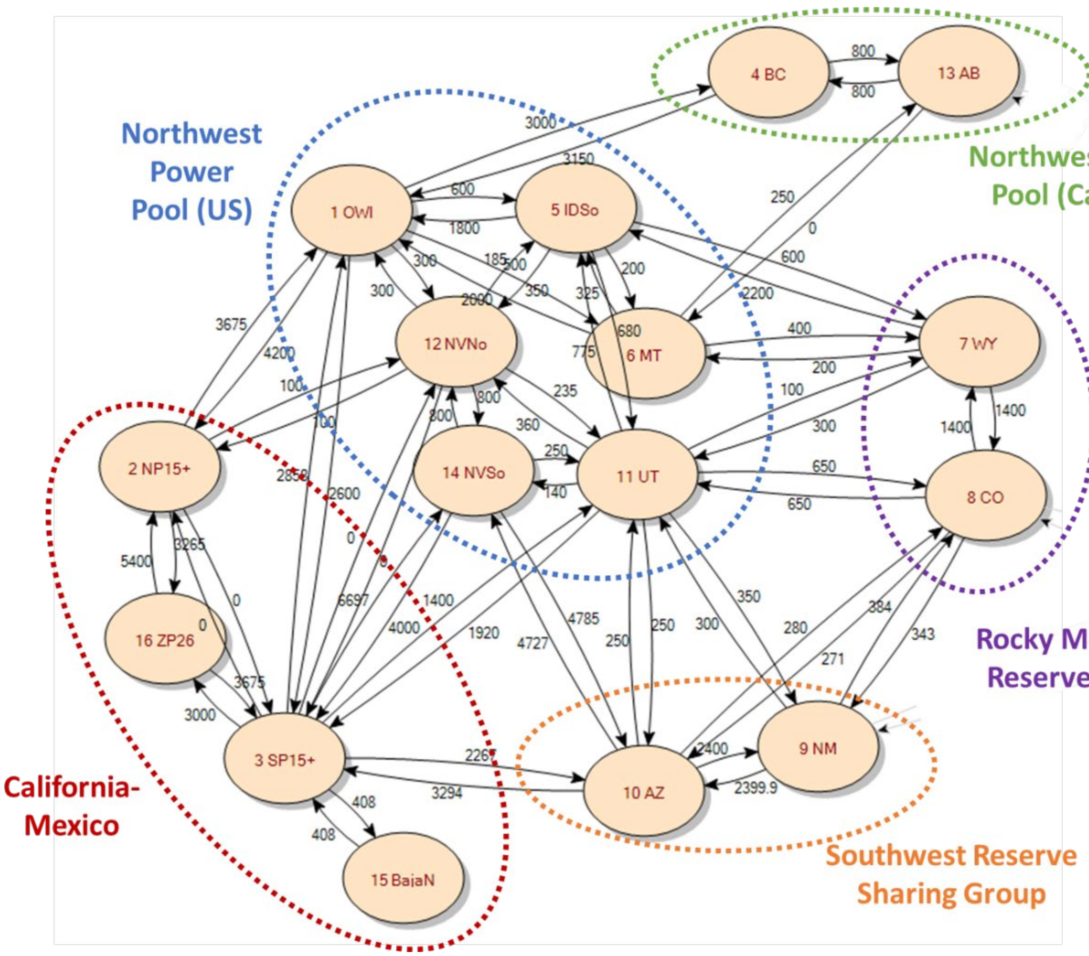

Figure 8-2 Zonal Topology Used in the AURORA Capacity Expansion Model

Because the primary objective of this analysis is to determine the relative change in system conditions and outcomes that result from introducing Banner Mountain to the power system, a reference capacity expansion outcome is first established for the entire WECC system without Banner Mountain. A second case is then considered where Banner Mountain comes online in 2028 and the capacity expansion plan in the region neighboring the BMSP is redetermined. For this second case, we only allow changes to the reference capacity expansion outcome in the specific demand areas in the proximity of Banner Mountain. For example, we assume that the addition of Banner Mountain will not influence investment or retirement decisions in Arizona or New Mexico. This helps limit the computations requirements of the model and isolates the more direct impacts of introducing Banner Mountain to the system. While investments and retirements are held fixed in some regions, unit operations are re-simulated throughout the entire WECC to account for any potential cascading impacts caused by introducing Banner Mountain and other changes into the generation mix.

8.1.4.2 Scenarios and Assumptions

In addition to the reference scenario, we also consider several additional sensitivity scenarios to better understand how the relative impacts of introducing Banner Mountain to the power system change under different conditions. In each sensitivity scenario, we similarly first determine a baseline capacity expansion plan for the entire WECC system. We then conduct a second run while introducing Banner Mountain in 2028 and re-optimizing unit investments and retirements in the vicinity of Banner Mountain.

The sensitivity scenarios that are analyzed are detailed in Table 8-2. These scenarios do not represent any judgement regarding likelihood of outcomes, but rather are intended to be directionally informative and identify broad system trends caused by changes in these parameters. For each scenario, two cases are run—one without and one with Banner Mountain—resulting in eight different capacity expansion plans.

Table 8-2 Scenarios Considered in the Capacity Valuation Analysis

Scenario	Abbreviation	Description
Baseline	Baseline	Capital costs based on the 2018 NREL ATB
EIA Capital Costs	EIA	Default AURORA capital costs, based on EIA projections
High Natural Gas Price	HighNG	The Henry Hub natural gas price is 19% greater than baseline in 2019, and the price difference escalates by an additional 2.5% annually
Aggressive Carbon Reductions	AggCarbon	No new natural gas additions beyond currently planned units; all coal units retired by 2030 with gradual scale-down

Table 8-3 provides an overview of the capital cost assumptions for candidate new technologies in both the Baseline scenario and the EIA scenario. Capital costs in the Baseline scenario are largely based on the overnight capital cost assumptions published in the 2018 ATB. Assumptions for the onshore wind technology are based on techno-resource group 5 and the "Mid" scenario; those for utility-scale solar are also for the Mid scenario. Technology costs for a generic, grid-scale, 4-hour, lithium-ion battery are taken directly from a separate and more targeted analysis of battery storage costs (Cole and Frazier, 2019). The battery pack costs from Cole and Frazier (2019) are then added to the balance of system (BOS) cost projections provided by the ATB to arrive at a total overnight system cost. The overnight costs presented in Table 8-3 are intended to provide a high-level overview of differences in assumptions across scenarios and technologies; however, AURORA considers a range of different technology types, and capital costs are further adjusted based on regional factors as well as a range of financial assumptions to arrive at an annualized carrying cost that is assessed each year the resource is in operation.

Table 8-3 Capital Cost Assumptions for Different Technologies

Capital Cost (2019$/kW)	Online Year	2020	2025	2030	2035
Advanced Combustion Turbine	Baseline	$944	$921	$898	$881
	EIA	$708	$654	$602	$561
Advanced Combined Cycle	Baseline	$1,104	$1,079	$1,055	$1,036
	EIA	$1,155	$1,080	$1,009	$946
Onshore Wind	Baseline	$1,616	$1,561	$1,519	$1,490
	EIA	$1,970	$1,875	$1,788	$1,695
Utility Scale Solar PV	Baseline	$1,024	$927	$872	$835
	EIA	$2,154	$1,881	$1,796	$1,694
Battery Storage (4-hr)	Baseline	$1,984	$1,592	$1,368	$1,259
	EIA	$2,231	$2,039	$1,861	$1,683

Natural gas price assumptions for both the Baseline and natural gas price escalation scenarios are shown in Figure 8-3. The price projections that are presented in Figure 8-3 represent the Henry Hub natural gas price. AURORA uses the Henry Hub price as a reference from which it applies a complex series of regional and unit-specific fuel price adjustments to arrive at a delivered cost of fuel for all natural gas-fired generation units. The intention of the natural gas price escalation scenario is not necessarily to project a future price trajectory that is likely to occur under a given set of circumstances, but to demonstrate the system impacts of a future with higher natural gas prices.

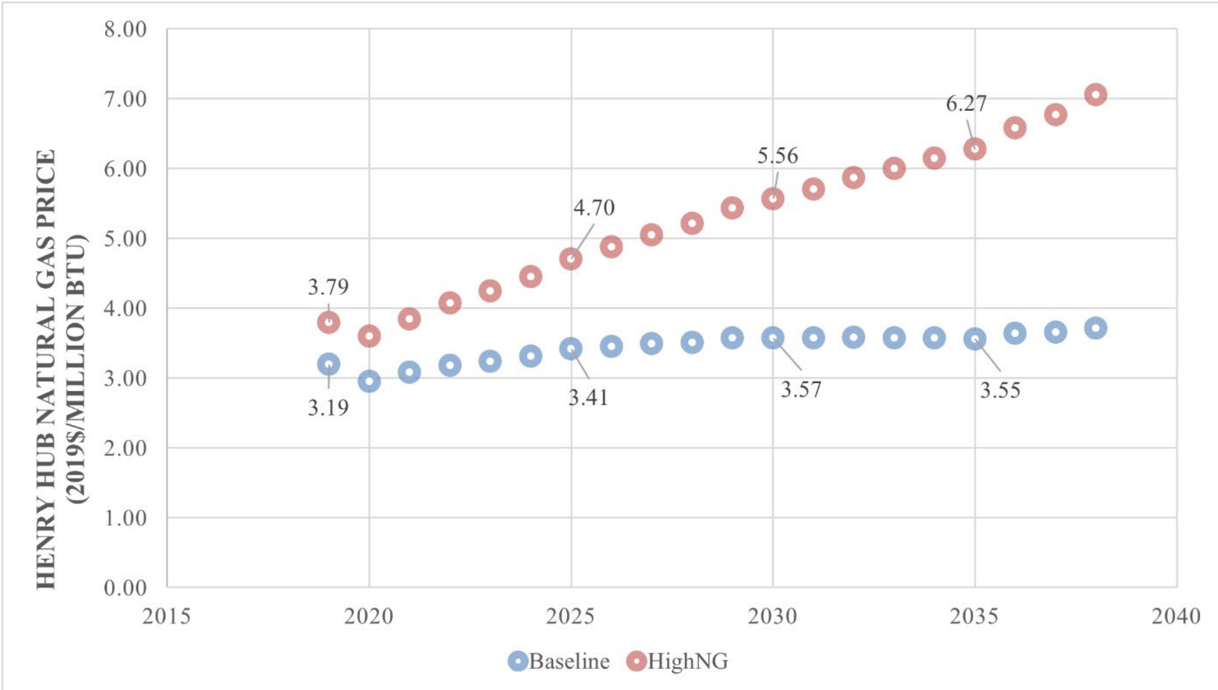

Figure 8-3 Henry Hub Natural Gas Price Projections

As outlined in Section 8.1.2, a capacity credit is also defined for each unit to represent the percentage of the unit's installed capacity that can reliably contribute to serving peak load. For most thermal and conventional hydro units, we use the default values provided by AURORA. These are generally based on forced outage rates for thermal units and historical generation profiles for hydropower units.

We updated the values AURORA provides for wind and solar resources to align with practices that were implemented in MISO. Wind units are allocated a uniform peak credit of 15.7%, while capacity credits for solar units were calculated individually based on resource availability. Specifically, the capacity credit for a given solar resource is set equal to its assumed resource availability during June, July, and August in hours ending 15:00, 16:00, and 17:00. This results in a wide range of capacity credits for solar resources throughout the WECC, from 41.4% to 90.9%. These capacity credits are used to define the contribution each unit makes to meeting the regional PRM, and to determine unit-specific revenue requirements on a UCAP basis. The operational implications of forced and unforced unit outages are addressed through a separate mechanism in AURORA. We assume a 100% capacity credit for both pumped storage and battery storage resources; capacity credits for different fuel types are shown in Table 8-4.

Table 8-4 Capacity Credits for Different Fuel Types

Fuel Type	Peak Credit
Coal	91.8%
Nuclear	91.8%
Natural Gas	75.8–96.4%
Conventional Hydro	72.2–91.8%
Wind	15.7%
Solar	41.4–90.9%
Pumped Storage Hydro	100%
Battery Storage	100%

8.1.4.3 Data Needs and Sources

Our model uses a baseline generation portfolio that also includes several planned unit additions and retirements, which is provided by AURORA and is largely based on public data from the EIA. In addition, we incorporated several prospective unit additions that are included in the 2019 PacifiCorp IRP.[1] These additions include 2,000 MW of new wind capacity in Wyoming and 2,250 MW of new solar capacity distributed throughout Wyoming, Utah, Oregon, and Washington.[2]

In addition to planned coal retirements provided by EIA, our Baseline scenario also considers a set of coal retirements that are currently anticipated by WECC.[3] We also explore a more aggressive coal retirement schedule in a sensitivity scenario. The planned additions and retirements that we consider across the entire WECC region are outlined by fuel type and year in Tables 8-5 and 8-6. Starting with the existing generation portfolio, and considering planned unit additions and retirements, the AURORA model then applies the aforementioned capacity expansion heuristic to determine a set of economic unit additions and retirements. This combination of planned and economic unit additions and retirements is considered to be the capacity expansion plan.

Table 8-5 Planned Resource Additions

Year	Planned Addition Types (MW)				
	Natural Gas	Wind	Solar	Water	Other
2019	532	261	200	3	6
2020	1,986	80	-	-	275
2021	-	180	-	-	-
2022	-	-	-	-	-
2023	-	-	-	-	-
2024	-	2,000	2,250	-	-

1 See https://www.pacificorp.com/energy/integrated-resource-plan.html.

2 These quantities may differ slightly from those detailed in the PacifiCorp IRP due to rounding, because the AURORA model considers wind and solar additions in discrete 250-MW increments.

3 See https://www.nwcouncil.org/news/coal-retirements.

Table 8-6 Planned Resource Retirements

Year	Planned Retirement Types (MW)					
	Natural Gas	Geothermal	Fuel Oil	Hydro	Coal	Nuclear
2019	1,681	-	6	167	3,760	-
2020	2,280	-	-	5	2,185	-
2021	1,604	-	-	1	254	-
2022	246	-	165	-	2,727	-
2023	178	-	-	0	531	-
2024	268	-	-	-	-	1,112
2025	185	-	43	-	4,245	1,118
2026	622	-	-	-	-	-
2027	-	-	-	-	762	-
2028	-	-	-	-	527	-
2029	-	-	27	-	3,086	-
2030	-	-	-	-	179	-
2031	-	-	-	-	1,787	-
2032	148	-	-	-	-	-
2033	-	-	-	-	428	-
2034	-	-	-	-	208	-
2035	-	105	-	-	262	-
2036	-	105	-	-	1,053	-
2037	-	105	-	-	3,086	-
2030	-	105	-	-	-	-

8.1.5 Modeling Runs and Results

8.1.5.1 Capacity Expansion without Banner Mountain

We now present the system-level results of our long-term capacity expansion analysis of the entire WECC system. The results are first presented for a reference case where Banner Mountain is not part of the system before examining the relative changes to the expansion plan that result when Banner Mountain is introduced in 2028.

Figure 8-4 shows the evolution of the generation portfolio of the entire WECC system from initial assumed conditions at the end of 2018 through 2038. The generation portfolio depicted for 2018 is a fixed input to the model and expansion modeling begins in 2019. The initial portfolio is largely made up of natural gas and hydro capacity, with moderate contributions from coal, solar, wind and nuclear.

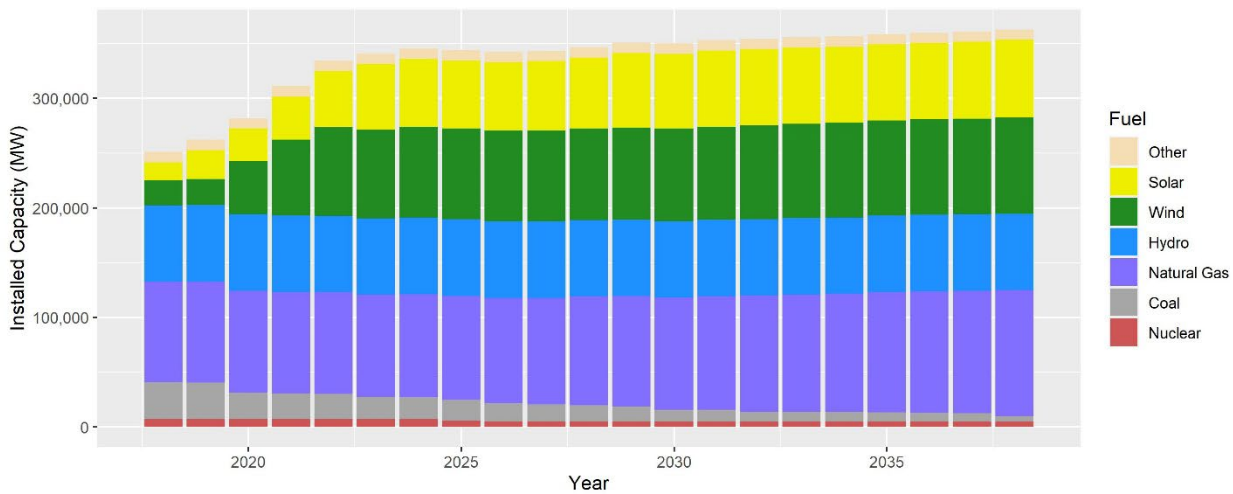

Figure 8-4 Total Installed Generation Capacity in WECC under the Baseline Scenario

The evolution of the system over time is more clearly highlighted in Figure 8-5, which shows the cumulative change in installed capacity relative to the initial portfolio. Results shown for each year represent the difference between the portfolio at the end of that year and the portfolio at the end of 2018. Values that fall below the horizontal axis represent a net retirement of that resource class. From this figure we can see that wind and solar dominate the new capacity investments, some new natural gas units are also developed, and planned and economic retirements lead to a net reduction in coal capacity.

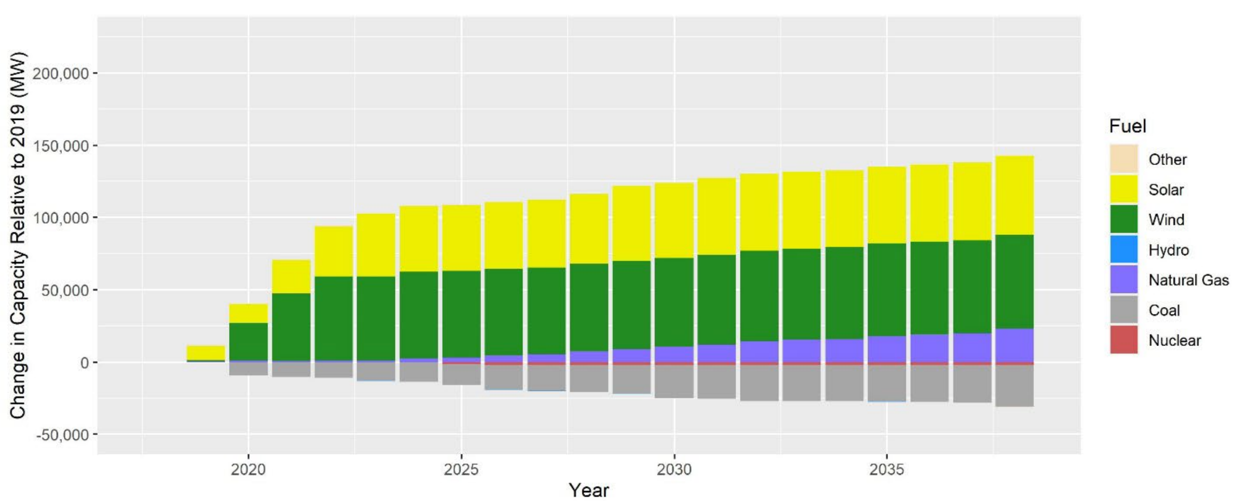

Figure 8-5 Change in Installed Generation Capacity in WECC under Baseline Scenario, Relative to Initial Portfolio at the End of 2018

The relative capacity expansion results for the three sensitivity scenarios are shown in Figures 8-6 through 8-8. These follow the same convention as Figure 8-5 and depict the net change in capacity for each scenario relative to the initial generation portfolio at the end of 2018. This initial generation portfolio is the same for the Baseline scenario and all three sensitivity scenarios, and all four figures use the same vertical axis range to facilitate direct comparison of the results. Table 8-7 also details the relative change experienced under each scenario at the end of the modeling horizon in 2038.

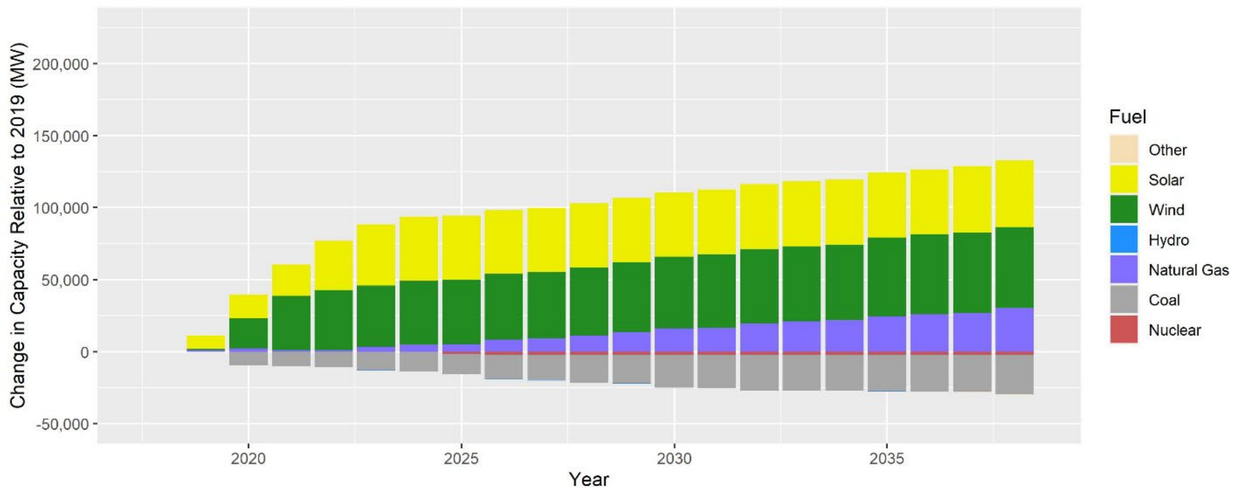

Figure 8-6 Change in Installed Generation Capacity in WECC under EIA Scenario, Relative to Initial Portfolio at the End of 2018

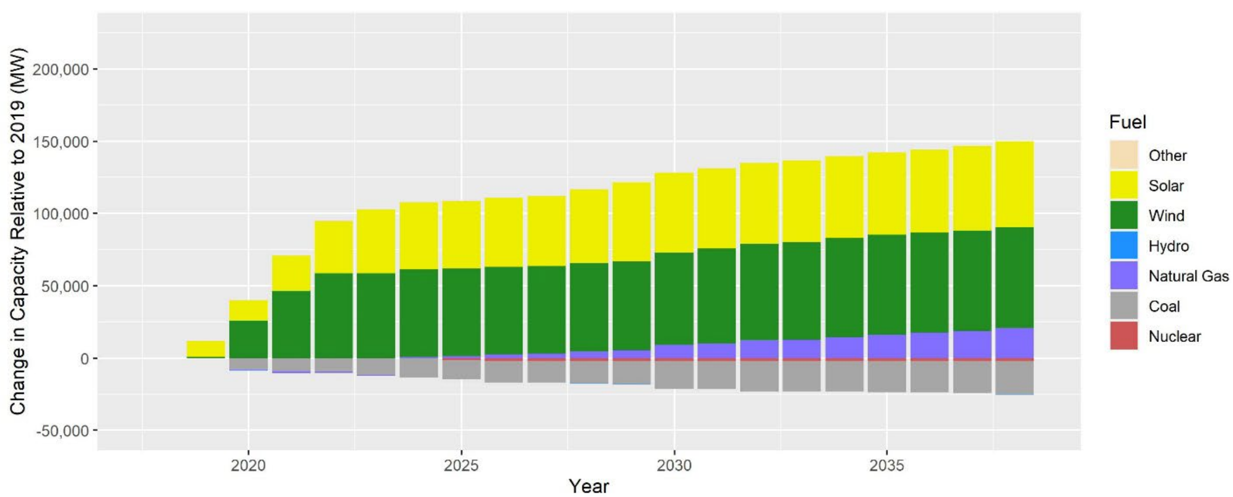

Figure 8-7 Change in Installed Generation Capacity in WECC under HighNG Scenario, Relative to Initial Portfolio at the End of 2018

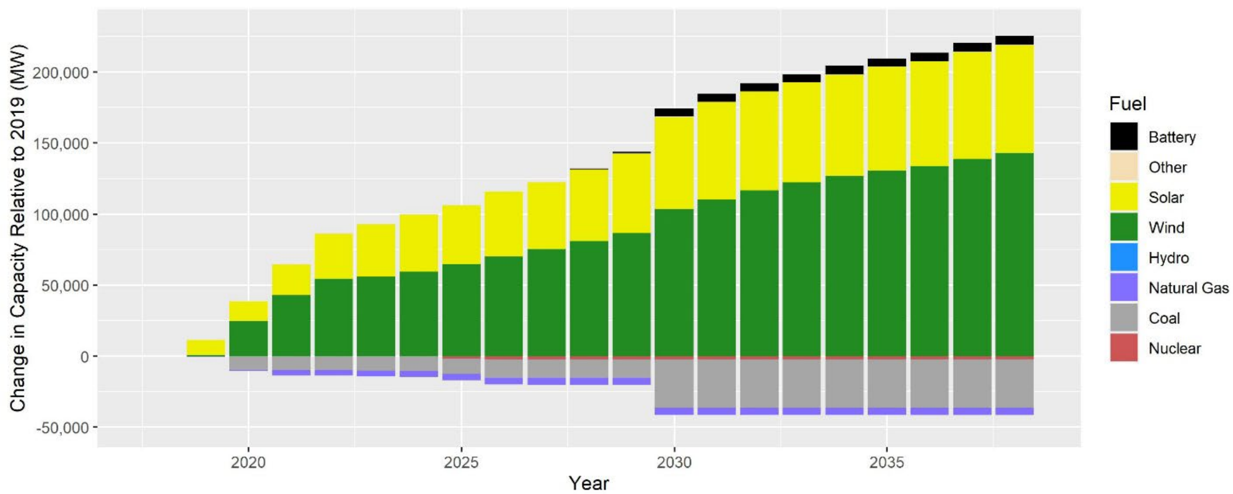

Figure 8-8 Change in Installed Generation Capacity in WECC under AggCarbon Scenario, Relative to Initial Portfolio at the End of 2018

Table 8-7 Total Initial Installed Capacity (in MW) at the Start (2018) and End (2038) of the Analysis Horizon

Type of Capacity	2018	Baseline		EIA		HighNG		AggCarbon	
		2038	Change	2038	Change	2038	Change	2038	Change
Nuclear	7,393	5,153	(2,240)	5,153	(2,240)	5,153	(2,240)	5,153	(2,240)
Coal	33,985	4,875	(29,109)	5,908	(28,076)	10,469	(23,515)	-	(33,985)
Natural Gas	91,774	14,932	23,157	122,069	30,294	112,390	20,615	86,535	(5,239)
Hydro	70,221	70,157	(64)	70,157	(64)	70,157	(64)	70,157	(64)
Wind	22,907	87,733	64,826	79,233	56,326	92,983	70,076	165,983	143,076
Solar	16,338	71,182	54,844	62,452	46,114	75,452	59,114	92,182	75,844
Battery	-	-	-	-	-	-	-	7,300	7,300
Other	3,971	4,300	329	4,227	256	4,300	329	4,250	279

The EIA scenario results in less new wind and solar investment and more new natural gas investment than the Baseline scenario. By 2038 the EIA (Baseline) scenario leads to 56,326 MW (64,826 MW) of new wind capacity, 46,114 MW (54,844 MW) of new solar capacity, and 30,294 MW (23,157 MW) of new natural gas capacity. This is because the EIA capital cost assumptions for wind and solar are higher than those for the Baseline scenario (Table 8-3). The EIA scenario also retains 1,033 MW more coal capacity than the Baseline scenario. The net change in generation capacity from other fuel sources are largely comparable between the two scenarios.

As might be expected, the HighNG scenario results in a smaller net increase in natural gas capacity relative to the Baseline scenario. By 2038, this scenario leads to 2,542 MW less natural gas capacity than the Baseline scenario, a 2.2% relative reduction. However, the relative reduction in generation output from natural gas units is much larger at 21.5%. This indicates that many natural gas units decrease their output due to the increased fuel cost even if they do not necessarily retire. To accommodate this decrease in natural gas generation nearly 5,594 MW of additional coal capacity is retained under the HighNG scenario, and 5,250 MW of additional wind capacity and 4,270 MW of additional solar capacity are developed by 2038 relative to the Baseline scenario.

The AggCarbon scenario results in the most substantial change in generation portfolio relative to the Baseline scenario. In particular, large quantities of new wind and solar capacity are developed because of the exogenously imposed constraints to restrict new natural gas capacity and force coal retirements. In addition, some battery storage capacity is developed in later years to help support the wind and solar additions. Specifically, 143,076 MW of new wind capacity is developed by 2038 (78,250 MW more than under the Baseline scenario) along with 75,844 MW of solar capacity (21,000 MW more than under the Baseline scenario). All 33,388 MW of coal capacity that is present at the start of the modeling horizon is retired by 2030 in accordance with the scenario parameters. In addition, 7,300 MW (29,200 MWh storage capacity) of grid-scale battery storage is developed by 2038.

Note that AURORA does not select any battery storage capacity for economic expansion under the other scenarios. This is likely because AURORA determines its generation expansion plan based on profitability in a simulated market clearing environment. The relatively low geographic resolution may not fully capture the occurrence of localized high-price periods that would provide a valuable revenue stream for storage resources. In addition, AURORA only considers revenues from providing energy and therefore does not consider revenues streams from providing other grid services such as operating reserves.

Because grid-scale battery storage resources are currently being deployed in several regions, these expansion results are clearly not fully representative of real-world conditions. We again stress that modeling results are never intended to provide a concrete prediction of what *will* happen, and must always be viewed and interpreted through a critical lens and in the context of the model that was employed. The fact that AURORA selects battery storage resources for economic expansion in the AggCarbon scenario indicates that it finds these resources to be increasingly profitable under such system conditions. In this section we are primarily concerned with battery storage resources to the extent that they impact the economic addition or retirement of other generation resources.

8.1.5.2 Capacity Expansion Impact of Banner Mountain

We now consider the case where Banner Mountain is introduced in 2028 and the capacity expansion plan in the surrounding region is redetermined for each scenario. Figure 8-9 shows the relative change in cumulative installed capacity in the case where Banner Mountain is brought online. Values above the horizontal axis represent a relative net increase in capacity, which may be caused by either additional investments or deferred retirements. Similarly, bars below the axis represent a net decrease in capacity, which may be caused by either additional retirements or deferred new investments. There are no relative changes to the reference portfolio prior to 2028 so these data points are omitted from the figure. The 420 MW of additional hydro capacity attributed to the Banner Mountain project itself is clearly visible.

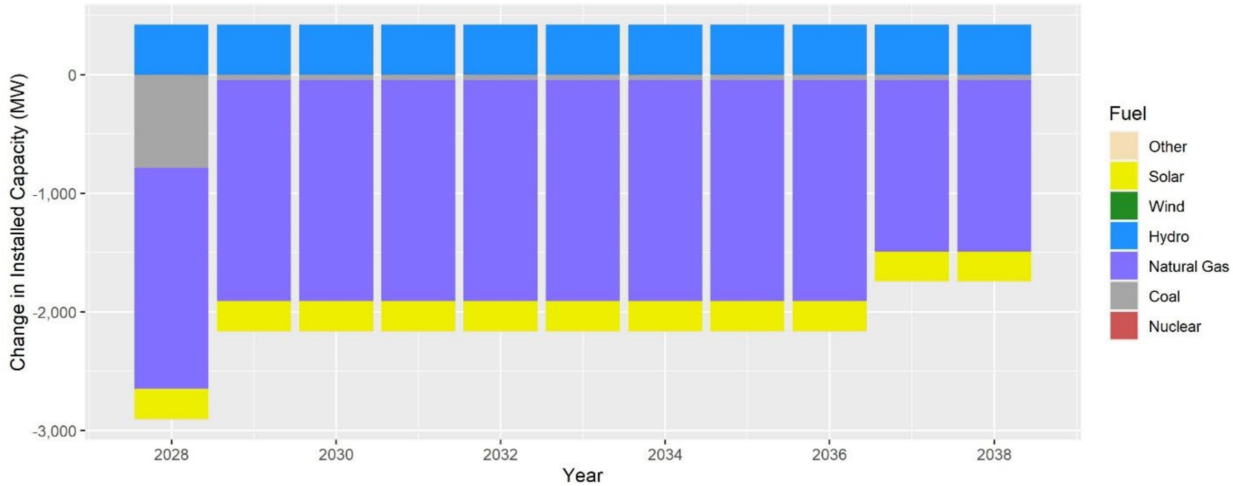

Figure 8-9 Change in Installed Capacity throughout WECC in Baseline Scenario where Banner Mountain Comes Online in 2028, Relative to Baseline Case without Banner Mountain

There is a net reduction of 1,864 MW of natural gas capacity starting in 2028 that decreases to 1,444 MW by 2038. This net difference is caused by the economic retirement of several natural gas units in Oregon and Wyoming at the start of 2028 in the Banner Mountain case that do not occur in the reference case without Banner Mountain, as well as the deferral of several new natural gas investments in Wyoming and Oregon. One coal unit in Montana retires in 2028 in the case with Banner Mountain, whereas it retires in 2029 in the case without Banner Mountain. There is also a net decrease of 250 MW in new solar capacity in 2028 that persists through 2038.

The relative change in installed capacity when Banner Mountain is brought online in the EIA scenario is shown in Figure 8-10. Similar to the Baseline scenario, there is a net decrease in natural gas capacity due to additional retirements: 752 MW in 2028, increasing to 1,173 MW in 2038. Some wind capacity is developed earlier in the EIA scenario with Banner Mountain compared to the case without Banner Mountain. However, by 2036 total wind capacity is the same in each case.

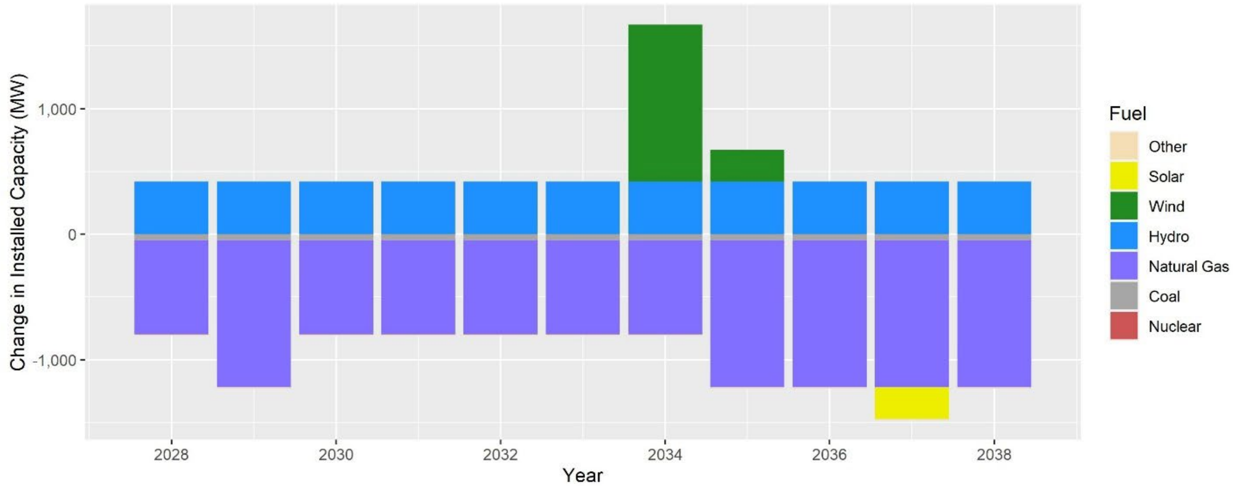

Figure 8-10 Change in Installed Capacity throughout WECC in EIA Scenario where Banner Mountain Comes Online in 2028, Relative to EIA Case without Banner Mountain

The relative change in installed capacity when Banner Mountain is brought online in the HighNG scenario is shown in Figure 8-11. In the HighNG scenario, the introduction of Banner Mountain results in a net reduction 1,023 MW of natural gas capacity in 2028 through 2036, which increases to 1,864 in 2038. Similar to the Baseline and EIA scenarios, this is caused by the retirement of several natural gas units, which does not occur in the case where Banner Mountain is not introduced to the system. There is also a net reduction in new solar investments: 250 MW in 2028, increasing to 750 MW in 2038.

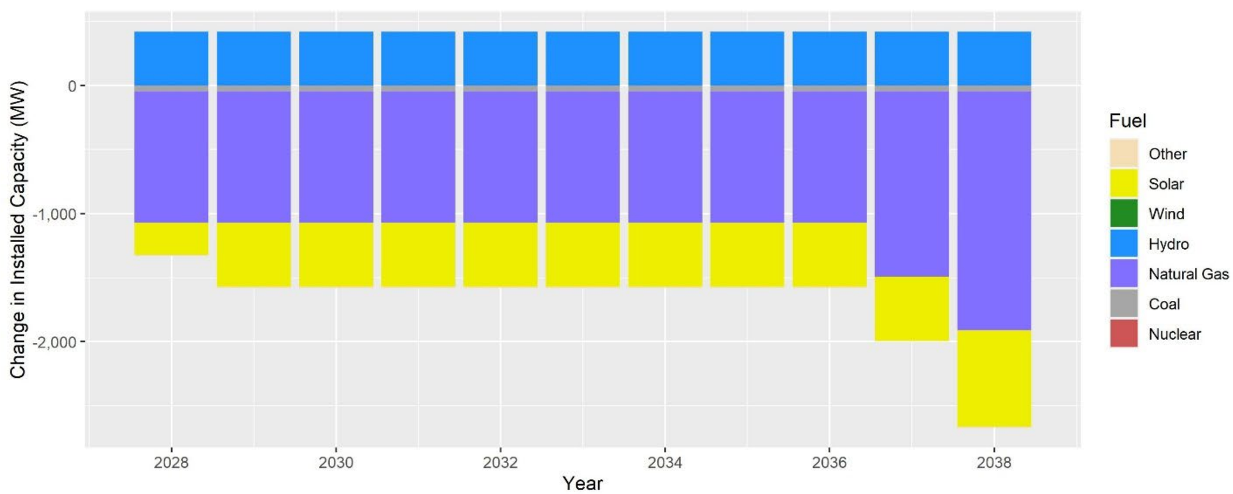

Figure 8-11 Change in Installed Capacity throughout WECC in HighNG Scenario where Banner Mountain Comes Online in 2028, Relative to HighNG Case without Banner Mountain

Finally, the relative change in installed capacity when Banner Mountain is brought online in the AggCarbon scenario is shown in Figure 8-12. The most apparent impact of bringing Banner Mountain online in 2028 is a large reduction in new battery storage capacity. In fact, the presence of Banner Mountain replaces 6,200 MW of the 7,300 MW of new 4-hour battery storage investments that were identified under the reference case, or 24,800 MWh of the total storage capacity. As discussed previously, AURORA is a high-level PCM that will not necessarily identify all economic storage investments due to the coarse geographic and temporal nature of the model. However, this result broadly indicates that the storage capabilities Banner Mountain provides may decrease the need for other battery storage resources in a high renewable future.

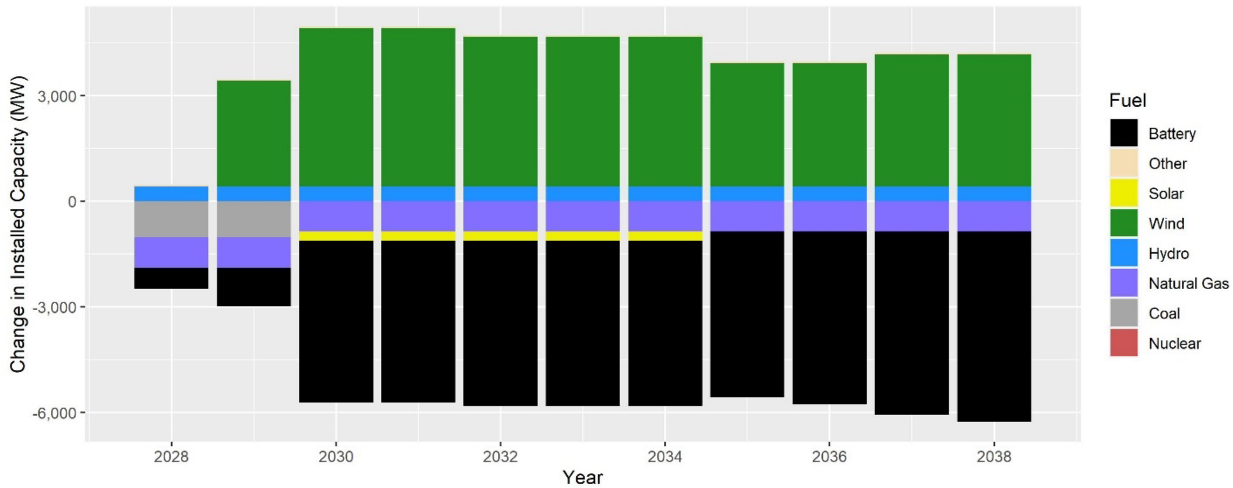

Figure 8-12 Change in Installed Capacity throughout WECC in AggCarbon Scenario where Banner Mountain Comes Online in 2028, Relative to AggCarbon Case without Banner Mountain

In addition to the reduction in new battery storage resources, the introduction of Banner Mountain also accelerates the retirement of 1,025 MW of coal capacity; this occurs in 2028, as opposed to 2030 in the reference case. Like the other scenarios, it further results in a net reduction of 864 MW of natural gas capacity in 2028, which persists through 2038. There is also a net increase in installed wind capacity in the case with Banner Mountain in the system, which reaches 3,750 MW in 2038. Table 8-8 details the net capacity investment and retirement impacts of introducing Banner Mountain for each scenario.

Table 8-8 Net Capacity Expansion Impacts of Bringing Banner Mountain Online in 2028

Change in Installed Capacity (MW)	Baseline		EIA		HighNG		AggCarbon	
	2028	2038	2028	2038	2028	2038	2028	2038
Nuclear	-	-	-	-	-	-	-	-
Coal	(787)	(47)	(47)	(47)	(47)	(47)	(1,025)	-
Natural Gas	(1,864)	(1,444)	(752)	(1,173)	(1,023)	(1,864)	(864)	(864)
Hydro	420	420	420	420	420	420	420	420
Wind	-	-	-	-	-	-	-	3,750
Solar	(250)	(250)	-	-	(250)	(750)	-	-
Battery	-	-	-	-	-	-	(600)	(6,200)
Other	(9)	(9)	(9)	(9)	(9)	(9)	40	40

8.1.5.3 Valuation of Capacity

We now quantify the value of capacity as a grid service in each of the four considered scenarios using the revenue requirement methodology outlined in Section 8.1.3. We present valuation results for both the RMPG where Banner Mountain is located, as well as for the CMPP, where there may also be capacity-related revenue opportunities for Banner Mountain.

Figure 8-13 summarizes the capacity valuation results in the RMRG in 2028 and 2038 in each scenario. The Baseline scenario results in a capacity valuation of $65.46/kW-year in 2028 and $52.53/kW-year in 2038, both in UCAP terms.

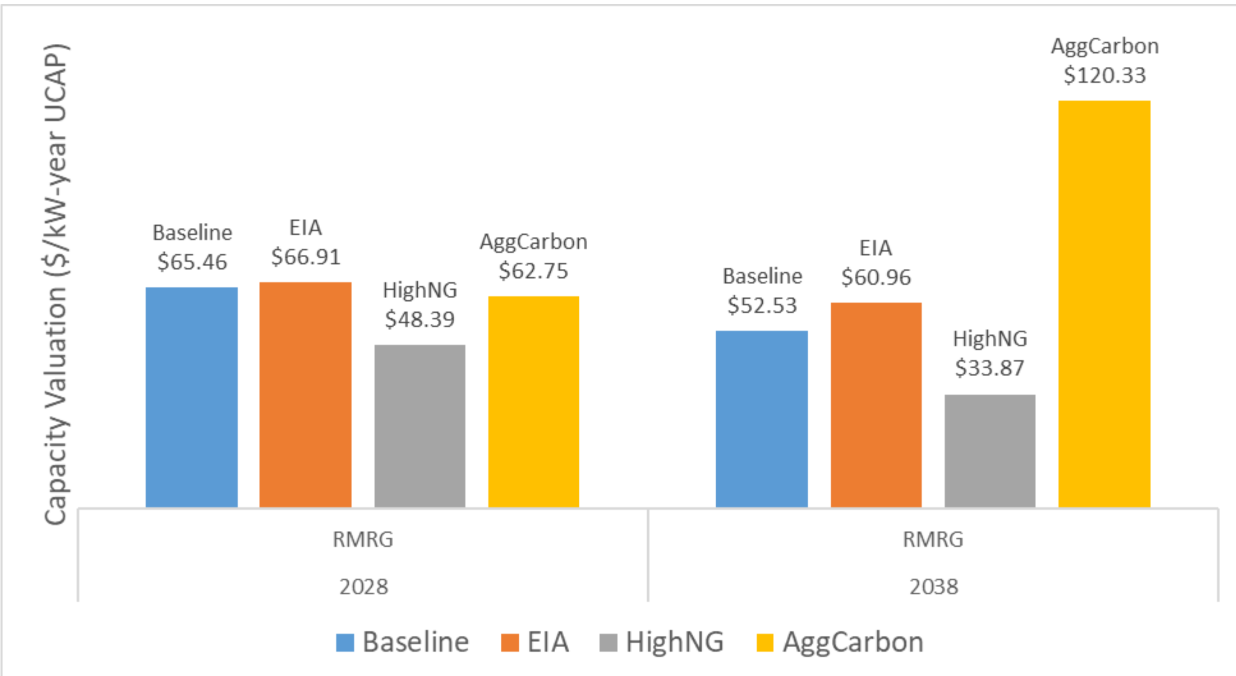

Figure 8-13 Capacity Valuations in the RMRG under Each Considered Scenario in 2028 and 2038

More detailed system results from each scenario are summarized in Table 8-9. In 2028 the projected peak demand level in the RMRG is 14,924 MW resulting in a peak capacity target of 17,034 MW based on the target PRM of 14.14%. At the start of the modeling horizon in 2019, the RMRG has a reserve margin of 33.45%, well in excess of the target level. As the system generation portfolio evolves over time, the realized pool reserve margin increases further, to 35.20% in 2028 and 33.76% in 2038.

In each sensitivity scenario, the target reserve margins are the same but actual realized margins differ in accordance with the resultant capacity expansion plan for each scenario. In the EIA scenario, the realized reserve margin is somewhat less than in the Baseline scenario, due to the net reduction in new solar capacity. This reduction in solar capacity is largely, but not entirely, offset by additional natural gas investments in the region. The final capacity valuation is greater than in the Baseline scenario in both 2028 and 2038 because capital costs of wind and solar resources are higher; this increases the revenue requirements of these resources and shifts the capacity supply curve upward. In the HighNG scenario, the capacity valuation is lower than the

Baseline valuation in both 2028 and 2038 because the higher natural gas fuel prices drive the average marginal cost of energy upward. This increases revenues for many resources, thereby decreasing their revenue requirements. Finally, the valuation in the AggCarbon scenario is smaller than the Baseline valuation in 2028, but significantly greater in 2038, reaching $120.33/kW-year. The factors that contributed to this outlier result will be discussed in more detail shortly.

Collectively the scenarios establish a range of valuations from $48.39/kW-year to $66.91/kW-year in 2028 and $33.87/kW-year to $120.33/kW-year in 2038. All values are presented in constant 2019 dollars. For each scenario we analyze the reference system without the inclusion of Banner Mountain. This allows us to estimate the value that Banner Mountain provides when entering that system. In practice, the analysis has confirmed that the inclusion of Banner Mountain itself does not significantly alter the revenue requirement calculation for other units or the resultant capacity value at the power pool level.

Capacity valuations can be difficult to predict and interpret because they are closely linked to other aspects of market design, including energy prices and polices designed to support specific technologies. In our analysis, the marginal cost of energy provision in each hour and each transmission zone serves as a proxy for a potential energy price in the region. We use this price to calculate potential revenues from energy provision, and when compared against the investment, fixed, and operating costs of each resource, determine its revenue requirement. The average marginal cost of energy throughout the entire RMRG is shown in Table 8-9 for reference. All else being equal, higher energy prices will increase unit revenues, thereby decreasing their revenue requirement and the resultant capacity valuation. However, the distribution of prices is important as well. A fat-tailed price distribution (more frequent low and high price periods) with the same average would tend to increase revenues for flexible resources like gas turbines and storage that can adjust their output in response to price signals. Alternatively, less-flexible units like coal, nuclear, or wind would be more exposed to periods of low prices and their revenues may decrease. This dynamic would shift revenue requirements for each unit and may therefore lead to a different capacity valuation, even though average energy prices remain the same.

Table 8-9 RA and Capacity Valuation Metrics for the RMRG

	Baseline		EIA		HighNG		AggCarbon	
Metric	**2028**	**2038**	**2028**	**2038**	**2028**	**2038**	**2028**	**2038**
Target Reserve Margin	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%	14.14%
Peak Demand (MW)	14,924	15,428	14,924	15,428	14,924	15,428	14,924	15,428
Target Peak Capacity (MW)	17,034	17,610	17,034	17,610	17,034	17,610	17,034	17,610
Realized Peak Capacity (MW)	20,176	20,636	19,898	20,570	19,832	20,401	20,719	20,571
Realized Reserve Margin	35.20%	33.76%	33.33%	33.33%	32.89%	32.23%	38.83%	33.34%
Average Marginal Energy Cost ($/MWh)	$42.40	$45.09	$40.41	$42.38	$51.19	$62.40	$45.11	$92.49

Metric	Baseline		EIA		HighNG		AggCarbon	
	2028	2038	2028	2038	2028	2038	2028	2038
Revenue-based Capacity Valuation ($/kW-yr)	$65.46	$52.53	$66.91	$60.96	$48.39	$33.87	$62.75	$120.33

Figures 8-14 and 8-15 illustrate the supply and demand curves that result from such a market framework in the RMRG in 2028 and 2038 under the Baseline scenario. The black dotted lines represent vertical demand curves for the region. In each figure the top plot shows the curves in their entirety, while the bottom plot shows a detailed view of the region where they intersect. The RMRG's demand for capacity is represented by the vertical dashed line at its target PRM, which is 17,034 MW or 14.14% greater than its projected peak demand level in 2028. The supply curve represents the ordered revenue requirement of each generation unit in the RMRG, a negative requirement indicates a unit that is profitable without any capacity revenue. The revenue requirement for each unit is normalized by its capacity contribution in UCAP terms. As discussed previously, this is its installed capacity multiplied by a unit-specific capacity credit. The assumed capacity credit for wind resources is relatively low compared to others (15.7%), and this small denominator tends to skew the revenue requirements for wind units toward either tail of the supply curve. The intersection of these supply and demand curves provides a capacity valuation in the given year.

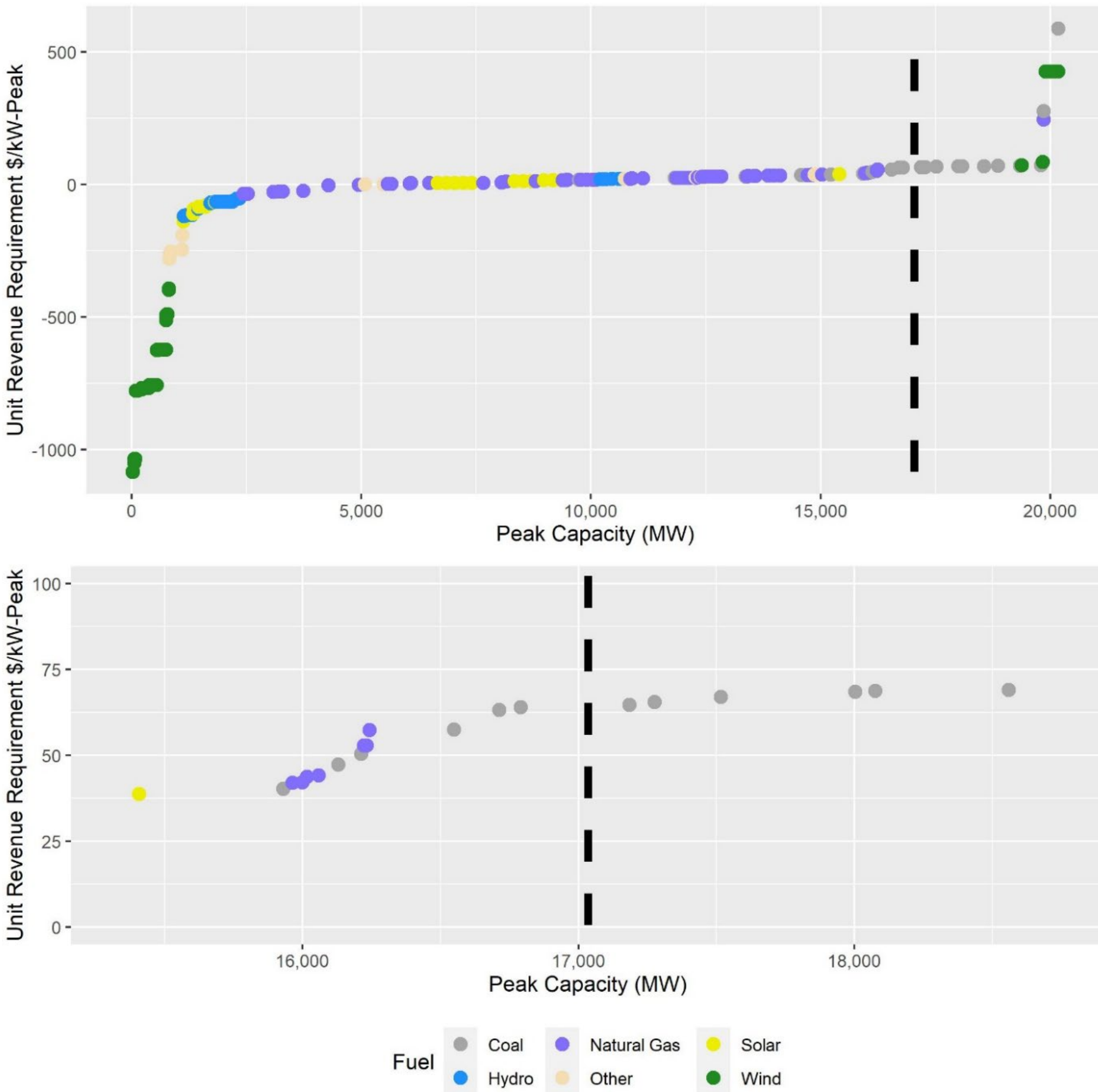

Figure 8-14 Capacity Supply and Demand Curves in the RMRG in 2028. Top: Curves in their entirety. Bottom: Region where the curves intersect.

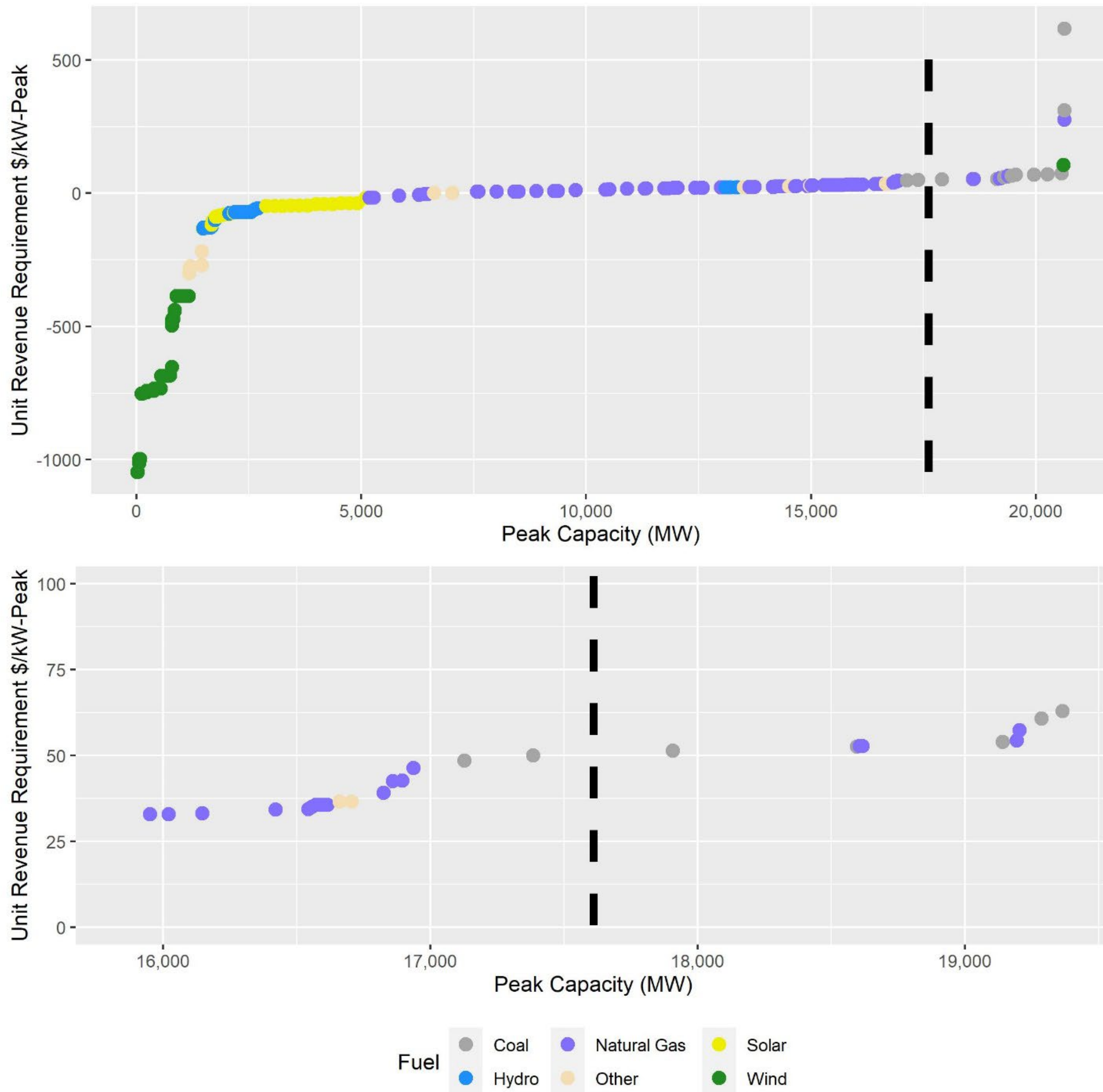

Figure 8-15 Capacity Supply and Demand Curves in the RMRG in 2038. Top: Curves in their entirety. Bottom: Region where the curves intersect.

Figure 8-16 shows the intersection of the supply and demand curves under the AggCarbon scenario in 2038. This provides further insight into the factors that lead to the relatively high capacity valuation in this scenario. This figure indicates that the battery storage resources that are brought online in the AggCarbon scenario have a relatively high revenue requirement and appear at the right end of the supply curve. These storage investments are made to support reliability in a system with high wind and solar penetrations, but the revenues generated from energy arbitrage alone are not sufficient to cover their fixed costs, which leads to a high revenue requirement. This outcome is likely caused to a certain extent by the relatively coarse geographic and temporal resolution used by AURORA, which may not fully capture potential localized energy arbitrage opportunities for storage resources.

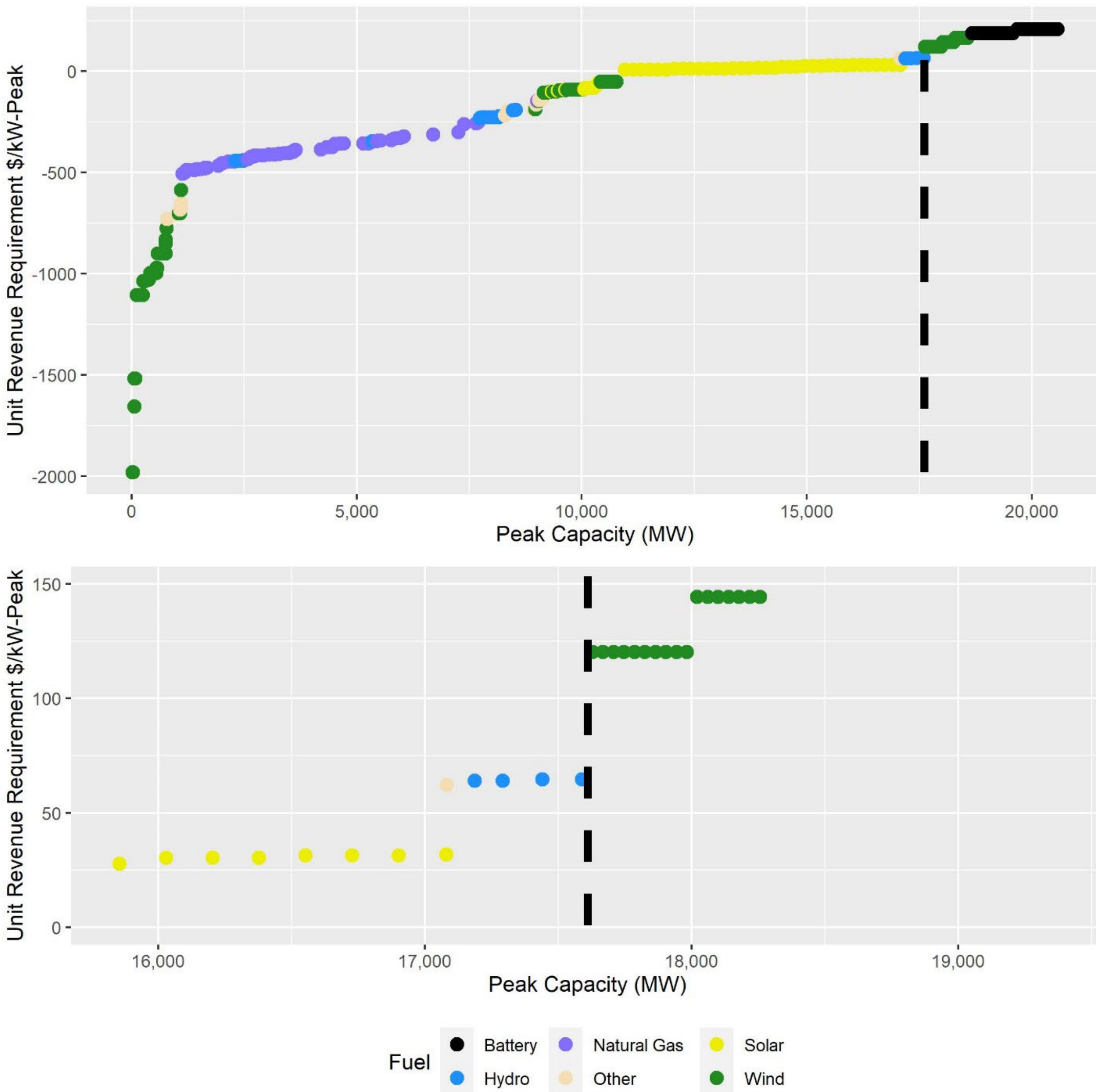

Figure 8-16 Capacity Supply and Demand Curves in RMRG in 2038 under AggCarbon Scenario. Top: Curves in their entirety. Bottom: Region where the curves intersect.

As discussed in Section 8.1.5.1, these are possible reasons AURORA does not select more battery storage capacity in other scenarios. These storage resources shift the capacity supply curve upward at the point of intersection with the demand curve, and therefore lead to a higher capacity valuation. Note that the last resource on the left side of the demand curve has a revenue requirement of $64.63/kW-year; therefore, if the target PRM were only slightly smaller, this resource would set the 2038 capacity valuation in the RMRG accordingly.

Also note that most other resources in the RMRG see greatly increased revenues in this scenario relative to the Baseline scenario, particularly the natural gas resources that are still in the system. This can be seen in how the left side of the supply curve is shifted downward compared to the Baseline scenario. We therefore once again stress that all reported capacity valuations should be interpreted critically, and in the proper context of how they are determined.

Figure 8-17 summarizes the capacity valuation results in the CMPP in 2028 and 2038 in each scenario. The Baseline scenario leads to a capacity valuation of $48.29/kW-year UCAP in 2028 and $48.51/kW-year UCAP in 2038, both lower than the corresponding valuations in the RMRG. The same is true of both the 2028 and 2038 valuation under the AggCarbon scenario.

However, the 2028 valuation in the EIA scenario is higher than the Baseline scenario, while the 2038 valuation is only slightly smaller. The CMPP contrasts with other regions where solar investments may decrease as a result of the higher capital cost assumptions associated with the EIA scenario relative to the Baseline scenario. These solar resources are supported by policy mandates and still enter the system, even though capital costs are higher, and they provide the marginal unit of capacity to satisfy the pool PRM. This means revenue requirements are higher than in the Baseline scenario, and the capacity valuation in 2028 is correspondingly higher. In the case of the HighNG scenario, both the 2028 and 2038 valuations in the CMPP are higher than the corresponding valuations in the RMRG.

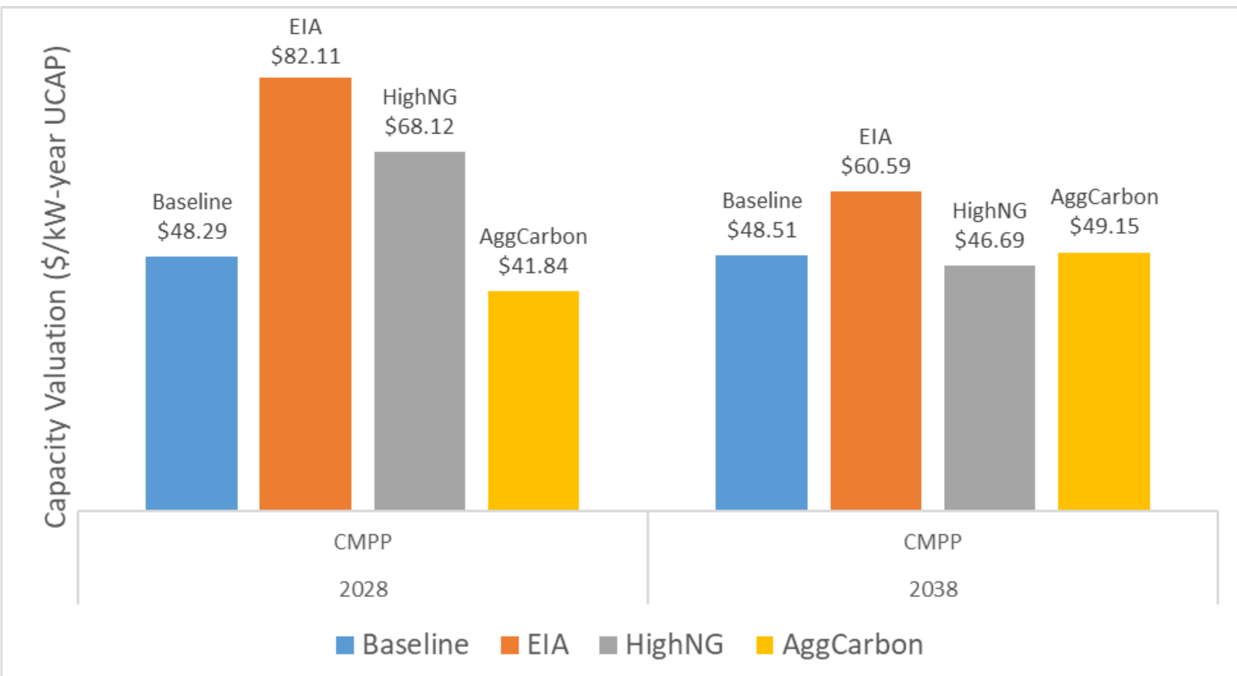

Figure 8-17 Capacity Valuations in the California Planning Pool under Each Considered Scenario in 2028 and 2038

It is clear that the EIA scenario results in a significantly higher valuation than the Baseline scenario in California, particularly in 2028. Unlike other regions, where solar investments may decrease because of the higher capital cost assumptions associated with the EIA scenario relative to the Baseline scenario, this is not the case in California. These solar resources are supported by policy mandates and still enter the system despite higher capital costs and provide the marginal unit of capacity to satisfy the pool PRM. This leads to higher revenue requirements relative to the Baseline scenario, and a correspondingly higher capacity valuation.

However, in 2038 the differences between the Baseline, HighNG, and AggCarbon valuations are fairly modest in California. This is because in California the Baseline scenario already largely satisfies the two constraints that are externally imposed under the AggCarbon scenario: no new natural gas investments and forced coal retirements. In the HighNG scenario, natural gas makes up a relatively small portion of the portfolio in California compared to other regions; therefore outcomes are less affected by the price of natural gas.

8.1.6 Summary of Results

Our revenue requirement-based capacity valuation analysis arrives at a baseline RMRG capacity valuation of $65.46/kW-yr in 2028 and $52.53/kW-yr in 2038. In both 2028 and 2038 the capacity valuations are greater than Baseline under the EIA scenario and smaller under HighNG scenarios. The increase in valuation under the EIA scenarios is likely caused at least in part by the higher capital cost assumptions for wind and solar resources, which increase their revenue requirements. The decrease in valuations under the HighNG scenario is likely a result of higher natural gas prices increasing the average marginal cost of energy, thereby increasing resource energy revenues and decrease revenue requirements. Finally, the AggCarbon scenario produces a moderately lower valuation than the Baseline scenario in 2028 and a much higher valuation in 2038. As discussed in Section 8.1.5.3, this high valuation in 2038 is caused in part by the presence of battery storage resources with relatively high revenue requirements. The decrease in valuation in 2028 is likely a result of the increase in the average marginal cost of energy, which drives up energy revenues. This is itself caused by more frequent supply shortages and load curtailment, which together lead to brief periods of high prices.

We also find that the capacity valuation in the RMRG generally decreases between 2028 and 2038, except in the AggCarbon scenario. This is in part because the realized reserve margin in the RMRG also decreases between 2028 and 2038 for each scenario, which in turn contributes to higher average energy prices. This may seem counterintuitive, as one might expect lower reserve margins to increase the relative value of capacity. However, it is important to remember that the capacity valuation is strongly linked to the valuation of other grid services, particularly energy. The higher energy prices that result also increase revenues for generation resources, and thereby contribute to decreasing resource revenue requirements. In essence, the energy market provides price signals to incentivize new investments and as a result these resources require less capacity revenue in order to recover their costs. As previously noted, AURORA does not consider potential revenues from ancillary services. Including these sources of revenue would increase revenues and decrease the revenue requirement for some units, shifting the supply curve down and potentially reducing the value of capacity.

For reference, we now briefly review the most recent auction results from the four competitive capacity markets in the United States. In PJM, the Base Residual Auction for delivery in 2021/2022 was held in May 2018 and cleared at $51.10/kW-yr at the RTO level. Prices in some individual zones were as high as $74.57/kW-yr. In MISO, the 2020/2021 Planning Resource Auction cleared most zones at $1.73/kW-yr to $2.51/kW-yr, the low price indicating that MISO generally has capacity in its system. However, MISO Zone 7, which covers most of Michigan, cleared at $94.00/kW-yr; this indicates a need for additional capacity in that zone. In NYISO, the Strip auction for delivery in summer 2020 cleared between $32.52/kW-yr and $58.80/kW-yr, with prices reaching $220.32/kW-yr in New York City; prices for most zones in winter 2020–2021 cleared close to zero with prices reaching $2.85/kW-yr in New York City. Finally, in ISO-NE, the cleared price in the Forward Capacity Market for delivery in 2023/2024 was $24.00/kW-yr. The wide variation of capacity prices across ISOs—and even across zones within individual ISOs—is indicative of the inherent difficulty in estimating future valuations of capacity as a grid service.

8.1.7 Conclusions

Our analysis arrives at a range of potential future capacity valuations in the RMRG under four different future scenarios, but it also highlights the inherent challenge and complexity involved in forecasting future capacity valuations. The concept of capacity value is inextricably linked to the RA framework in a given system, the system operator's explicit or implicit demand for capacity, and the specific market mechanisms that are used to value other grid services. In some U.S. power markets, these valuation frameworks and processes are formalized through a regular auction process that clears at the intersection of well-defined supply and demand curves, while in other markets different mechanisms are used. In vertically integrated frameworks the value of capacity may be formally quantified through bilateral contracts, or it may be considered implicitly as part of long-term planning processes.

The capacity value of a resource in a given system is also dependent on a range of other complex market rules or planning procedures that exist or are implemented in that system, which either implicitly or explicitly allocate the total value that the resource provides to the power system between the various discrete grid services that it can deliver. Take, for instance, the ERCOT system in Texas, which does not currently have a remuneration mechanism for capacity or RA. The system instead chooses to rely on higher price caps and its operating reserve demand curves to provide price signals that guide long-term investment and retirement decisions; what is known as an "energy-only" framework. One interpretation of this market structure could be that "capacity as a grid service" has no quantifiable value in the ERCOT system. Resources of course still contribute to RA and support long-term reliability; however, in ERCOT this system value is reflected through the provision of other services, namely energy and operating reserves.

Therefore, we again reiterate that concept and quantification of capacity value from a system perspective must also be considered in the context of that specific power system, the other services that are provided in that system, and how the other services themselves are valued in that system.

8.1.8 References

Byers, C., T. Levin, and A. Botterud, 2018, "Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves," *The Electricity Journal* 31(1): 65–74. Available at: https://doi.org/10.1016/j.tej.2018.01.006.

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8.2 PLEXOS Modeling of Energy Generation Costs and Ancillary Services

8.2.1 Overview of Analysis

This section presents the PCM portion of the technoeconomic analysis. We compare two capacity buildout scenarios: a Base scenario and a High Renewable scenario. For each scenario we compare two cases, one without the additional PSH plant and one with the PSH plant included. The analysis focused on the system benefits provided by the plants, the ancillary services provided by the plants, and the generation and pumping patterns for the PSH plant.

The modeling was done using the PCM PLEXOS developed by Energy Exemplar. This study ran a least-cost optimization using mixed-integer linear programing in PLEXOS. The database was built using the WECC TEPPC 2024 database, which has already been used for similar studies such as the Low Carbon Grid Study and the Interconnections Seam Study (Bloom et al., 2020; Brinkman et al., 2016). The database was updated with inputs from the capacity expansion model AURORA, which Argonne ran. The analysis found a consistent reduction of production costs, made up of start costs and fuel costs, as well as reduction in curtailment with the inclusion of the Banner Mountain PSH plant. The use of the BMSP increased in the High Renewable scenario.

8.2.2 Background on "Service"

PCMs focus on the operations of the electricity grid usually for a full year with an hourly or sub-hourly resolution and run a least-cost optimization with the available resources in the model to meet the load and reserve requirements in the most cost-effective way. PCM runs optimize resources using multiple inputs, including generation types, load, heat rates, fuel prices, and transmission connections, as well as constraints, such as maximum generation, minimum down time, ramping limits, and transmission line maximums, while running the cost optimization. Transmission constraints can be simplified by running PLEXOS regions nodally.

The temporal representation inside PLEXOS moves from larger time increments to smaller time increments as the model progresses. Initially, the model runs a medium-term look at the year. In this case, the medium-term ran a coarse analysis of each month decomposing monthly hydropower energy limits into daily limits, subtracting the wind and solar from the load and matching generation to the peak and average load for the month. This coarse analysis is then passed down to the short-term scheduler that optimizes the system for the hourly time step while respecting all constraints, including ramping, minimum up and down times, minimum stable levels, and many others. For this part of the analysis, two short-term models were used:

- The DA unit commitment model, which commits slow start generation, such as coal, nuclear, and combined-cycle natural gas; and

- The hourly unit commitments from the DA run were then read into the RT run, which dispatched faster start generation at the smaller time step.

Because solar and wind resources are zero-marginal cost and non-dispatchable, they are generally deployed first by the model. Hydro generation is also a zero-marginal cost resource and is usually dispatchable—so it is deployed within constraints that often consider the hydropower resources needed in the future, usually within the month. Baseload resources, such as nuclear and coal, are dispatched next; they generally have high capital costs and low fuel costs, but also low flexibility. They usually run most of the hours of the year.

In contrast, peaking units have high flexibility—but also high costs—and are thus only turned on during the highest load hours of the year, or when high flexibility is needed. Peaking plants are usually combustion turbines. There are also intermediate units, usually combined-cycle natural gas, which have operating costs that are between those of baseload and peaking and have moderate levels of flexibility.

Run-of-river hydropower is like solar and wind in that it is not dispatchable and must be taken as-is or curtailed. Most other hydroelectric generation has a high level of flexibility and low operating costs, because no fuel costs are associated with generation. PSH also has a high level of flexibility and can often compete with combined-cycle and combustion turbines. Providing energy to meet load is a large part of the value seen in the PCM from PSH.

PCMs co-optimize generation and ancillary services (also known as reserves). For ancillary services, a portion of generation is held in reserve, often with a price attached, in case something changes quickly on the grid and this reserve energy is needed. The PSH plant can provide the ancillary services to the grid. In this study, we focused on two types of reserves: regulation and spinning. With spinning reserves, a response is required in 10 minutes or less. Spin reserve requirements typically total about 3% of the balancing area's load. For regulation, a response is required in 5 minutes or less, and requirements typically total about 1% of the balancing area's load.

8.2.3 Valuation Methodology

The valuation methodology for PCMs in a study like this is to run the model without the generator of interest (Case 1). Then the same model is run with the generator of interest included (Case 2), and the results are compared. This allows for like to be compared with like. It also ensures that any differences between the two models are due only to the generator of interest—in this case, the Banner Mountain PSH plant. Many of the outputs from the model include a cost component. These model outputs include total generation cost, fuel costs, and start costs; thus, we can calculate the cost and benefits to the system directly. Other comparisons do not have a cost component, but are beneficial to the system, such as reduction in curtailment and reduction in emissions.

Other results are included in this chapter that focus solely on the services provided by the Banner Mountain plant; these are calculated directly from PCM outputs from Case 2 only. For capacity factor and use rate, we use the generation and pumping data. For ancillary services, the regulation and spin provisions, as well as the price in the region for those provisions, are used to calculate the value of ancillary services.

The model was run for both the DA (hourly) resolution and the RT (5-minute) resolution, and results will be presented for both types of runs. Note that the value of Banner Mountain is not the sum of the DA and RT benefits. It is more accurate to think of the DA and RT results as showing a range of possible benefit values.

8.2.4 Analysis

8.2.4.1 Overall Design of Study

In PLEXOS, we modeled the entire WECC region, taking advantage of the nodal and zonal settings in the model. Areas of high interest—in this case Wyoming, the PNW, and California—were modeled nodally, allowing us to have higher resolution geographical outputs. The areas outside of this footprint were modeled zonally, meaning they will have the same temporal resolution but less geographical resolution, allowing for a faster solve time.

This project used the PCM PLEXOS for the model year 2028. The base model was WECC's 2014 database with updates from the AURORA model for the representative year. The model represents the electricity grid both spatially and temporally. The spatial representation is through nodes and transmission limits, as well as region separation and interface hurdle rates, which means it costs money to send electricity from one region to another. The hurdle rates were in place for the DA runs and turned off for the RT runs. This is representative in that systems like the California EIM are removing hurdles to trading electricity in RT, but there is currently no widespread DA market for the region.

The study focused on two scenarios: a Base scenario and a High Renewable scenario. The Base scenario is consistent with the 2028 ATB from AURORA and is the first year of planned operations for Banner Mountain. The load from the 2024 WECC database was scaled up to the 2028 load using the AURORA peak demand for the year. For the High Renewable case, the load stayed the same as the Base scenario. The solar in the model was increased from 64 to 97 GW and wind was increased 8 GW, from 83 to 91 GW.

The wind data came from NREL's Wind Toolkit. It is from the year 2012 and included hourly data and 5-minute data (Draxl et al., 2015). The solar data was from the National Solar Radiation Database, also from 2012, and was at a 30-minute resolution (Sengupta et al., 2018).

8.2.4.2 Scenarios and Assumptions

This section will discuss the scenarios and cases. The scenarios all focus on the Western Interconnect using the 2024 TEPPC database as a starting point. Two scenarios (see Table 8-10) were run in PLEXOS with a focus on how they might impact the value of the PSH plant energy and services, and the grid impacts of the PSH plant. The first scenario was a BAU case (Base scenario), which includes current RPS standard for states and announced coal retirements. The BAU scenario represents the most likely capacity build-out and uses average conditions for factors such as hydro and natural gas prices. We ran the BAU model for the Base scenario, as well as the model with the additional PSH plants individually.

Table 8-10 lays out the scenarios, time resolution, and case for each run included in the production cost portion of the study and gives each a unit abbreviation that will be used throughout the rest of the section to indicate which run is being referenced.

Table 8-10 Proposed Scenarios, Cases, and Abbreviations

Scenario	Time Resolution	Case	Abbreviation
Base (2028)	DA	No Banner Mountain	ATBDA
		With Banner Mountain	BMDA
	RT	No Banner Mountain	ATBRT
		With Banner Mountain	BMRT
High Renewable	DA	No Banner Mountain	HR_ATBDA
		With Banner Mountain	HR_BMDA
	RT	No Banner Mountain	HR_ATBRT
		With Banner Mountain	HR_BMRT

Figure 8-18 shows the percentage of electricity provided throughout the year by each type. For the Base scenarios, there is about 20% wind, 10% solar, and 8% coal. Hydro and natural gas are large contributors as well, with contributions of 24% and 28%, respectively. The hydro and natural gas stay consistent for the High Renewable scenario, while the wind and solar increase about 5% each, and coal decreases to zero. Note that this is not a full-capacity expansion exercise, and transmission was not expanded at all. The goal of this scenario was to explore how the value of the PSH plant changed under conditions with more renewables and less coal.

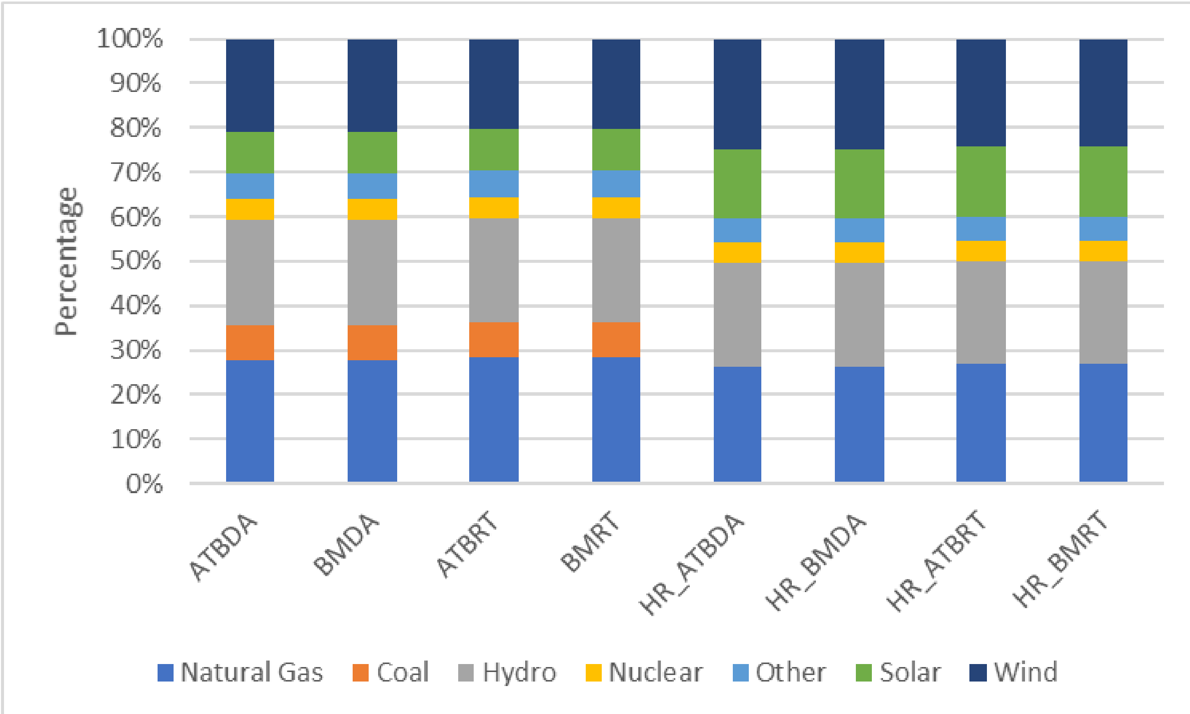

Figure 8-18 Types of Generation by Percentage for Different Scenarios and Cases

8.2.4.3 Data Needs and Sources

As mentioned in Section 8.2.4.1, this work was built on the 2024 TEPPC database and used capacity expansion scenarios defined in Section 8.1. Additional data were required for the wind and solar profiles, for which we used the Wind Toolkit (Draxl et al., 2015) and the National Solar Radiation Database (Sengupta et al., 2018). Information about the PSH plants was provided by the developers. In this case, there were three 140-MW units for a total of 420 MW with 80% efficiency.

8.2.5 Modeling Runs and Results

8.2.5.1 Production Costs

Table 8-11 shows the production costs for each of the runs and the production cost delta due to the inclusion of Banner Mountain. The production cost, generally thought of as the generation cost, includes start costs, fuel costs, and variable O&M costs. Start costs and fuel costs will be explored further in subsequent sections. Note that for the same scenario the production costs decrease with the inclusion of Banner Mountain. With the RT runs, the costs increase, and the production cost benefit of Banner Mountain also increases. In the RT runs, the baseload and intermediate generation are limited in their ability to start and ramp; consequently, we saw an increase in the use of higher cost, flexible peaking units being used to address the forecast errors related to wind, load, and solar. The production cost benefits of Banner Mountain also increase with the High Renewable scenario, in part due to the flexibility and balancing ability of the additional PSH units.

Table 8-11 Production Costs for Runs With and Without Banner Mountain

Scenario	Time Resolution	Case	Production Costs ($M)	Production Cost Delta ($)
Base	DA	No Banner Mountain	10,782	
		With Banner Mountain	10,771	11
	RT	No Banner Mountain	11,428	
		With Banner Mountain	11,402	26
High Renewable	DA	No Banner Mountain	9,188	
		With Banner Mountain	9,162	26
	RT	No Banner Mountain	9,999	
		With Banner Mountain	9,957	42

8.2.5.2 Starts and Start Cost

Figures 8-19 and 8-20 show the capacity-weighted starts for the DA and RT runs, respectively. Generally, the starts for combined cycles, combustion turbines, and internal combustion units increase with the High Renewable scenarios and decrease in the cases that include Banner Mountain. This is not surprising, because the addition of the PSH unit displaces some of these starts where it makes more economical sense for the PSH units to start instead of the fossil units.

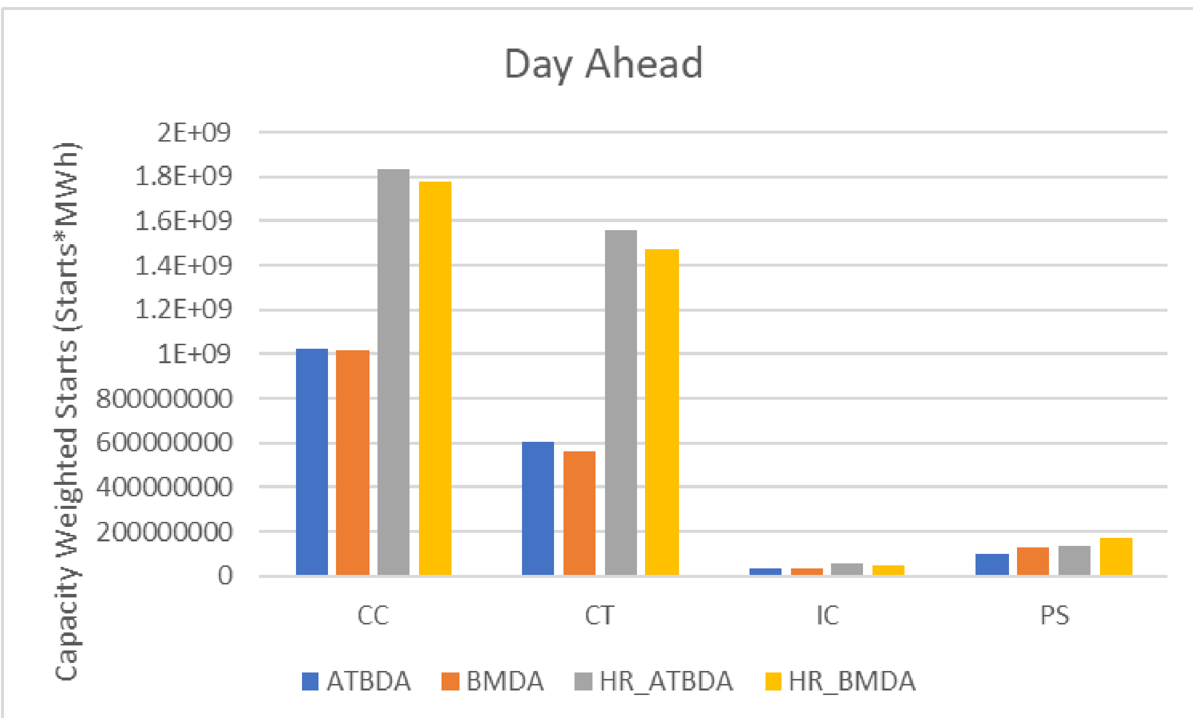

Figure 8-19 Capacity-Weighted Starts for DA Runs, by Type of Generation

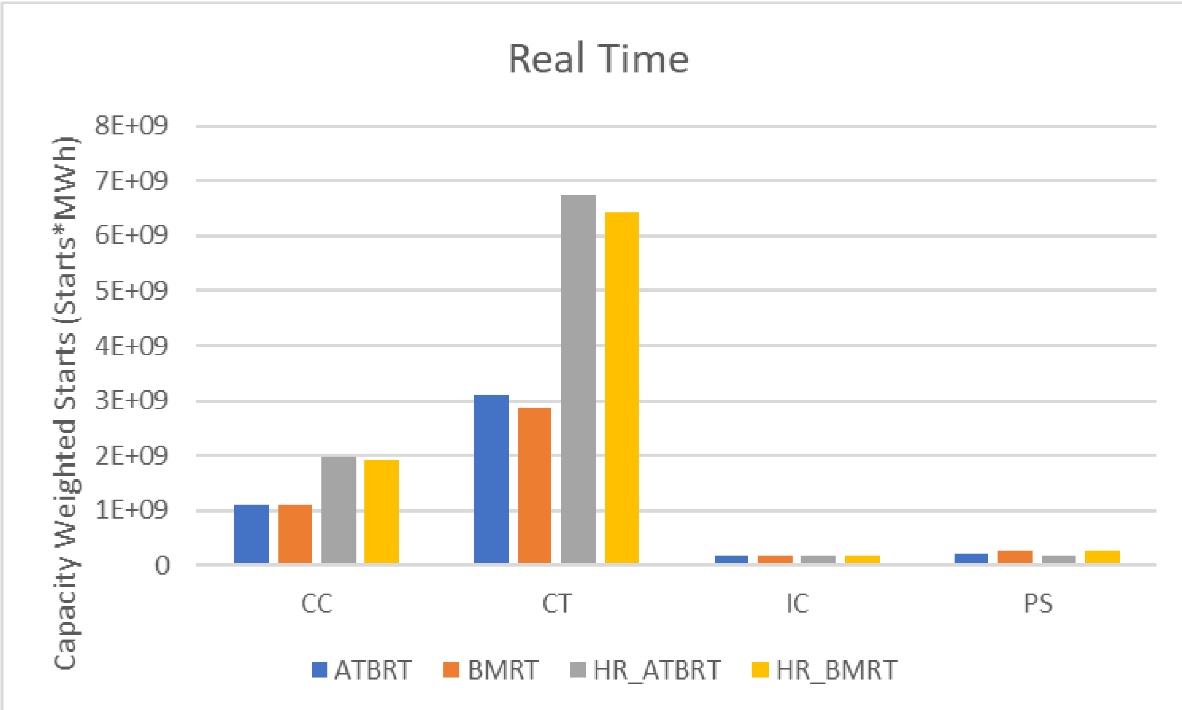

Figure 8-20 Capacity-Weighted Starts for RT Runs, by Generation Type

Figure 8-21 shows the start costs by type for the runs, while Table 8-12 highlights the start cost reduction due to the inclusion of Banner Mountain. The start costs are included in the production costs. The start cost reductions range from \$3 million to \$12 million and increase for the RT runs and the High Renewable scenario. Because the capacity-weighted starts decreased and the combined cycle, combustion turbine, and internal combustion units have start costs associated with them, it follows that the inclusion of Banner Mountain—and the decrease in fossil unit starts—decreases start costs overall.

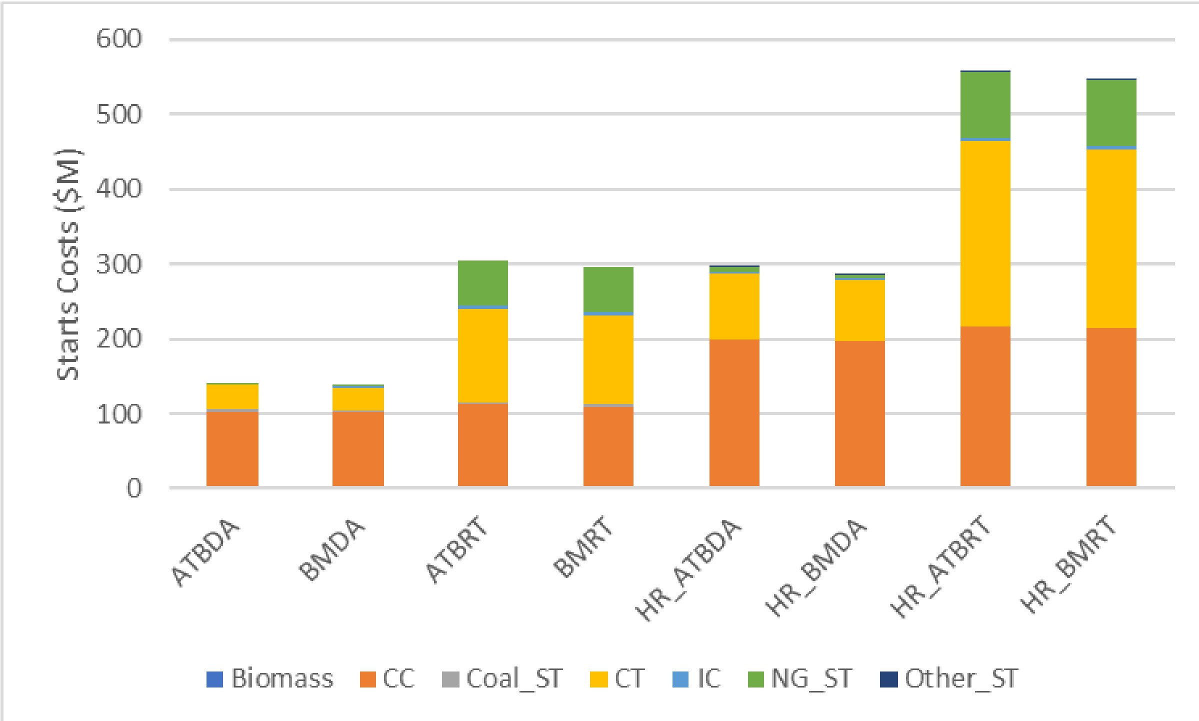

Figure 8-21 Start Costs by Type for Different Runs

Table 8-12 Total Start Costs and Start Cost Reduction Due to Inclusion of Banner Mountain

Scenario	Time Resolution	Case	Abbreviation	Start Costs ($M)	Start cost reduction ($M)
Base	DA	No Banner Mountain	ATBDA	140	–
		With Banner Mountain	BMDA	137	3
	RT	No Banner Mountain	ATBRT	304	–
		With Banner Mountain	BMRT	296	8
High Renewable	DA	No Banner Mountain	HR_ATBDA	295	–
		With Banner Mountain	HR_BMDA	286	9
	RT	No Banner Mountain	HR_ATBRT	557	–
		With Banner Mountain	HR_BMRT	545	12

8.2.5.3 Fuel Costs

Table 8-13 shows the fuel costs for the runs. Fuel cost is a major component of the production costs, and fuel costs savings is a major component of the production costs savings. The fuel cost reduction ranges from $8 million to $31 million. Like start costs, it increases for RT runs and for the High Renewable scenario. The decrease in fuel costs is due to both the generation of Banner Mountain as well as the reduction in curtailments because the PSH can balance more of the wind and solar on the system.

Table 8-13 Fuel Costs

Scenario	Time Resolution	Case	Abbreviation	Fuel Costs ($M)	Fuel Cost Reduction ($M)
Base	DA	No Banner Mountain	ATBDA	9,661	–
		With Banner Mountain	BMDA	9,653	8
	RT	No Banner Mountain	ATBRT	10,109	–
		With Banner Mountain	BMRT	10,092	17
High Renewable	DA	No Banner Mountain	HR_ATBDA	8,163	–
		With Banner Mountain	HR_BMDA	8,146	17
	RT	No Banner Mountain	HR_ATBRT	8,687	–
		With Banner Mountain	HR_BMRT	8,656	31

8.2.5.4 Emissions

Figure 8-22 shows the carbon dioxide emissions for the runs while Figure 8-23 shows the NO_x and sulfur dioxide emissions. The carbon dioxide emissions are slightly lower when Banner Mountain is included. In a system with mainly fossil fuels, the expectation would be for a PSH plant to increase emissions because it charges using fossil fuel. Because emissions are slightly lower, we conclude that the PSH unit is charging from wind and solar, and sometimes hydro, which sometimes may have otherwise been curtailed. Taking the reduction in emissions with the reduction in start costs and the reduction in fuel costs, it is reasonable to assume that the PSH unit is replacing fossil fuel generation and supporting renewable generation.

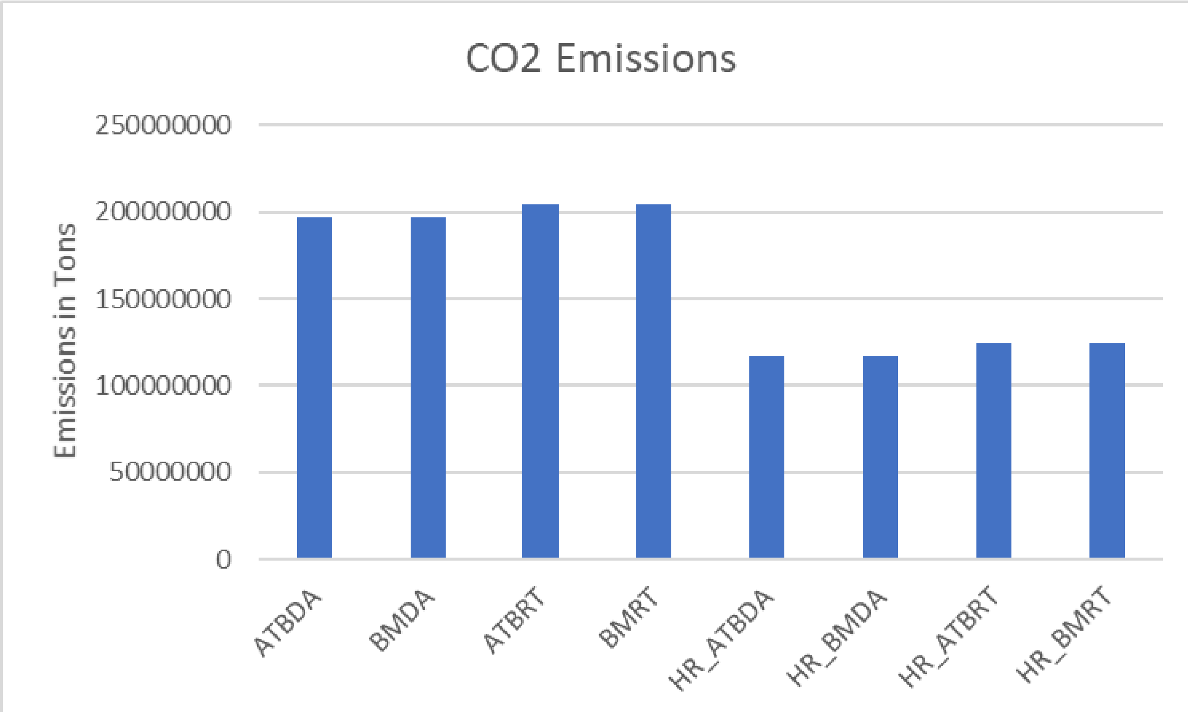

Figure 8-22 Carbon Dioxide Emissions for Scenarios and Cases

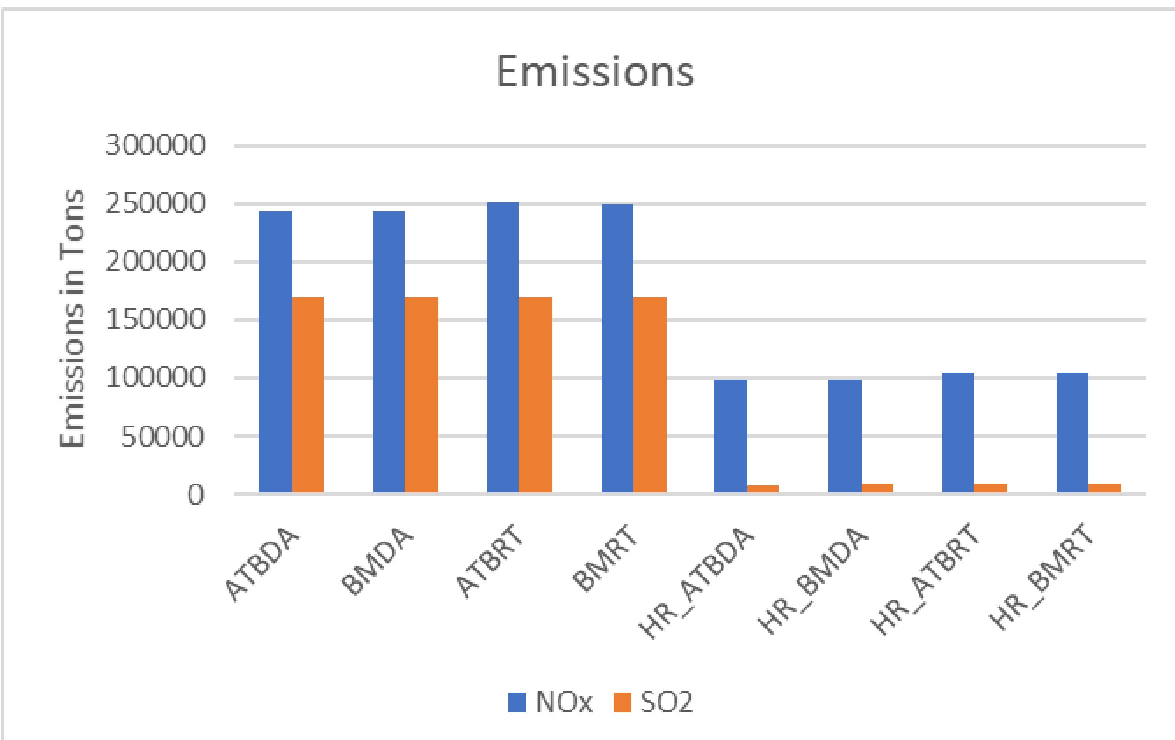

Figure 8-23 SO_2 and NO_x Emissions for Cases and Scenarios

8.2.5.5 Ramping

Figures 8-24 and 8-25 show the ramp up for the Base scenarios and the High Renewable scenarios. Only ramp up is shown, because ramp up and ramp down are nearly identical. Generally, for the Base scenarios, ramping is slightly decreased with the inclusion of Banner Mountain—but the change is small overall. The change is even smaller for the High Renewable scenarios. The ramping is more influenced by other factors including the load and renewable additions (especially solar) in contrast to the inclusion of Banner Mountain.

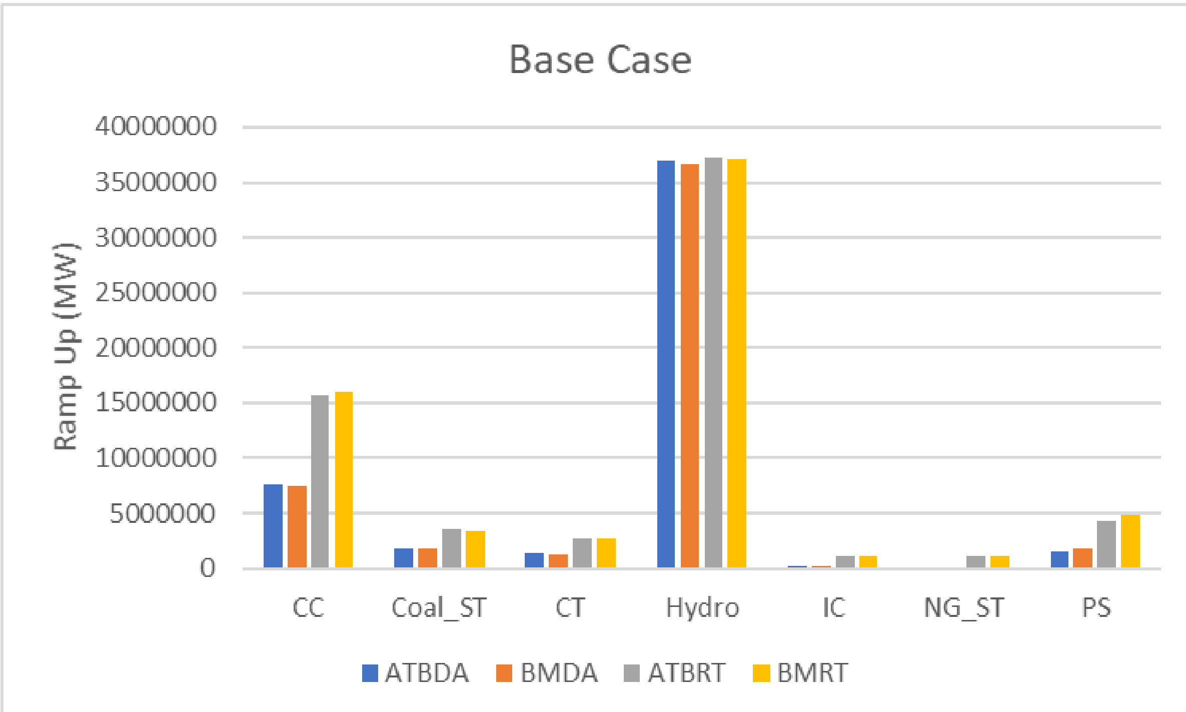

Figure 8-24 Ramp Up in MW for Base Cases

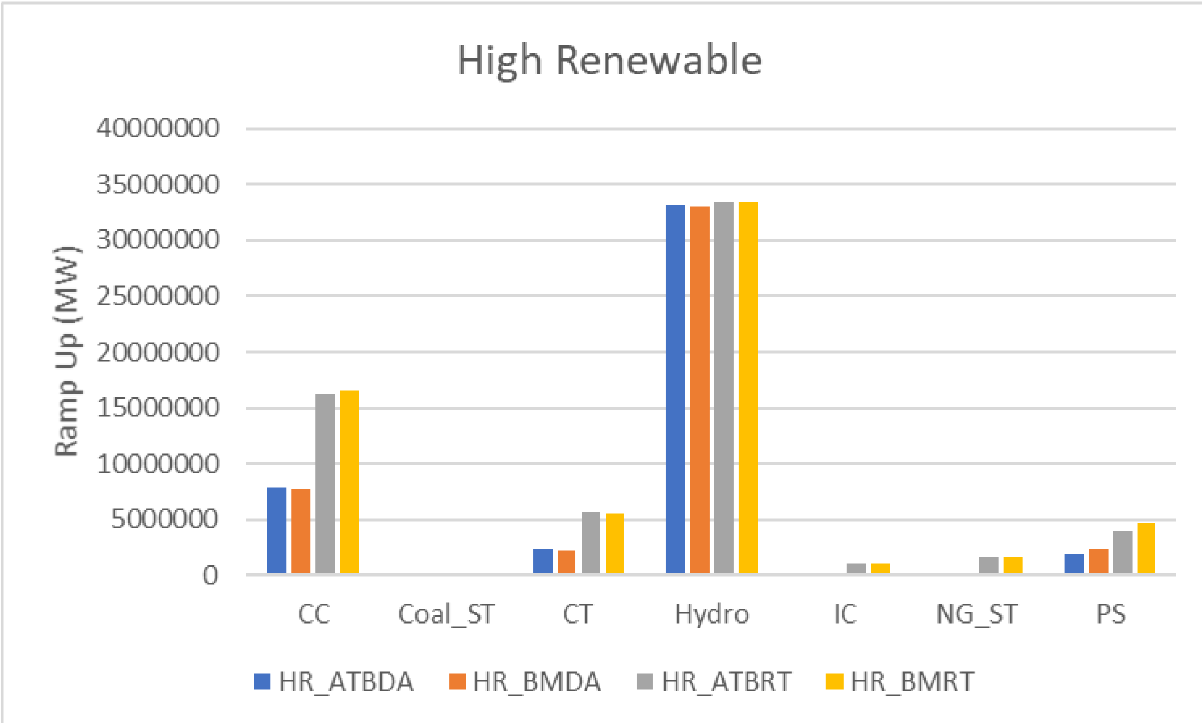

Figure 8-25 Ramp Up in MW for High Renewable Cases

8.2.5.6 Curtailment

Figure 8-26 shows the wind and solar curtailment, while Table 8-14 shows the total curtailment and the reduction in curtailment because of the inclusion of Banner Mountain. Curtailment reductions range from 186 to 479 GWh. The third column of the table shows the percentage of pumping energy that came from previously curtailed energy. The percentages range from 19% to 40%, with the highest percentage in the High Renewable DA case. The reduction in curtailment supports the other findings of reduction in fuel costs and start costs; taken together, these support the finding that PSH supports the integration of renewables.

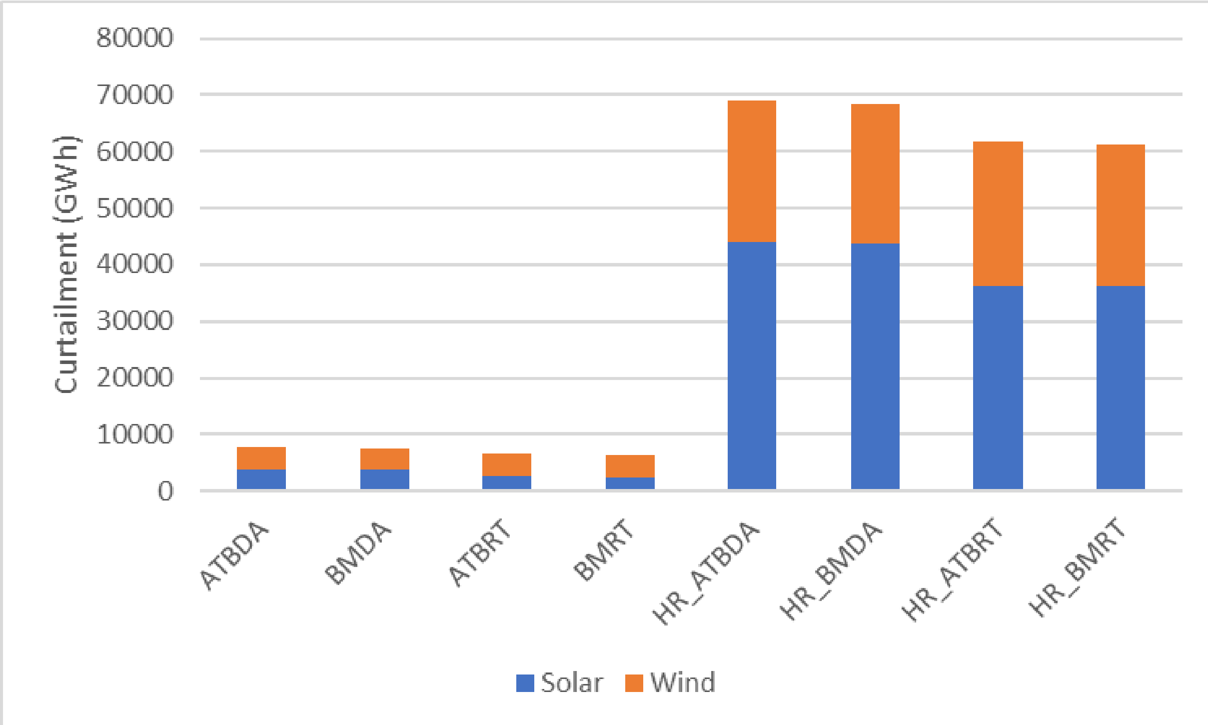

Figure 8-26 Solar and Wind Energy Curtailed (GWh) for Scenarios and Cases

Table 8-14 Total Curtailment and Curtailment Reduction Due to the Inclusion of Banner Mountain

Scenario	Time Resolution	Case	Curtailment (GWh)	Reduction in Curtailment (GWh)	% Of pumping from Curtailment
Base	DA	No Banner Mountain	7,865		
		With Banner Mountain	7,630	235	28%
	RT	No Banner Mountain	6,690		
		With Banner Mountain	6,504	186	19%
High Renewable	DA	No Banner Mountain	68,946		
		With Banner Mountain	68,511	434	40%
	RT	No Banner Mountain	61,663		
		With Banner Mountain	61,183	479	35%

8.2.5.7 Generation Profiles

Figures 8-27 through 8-30 show the generation and pumping for 4 days of each season for the Base scenario. Figure 8-31 shows the average generation and pumping for the Banner Mountain plant for the Base scenario. There is a tendency to generate more in the morning and evening hours and pump overnight and in the middle of the day. Figures 8-32 through 8-35 show the same 4 days for each season as Figures 8-27 through 8-30, but for the High Renewable scenario. Figure 8-36 shows the average generation and pumping for the High Renewable Scenario. The PSH response to solar is evident in the high generation during the morning and evening and the large amount of pumping during the middle of the day—when solar is highest.

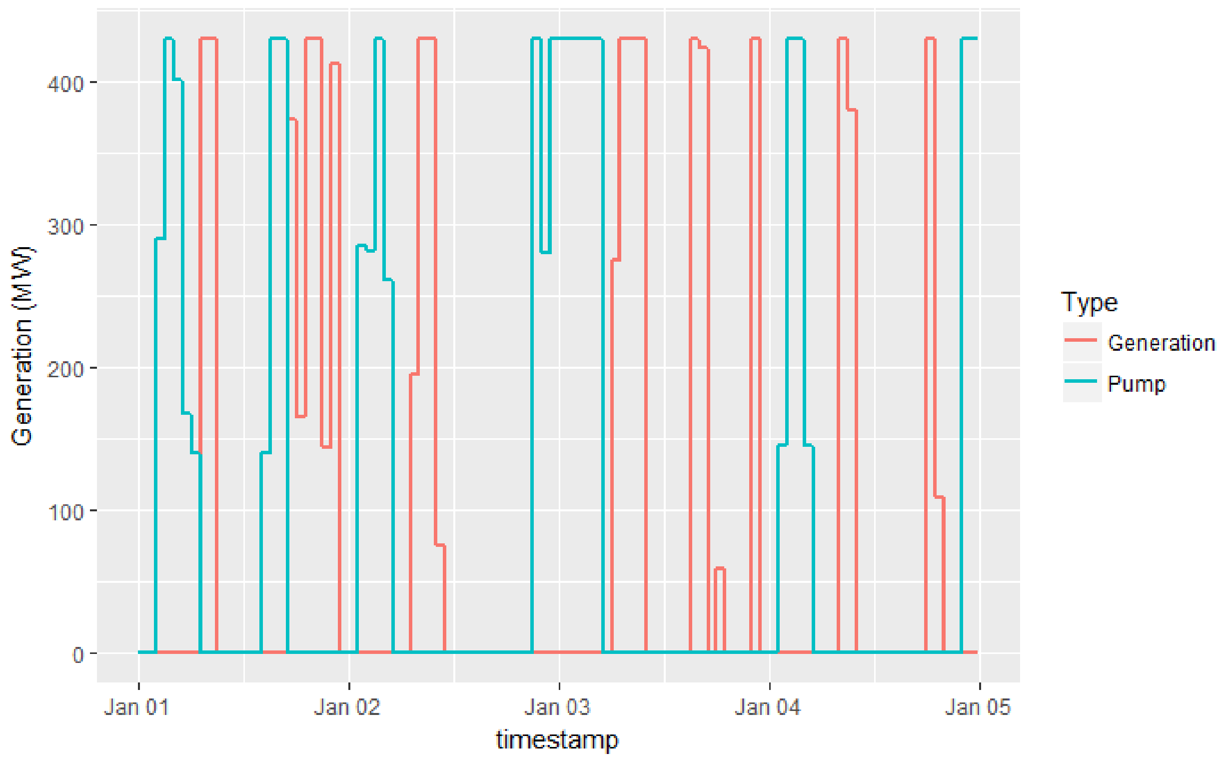

Figure 8-27 Generation and Pumping for Base Scenario in Winter

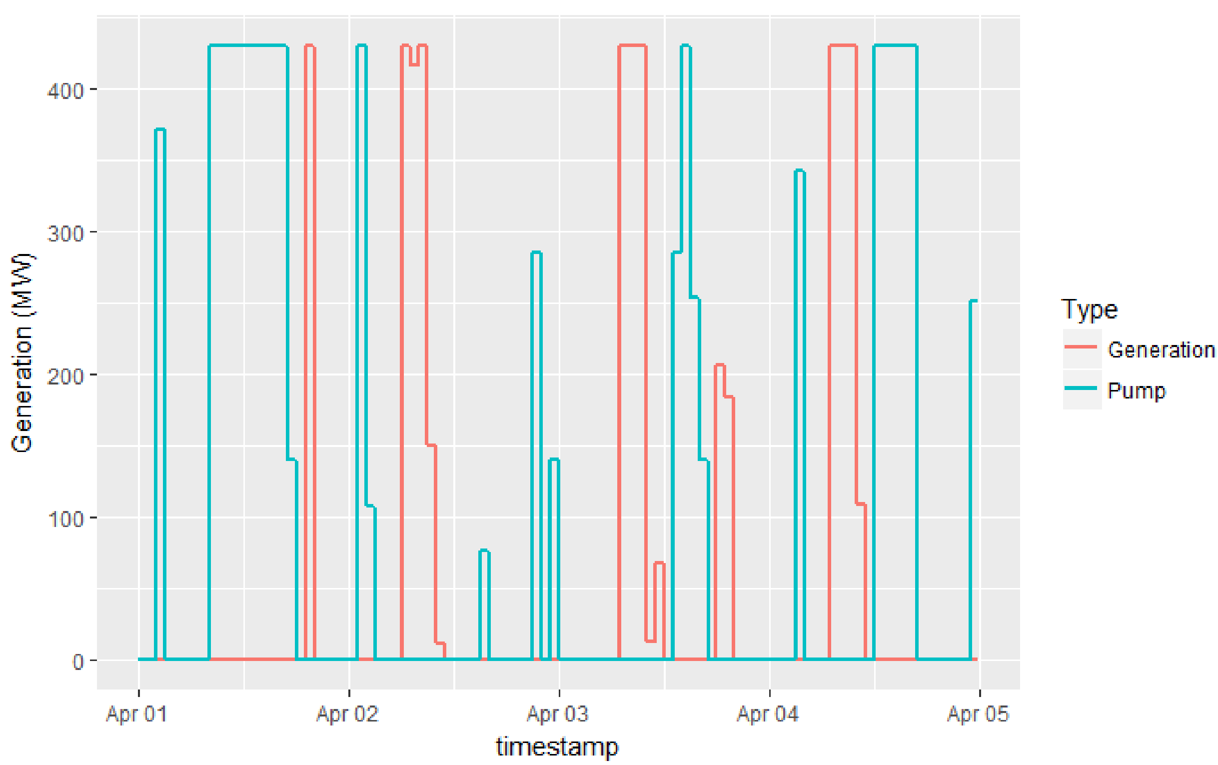

Figure 8-28 Generation and Pumping for Base Scenario in Spring

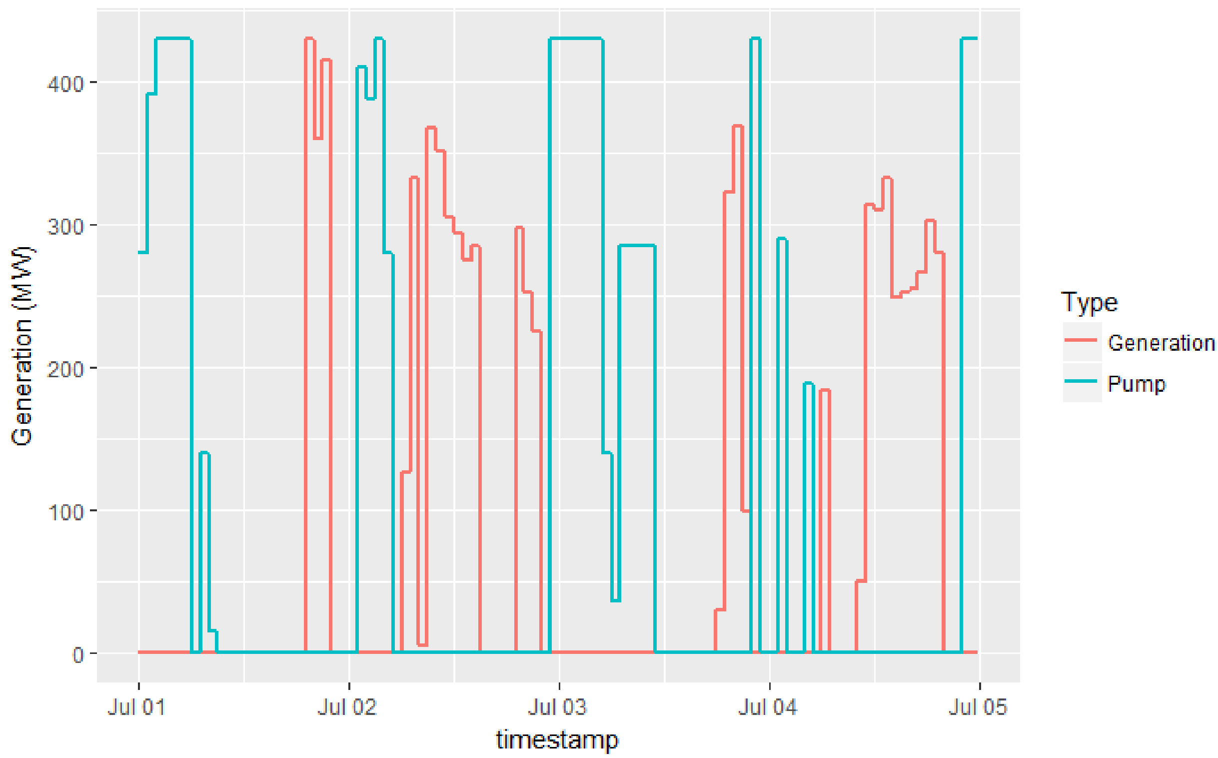

Figure 8-29 Generation and Pumping for Base Scenario in Summer

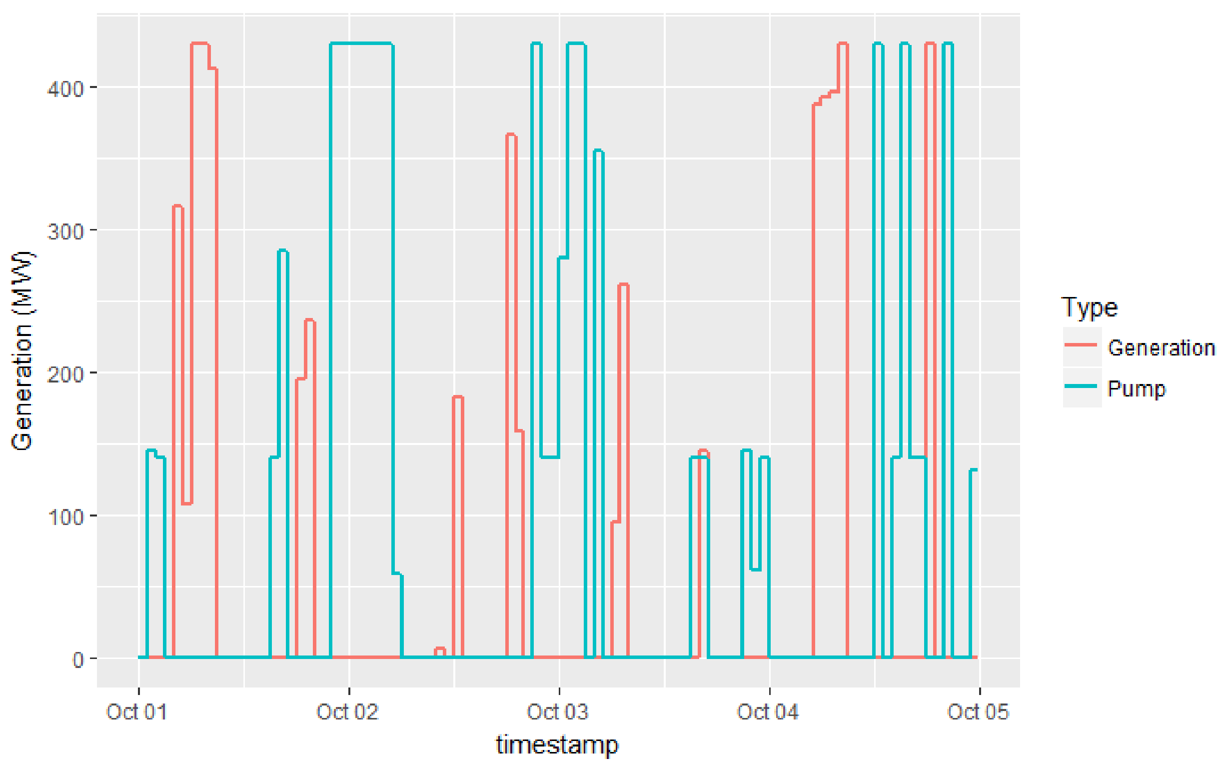

Figure 8-30 Generation and Pumping for Base Scenario in Autumn

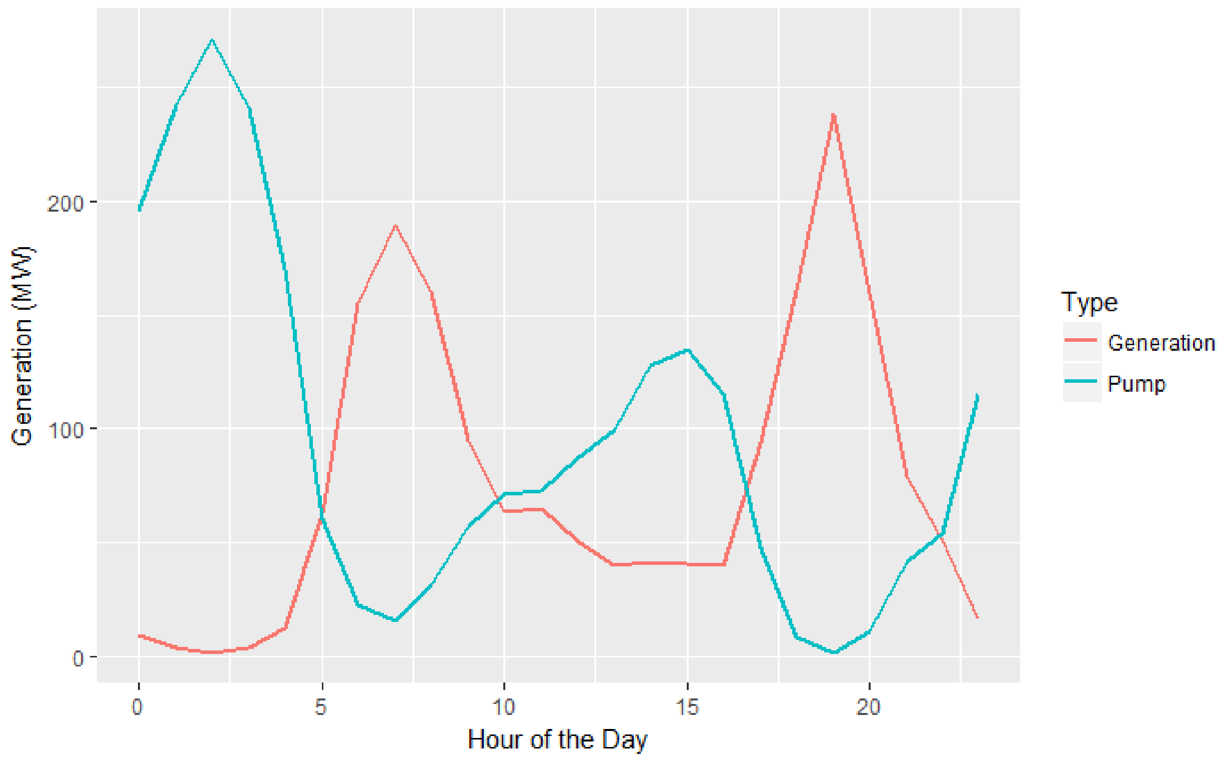

Figure 8-31 Average Daily Generation and Pumping for Banner Mountain Plant for Base Scenario

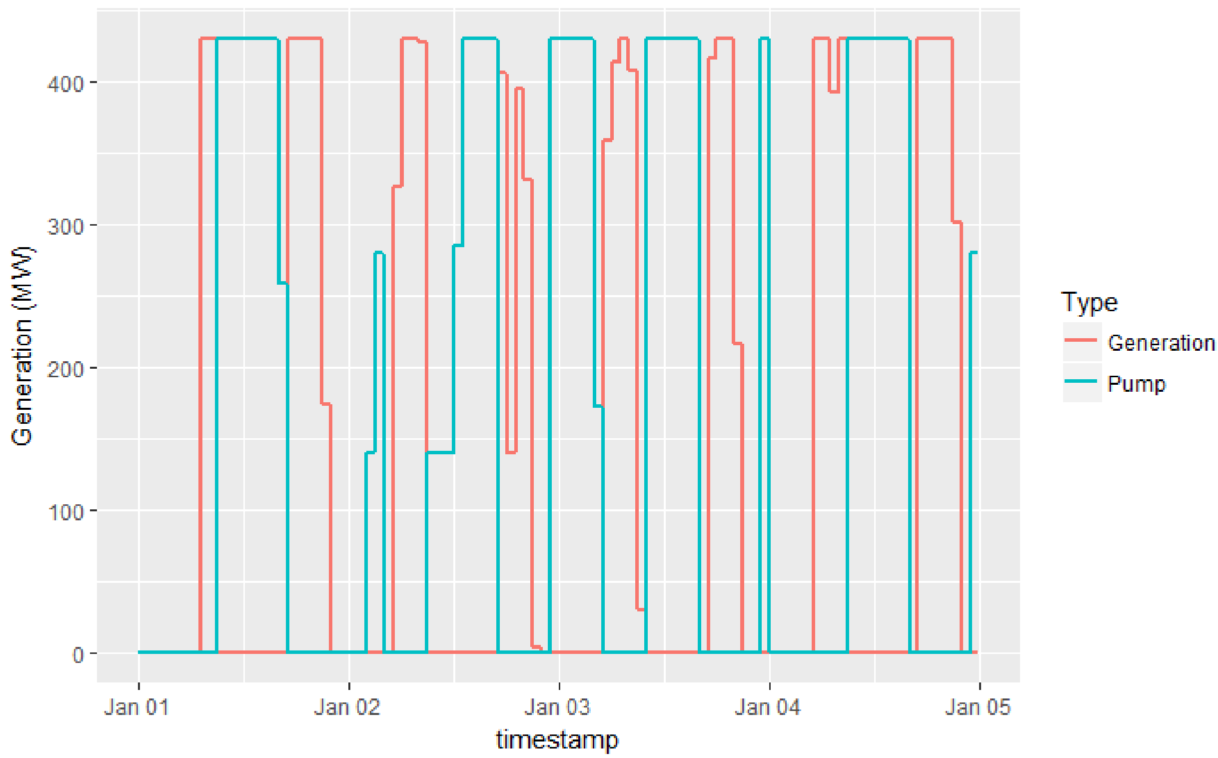

Figure 8-32 Generation and Pumping for High Renewable Scenario in Winter

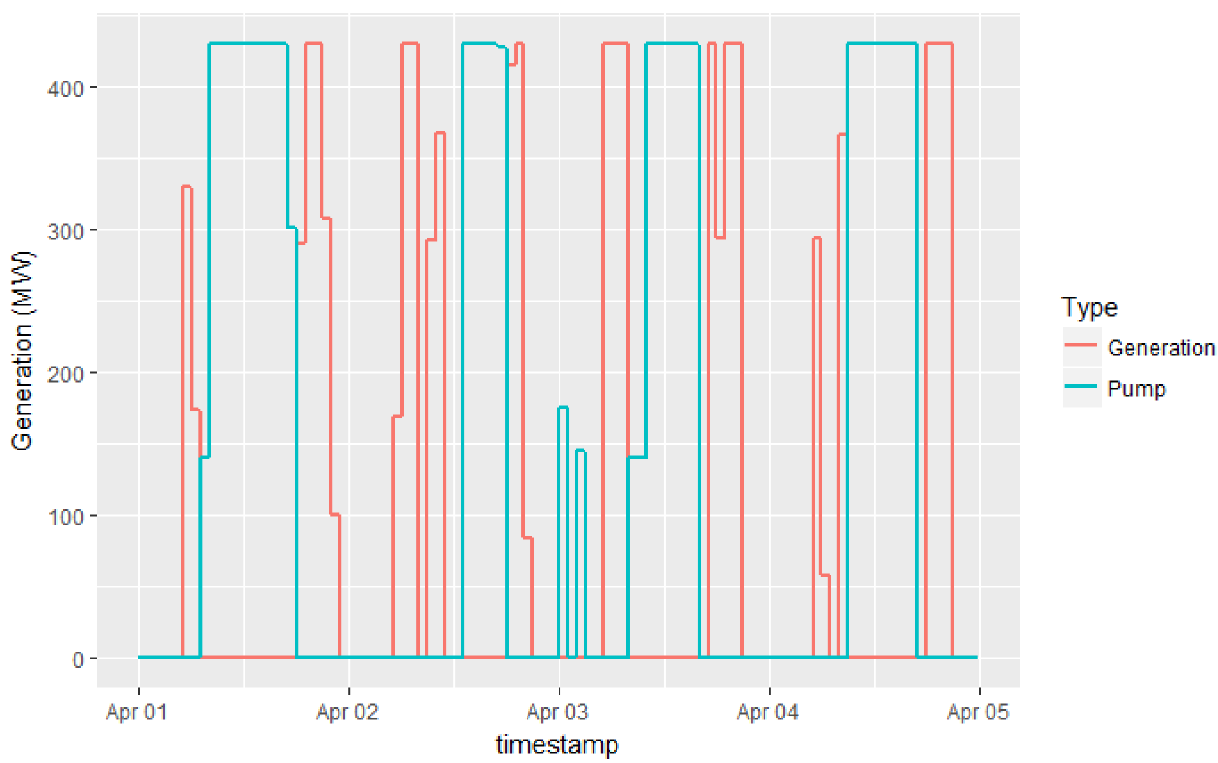

Figure 8-33 Generation and Pumping for High Renewable Scenario in Spring

Figure 8-34 Generation and Pumping for High Renewable Scenario in Summer

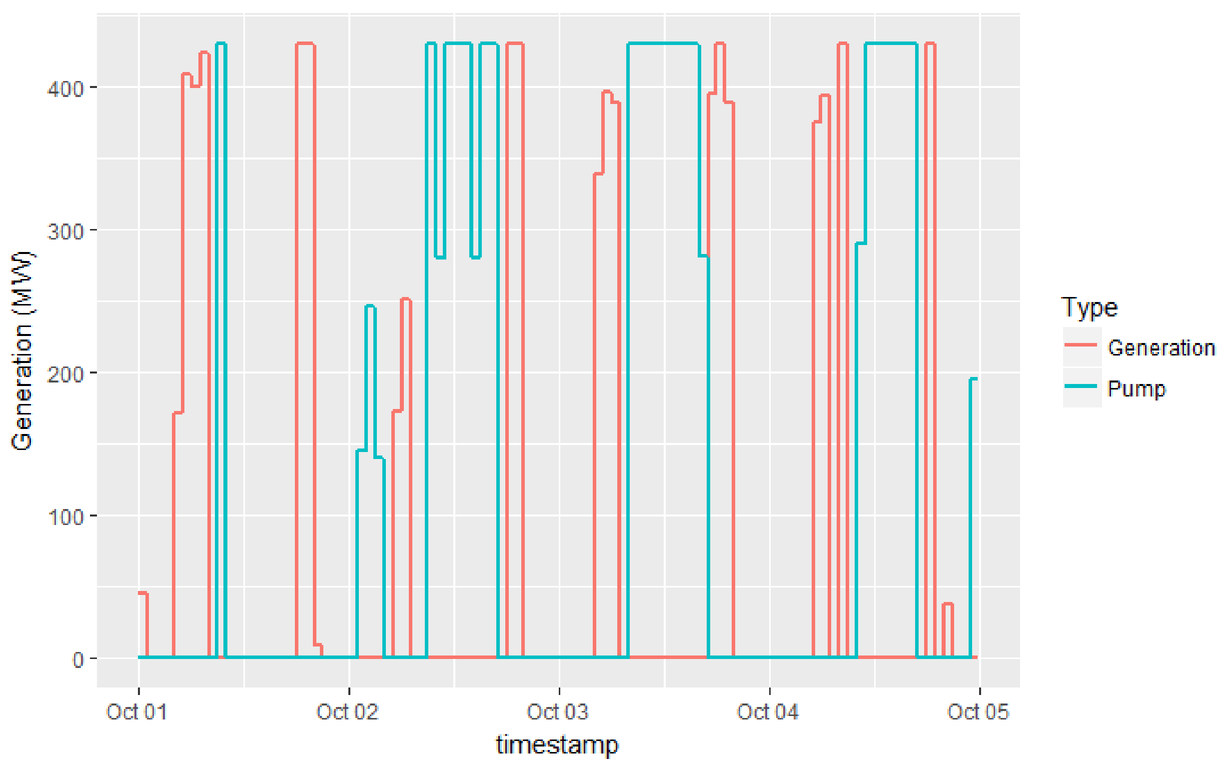

Figure 8-35 Generation and Pumping for High Renewable Scenario in Autumn

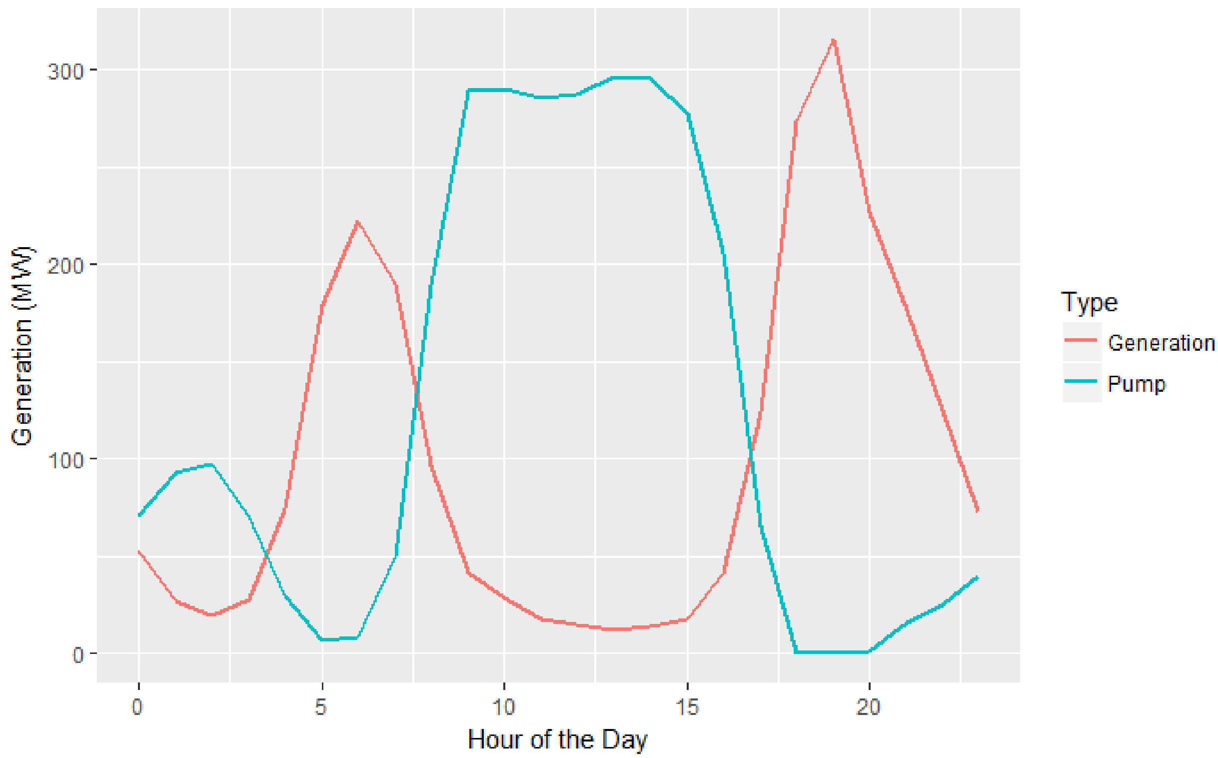

Figure 8-36 Average Daily Generation and Pumping for Banner Mountain Plant for High Renewable Scenario

8.2.5.8 Capacity Factor, Capacity Value, and Utilization Rate

Capacity factor is a measure of how much a generator is used throughout the year compared to if it were to run at full capacity all year long. Due to the constraints on PSH, its theoretical maximum capacity factor is 44%. To put this in context, baseload generators typically have high capacity factors, usually in the 80–90% range, because they are running most of the time. In contrast, peaking generation units like combustion turbines usually have a capacity factor of less than 10%. The top two rows of Table 8-15 show the capacity factor for Banner Mountain for the Base scenario and High Renewable scenario for both the DA and RT runs. The capacity factor ranges from 17.7% for the Base scenario DA to 29.3% for the High Renewable RT case. This is very much in line with what is expected—the plant runs more when there is more renewable energy, especially solar—which is consistent with other studies on storage.

The utilization rate is the percentage of hours throughout the year the PSH plant is either pumping or generating and is shown in the bottom two rows of Table 8-15. The utilization rate ranges from 54.7% to 75.4% and is higher for the High Renewable scenario. Although the capacity factor only includes the generation, the utilization rate also considers the pumping time, which is more than 50% of the PSH's activities, since the efficiency rate is 80%.

Table 8-15 Capacity Factor and Utilization Rate for Banner Mountain Plant

Metric	Interval	Base Scenario (%)	High Renewable (%)
Capacity Factor	DA	17.7	23.1
	RT	20.4	29.3
Utilization Rate	DA	54.7	65.3
	RT	58.0	75.4

8.2.5.9 Ancillary Services

An important function of generation on the grid is to provide ancillary services. For this analysis, we focused on spin and regulation. Spin is required to respond to a change in the grid within 10 minutes, while regulation must respond within 5 minutes. Banner Mountain was able to provide ancillary services to several locations, including California and Washington state. However, because regulation and spin prices are low in those locations, it is not economically beneficial for Banner Mountain to provide spin or regulation there. Instead, the model chose to have all ancillary services provided in the BS_PACE region, which covers all of PacifiCorp's service area in Idaho, Wyoming, and Utah.

Table 8-16 shows the type of ancillary service, the provision in megawatt-hours over the year, the model price, the capped price, the model revenue, and the capped revenue. In the model, there is a penalty of $6,500/MW for not meeting the regulation requirement and a $6,000/MW penalty for not meeting the spin requirement. This incentivizes the model to meet the ancillary service requirements. Sometimes the model will make the choice to not start new units and instead pay the high penalty. In the real world, the cap on ancillary services is lower, generally around $1,000/MW (Market Analysis and Forecasting, 2019). We used this cap to better calibrate the revenue numbers. Ancillary service revenues were highest in the High Renewable DA run ($40 million) but came down to $10 million after the cap was applied.

Table 8-16 Ancillary Services Provided by Banner Mountain Units: Average Price, Theoretical Real-world Price, and Theoretical Ancillary Revenue

Case	Ancillary Service Type	Interval	Provision (MWh)	Model Average Price ($)	Capped Average Price ($)	Model Ancillary Revenue	Capped Ancillary Revenue
Base Case	BS_PACE Reg	DA	148,095	4.09	2.51	911,724	600,148
	BS_PACE_Spin	DA	206,045	4.09	2.51	605,338	480,690
	BS_PACE Reg	RT	149,811	13.20	12.91	3,796,350	3,761,455
	BS_PACE_Spin	RT	209,184	13.27	12.98	4,140,873	4,123,907
High Renewable	BS_PACE Reg	DA	156,304	33.36	9.54	17,498,484	4,501,030
	BS_PACE_Spin	DA	202,534	33.36	9.54	23,116,171	5,605,997
	BS_PACE Reg	RT	125,294	48.90	40.99	14,184,095	10,750,328
	BS_PACE_Spin	RT	255,296	50.19	42.20	17,809,715	13,014,294

8.2.5.10 Valuation of "Service"

The addition of Banner Mountain PSH plant had a value of $11 million to $42 million in production cost benefits, consisting of start cost reductions and fuel cost reductions. The value of Banner Mountain on the system increases in the RT runs and in the High Renewable scenario.

There are also benefits to the system that were captured but not valued in this analysis, namely reduction in emissions and reductions in curtailments.

The value of ancillary services was also calculated using the provisions and theoretical real-world prices (based on CAISO actual prices). The payments to Banner Mountain for ancillary services were about $1 million to $10 million in spin and regulation in the DA runs.

8.2.5.11 Summary of Results

The inclusion of the Banner Mountain plant generally benefits the generation system. This can be seen in the reduction in production costs, start costs, and fuel costs. It is also evident in the reduction in emissions and curtailment. These benefits increase in the RT runs as well as in the High Renewable scenario. Ramping is more affected by other factors and therefore does not seem to respond to the inclusion of Banner Mountain.

The utilization for Banner Mountain, as seen with the utilization factor and capacity factor, also increases with the RT and High Renewable scenarios. For ancillary services, Banner Mountain provides about $1 million to $40 million in spin and regulation in the DA runs.

8.2.6 Conclusion

Banner Mountain provides a variety of benefits to the grid, including production cost reductions as well as emissions and curtailment reductions. As mentioned previously, these benefits increase in the RT runs as well as in the High Renewable scenario. Although this study only looked at renewables up to about 40% of total generation, it would stand to reason Banner Mountain would increase its benefit the system under higher renewable penetrations.

8.2.7 References

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8.3 Energy Arbitrage

8.3.1 Overview of the Analysis

This section provides the energy arbitrage valuation results for the BMSP. The goal of the energy arbitrage valuation study is to assess the monetized value of the BMSP's contribution to system reliability in short-term operations through load leveling. The future power system generation portfolios under two future cases (i.e., Base and High Renewable cases) are obtained from the capacity valuation study performed by Argonne and the production cost simulations conducted by NREL. We evaluate the value of energy arbitrage using two approaches:

- **System benefit analysis**[1]—In this approach, we use production cost simulation results to assess the value of PSH energy arbitrage operations from a system perspective. The value of energy arbitrage (i.e., production cost savings) can be estimated by comparing the total system production costs in two cases: (1) with, and (2) without the Banner Mountain PSH plant. The results show that the BMSP can provide production cost savings in all future cases. The total estimated annual system benefit (i.e., avoided cost of production) is between $11.3 million and $24.8 million in the Base case and $26.4 million and $42.9 million in the High Renewable case.

- **Asset owner benefit analysis—**This approach provides the value of energy arbitrage from the perspective of asset owners based on the difference between the value of PSH electricity generation and the cost of energy used for pumping. The estimated annual profit of the BMSP is between $22.6 million and $51.2 million in the Base case, and $32.7 million and $203.4 million in the High Renewable case.

The results show a higher utilization rate of the Banner Mountain PSH plant and higher production cost savings in the High Renewable case. This indicates that the value of PSH may become increasingly important in future power systems with high penetration of VRE resources. In addition, the cases with 5-minute time resolution show the importance of considering a finer time resolution in assessing the value of energy storage that has a high ramping capability.

8.3.2 Background on Energy Arbitrage

Energy arbitrage refers to the operation of energy storage facilities that generate electricity when electricity prices are high and consumes electricity when prices are low. Because this type of operation reduces the net system load during peak hours and increases the load during off-peak hours, it is also often referred to as load leveling or load shifting.

Energy arbitrage operations allow the system to dispatch the Banner Mountain PSH plant as peaking capacity and reduce the need for expensive peaking generating units. Therefore, PSH operation during the peaking hours will significantly reduce the cost of electricity generation during those hours. The cost savings during peak hours will be partially offset by increased system production costs during the off-peak periods when additional electricity will need to be generated by the system to provide PSH pumping energy. However, because pumping energy is

[1] The production cost savings are also reported in Section 8.2.

typically provided by low-cost baseload units or by renewable generation, the value of PSH energy generated during the peak period will outweigh the value of energy used for pumping during the off-peak period, even considering the 20–25% energy losses due to PSH round-trip cycle efficiency.

8.3.3 Valuation Methodology

The goal of the energy arbitrage valuation study is to assess the monetized value of the BMSP's contribution to system reliability in short-term operations through load leveling. We evaluate the value of energy arbitrage using two approaches:

- **System benefit analysis**—In this approach, we use production cost simulation results, performed by NREL, to assess the value of PSH energy arbitrage operations from the system perspective, as shown in Figure 8-37. Production cost simulations typically dispatch the Banner Mountain PSH plant as peaking capacity when the marginal costs of electricity generation in the system are high and use the plant as load in pumping mode when the marginal costs of electricity generation are low. Because the operation of the Banner Mountain PSH plant as peaking capacity will reduce the need for the operation of expensive peaking generating units, the PSH operation during the peaking hours will significantly reduce the cost of electricity generation during those hours. Therefore, the value of energy arbitrage (i.e., production cost savings) can be estimated by comparing the difference in the total system production costs in two cases: (1) with, and (2) without the Banner Mountain PSH plant.

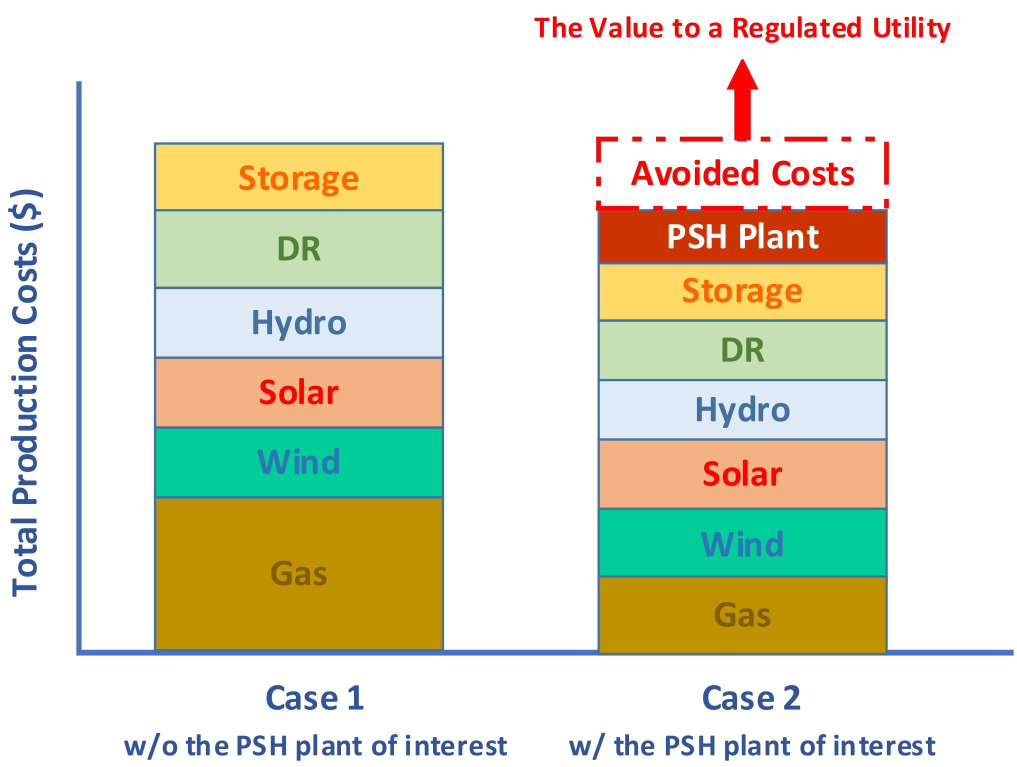

Figure 8-37 Example of Production Cost Savings

- **Asset owner benefit analysis—**This approach provides the value of energy arbitrage (i.e., profit) from the perspective of asset owners based on the difference between the value of PSH electricity generation and the cost of energy used for pumping, as shown in Figure 8-38. The market revenue can be calculated using the pumping and generating schedule and the LMPs from the production cost simulations.[1]

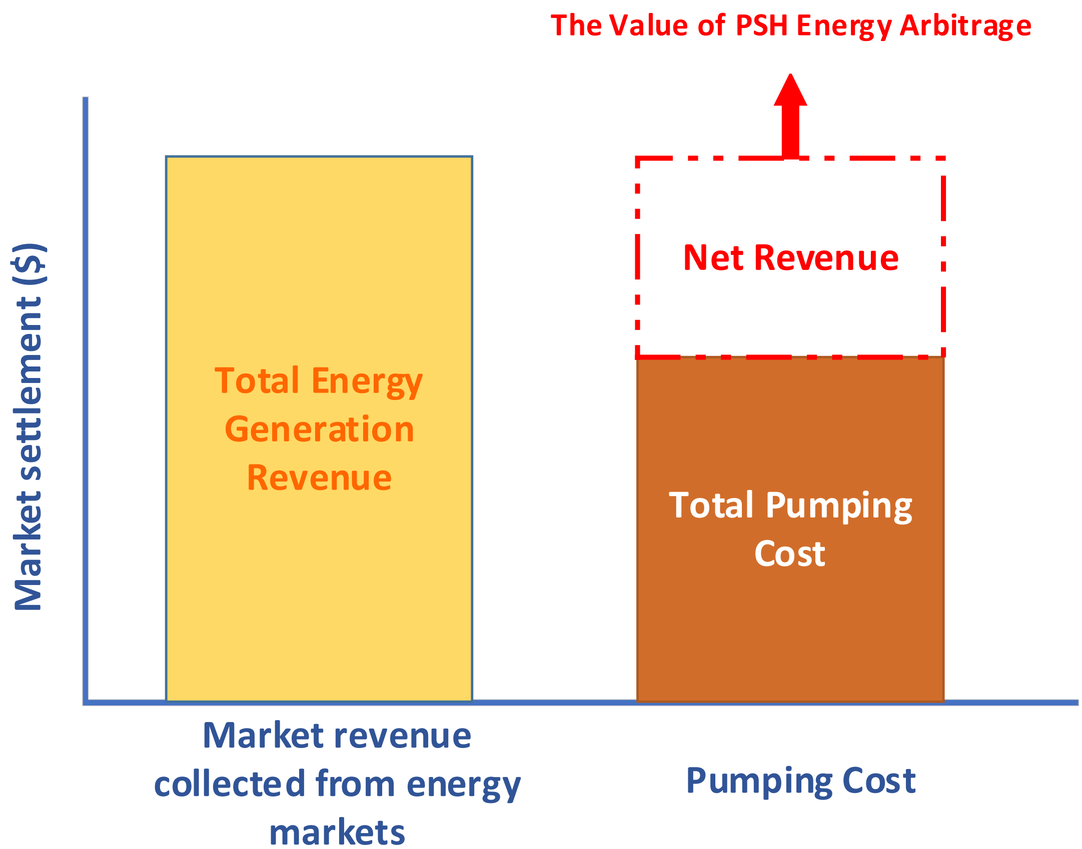

Figure 8-38 Example of Energy Arbitrage Profit

8.3.4 Analysis

8.3.4.1 Overall Design of Study

We estimate the potential energy arbitrage value of the BMSP in the future power system. The future power system generation portfolios are developed by Argonne using AURORA for the capacity valuation study. Then, the production cost simulations are performed by NREL using PLEXOS. Finally, Argonne quantifies the energy arbitrage values using the generation and pumping schedules and prices for energy from the production cost simulation results.

[1] The simulated LMPs are a proxy for market clearing prices. Future market clearing prices may differ from the modeled LMPs for a number of reasons, including bidding practices, building of opportunity costs into bid prices, and generating capacities being reserved for non-market purposes. Therefore, caution should be used when interpreting the results, because the estimated values may not reflect the actual market profit.

8.3.4.2 Scenarios and Assumptions

Two cases, Base and High Renewable, are developed to simulate costs. The main difference between the Base case and the High Renewable case is the generation portfolio. The Base case uses the reference generation portfolio developed by Argonne using AURORA. The High Renewable case has increased wind and solar capacity, along with additional coal plant retirements. In addition, the production cost simulation study considers hourly and 5-minute time resolutions.

8.3.4.3 Summary of Results

We first evaluate the value of PSH energy arbitrage operations from the system perspective (i.e., production savings). The production cost simulations typically include several terms in the objective functions. In this study, we consider the fuel and startup costs in assessing the production cost savings. Table 8-17 summarizes the production cost savings. The results show that the BMSP can provide production cost savings in all future cases. In particular, the results show higher production cost savings in the High Renewable case. This result indicates that the production cost savings provided by PSH may become increasingly important in future power systems with high penetrations of VRE resources. In addition, the cases with 5-minute time resolution show higher production cost savings than the cases with hourly time resolution. This trend shows the importance of considering a finer time resolution in assessing the value of energy storage that has a high ramping capability.

Table 8-17 Production Cost Savings Results

Cost Savings	Base Case (Hourly)	High Renewable (Hourly)	Base Case (5-minute)	High Renewable (5-minute)
Reduction in Fuel Costs ($M)	3.1	8.9	7.8	11.4
Reduction in Start-up Costs ($M)	8.2	17.5	17.0	31.5
Annual Avoided Costs ($M)	11.3	26.4	24.8	42.9

Second, we estimate the potential energy arbitrage profit of the BMSP as presented in Table 8-18. The estimated energy arbitrage profit is between $22.56 million and $51.21 million in the Base case, and $32.64 million and $203.35 million in the High Renewable case. The BMSP's utilization rate increases with (1) the increasing variable renewable resources capacity in the system and (2) the consideration of a finer time resolution (i.e., 5 minutes).

Table 8-18 Annual Energy Arbitrage Profit Results[1]

Parameter	Base Case (Hourly)	High Renewable (Hourly)	Base Case (5 min.)	High Renewable (5 min.)
Annual Generation (GWh)	667.69	869.75	769.75	1,104.55
Annual Pumping (GWh)	835.0	1,087.21	962.64	1,380.72
Annual Generation Revenue ($M)	39.96	52.00	84.56	268.49
Annual Pumping Cost ($M)	17.39	10.35	31.52	59.04
Energy Arbitrage Profit ($M)	22.56	32.64	51.21	203.35

8.3.5 Conclusions

This study estimates the potential energy arbitrage value of the BMSP in the future power system. The future power system generation portfolios under two future cases (i.e., Base and High Renewable) are obtained from the capacity valuation study performed by Argonne and the production cost simulations conducted by NREL.

This study shows that the BMSP can provide production cost savings while achieving positive net revenue in all future cases as follows:

- System benefit (i.e., production cost savings)—The results show that the BMSP can provide production cost savings in all future cases. The total estimated annual system benefit (i.e., avoided cost of production) is between $11.3 million and $24.8 million in the Base case and $26.4 million and $42.9 million in the High Renewable case.

- Asset owner benefit (i.e., energy arbitrage profit)—The estimated annual profit of the BMSP is between $22.56 million and $51.21 million in the Base case, and $32.65 million and $203.35 million in the High Renewable case.

The results show the increasing value of long-duration energy storage technology when the system has high VRE resource capacity. In addition, the cases with the 5-minute time resolution show the importance of considering a finer time resolution in assessing the value of energy storage that has a high ramping capability in a system with high VRE resource capacity.

8.4 Power System Stability Valuation

Power system stability studies are required for both planning and operating the power grid. Furthermore, any new interconnection planned or proposed in the power grid should be studied extensively for various criteria to ensure the practicality and feasibility of the proposed interconnection, and to ensure there are no detrimental impacts on the existing stability and reliability of the power grid. As such, the following steps must be considered for any proposed interconnection to the power grid:

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[1] Note that the pumping schedules in the 5-minute runs are adjusted in post-processing to correct the inaccurate RTE caused by the modeling limitation in PLEXOS.

- Feasibility Study—Performed to assess the practicality and cost of incorporating the proposed generation unit to the power grid. It includes capacity expansion studies and PCM.

- System Impact Study—A comprehensive regional analysis of how the proposed generation units would affect system operation. This study includes dynamic stability studies, network congestion studies, and contingency analysis.

- Interconnection Facilities study—Identifies control equipment and infrastructure needed for interconnection of the proposed generation unit (e.g., substation design study).

As the interconnection of renewable energy resources in the grid increases, the need to understand the implications of a generation source on overall system reliability becomes even more important. To maintain reliability and resiliency of the bulk power system against both expected and unexpected RT disruptions and changing conditions, power systems should be stable for given operating conditions. The stability of a power system is defined by an IEEE/CIGRE Joint Task Force on Stability Terms and Definitions as:

> *The ability of an electric power system, for a given initial operating condition, to regain a stable operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact* (Kundur, 2004).

The ability of the electric power system to regain a stable operating equilibrium following the fault is highly dependent on the response and/or service of various assets within the power system. The value of power system stability services is primarily derived from a unit's contribution to maintaining synchronism among generators and maintaining systemwide frequency and acceptable voltage of the synchronous interconnection. This section focuses on dynamic stability studies to assess the impacts of PSH interconnection on power system stability.

The power system stability valuation approach presented here quantifies the impact of PSH on various attributes of power system stability through the services they provide. PSH plants can potentially contribute stability services at both the machine level and as a service to the larger electric grid. Thus, stability services provide value by automatically and autonomously controlling deviations of synchronism, frequency, and voltage: (1) before a particular synchronous machine exceeds limits to remain in equilibrium with other synchronous generators and trips offline, (2) before grid imbalances trigger frequency or voltage protection to enact load-shedding of a subset of customers, and (3) before larger grid stability concerns result in islanding or widespread blackouts.

The relevant value streams for stability services have been determined using the simulation-based methodology under various operational scenarios. Because some of the stability services from a PSH plant are not currently directly compensated through market mechanisms in both regulated and restructured markets, parallels are drawn in terms of existing market mechanisms to quantify the value of the stability services.

8.4.1 Overview of the Analysis

The primary objective of the technoeconomic study is to quantify both the stability implications and the monetary incentives that can be earned for providing various stability services. The proposed PSH plant's contribution to grid stability is computed under various operating scenarios (e.g., heavy load, light load, high wind penetration) with varying types of disturbances (e.g., loss of generator, fault on transmission line). The economic value of the stability services is, in part, a function of the influence that the proposed PSH plant has on the likelihood of a grid event or changes to reliability when an event occurs.

Results from the power system valuation technoeconomic studies show that the presence of a PSH plant at the proposed location beneficially impacts the various stability attributes under consideration, and proper allocation of the various services can help maximize the financial revenues that can be generated through PSH participation in ancillary services markets.

8.4.2 Background on Service

The overall stability of the power system is a result of many interconnected physical processes across multiple assets and at multiple time scales within the power system. For the purpose of stability valuation from a proposed PSH unit, the stability attributes and services shown in Figure 8-39 can be considered (Kundur et al., 2004). These stability attributes and services to maintain and/or enhance stability are important to overall system stability and are largely related to the components and capabilities of a PSH plant.

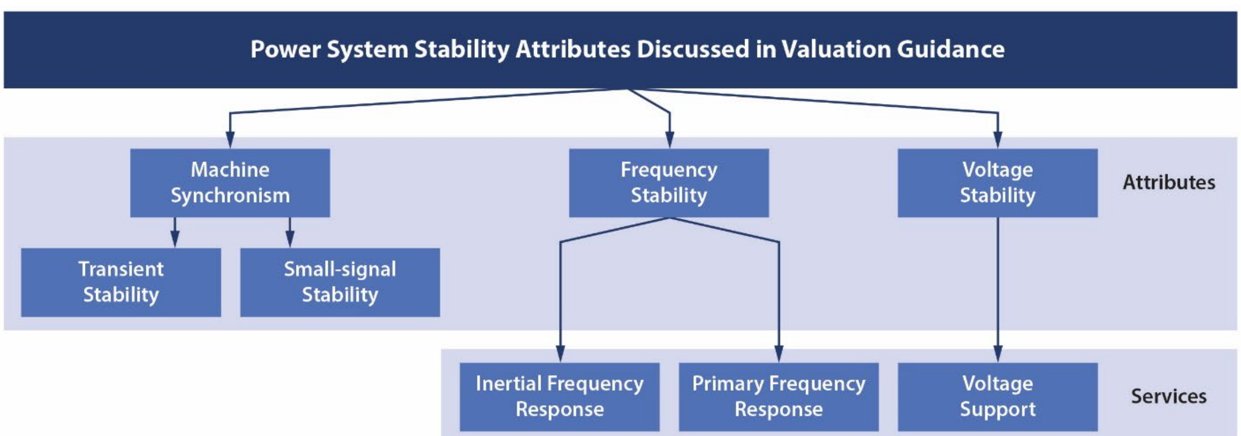

Figure 8-39 Classification of Power System Stability Attributes and Services

Machine synchronism refers to the generator rotor's ability to remain synchronized with other generators under quiescent disturbances, as well as when a larger disturbance event occurs. Conventional PSH plants, as well as modern PSH plants like ternary and quaternary PSH plants, interface with the grid as synchronous machines while operating in turbine mode. Because they interact with the grid as a synchronous machine, in turbine mode, PSH plants can contribute to maintaining synchronism with other generating units in the grid. This is achieved through the synchronizing torque, which acts on the turbine shaft of the PSH plant as soon as the rotational speed of the PSH shaft deviates from the system synchronous speed.

For adjustable PSH units, whose generator shaft speed can deviate away from synchronous speed, the contribution to overall system synchronism comes through the control methodology implemented in them. Adjustable-speed PSH units use phase-locked loops to obtain the phase angle of the grid voltage and to remain in sync with grid. Transient stability of the grid refers to the ability of the grid machines to maintain synchronism in the face of large instantaneous disturbances, including generator or load outages, transmission lines faults, and other disturbances. PSH units support the grid during transient stability events by properly modulating their power output according to the nature of disturbance and through their inherent inertia—that is, for the PSH units with a synchronous generator interface.

Conversely, small-signal stability is the ability of the grid machines to maintain electromechanical synchronism in the presence of small disturbances. PSH plants affect the small-signal stability of the overall system through the inertia, both actual and synthetic, via controls for adjustable-speed PSH, and control topology implemented in them. PSH plants aid transient and small-signal stability inherently during normal operation. There are no standard services associated with the small-signal and transient stability attributes that could be scheduled and coordinated by the grid operators.

Inertial frequency response principally refers to the sub-second response resulting from the machine transferring mechanical kinetic energy into electrical energy. This service is critical because it provides non-inertial frequency controls the time to respond. Inertial frequency responses from PSH units can come from their inherent response to changes in load and generation (for PSH units with a synchronous generator interface) or their implementation of inertia emulation (for adjustable-speed PSH units with a converter interface). No system operator in the United States currently pays for inertial frequency response. However, with the rise in converter-interfaced renewable generation, procurement of inertial frequency response through inertia emulation by using some of the kinetic energy in the rotating turbines could be a monetized service in the near future.

Primary frequency response refers to the ability of the prime mover controls to respond to a change in frequency and the ability of these systems to support automatic and autonomous frequency correction. It includes governor response, provided by single-speed synchronous PSH generators, and fast frequency response provided by adjustable-speed non-synchronous generators. Like inertial frequency response, primary frequency response has not been historically compensated by system operators in the United States. However, with the advent of NERC BAL-003-1, which requires BAs to maintain interconnection frequency within defined bounds, some BAs and ISOs are paying to transfer their obligation to third parties (Balducci et al., 2017). CAISO, for example, has primary frequency response contracts with SCL (CAISO, 2016a) and BPA (CAISO, 2016b).

Voltage support refers to the ability of the PSH unit (and other components of the relevant power grid system) to correct voltage deviations through reactive power support, thus enhancing overall voltage stability of the system. PSH plants, depending on their operating conditions and capacity (irrespective of their type and operating mode) can exchange reactive power with the grid and help the local grid maintain voltages within the allowed band. This service ensures that both the customer's and the power system's equipment can function properly. In the United States, generating units are either not compensated for installed reactive power capability (in CAISO), are paid based on a fixed rate (NYISO, ISO-NE), or are using a fixed-cost recovery approach (PJM) (Anaya, 2020).

To understand the overall beneficial impacts of PSH, both the services provided by the PSH units and how those services impact stability attributes should be studied. For example, by providing services like inertial frequency response and primary frequency response, PSH units can enhance the frequency stability of the system. The enhancement in frequency stability can be quantified using various metrics associated with frequency stability. The number of services provided by the PSH unit can also be quantified to evaluate the benefits associated with the service provided.

8.4.3 Valuation Methodology

8.4.3.1 Stability Metric Assessment

The valuation methodology used to evaluate the stability service varies based on the stability attribute under consideration. For the stability valuation of PSH, a digital simulation can be used. Digital simulations help in evaluating the power system response to a wide variety of disturbances (i.e., inputs) in the proposed state-space model (e.g., normal variations of loads, faults, trips). The following assessment methodologies were used for each of the power system stability attributes and stability services:

- Prony Analysis to estimate damping ratio—To assess the impact of the PSH plant on small-signal stability of the system, various ringdown events (e.g., self-clearing three-phase fault) were simulated. Small signal stability analysis helps determine the behavior of the system around an operating point and provides insight about the damping and frequency of electromechanical oscillations in the system. For stable operation of the system, all electromechanical oscillations must be damped out as soon as possible. Damping ratio is a metric that can be used to assess how electromechanical oscillations in the system damp out. Prony analysis extracts the damping ratio information from the system frequency oscillation signals by decomposing the signals into decaying sinusoids (Hauer et al., 1990). Using Prony analysis and PMU data from post-disturbance ring down events, PSH operators, planners, and/or developers can estimate the modes of the system and hence develop an understanding of how a PSH plant can be used strategically to improve damping and the overall stability of the system.

- Digital simulation results-based assessment of CCT and level of contingency withstood to understand the impact of PSH on transient stability of the system—The simulation environment can be used to assess faults at various locations and at various magnitudes, lengths, and types to determine the type of events and their duration, which can cause the machines in the system to start losing synchronism. CCT is the maximum time during which a disturbance can be applied without the system losing its stability. The aim of this calculation is to determine the characteristics of protections required by the power system. To determine the CCT of the test system or the unit under consideration using the simulation methodology, the user can run multiple contingency scenarios with variable fault durations to determine the duration above which the machines in the system lose synchronism. The minimum CCT based on the real power delivered or consumed by the PSH unit observed in the range of scenarios from the test matrix can be computed using dynamic simulation runs using industry available simulation tools. The other metric that has been used to evaluate the value of PSH related to transient stability of the system is the level of contingency withstood. This metric is estimated by performing multiple simulation runs with different types of disturbances (e.g., loss of generators of different sizes from largest to smallest) and determining at what point the synchronous generators in the system lose synchronism and the overall system loses its stability.

- Digital simulation results-based computation of ROCOF and frequency nadir/zenith for a given event with and without PSH—This can be used to assess the impact of PSH on inertial frequency response. To compute ROCOF using the simulation results, pre-disturbance frequency at the center of inertia (COI) and post-disturbance frequency after a certain time before the frequency nadir or zenith is reached is used.

- Digital simulation results-based computation of arresting period rebound period and stabilized steady state frequency at the end of 20–25 seconds for a given event with and without PSH to assess the impact of PSH on primary frequency response.

- Digital simulation-based analysis of local voltage sag and voltage recovery in terms of buses below the allowed voltage threshold after the disturbance with and without PSH to assess the impact of PSH voltage support on voltage stability of the system.

8.4.3.2 Financial Assessment of Stability Services

We based the financial assessment of the stability services on either the existing market mechanism available for various stability services or on certain sets of assumptions drawn from existing market mechanisms. For example, the cost evaluation of the frequency response is based on the existing market mechanism between CAISO and neighboring BAs for frequency regulation. Similarly, the cost is evaluated from the unserved energy perspective for loss of load, which helps to evaluate the financial merits of PSH operation in the system.

8.4.4 Analysis

The stability valuation study quantifies the proposed PSH plant's contribution to grid stability under various faults (for example, an N-1 contingency, as well as others of interest to the NOTA awardee), disturbances, and scenarios with high wind power generation within the BA area. Based on this assessment, an estimate of the grid value of the proposed PSH plant to power system stability is created. Finally, the services provided by the PSH unit are quantified in terms of revenue that can be generated by participation within the ancillary services market.

8.4.4.1 Overall Design of Study

Among the types of power system analysis tools that can be used to study the value of stability services and their impact on overall system stability (as shown in Figure 8-40), this study chose to use a digital non-RT simulation-based approach using the Siemens Power System Simulator for Engineering (PSSE) tool. This approach helps to make design and implementation of test setup easier for very large-scale power systems. This approach also provides a seemingly high-fidelity model of both the power system and its components, and is the current state-of-the-art used by power system engineers to perform dynamic stability assessment of the power system.

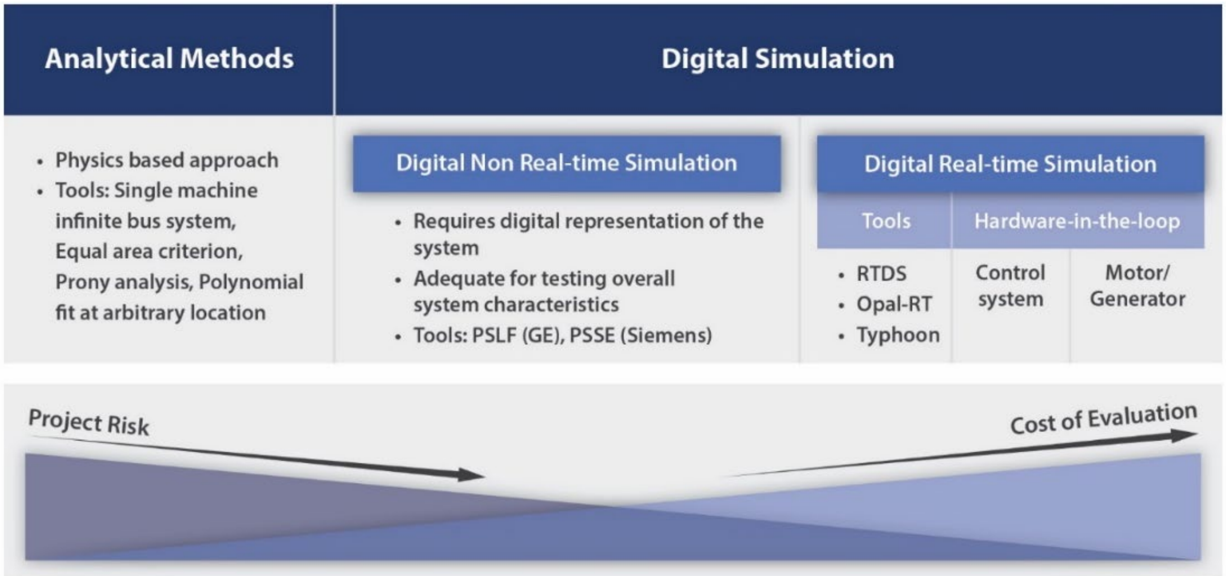

Figure 8-40 Progression of Stability Valuation Approaches from Least to Most Computational and Resource Exhaustive

A series of dynamic simulations using the digital non-RT simulation platform was performed, and the results were used to evaluate the impact of the stability services of the proposed PSH plant on the power system stability attributes in connection with the relevant portion of the electric grid. Different grid events were studied, including line faults, generator outages, transmission line outages, and sudden changes in loads. Varying penetrations of wind generation were also incorporated into the analysis. The analysis approach taken for the technoeconomic valuation of the stability services can be summarized with the following steps:

- Selection and development of various scenarios of interest—This is the first step in the stability valuation of the PSH unit, in order to select and develop various cases of interest and relevance. Because the dynamic simulation study for stability valuation is based on a particular operating point, it is important to consider which scenarios are relevant among all the various possible operating scenarios. Some of the scenarios considered in the valuation study are summer peak load case, winter light load case, summer peak with high wind generation, and winter light load with high wind generation. These scenarios were selected based on the feedback from the NOTA awardees and the scenarios that interested them. Once the scenarios were selected, the base case model was modified to reflect the operating condition for the scenario considered. This modification involves changes in the load profile as well as generation profile within the system. The developed scenarios are discussed in detail in Section 8.4.4.2.

- Validation of model files created for each scenario—Once the scenarios have been identified and the base case file is modified based on the requirements of the scenario, the next step is to verify and validate the new scenario specific simulation models. Model validation involves performing load flow simulations and ensuring that the load flow converges, the voltage at the various buses within the BA and overall interconnection is within the allowed limits, the generation from various generating units are within their allowed limits, and none of the major transmission lines are significantly overloaded. The validation check ensures the scenario specific model does not have any inherent stability violation that can affect the conclusions drawn from the dynamic simulation studies. Once the load flow and system operating condition are validated, the scenario-specific model is checked for proper initialization of dynamic states. This process involves checking the initialization of the various states of the dynamic models of the generators and loads in the system and ensuring that no significant violation of states occurs. This can be done using the dynamic model initialization tool within the power system stability evaluation software (e.g., Siemens PSSE, General Electric Positive Sequence Load Flow software). Once the model is properly initialized, a flat-start run (dynamic simulation run without any disturbances) is performed for 15–20 seconds to ensure that the system operating condition is stable. Figures 8-41 and 8-42 demonstrate generator terminal voltage and generator rotor speed deviation, respectively, for all the generators within BPA for a flat-start run. Insignificant deviation at time $t = 0$ and $t = 20$ seconds demonstrates that the model is initialized properly and can be used for dynamic simulation for various contingencies and disturbances.

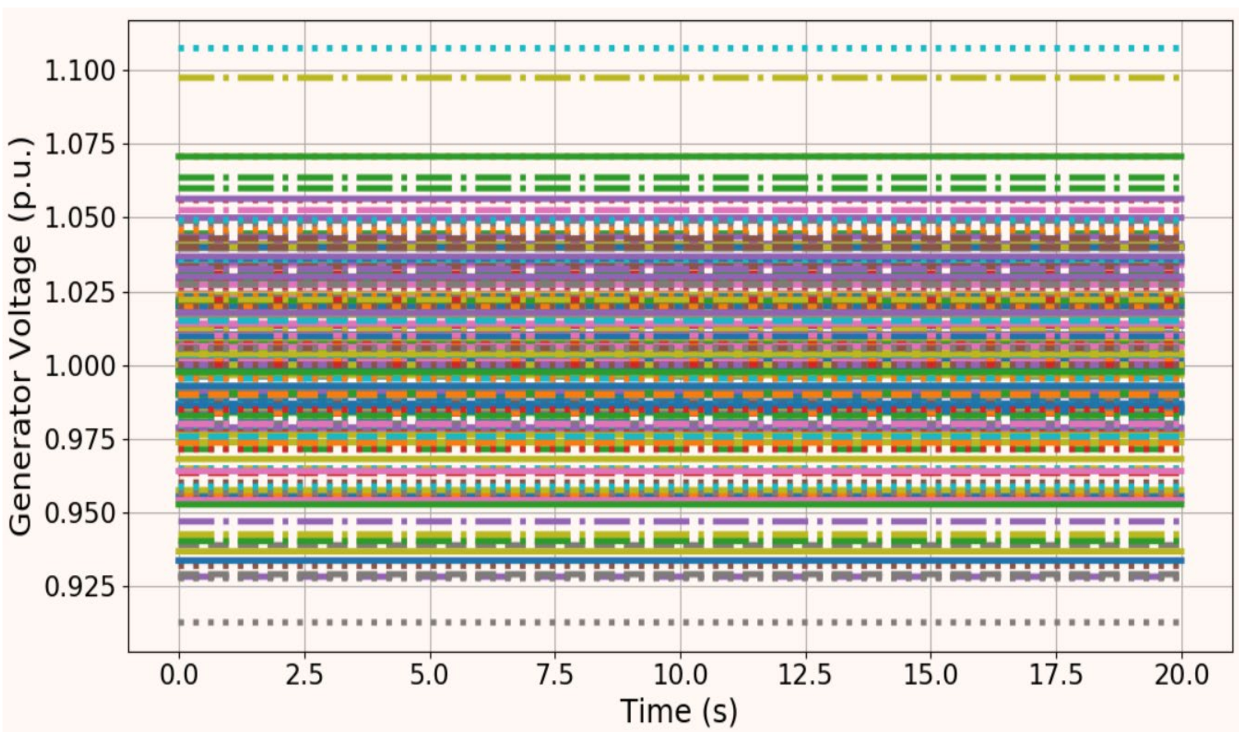

Figure 8-41 Generator Terminal Voltage for a Flat-Start Run

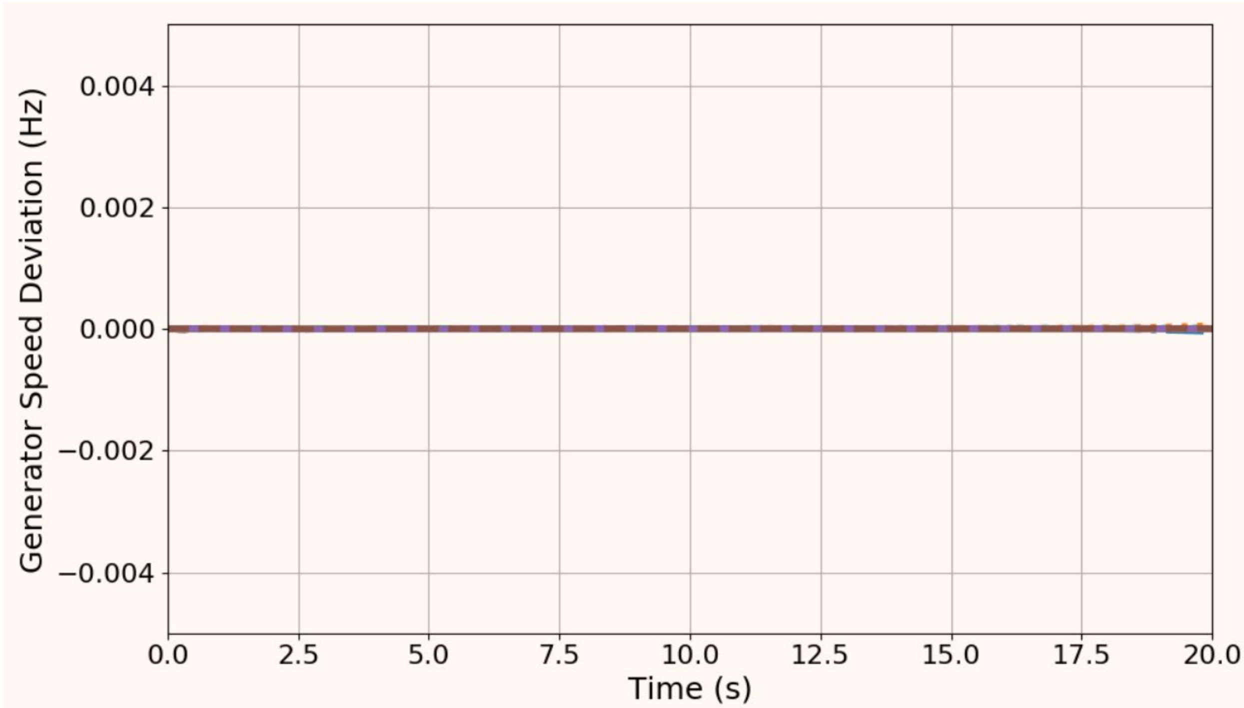

Figure 8-42 Generator Rotor Speed Deviation for a Flat-Start Run

- Identification of contingencies and disturbances of interest and relevance—The third step in the stability valuation approach is to identify contingencies and disturbances of interest for each of the scenarios considered. Selection of credible contingencies is of the utmost importance, in order to understand the impact of the interconnected PSH unit on power system stability and to quantify the metrics associated with various stability attributes. Power system stability analysis involves verifying the factors below, following various faults and disturbances in the system and their subsequent clearing:
    - Sufficient margin of transient angle stability and adequate damping of power swings;
    - No cascade tripping of system components (both load and generation);
    - Sufficient voltage stability margin; and
    - Sufficient recovery of frequency.

  When performing dynamic studies, contingencies should be selected in such a way that these factors can be adequately assessed, issues and unstable situations in the system can be identified, critical configurations can be recognized, operating constraints can be applied, and remedial actions can be planned. To identify the most severe contingency in the system, a user can start with the list of possible contingencies or scenarios that can occur in the system. With that information and the system model for an operating scenario, the user should perform PF analysis to obtain a “network solution” that consists of information about voltages at every bus and line flow in every line for each contingency in the list. The failure or outage of each element in the contingency list (e.g., loss of a generator or a transmission line) is simulated in the network model by removing that element. The resulting network is solved again to calculate the PFs, voltages, and currents for the remaining elements. From these analyses, the user can begin to understand how each contingency affects the different buses and components in the network. For example, for a fault case, during the fault, it can be observed that *n* number of buses are below a certain allowed voltage threshold, or *m* number of lines are operating at 120% or above their rated capacity. The user can then keep a tally of such violations for each contingency in their list; when they finish, they can review the results to rank the contingencies based on the severity of impact. This enables the user to identify the most severe or critical contingency in the system for which a dynamic simulation can be performed later. Based on the severe contingency identified, cases were developed for each scenario of interest and stability valuation studies were performed for each case considered. For each case developed for the Banner Mountain PSH unit, results were presented based on observations made within the PACE WY territory.

- Verification and validation of the results—Once the dynamic simulation studies for the cases considered are complete, the results should be analyzed, compared, and discussed with the multi-project team and NOTA awardees to ensure the validity of the results obtained and the conclusions drawn from the results. The results are quantified using metrics chosen for each stability attribute considered, and the technical value of the proposed PSH plants to system stability is established.

- Economic valuation of the proposed PSH plant—Once the technical value of the proposed PSH plant has been established using the metrics associated with the stability metric, the financial evaluation of the stability service provided by the PSH plant is performed. First the PSH plant's response after the disturbance is quantified. Then cost values are attached to the response/service provided based on the current market mechanism, if available. For cases where a market mechanism is not available, the financial incentives are estimated based on a current service that closely resembles the stability services considered in the current ancillary service markets.

8.4.4.2 Scenarios and Assumptions & Data Needs and Sources

The model development process for the stability valuation study starts with the base case model file. The simulation platform used for model development and dynamic stability valuation studies is Siemens PSSE. For all the studies performed for stability valuation, the base case uses the 2025 Heavy Summer case file obtained from the WECC system stability planning and interconnection database.[1] From the base case files, the following scenario files were generated for 2028:

- 2028 Heavy Summer
- 2028 Light Winter
- 2028 Heavy Summer with High Wind

[1] See https://www.wecc.org/SystemStabilityPlanning/Pages/BaseCases.aspx?.

- 2028 Light Winter with High Wind
- 2029 Heavy Spring

When developing the 2028 and 2029 scenario files based on the 2025 Heavy Summer base case file, the output from the PCM simulation runs from PLEXOS is considered. For the High Wind scenario, all available wind turbine generator models within the BA are brought to service at their rated capacity. Note that during scenario file generation, we assume that each BA balances its power generation, load, and power transfer with other balancing authorities.

The total load and generation profile within the PacifiCorp Wyoming (PACE-WY) region for the various scenarios developed is provided in Table 8-19.

Table 8-19 Generation and Load Profile Within PACE WY for Scenarios Considered

Scenario	Total Generation (GW)	Total Load (GW)	Total Wind (GW)
2025 Heavy Summer Case	9.24	5.26	0.13
2028 Heavy Summer Case	9.18	5.26	0.54
2028 Light Winter Case	7.68	3.71	0.54
2028 Heavy Summer with High Wind Case	8.82	5.26	0.95
2028 Light Winter with High Wind Case	7.25	3.71	0.95
2029 Heavy Spring Case	8.12	4.49	0.80

Once the 2028 scenario files are created, the next step is to add the PSH unit at the proposed location. For the Banner Mountain PSH unit, the specifications provided by the NOTA awardee were used. Because the Banner Mountain PSH unit was added to the 2028 scenario file, based on the operational mode (turbine or pump), a conventional coal-based power plant close to the vicinity of the proposed location of the Banner Mountain PSH was retired, or additional renewable energy resources were dispatched. The plant retirement decision for the turbine mode of operation was based on the EIA generation retirement data.

Various cases were designed for each scenario based on the stability attribute of interest and the operational condition of the Banner Mountain PSH unit. The following operational conditions were considered for the Banner Mountain PSH unit:

- Turbine mode of operation: 200 and 400 MW
- Pump mode of operation: 200 and 400 MW
- Banner Mountain PSH unit will have an installed capacity of ±400 MW.

The stability attributes, corresponding metric of interest and the case considered to quantify stability valuations are as defined in Table 8-20.

Table 8-20 Stability Attribute, Corresponding Metric Considered to Assess the Stability Attribute, Cases Studies Performed, and Technique Used to Compute Metric

Stability Attribute	Metric Considered	Case Study Performed	Technique Used
Small Signal Stability	Damping ratio	Self-clearing three-phase fault to generate ringdown oscillations	Prony analysis
Transient Stability	CCT	Fault close to unit under consideration and in major tie-lines	Vary the fault duration until generators in the system lose synchronism after fault is cleared
Frequency Stability	ROCOF, frequency nadir/zenith, arresting period, steady state frequency deviation	Loss of generation, loss of load	Simulation data-based technique by considering pre-disturbance and post-disturbance frequency
Voltage Stability	Number of buses above certain voltage threshold	Fault in major 500-kV substation	Count the number of buses above certain voltage threshold with/without voltage support from PSH units

The proposed technology for the Banner Mountain PSH unit is a Quarternary PSH unit. Because a dynamic model for the Quarternary configuration of a PSH unit was not readily available in the simulation tool used (PSSE) to perform dynamic simulation runs and stability studies, we used custom-built dynamic models (Feltes, 2014). In particular, the following two dynamic models were used to represent Banner Mountain PSH unit in turbine mode and pump mode of operation:

- Model of ternary PSH unit in turbine mode (pumped storage hydro ternary or PSHTN model)
- Model of converter-based storage DER in pump mode (distributed energy resource generator/converter model or DERAU1 model)

To justify the use of the above two models for representation of a Quaternary PSH unit, consider the configuration of a Quaternary PSH unit as shown in Figure 8-43 (Koritarov, 2013). As shown in Figure 8-43, the unit interfaces with the grid in the pump mode of operation via AC\DC\AC converters. The DERAU1 model readily available in PSSE was therefore used to emulate the operation of a Quaternary PSH in pump mode.

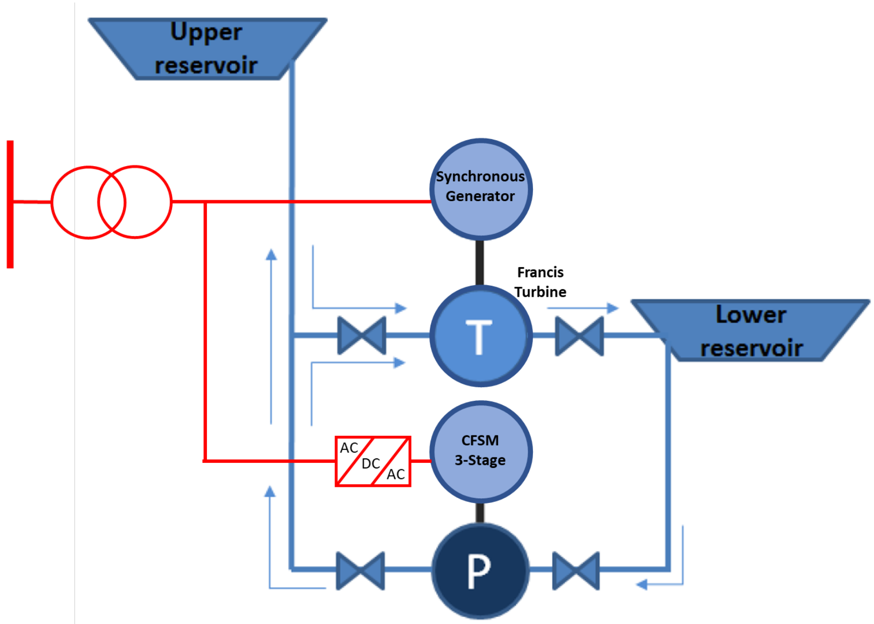

Figure 8-43 Schematic Diagram of Quaternary PSH Unit

8.4.5 Modeling Runs and Results

8.4.5.1 Small-Signal Stability

For small-signal stability evaluation, simulations were performed based on a ringdown event (self-clearing three-phase faults at various locations in the grid). The damping of low-frequency oscillation (frequency of oscillation below 0.6 Hz) was computed and compared for small disturbances at locations within PACE WY to excite the low-frequency oscillations.

Figure 8-44 compares the damping ratio of low-frequency oscillations for the cases considered for the 2028 summer peak scenario. We observe that Banner Mountain PSH operation in turbine mode has a better damping ratio, but lower or comparable damping ratio conditions during pump mode. In particular, the damping ratio is lowest when the Banner Mountain PSH unit operates at 200 MW in pump mode. This can be associated with the asynchronous nature of the Banner Mountain PSH unit in pump mode. Operation of the Banner Mountain PSH unit in turbine mode, even with displacement of existing synchronous generators in the system, causes the overall damping ratio of low-frequency oscillations to increase. This can be associated with the synchronous nature of Banner Mountain PSH during turbine mode, which helps damp low-frequency oscillations. For the pump mode, as the amount of synchronous generators in the system is kept constant and wind turbine generators are added to operate the Banner Mountain PSH unit in pump mode, we observe that the damping ratio for pump mode is higher than for turbine mode. However, adding asynchronous wind turbine generators causes the damping ratio to drop compared to the 2028 base case.

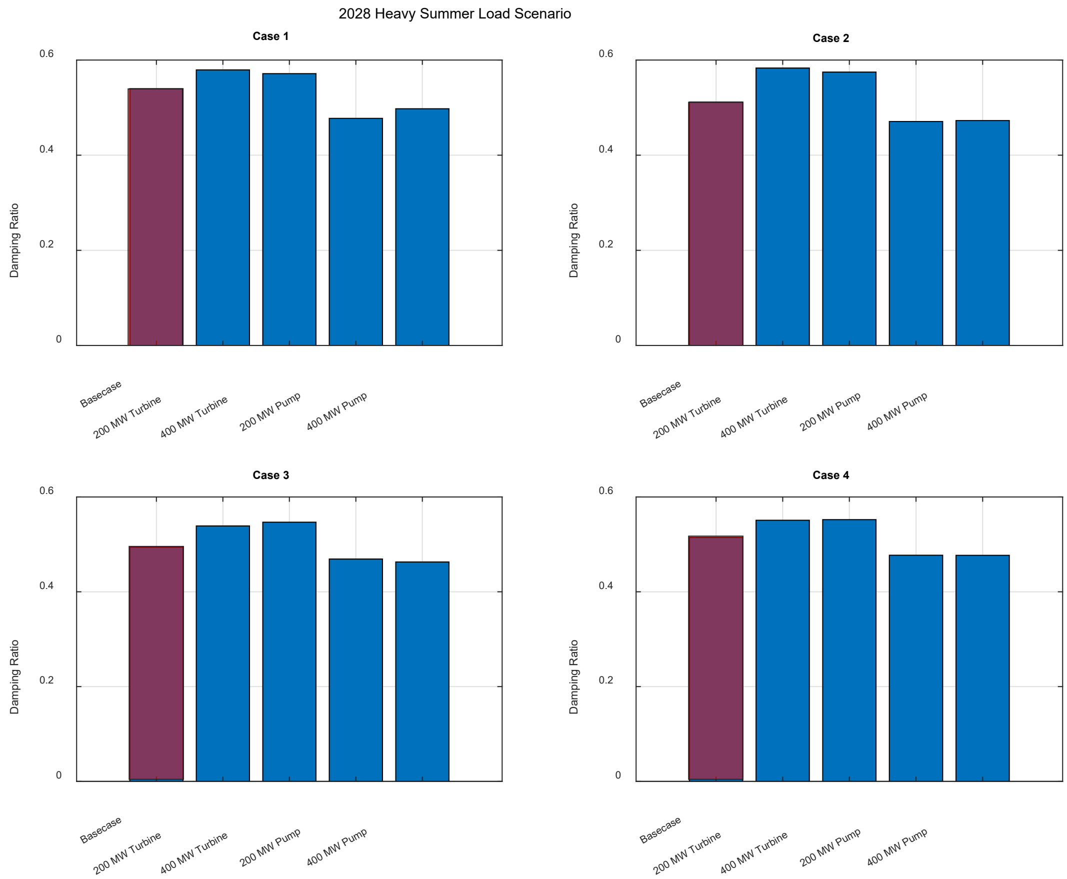

Figure 8-44 Damping Ratios of Low-Frequency Oscillations with and without Banner Mountain PSH Unit for the 2028 High Summer Load Scenario

Figure 8-45 compares the damping ratio of low-frequency oscillation with and without the Banner Mountain PSH unit for the 2028 high summer load scenario with high wind. For the high wind scenario, all available wind turbine generators within the PACE WY territory were brought online. To balance load and generation with PACE WY, coal-powered synchronous generators close to their retirement were taken offline. As synchronous generating units in the system are displaced by wind turbine generators in the system, the damping of low-frequency oscillation decreases compared to the 2028 high summer load case in Figure 8-43. When the Banner Mountain PSH unit operates in turbine mode in the high wind scenario, damping of low-frequency oscillations increases. However, in pump mode, the damping ratio decreases. The increment of damping ratio can be associated with the control associated with the synchronous mode of operation and changes in the system PF resulting from the addition of wind turbine systems displacing synchronous generators.

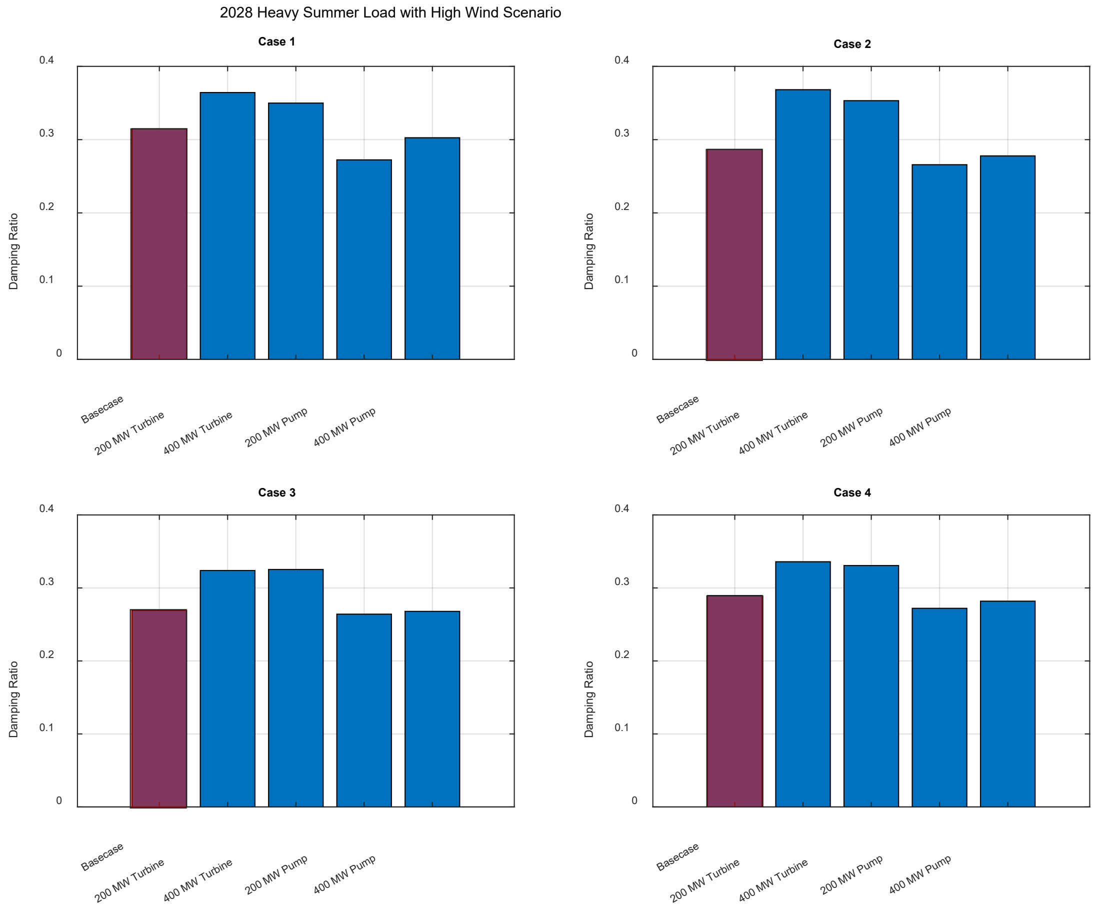

Figure 8-45 Damping Ratios of Low-Frequency Oscillations with and without Banner Mountain PSH Unit for the 2028 High Summer Load with High Wind Scenario

8.4.5.2 Transient Stability

To assess the impact of PSH on the transient stability of the system, the level of contingency withstood and average CCT were used as metrics. To determine the level of contingency withstood, the largest generator within the WECC territory was removed from the system during the simulation. The system stability was then observed to see whether the rest of the synchronous generators in the system could maintain synchronism and stabilize system frequency and voltage. For all the cases considered, the level of contingency withstood was observed to be N-1 stable. Irrespective of the PSH unit, the system could not withstand more than one of its largest generator trips in any of the operational scenarios.

CCT was determined by applying faults on major tie-lines between PACE WY and neighboring balancing authorities. We observed that for all the cases considered for various scenarios, the average CCT of the fault on major tie lines is better or comparable (by a few cycles) when the Banner Mountain PSH unit is operating in pump mode. CCT improves (by a few cycles) when the Banner Mountain PSH unit is operating in turbine mode. This could be associated again with the synchronous mode of operation of the Banner Mountain PSH unit in turbine mode and its ability to provide fault current.

Figure 8-46 compares the CCT for cases with and without Banner Mountain in operation for operational scenarios in 2028. For the high wind scenario with larger levels of wind generation within the PACE WY territory, the average CCT for a fault in a tie-line connecting PACE WY to neighboring BAs increases when the Banner Mountain PSH unit operates in turbine mode. Average CCT drops when the Banner Mountain PSH unit operates in pump mode and when there is a higher amount of wind generation in the system. With the increment of wind generation in the system, the number of generating units contributing to the fault and maintaining the system voltage drops along with overall system inertia, which results in a drop of CCT. The improvement of CCT while operating in the turbine mode enables the Banner Mountain PSH unit to provide voltage support. In addition, it enables the unit to provide fault current and to ride through the fault for a longer time. CCT decreases in pump mode because of the direction of PF in this mode. During pump mode, the Banner Mountain PSH unit continues to draw current from the system as opposed to contributing current to the fault, which causes CCT to drop.

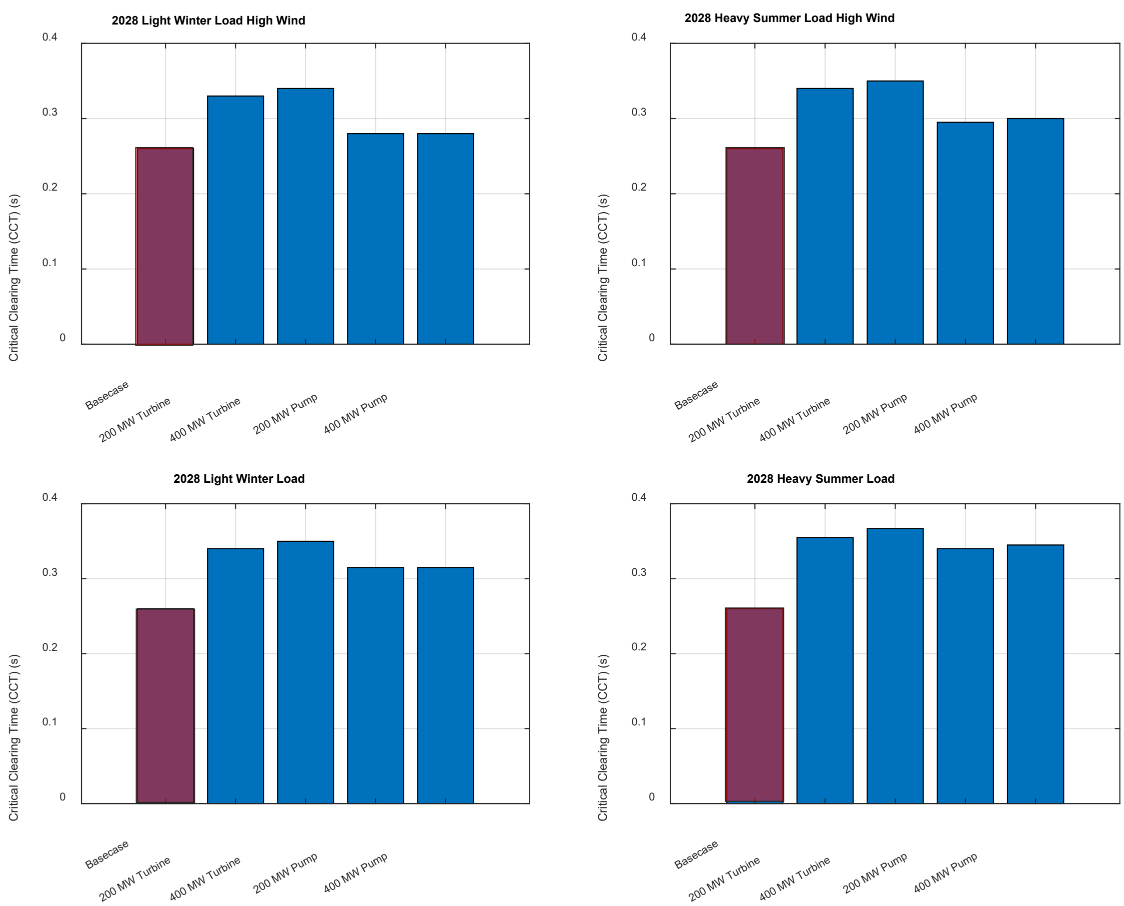

Figure 8-46 CCTs with and without Banner Mountain PSH Unit for Various Operational Scenarios

8.4.5.3 Frequency Stability

The Banner Mountain PSH unit's impact on the frequency stability of the system is evaluated based on its ability to provide fast frequency response and primary frequency response. The COI frequency of all generators within the PACE WY territory is used to compute the metrics associated with frequency stability: ROCOF, frequency nadir, arresting period and settling frequency deviations. The simulation case performed was the loss of largest generator within the BA. One such example for the 2028 winter light load scenario is shown in Figure 8-47.

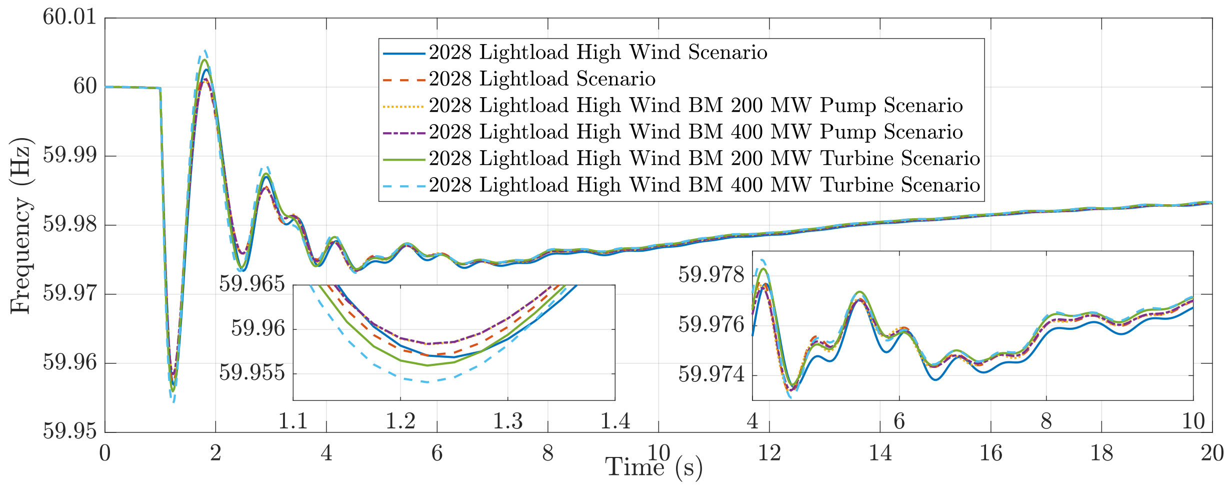

Figure 8-47 COI Frequency Response for Loss of Largest PACE WY Generator with and without Banner Mountain PSH for 2028 Winter Light Load Scenario

Figure 8-47 shows that, following the loss of the largest generator within PACE WY, the frequency response is worse in the high wind scenario in terms of frequency nadir, arresting period, and setting frequency. During high wind, operation of the Banner Mountain PSH unit beneficially affects the frequency response of the system. We see that fast frequency response from the Banner Mountain PSH unit helps to arrest the initial ROCOF, even with higher wind and lower synchronous generation in the system.

Figure 8-48 shows that active power modulation by the Banner Mountain PSH unit is similar in both pump and turbine mode. The active power modulation from Banner Mountain PSH following the change in system frequency results in a better ROCOF, arresting of frequency nadir, and eventually lower settling frequency deviation. ROCOF, frequency nadir, arresting period, and settling frequency for various scenarios are compared in Figures 8-49 through 8-52.

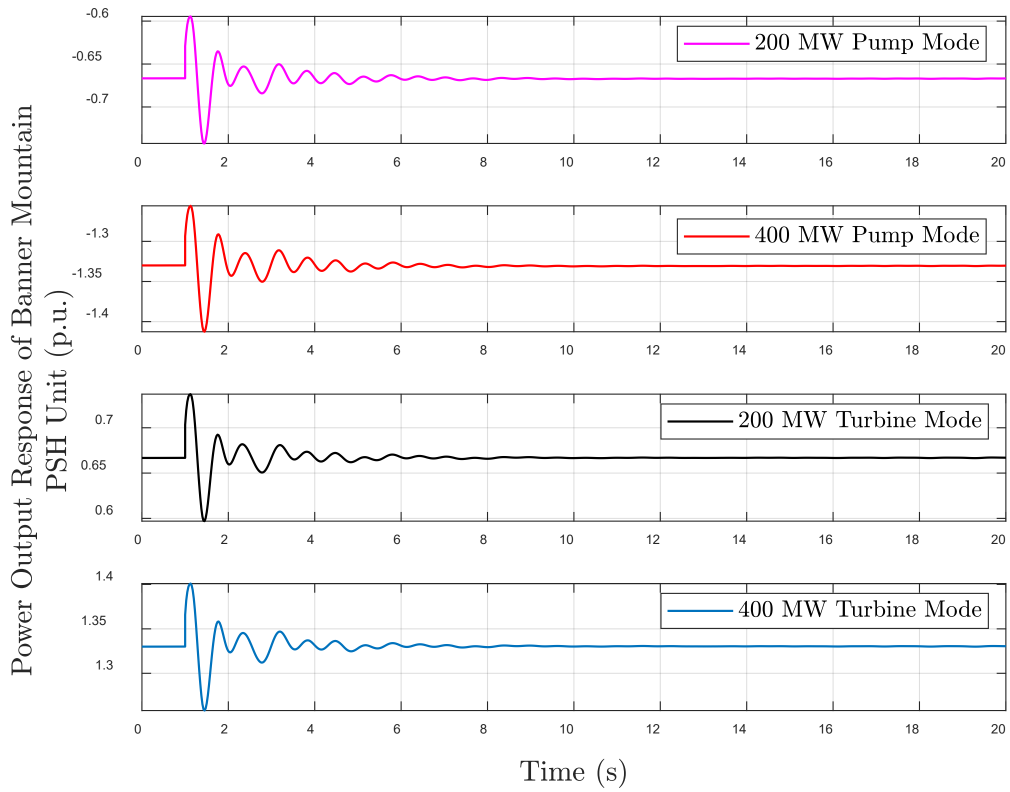

Figure 8-48 Power Output Response of Banner Mountain PSH Unit under Various Operational Conditions Following Loss of the Largest Generator in PACE WY Region

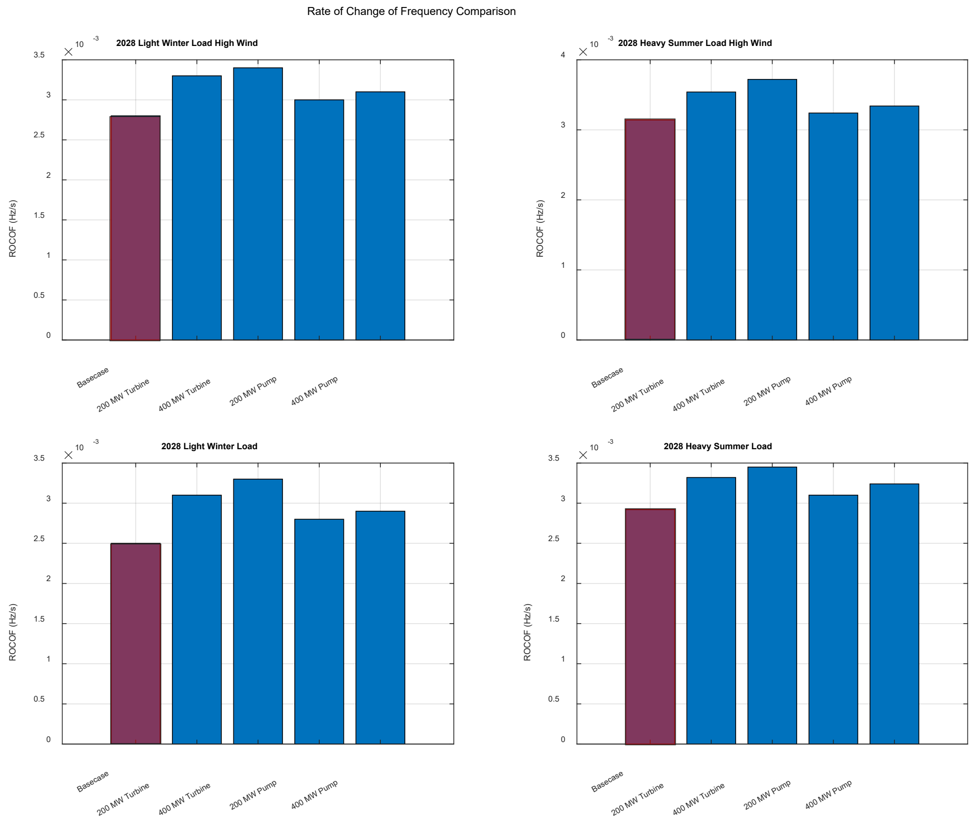

Figure 8-49 ROCOF with Banner Mountain PSH Unit under Various Operational Conditions Following Loss of the Largest Generator in PACE WY Region

Figure 8-49 shows the ROCOF improvement with Banner Mountain PSH operation for the scenarios with a large number of wind turbine generators in operation in PACE WY. However, in scenarios without high wind penetration, ROCOF worsens for the turbine case because the Banner Mountain PSH unit displaces existing synchronous generators. Figure 8-50 shows that for the scenarios with high wind penetration, frequency nadir improves with the addition of Banner Mountain in pump mode. The frequency nadir performance was better in pump mode compared to turbine mode.

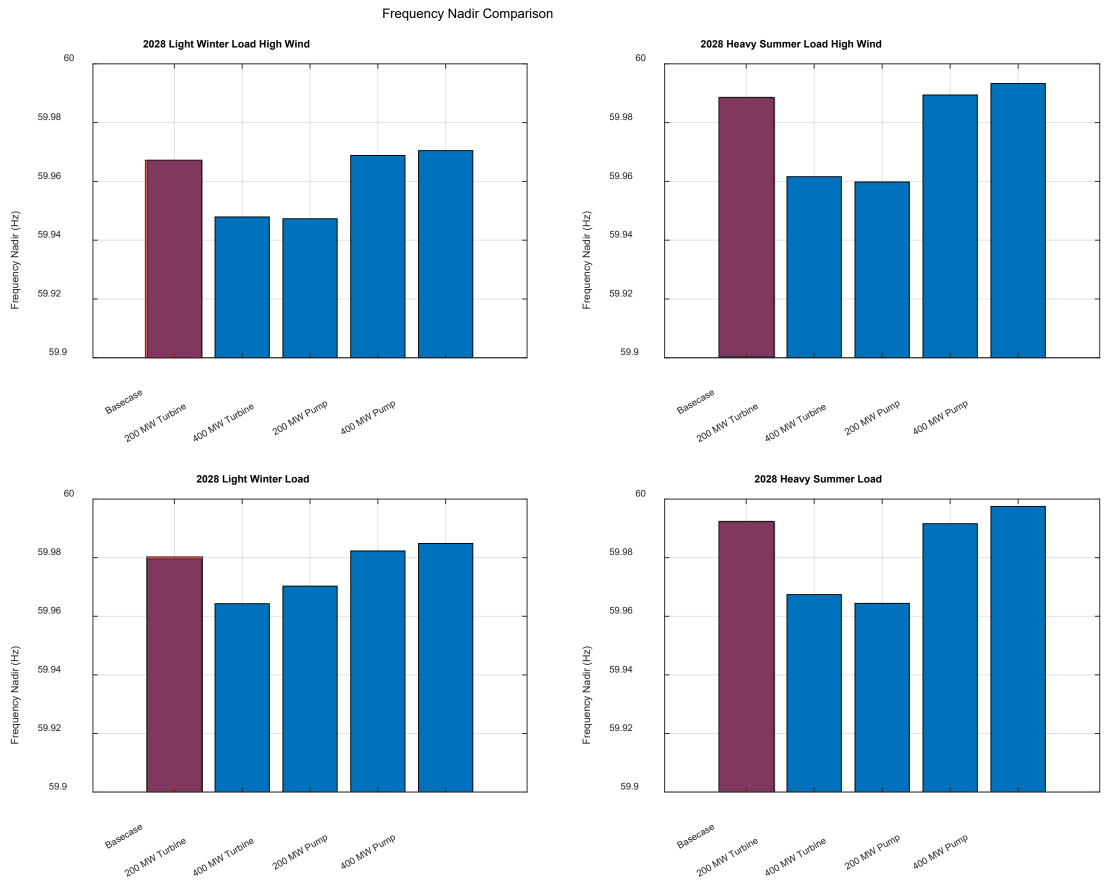

Figure 8-50 Frequency Nadir with Banner Mountain PSH Unit under Various Operational Conditions Following Loss of the Largest Generator in PACE WY Region

Figure 8-51 compares the COI frequency arresting period with the Banner Mountain PSH unit under various operational conditions following the loss of the largest generator within PACE WY. When the Banner Mountain PSH unit is operating, the arresting period of COI frequency increases. This could be the result of a reduction of system inertia. Figure 8-52 compares the COI settling frequency with the Banner Mountain PSH unit under various operational conditions following the loss of the largest generator within PACE WY. The settling frequency is compared after 25 seconds. This metric measures the impact of the generating unit on fast frequency response and primary frequency response. Figure 8-52 shows that the faster response of the Banner Mountain PSH unit results in better frequency recovery in light load scenarios compared to heavy load scenarios.

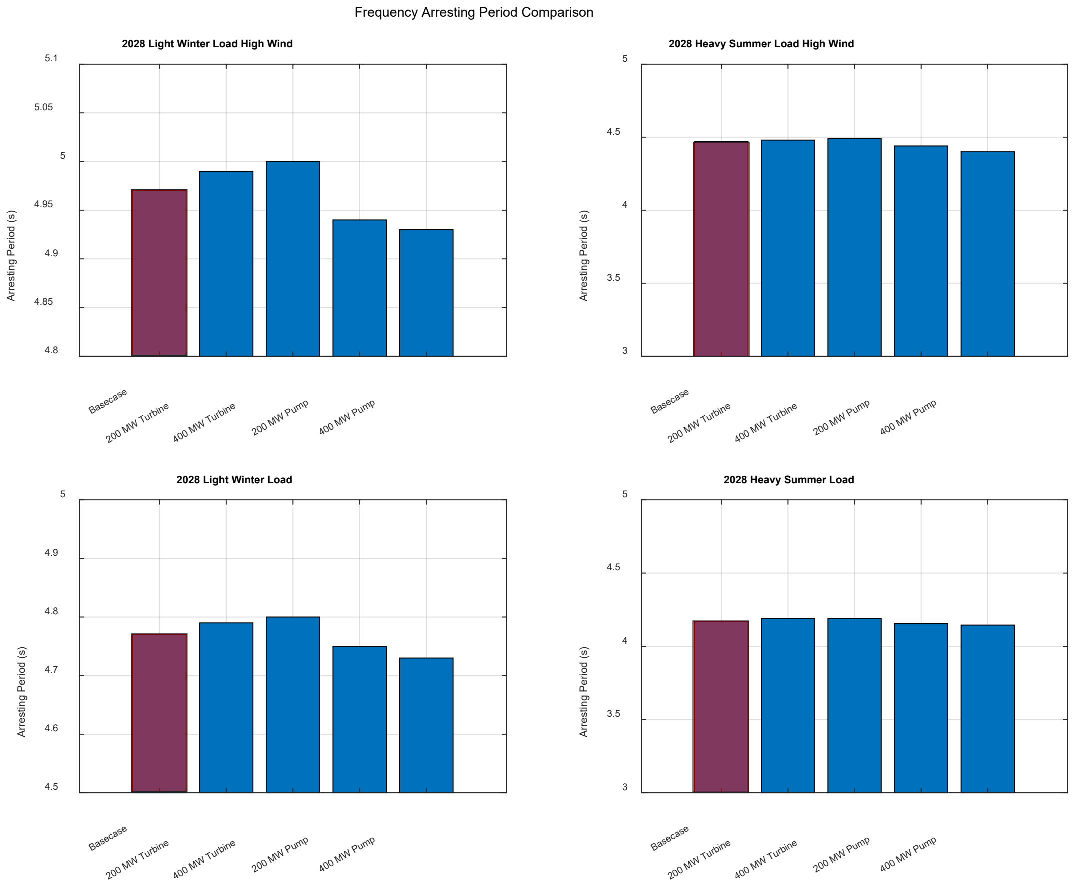

Figure 8-51 COI Frequency Arresting Period with Banner Mountain PSH Unit under Various Operational Conditions Following Loss of the Largest Generator in PACE WY Region

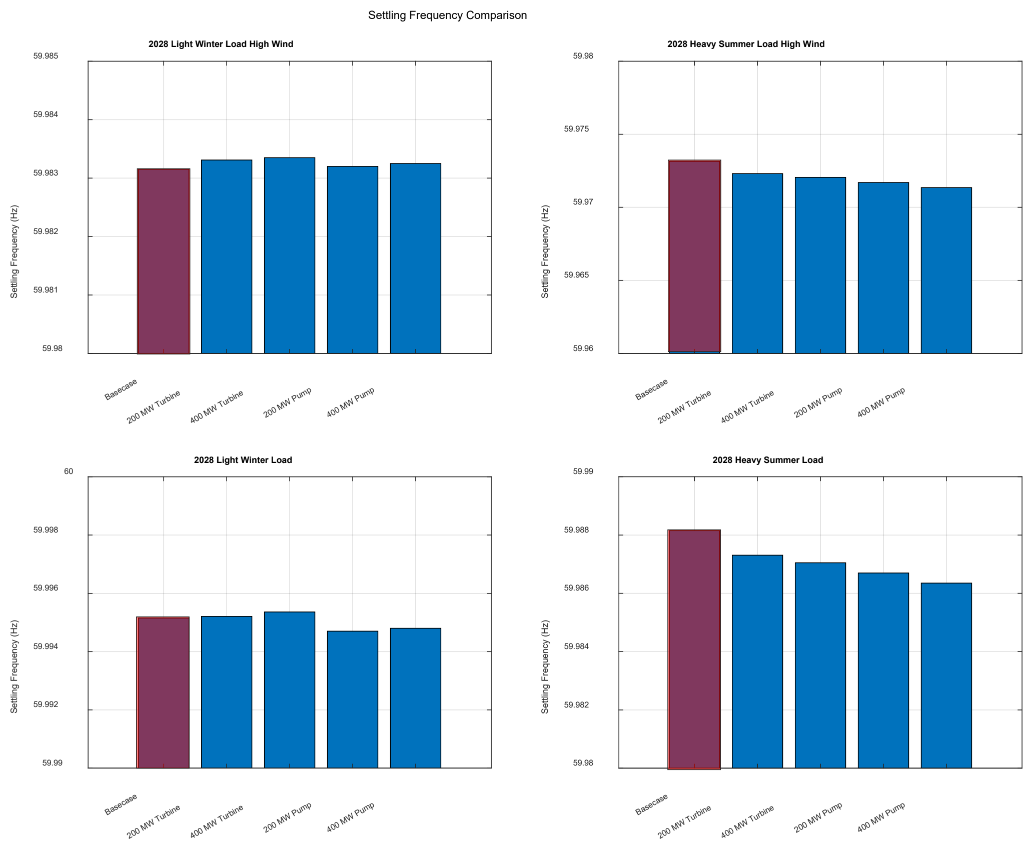

Figure 8-52 COI Settling Frequency with Banner Mountain PSH Unit under Various Operational Conditions Following Loss of the Largest Generator in PACE WY Region

8.4.5.4 Voltage Stability

To assess the impact of voltage support from the Banner Mountain PSH unit on voltage stability of the system, we considered scenarios including the loss of the largest capacitor in the system and three-phase self-clearing faults. Figure 8-53 compares the voltage profile of generator terminals for the winter light load scenario with and without the Banner Mountain PSH unit in operation. We observe that following a 6-cycle self-clearing fault at 1 second, for the cases without Banner Mountain PSH unit in operation, the voltage in most of the generator buses within PACE WY sag to a lower value. However, with the Banner Mountain PSH unit in either turbine or pump mode, we observe that the voltage sag is not lower and slowly starts to recover. This is attributed to the reactive power injection from the Banner Mountain PSH unit to support voltage in the system as shown in Figure 8-54.

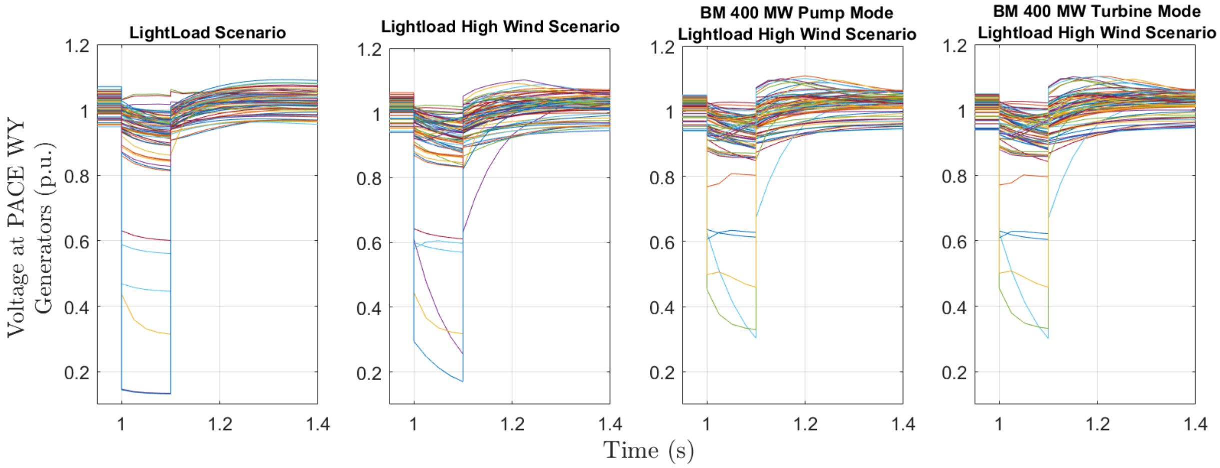

Figure 8-53 PACE WY Bus Voltages Following Loss of the Largest Capacitor in PACE WY, with and without Banner Mountain PSH Unit in Operation

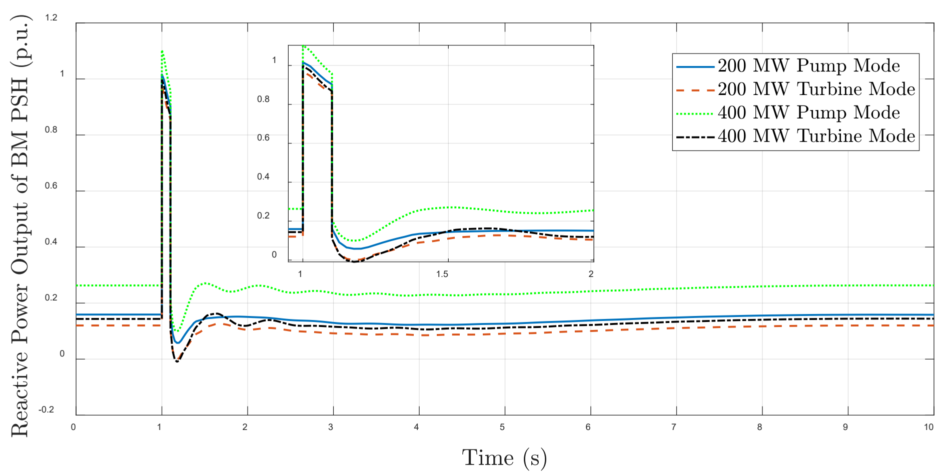

Figure 8-54 Reactive Power Injection Profile from Banner Mountain PSH Following the Loss of Largest Capacitor Voltage

The other scenario used to assess the impact of voltage support from the Banner Mountain PSH unit on stability of the system was based on the loss of the largest capacitor within PACE WY. For example, in Figure 8-55 we observe that after the loss of the largest capacitor within PACE WY, the Banner Mountain PSH injects reactive power into the system and continues to adjust its reactive power output in order to return the voltage to pre-disturbance levels.

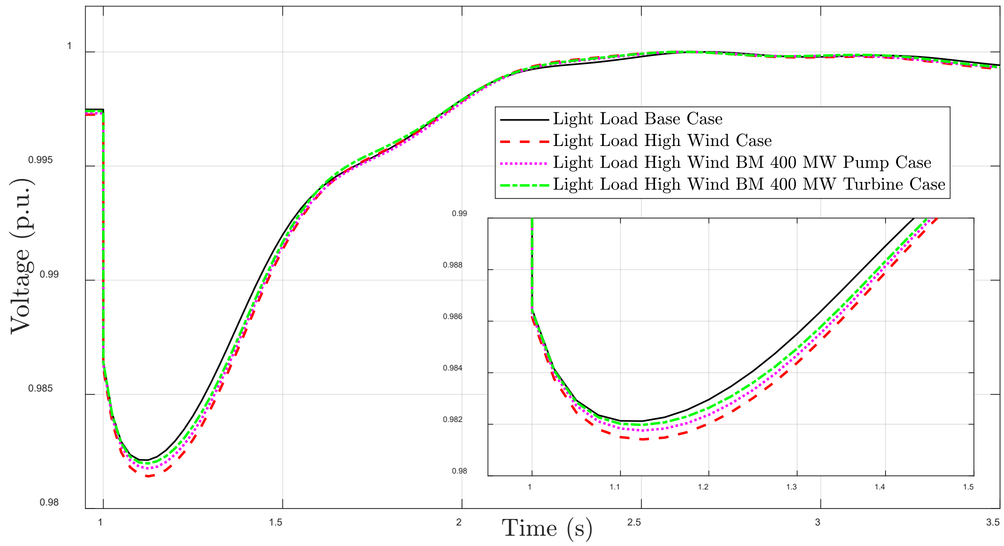

Figure 8-55 Voltage Profile at the Largest Capacitor Bus under Various Operational Conditions

Figure 8-56 compares the impact of local voltage support from the Banner Mountain PSH unit within the PACE WY territory. Following the introduction of the most severe three-phase fault within PACE WY, we recorded the number of buses with voltage below 88%. We observe that for all the scenarios, with voltage support enabled during Banner Mountain operation, the number of buses below 88% threshold is reduced. The effect is more pronounced with the Banner Mountain unit in operation in turbine mode as opposed to pump mode.

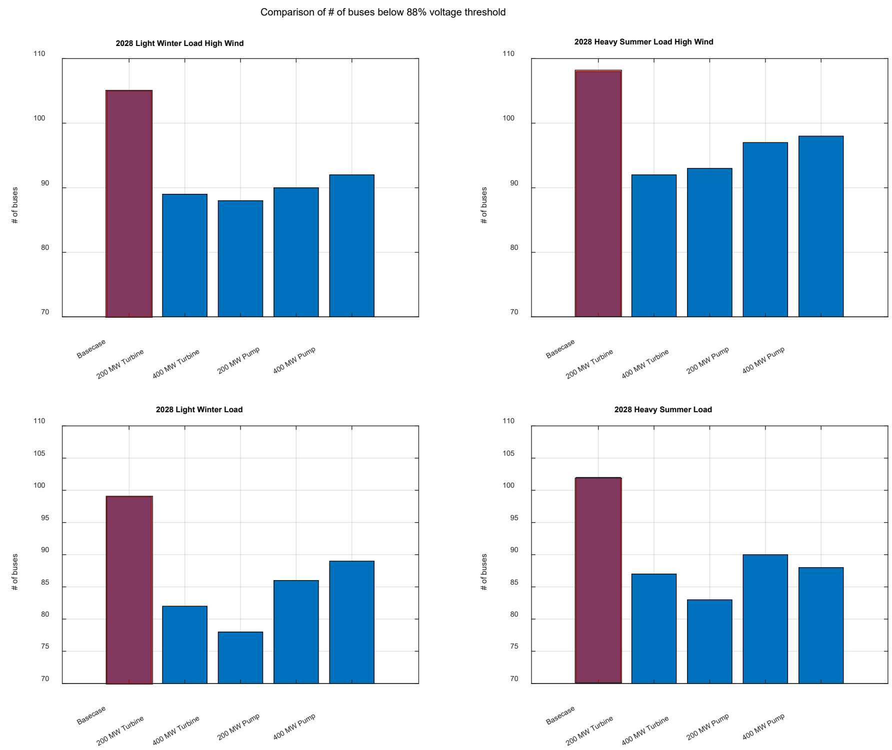

Figure 8-56 Comparison of Number of Buses below 88% Voltage Threshold with and without the Banner Mountain PSH Unit in Operation for Various Scenarios

8.4.6 Valuation of Service

After assessing stability attributes and the impact of the Banner Mountain PSH unit on the stability of the system, the next set of studies we performed investigated the cost evaluation of various services provided by the Banner Mountain PSH unit. We evaluated the cost of the stability services from the Banner Mountain PSH unit in terms of the frequency response and voltage support, and from the unserved energy perspective.

8.4.6.1 Cost Evaluation of Frequency Response

For the cost evaluation of the frequency response from the Banner Mountain PSH unit, some of the information used and assumptions made can be summarized as follows:

- The assessment performed and the results obtained are based on the known contract pricing between CAISO and BPA, and between CAISO and SCL, for frequency response services for 2017. Future market mechanisms and incentives could differ. For the analysis in the report, we used as a reference price for frequency response services a contract between BPA and CAISO for 50 MW/0.1 Hz of frequency regulation for a contract price of $2.22 million, or $44.40/kW-year, and a contract between SCL and CAISO for 15 MW/0.1 Hz of frequency regulation for contract price of $1.22 million, or $81/kW-year.

- One key assumption during the cost evaluation of frequency response is that the Banner Mountain PSH unit can commit 5% of its capacity throughout the year for frequency response/regulation services. This assumption derives from an evaluation of the capacity remaining after the production cost runs were performed exclusively for energy and ancillary services. A more detailed study should be performed using a PCM, in order to provide the economic viability of dedicating the allotted capacity for frequency response services as opposed to participating in energy and ancillary service markets.

- The analysis does not include any cost incurred by the Banner Mountain PSH unit operators for capacity maintenance, operational costs, or cost of components.

- The pricing for frequency response is assumed to be a two-part payment as per FERC Order 755. This order directs RTOs and ISOs to implement a two-part payment for frequency regulation service, including: (1) a capacity payment that includes the marginal unit's opportunity costs and (2) a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.

Figure 8-57 shows the frequency response of COI and the corresponding power output response of the Banner Mountain PSH unit in response to the frequency deviation. We then used the area under the power output curve along with the 5% of Banner Mountain capacity reserve for frequency response services to evaluate the cost of frequency response service from the Banner Mountain PSH unit. If the Banner Mountain PSH unit commits 20 MW (5%) of its capacity year-round for frequency support, the capacity-based revenue generated will be in the range of $0.88 million to $1.62 million. In addition, if the average RT market price of energy is $15/MWh for about 200 frequency events in a year for which the Banner Mountain PSH unit absorbs/provides about 3 MWh of energy in response to the frequency events, the regulation performance revenue generated will be approximately $9,000. Based on these assumptions, the inflation-adjusted estimated annual revenue for frequency response services from the Banner Mountain PSH unit in 2020 dollars is in the range of $0.96 million to $1.74 million annually.

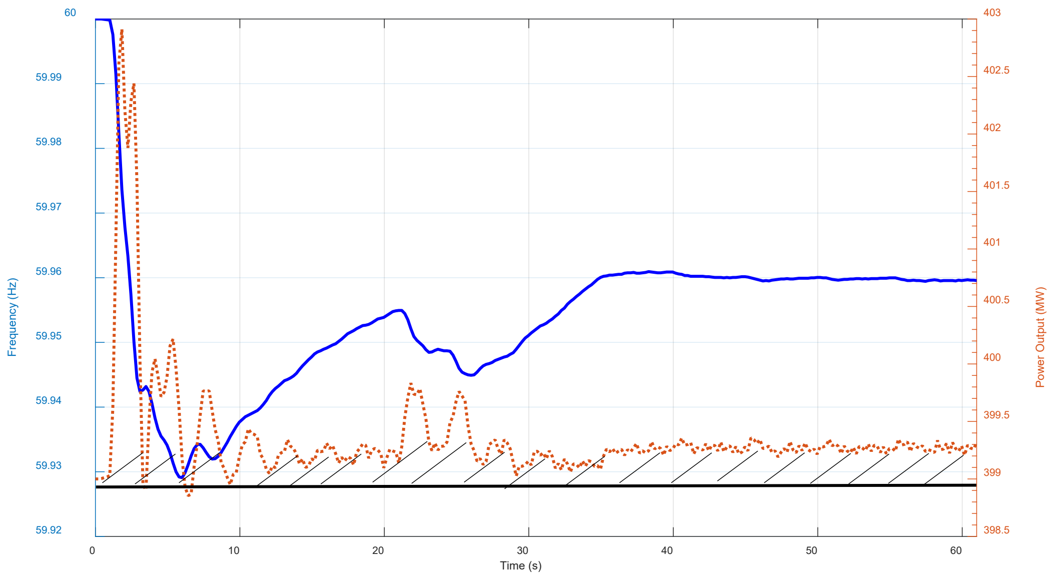

Figure 8-57 COI Frequency Response and Corresponding Power Output Response of Banner Mountain PSH Unit in Turbine Mode Following the Disturbance

8.4.6.2 Cost Evaluation of Voltage Support

The benefit of voltage support from the Banner Mountain PSH unit is assessed by quantifying the reactive power contribution made by the unit during widespread voltage events. Reactive power support from generators has been compensated differently by various ISOs/RTOs across the United States. CAISO does not provide compensation for generators operating within ±0.95 power factor, but they have provisions to compensate generators based on the capacity and the lost opportunity costs when CAISO specifically requests generators for reactive power support. ISOs like NY-ISO, ISO-NE, and PJM publish their reactive power tariffs and payments. These range from $1.10/kVAR for ISO-NE to $2.93/kVAR for NYISO and $3.92/kVAR for PJM (Kueck et al., 2006).

Because around 15 MVAr reactive power capacity is available from the Banner Mountain PSH unit throughout the year for voltage support, the range of revenue Banner Mountain generates for reactive power support can range from $15,750 to $71,590, assuming around 200 voltage events require reactive power support. Figure 8-58 shows the reactive power response from the Banner Mountain PSH unit following a voltage sag event within the PACE WY territory. Note that as the voltage falls below the reference set-point level, the Banner Mountain PSH unit continues to provide reactive power to support the system voltage.

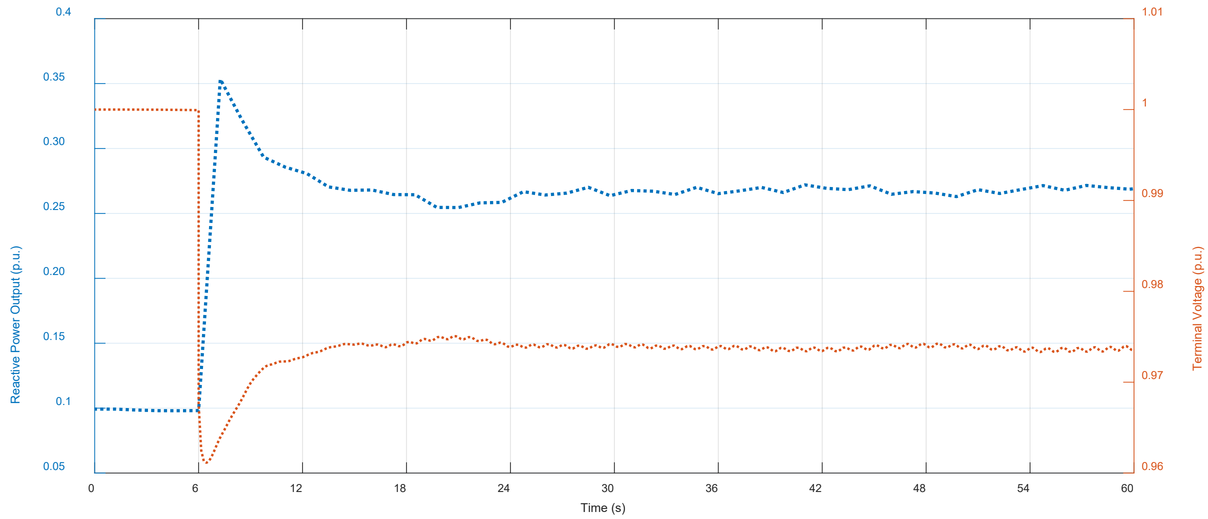

Figure 8-58 Reactive Power Support from Banner Mountain PSH Unit in Response to the Voltage Drop Observed Close to its Terminals

8.4.6.3 Cost Evaluation from Unserved Energy Perspective for Loss of Load

Unserved energy is defined as the expected amount of energy not supplied by the generating system during the period of observation due to capacity deficiency, interconnection congestion, or other disturbance events. Response from some of the complex load model shows that a certain percentage of motor load trips are due to low voltage for fault events. Some of these motor loads do not recover after fault clearance. Such loss of load and its associated cost can be used to quantify the benefits of operating Banner Mountain PSH units, because frequency and voltage support from Banner Mountain PSH units minimize the amount of load lost in the system following large disturbances. Using the interruption cost estimates provided by the interruption cost calculator developed by the Lawrence Berkeley National Laboratory (LBNL), we evaluate the cost of operation of the Banner Mountain PSH unit from minimization of unserved energy (Interruption Cost Estimate Calculator, 2022).

From the analysis of multiple fault cases, we observed that for the extreme cases about 7 MW of load continue to remain online, as compared to the cases without the Banner Mountain PSH unit. Assuming it takes 10 minutes for the loads to be restored, the total unserved energy for the Base case was equal to 1.2 MWh. Assuming there will be 100 such events in a year, total unserved energy in a year will be 120 MWh.

Considering an average cost of unserved energy to be $12.5/kWh (in 2016 dollars), the economic loss avoided by stability services from Banner Mountain PSH could be up to ~$1.75 million in 2020 dollars. Note that the cost computed does not include additional cost to possibly dispatch operators for load restoration and equipment like reclosers to bring loads back online.

8.4.7 Summary of Results & Conclusions

From the analysis performed, we observe that when the Banner Mountain PSH unit operates, the small-signal stability and transient stability of the system is improved, especially in the turbine mode of operation, irrespective of operating scenarios. In terms of frequency stability, although the ROCOF of the system increases with the addition of the Banner Mountain PSH unit in the system, improvements are observed in other stability metrics including the frequency nadir, frequency arresting period, and settling frequency. In addition, the turbine mode of operation for the Banner Mountain PSH unit during the high wind scenario is beneficial to overall system frequency stability compared to the pump mode of operation. In terms of voltage stability, the results demonstrate that the local reactive power support from the Banner Mountain PSH unit in either turbine mode or pump mode significantly improves the voltage recovery of the system following a disturbance. This leads to a larger amount of load and generators that continue to remain online, which has a positive impact on overall system stability.

The cost evaluation of the services provided by the Banner Mountain PSH unit demonstrates that the Banner Mountain PSH unit can generate a significant amount of revenue from the frequency and voltage support it can provide. On top of that, operation of the Banner Mountain PSH unit can lead to cost savings in operation of the grid because it minimizes the loss of load in the system and hence the amount of unserved energy in the system.

Note that as the amount of renewable energy in the system continues to increase in the power grid, the stability services provided by the Banner Mountain PSH unit will continue to become more valuable from a grid stability perspective; hence the value of these "stability services" from Banner Mountain will continue to increase. Of significance is the result that demonstrates the operation of the Banner Mountain PSH unit in turbine mode in the high wind scenario significantly improves the stability metrics of the system compared to operation in pump mode.

Note that the analyses performed and reported here are not comprehensive analyses of valuation of stability services from the PSH unit. Further, studies including but not limited to eigenvalue analysis, inertia sensitivity, and voltage sensitivity analysis can also be performed to further assess the stability implications of the Banner Mountain PSH unit.

8.4.8 References

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8.5 Black Start Valuation

8.5.1 Overview of the Black Start Valuation Study

This section describes the application and results of the black start valuation methodology to the BMSP. A key factor associated with the valuation process is that the facility is in an unstructured market. The implication of this location on the valuation methodology is that a cost-of-service approach was deemed to be the most appropriate valuation approach, given insufficient access to information around unstructured black start markets. A primary factor leading to this dearth of information is concern regarding grid security; the reasonably high-resolution data needed to inform a market-based assessment can have potential security implications. The research team expended a significant amount of effort to perform a market-based assessment using black start testing outage data out of the NERC Generating Availability Data System (GADS), which has resource aggregated annual outage statistics under Cause Code 9998. However, we found that not only was the regional resolution too large to provide site-specific insights, but also the information provided through the NERC-GADS database was insufficient to assess the market value for black start service.

Therefore, the cost-of-service approach was deemed to be appropriate for this work. The primary implication of this methodology is that the resulting values should reflect the minimum revenue that the facility should be compensated for its service, because this value indicates the cost to provide black start service. A variety of sensitivities will be explored in the following sections, but a reliable estimate for the minimum revenue needed to cover the cost of BMSP providing black start services is $151,929 per year.

8.5.2 Black Start Background

A more detailed background on system black start is presented in Section 4 of the *PSH Valuation Guidebook*, as well as in other literature, but it is appropriate to provide a limited discussion here to provide context to this report. A system black start is the process of restoring the power to an electric power station, without relying on the external power from the grid, so that it can be used to gradually energize other power stations and restore power to the electric power system. In the absence of grid power, a so-called black start needs to be performed to bootstrap the power grid into operation. Due to the bootstrapping requirements, only a small subset of generator types is able to provide black start service, including small diesel generators, specialized natural gas plants, and hydroelectric power plants. In addition to their ability to self-start, there are a variety of other requirements dictated by transmission owners (who are mandated to ensure appropriate black start coverage for their service area), which typically includes the capability to accept instantaneous demand blocks; the ability to provide sufficient generation for the duration of the restoration plan (typically 7–16 hours); and the ability to maintain a high service availability (typically 90%).

8.5.3 Valuation Methodology

As stated above, the methodology employed for this assessment is a cost-of-service approach. This methodology was selected because it is recognized as using a reasonable set of assumptions by the industry, and because there is sufficient information within the public domain for the user of this methodology to either leverage their own internally established values or use information within the public domain. The specific cost-of-service format applied in this analysis leverages one created by the PJM interconnect, because the other markets that use this approach (MISO, CAISO, and NYISO) use formulas that require detailed system knowledge or variables that are subject to negotiation. The desire to make this a generally applicable methodology and somewhat limited system information prevents these other market equations from being included in this analysis.

Note that the general forms of these cost-of-service equations leverage most of the same variables. The limitation, however, is how to determine the values for these variables. The equation used in the PJM calculation is below. It is comprised of five subcomponents: fixed costs, variable costs, training costs, fuel storage costs and incentive factors, which are explored further in Sections 8.5.3.1 through 8.5.3.4, respectively. Note that all these values are a function of annual revenue and are likely to evolve throughout the lifespan of the PSH facility. The incentive factor represents a bulk mechanism to help adjust the compensation to facilities that provide these services. Traditionally this value is 0.1 (PJM, 2019):

$$\mathrm{BS_{Revenue}} = [\mathrm{FBSSC} + \mathrm{VBSSC} + \mathrm{Training} + \mathrm{Storage}](1 + \mathrm{Incentive})$$

where:

- $\mathrm{BS_{Revenue}}$ = annual black start revenue
- FBSSC = fixed black start service costs
- VBSSC = variable black start service costs
- Training = cost of training

- Storage = cost of storing fuel
- Incentive = site-specific incentive for black start deployment

8.5.3.1 Fixed Black Start Service Costs

The fixed black start service costs represent the compensation component associated with the fixed costs of the black start facility. These costs are broadly a function of the net CONE within the region, and the scale of the facility as indicated in the equation below. The net CONE represents the difference between the levelized annual costs to construct a resource and the expected revenue from energy and ancillary services. Numerous documents that provide insight into these region-specific values are available; however, for this analysis we used the results of a MISO study (MISO, 2016). This investigation demonstrated that the average net CONE in the region was \$91,491/MW-year. To better understand the influence of the selected value on the overall results, the study also investigated a ±20% sensitivity around this net CONE (\$109,790/MW-year and \$73,193/MW-year). The results of this sensitivity analysis are presented in the final results. Also note that an allocation factor is included in the equation below. This is a region-specific factor that indicates the overall percent of the net CONE that can be attributed to the provision of black start services. For hydropower plants this value is 1% (PJM Interconnection, 2019):

$$\text{FBSSC} = \text{Net CONE} \times \text{BS PSH Capacity} \times \text{Allocation Factor}$$

where:

- FBSSC = fixed black start service costs
- Net CONE = region-specific net CONE
- BS PSH Capacity = capacity of the PSH plant dedicated to black start service
- Allocation Factor = percent of total fixed costs attributable to black start service

8.5.3.2 Variable Black Start Service Costs

The variable black start service costs represent the variable operating costs that can be attributed to the provision of black start service. The system variable operating costs are those that are a function of the amount of energy produced by the PSH facility and are traditionally described as consumable and waste-related costs. In general, variable costs include factors such as fuel consumption, labor, and maintenance costs; however, for PSH and other renewables, the "fuel" costs are negligible. Therefore, PSH and hydropower writ large have very low variable costs.

The variable costs associated with black start are calculated as outlined in the equations below. While this is a relatively simple equation, it requires insight into hydropower plant operations and costs. In an ideal application of this methodology, site-specific data would be used in the assessment. However, in many instances it is unlikely that this data will be readily available (as in the current iteration of this assessment). Therefore, data was collected from a variety of open-source locations and analyzed to provide a reasonable means of estimating these values.

The latter part of the first equation below is a site-specific value that should be gathered from the operational simulations; however, it can be estimated based on the utilization factor outlined in Table 8-21 along with the second equation below. The utilization factor is designed to be an energy storage system analog to the capacity factor as prescribed by the EIA but note that gross generation levels are not made readily available by the EIA and therefore gross generation must be estimated using a "closed-loop" operation assumption in combination with an estimate on the RTE of the system (80%) (Mongrid et al., 2019; EIA, 2019, 2020).

Table 8-21 Pumped Storage Variable O&M Characteristics

Plant	Capacity (MW)	Average VO&M ($2020/MWh)	Utilization Factor
Bad Creek	1,065	4.1	0.23
Bath County	2,100	2.9	0.21
Bear Swamp	600	–	0.13
Blenheim-Gilboa	1,000	26.9	0.13
Cabin Creek	300	18.7	0.18
Fairfield	512	5.0	0.22
Helms	1,206	23.5	0.12
Jocasse	610	6.1	0.17
Ludington	1,979	6.7	0.21
Raccoon Mountain	1,530	24.0	0.18
Rocky Mountain	760	8.0	0.28
Yards Creek	360	6.4	0.25

The data for the variable O&M (VO&M) component of the equation below should ideally be populated using site-specific information; however, in many instances this information will not be available. As such, it is possible to estimate these costs (which are strictly a function of Gross Generation) using VO&M data reported through FERC Form 1 in combination with the estimated utilization factor of the facility (MWH Americas, Inc., 2009). This relationship is demonstrated in Figure 8-59, where good agreement can be seen between these two trends (R^2 of 0.6) along with the second-order polynomial fit for the data. Note that the data reported in FERC Form 1 has been acknowledged to have issues regarding accuracy and consistency; however, this represents the best fleet-level insight currently available.

The final component of the equation below is the allocation factor, which represents the percent of the VO&M costs attributable to black start compensation. In most instances this is 1% (PJM Interconnection, 2019).

$$\mathrm{VBSSC} = \mathrm{VO\&M} \times \mathrm{Gross\ Generation} \times \mathrm{Allocation\ Factor}$$

$$\mathrm{Usage\ Factor} = \frac{\mathrm{Gross\ Generation}}{\mathrm{Capacity} \times \mathrm{Hours\ in\ Year}}$$

where:

- VO&M = variable operation and maintenance costs ($/MWh)

- Allocation Factor = percent of total variable costs attributable to black start service.
- Net Gen = difference between the energy provided by the facility and the energy provided to the facility (MW)
- Gross Generation = generation provided by the facility to the grid (MW)
- Capacity = rated capacity of the PSH facility (MW)
- Hours in Year = total number of hours in the year

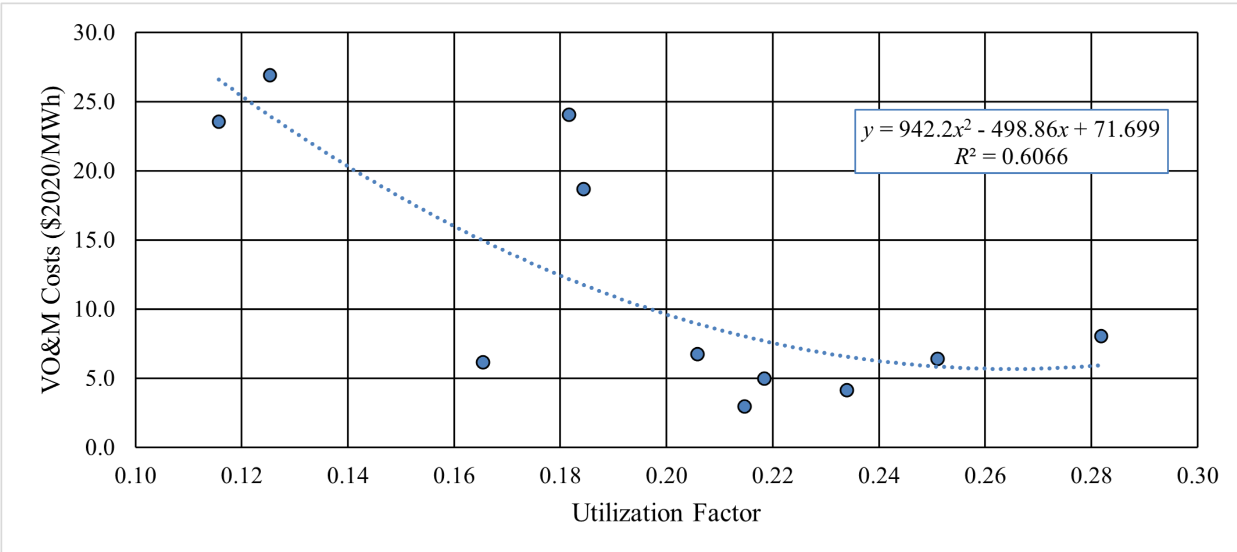

Figure 8-59 VO&M Costs as a Function of PSH Utilization Factor

8.5.3.3 Training Costs

The training cost component of black start compensation represents the cost to perform mandated annual staff training in black start procedures. The basic equation is a function of NERC training requirements as per EOP-005-2, which states that personnel responsible for startup of the black start resource and energizing buses shall receive a minimum of 2 hours of training every 2 calendar years (NERC, 2009; NYISO, 2019; PJM Client Management & Services, 2019). However, in many instances the official training in black start restoration spans 2 or 3 days, and these extended training sessions were included as sensitivity studies (Electricity Reliability Council of Texas, 2020; Southwest Power Pool, 2020). For the purposes of estimation simplicity, the annual training requirements have been consolidated to a single hour, along with sensitivities of 8 and 12 hours each year, as seen in the training cost equation.

The first component in this equation is the number of employees that would need to be trained in black start restoration procedures. In an ideal assessment, this calculation should be made using site specific values; however, as with the other components, it is important to be able to produce reasonable estimates of this during system planning. Therefore, it is possible to leverage information from FERC Form 1 regarding the number of listed employees and the rated capacity of pumped storage facilities to develop an estimate (MWH Americas, Inc., 2009). As shown in Figure 8-60, this provides a reasonable estimate (R^2 of 0.58). However, note that this is a general estimation of the number of employees, as the FERC Form 1 does distinguish between types of employees (which include operations, administration, management, and custodial staff—not all of whom will necessarily need to be trained).

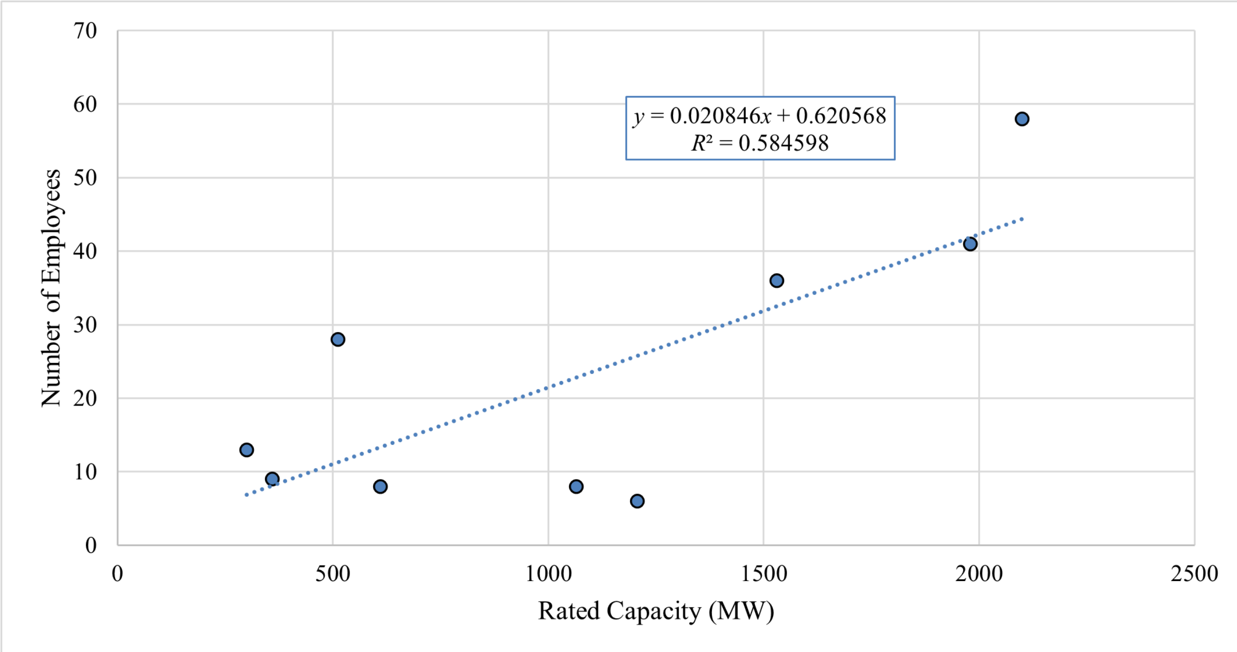

Figure 8-60 Number of Plant Employees

The second component of the training cost estimate is the hourly cost of the staff and, as with the number of employees, where it would be preferable to use a site-specific average, this can also be estimated using open-source data. We recommend that an average staff cost of $75/hour, as prescribed by PJM, be used in this analysis (PJM Interconnection, 2019). The accuracy of this value was then confirmed using data from the Bureau of Labor Statistics on average hourly earnings of utility workers ($43/hour) along with an estimated overhead of 42%, which results in an average staff cost of $61/hour (which was judged to be in reasonable proximity) (U.S. Bureau of Labor Statistics, 2020) (Magette & Levin, 2015):

$$\text{Training} = \text{Number of Employees} * \text{Staff Hour Cost} * \text{Training Duration} \tag{5}$$

where:

- Number of Employees = number of employees that require black start restoration training
- Staff Hour Cost = cost per staff-hour of training

8.5.3.4 Fuel Storage Costs

Fuel storage costs are not applicable to hydropower cost of service compensation for black start because hydropower systems that employ the cost-of-service approach in unstructured markets do not qualify to receive compensation for this. On the other hand, qualifying generation technologies assess this as a function of the black start restoration period, the fuel usage rate, fuel forward prices, and fuel transportation rates. If this were applied to a pumped storage facility, it would likely be calculated as a function of the amount of water that must be held in reserve to provide black start along with the market price of the energy that could be produced with this water.

8.5.4 Valuation Method Application

This section walks the user through the calculation of the black start value for Banner Mountain. This initially begins with an assessment of firm capacity and then is expanded through each of the individual components (along with their associated sensitivities) and culminates with the estimated total system value.

8.5.4.1 Firm Capacity Estimation

A key to calculating the value of black start for pumped storage facilities (or any other storage system) is understanding the firm capacity that can be dedicated to providing black start services. This is because, at any instant, the amount of water in the upper reservoir that can be leveraged to provide service varies based on the operation of the facility. Therefore, the operational simulations of the facilities should be analyzed to determine the capacity that is available at least 90% of the time. The raw and processed operational profiles for Banner Mountain are presented in Figure 8-61, where the exceedance curves show that the firm storage available for black start service is 1.73 GWh. When these values are then divided over the 16-hour maximum restoration period, the firm capacity that can be bid for black start service is 108.2 MW.

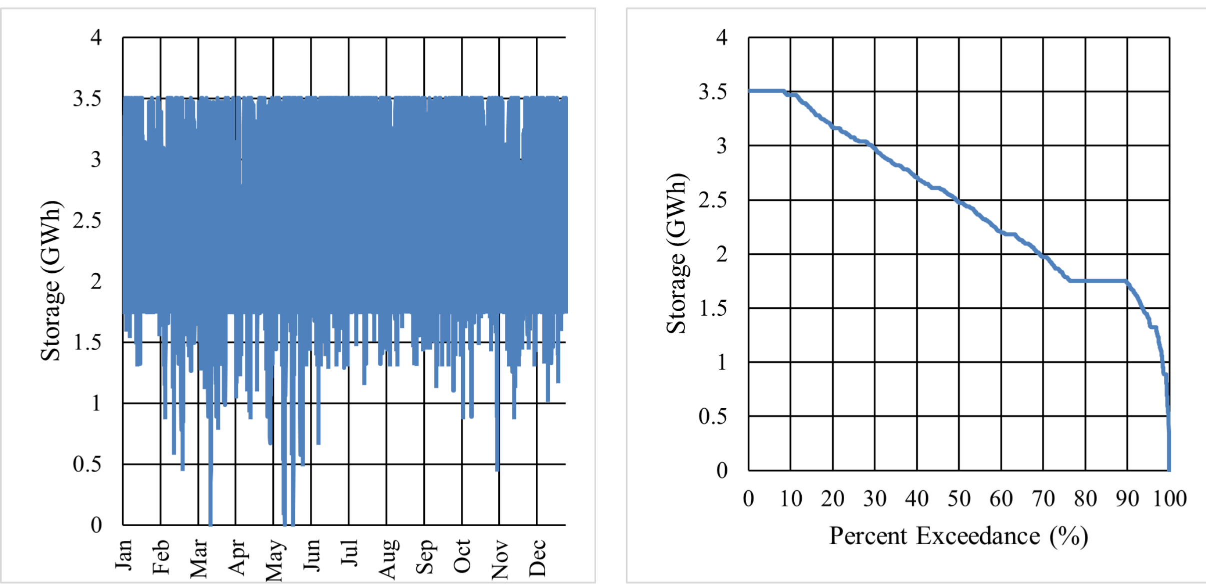

Figure 8-61 (a) Banner Mountain Upper Reservoir Operational Profile; (b) Banner Mountain Upper Reservoir Storage Exceedance Curve

8.5.4.2 Fixed Cost Compensation

As noted in Section 8.5.3.1, the net CONE used in this analysis is $91,491/MW-year, along with a sensitivity assessment of ±20%. When this is coupled with an allocation factor of 1%, it produces an estimated compensation as presented Table 8-22.

Table 8-22 Annual Fixed Black Start Compensation

Pumped Storage Facility	Avg. Net Cone: $91,491/MW-year	+20% Net Cone: $109,789/MW-year	-20% Net Cone: $73,193/MW-year
Banner Mountain	$98,993	$118,792	$79,195

8.5.4.3 Variable Cost Compensation

The first step in assessing the variable cost compensation for the facility is determining its utilization factor. When the generation simulation profile was analyzed, it showed that Banner Mountain has a utilization factor of 0.19. Comparing these values to the utilization factor presented in Table 8-23, the value is well within the bounds of other factors from known PSH facilities. This factor is then applied to the best-fit curve for variable costs to calculate the required annual variable cost revenue, as presented in Table 8-24.

Table 8-23 Annual Variable Black Start Compensation

Pumped Storage Facility	Utilization Factor	VO&M Rate ($/MWh)	Gross Generation (MWh)	Annual Variable Cost Revenue ($)
Banner Mountain	0.19	10.93	731,694	79,967

8.5.4.4 Training Cost Compensation

Using the employee curve estimation outlined in Figure 8-60, it is possible to estimate that Banner Mountain will have an estimated 10 employees who will require training. At the estimated staff hour cost of $75 along with the training duration sensitivities, the annual training compensation is demonstrated in Table 8-24.

Table 8-24 Annual Black Start Training Compensation

Pumped Storage Facility	Number of Employees	1 Hour of Annual Training	8 Hours of Annual Training	12 Hours of Annual Training
Banner Mountain	10	$750	$6,000	$9,000

8.5.4.5 Total Estimated Annual Black Start Service Cost Compensation

Leveraging the values outlined previously in this section, it is possible to estimate the annual black start cost of service. While the sensitivities are presented for Banner Mountain in Table 8-25, the typical estimated value is $151,929 annually.

Table 8-25 Banner Mountain Estimated Annual Cost of Black Start Service

Training Duration	Net CONE Sensitivity		
	+20% Typical Net CONE	Typical Net CONE	-20% Typical Net CONE
12 Hours Annual Training	$166,702	$155,229	$143,756
8 Hours Annual Training	$163,402	$151,929	$140,456
1 Hour Annual Training	$157,627	$146,154	$134,681

8.5.5 Conclusions

A key factor associated with the valuation process is that the facility is located in an unstructured market. The implication of this location on the valuation methodology is that a cost-of-service approach was deemed the most appropriate valuation approach given insufficient access to information around unstructured black start markets. A primary factor leading to this dearth of information is a concern regarding grid security, because the reasonably high-resolution data needed to inform a market-based assessment can have potential security implications. The research team expended a significant amount of effort to perform a market-based assessment using black start testing outage data out of the NERC-GADS, which has resource-aggregated annual outage statistics under the Cause Code 9998. However, we found that not only was the regional resolution too large to provide site-specific insights, but also the information provided through the NERC-GADS database was insufficient to assess the market value for black start service.

Therefore, the cost-of-service approach was deemed appropriate for this work. The primary implication of this methodology is that the resulting values should reflect the minimum revenue that the facility should be compensated for its service, because this value indicates the cost to provide black start service. Although a variety of sensitivities were explored in the previous sections, a reliable estimate for the minimum revenue needed to cover the cost of BMSP providing black start services is $151,929 per year.

8.5.6 References

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8.6 Transmission Benefits

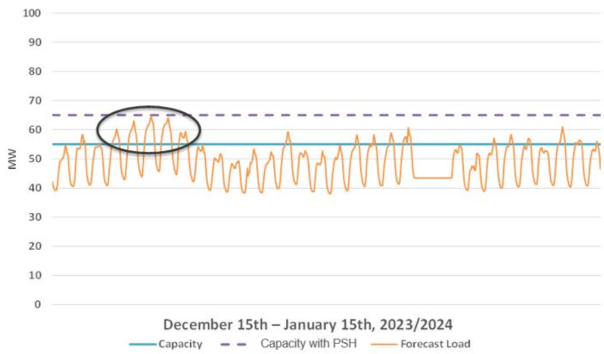
8.6.1 Overview of the Transmission Benefits Study

An analysis of the transmission benefits for the BMSP was undertaken. Section 8.6 summarizes the transmission benefits analysis, which includes transmission congestion relief and transmission upgrade deferral.

The specific utility application addressed herein is the use of PSH to reduce the cost of electricity delivery by reducing the cost of electricity transmission equipment. In particular, PSH can be used to defer expensive improvements or capacity additions to transmission equipment by providing congestion relief as needed.

Congestion occurs whenever the demand for energy exceeds transmission capacity in a particular area of the grid where the system state of the grid is characterized by one or more violations of the physical, operational, or policy constraints under which the grid operates in the normal state, or under any one of the contingency cases in a set of specified contingencies. Congestion is associated with a specific point in time. As such, the problem of congestion may arise during the DA dispatch, in the DA market. Therefore, a good approach to relieving transmission system congestion is to improve the use of existing infrastructure by permitting more flexibility and controllability of the available generation resources. Among all the possible options to reduce congestion, PSH plants are a good candidate for congestion relief service because they are flexible and can be quickly dispatched with a high ramp rate in order to alleviate system congestion during peak hours.

In order to use a PSH plant to provide congestion relief service, there are two criteria that need to be satisfied by the PSH plants. First, as shown in Figure 8-62 (left panel), the generation capacity of the PSH needs to be greater than the capacity requirement of the congested line. Second, the available energy of the PSH plant also needs to be higher than the overall peak hour energy deficiency of the congested line (Figure 8-62, right panel).



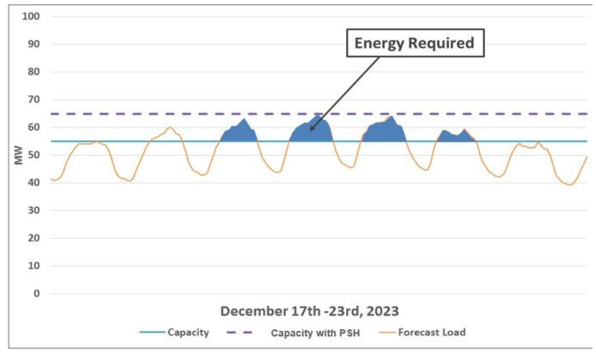


Figure 8-62 Left: Generation Capacity of PSH Must Be Higher than Capacity Needed; Right: Available Energy of PSH Must Be Higher than the Requirement

The system operators at different ISOs usually have different methods to handle congestion relief. CAISO uses partitioning to divide the grid into a number of predefined zones (CAISO, 1998). The market dispatch stage establishes the hourly market zonal prices for the next-day markets. If the market dispatch solution leads to congestion, it is eliminated by invoking the second stage action, called exceptional redispatch. Congestion charges are applied using the transmission charges in the interzonal interfaces to account for the added costs of redispatch. The benefit can be measured as the reduction in congestion charges resulting from the introduction of the PSH facility.

8.6.2 Valuation Methodology

8.6.2.1 Congestion Relief

For Banner Mountain, a price-influencer approach was used to calculate the value of congestion relief that the PSH facility would provide. Typically, the problem of congestion relief is formulated as the optimization of some objective function subject to satisfying various constraints. The ACOPF tool was developed to determine the solution for this problem. The overall procedure of calculating congestion relief is shown in Figure 8-63. First, the generation dispatch and commitment status are generated from a PCM. Then the ACOPF model is used to examine all transmission violations in the system by comparing the flow at each branch with the line rating at the selected hour. Finally, after the locations of the congestion are calculated through the ACOPF model, the value of congestion relief can be calculated through the change in shadow prices before and after the congestion relief.

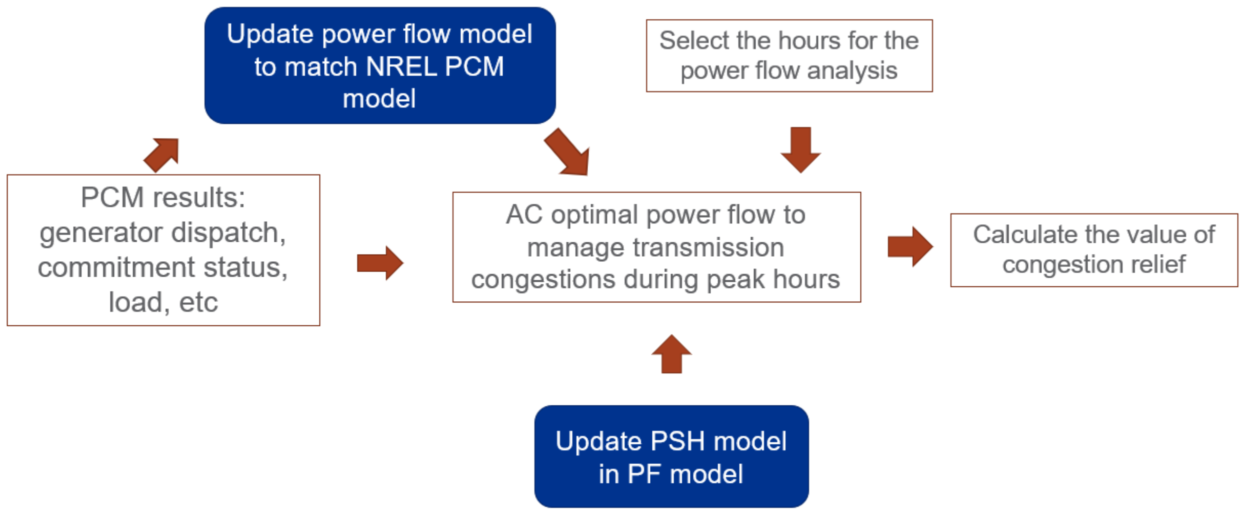


Figure 8-63 Conceptual Procedure of Calculating Congestion Relief with ACOPF

The detailed congestion relief ACOPF model formulated for use in this study is shown in the equations that follow.

Let $G(N,E)$ be a power system with the set of buses being N and the set of lines being E. In each bus, let V_i^R and V_i^I be the real and imaginary parts of the voltage at bus i. In each line, let b_{ijc} and g_{ijc} $(i \neq j)$ denote the susceptance and conductance at line c from bus i to bus j $(i, j \in N)$, and V_i^R and V_i^I are the real and imaginary parts of the voltage at bus i, in rectangular form.

The objective function for penalizing a branch violation of each transmission line rating is formulated as:

$$min\, f_1 = \begin{cases} \sum_{i \in L} \left(\sqrt{(V_i^R)^2 + (V_i^I)^2 + \left(I_{ijc}^R\right)^2 + \left(I_{ijc}^C\right)^2} - p_{ijc}^{set} \right)^2 & \\ \qquad \text{if } \sqrt{(V_i^R)^2 + (V_i^I)^2 + \left(I_{ijc}^R\right)^2 + \left(I_{ijc}^C\right)^2} > p_{ijc}^{set} & \\ \qquad 0 & \text{o.w} \end{cases} \tag{1}$$

Subject to the following constraints:

$$I_{ijc}^R = a_{ijc} \left(\frac{1}{\tau_{ijc}^2} \left(g_{ijc} V_i^R - \left(b_{ijc} + \frac{b_{ijc}^C}{2} \right) V_i^I \right) - \frac{1}{\tau_{ijc}} \left(g_{ijc} V_j^R - b_{ijc} V_j^I \right) cos(\phi_{ijc}) + \frac{1}{\tau_{ijc}} \left(g_{ijc} V_j^I + b_{ijc} V_j^R \right) sin(\phi_{ijc}) \right) \tag{1}$$

$$I_{ijc}^I = a_{ijc} \left(\frac{1}{\tau_{ijc}^2} \left(g_{ijc}^{\varepsilon} V_i^I + \left(b_{ijc}^{\varepsilon} + \frac{b_{ijc}^C}{2} \right) V_i^R \right) \right.$$

$$- \frac{1}{\tau_{ijc}} (g_{ijc}^{\varepsilon} V_i^I + b_{ijc}^{\varepsilon} V_i^R) \cos(\phi_{ijc}) - \frac{1}{\tau_{ijc}} (g_{ijc}^{\varepsilon} V_i^R - b_{ijc}^{\varepsilon} V_i^I) \sin(\phi_{ijc}) \Big) \quad (2)$$

$$0 = \sum_{k \in G_i} P_k^g - d_i^P - V_i^R \left(\sum_{(jc),ijc \in \varepsilon} I_{ijc}^R + \sum_{(jc),ijc \in \varepsilon} I_{ijc}^I \right) - V_i^I \left(\sum_{(jc),ijc \in \varepsilon} I_{ijc}^R + \sum_{(jc),ijc \in \varepsilon} I_{ijc}^I \right) - ((V_i^R)^2 + (V_i^I)^2) g_i^s \quad (3)$$

$$0 = \sum_{k \in G_i} Q_k^g - d_i^Q - V_i^R \left(\sum_{(jc),ijc \in \varepsilon} I_{ijc}^R + \sum_{(jc),ijc \in \varepsilon} I_{ijc}^I \right) - V_i^I \left(\sum_{(jc),ijc \in \varepsilon} I_{ijc}^R + \sum_{(jc),ijc \in \varepsilon} I_{ijc}^I \right) + ((V_i^R)^2 + (V_i^I)^2) b_i^s \quad (4)$$

$$\underline{V}_i^2 \leq (V_i^R)^2 + (V_i^I)^2 \leq \bar{V}_i^2 \quad (5)$$

$$((I_{ijc}^R)^2 + (I_{ijc}^I)^2) \leq \bar{I}_{cap}^2 \quad (6)$$

$$p_i^{min_i^{g_i^{max}}} \quad (7)$$

$$q_i^{min_i^{g_i^{max}}} \quad (8)$$

$$V_i^g = v_i^{sch} \quad (9)$$

Equation (1) is the objective function of the congestion relief ACOPF model, which includes penalizing branch violation of line rating at each transmission line. The purpose is to minimize congestion at all transmission branches.

Constraints (2) and (3), that is I_{ijc}^R andI_{jic}^I, represent the real and imaginary parts of the current flowing from bus *i* to bus *j* through line circuit *c*.

Constraints (4) and (5) represent the real and reactive power balance at bus *i*. Whereas P_k^g and Q_k^g represent the real and reactive power of generators at bus k, d_i^P and d_i^Q represent the real and reactive load at bus i, and g_i^s is the shunt conductance at bus i.

Constraints (6) and (7) represent the current and voltage magnitude limitations for each bus and each transmission line.

Constraints (8) and (9) give the limits for the real and reactive power output from the generator. As can be seen from constraint (8), as in the proposed volt-var ACOPF solution, the generation dispatch should remain the same as the production cost result.

Constraint (10) requires the generation voltage set point to remain as close as in the case where the reactive compensative devices are not controlled.

8.6.2.2 Transmission Upgrade Deferral

In simplest terms, the transmission upgrade deferral benefit is the "avoided cost"—the deferral cost if the transmission upgrade was deferred. A generalized framework was used to estimate the financial benefit of deferring a transmission upgrade with PSH from a system operator's perspective. The results could be used to negotiate a contract between the PSH owner/developer and the system operator. The framework followed four fundamental steps to evaluate the PSH benefits of deferring new transmission investment:

- Identify the transmission line upgrades to be deferred. In the initial step, the transmission congestion for the lines of interest were evaluated to determine the line upgrades needed. This step identified the presence and location of transmission investments with the potential for deferral through the deployment of PSH.

- The PSH facility must satisfy both the capacity requirement and energy requirement. These requirements are defined as follows:

    - Capacity requirement—The branch congestions in the two cases (case 1 with PSH project, case 2 without PSH project) were compared to see if the PSH facility minimized the congestion that appeared in case 1.
    - Energy requirement—The water/energy stored in the PSH reservoir was examined to determine if the PSH facility could meet the charging/discharging command from system operator.

  The detailed flow chart appears in Figure 8-64. Based on the current load and future load growth rate, the PF model calculated the duration of transmission upgrade deferral. The branch congestions for the two cases (case 1 with PSH project, case 2 without PSH project) were compared. With a given load condition, the model was run to determine if the PSH facility could alleviate the congested line in case 1 with satisfied capacity requirement and energy requirement. If the PSH could successfully defer the transmission upgrade for the first year, then a 1-year deferral of the transmission upgrade could occur. The process at the given load growth rate was repeated until the PSH plant could no longer relieve the congestion in case 2.

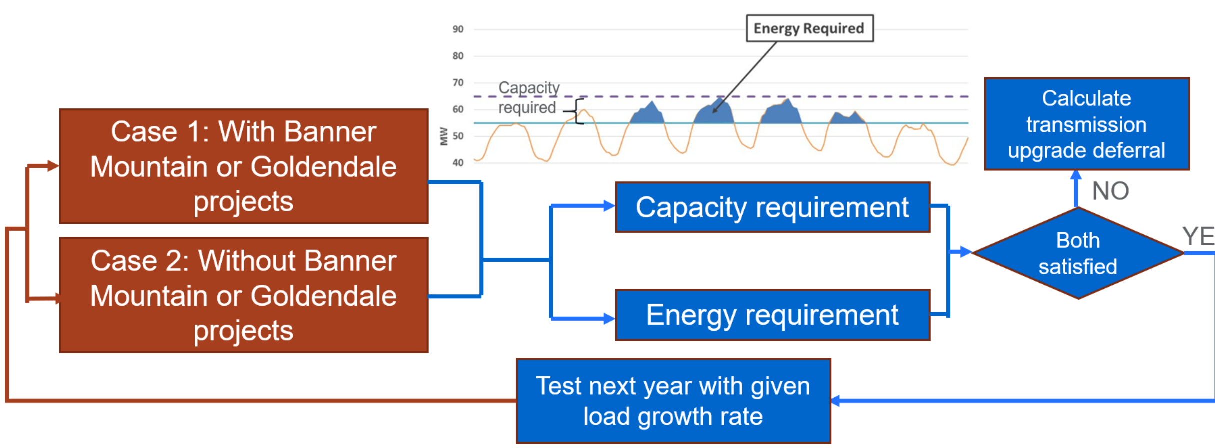


Figure 8-64 Procedure of Calculating Transmission Upgrade Deferral Time

- Based on the location and length of the upgraded transmission line, the estimated installation cost for the upgraded lines was determined; then the annual charge (annual revenue requirement) to own the upgraded transmission line was calculated. The WECC 2019 Transmission Capital Cost Tool was used to estimate the deferred transmission line costs by line length, land and right-of-way, structures, and foundations.

- The estimated present value of the transmission upgrade deferral in units of dollars per kilowatt or megawatt. The present value of the transmission upgrade deferral was calculated from:
    - The installation cost of the upgraded lines,
    - The fixed charge rate (FCR) is used to estimate the annual cost of utility capital equipment based on the total installed cost of the equipment. The fixed charge rate FCR reflects all elements of the carrying charges: annual payments for return of principal, interest, taxes, insurance, and other key financial requirements.
    - The PacifiCorp discount rate of 6.92% was used to calculate revenue requirements assuming a Wyoming state tax rate of 0% and a 21% Federal tax rate. The resulting FCR for Pacific Corp is 8.3%.
    - A 2.5% annual inflation rate was used to estimate capital cost growth over the deferral period.
- The transmission deferral value is the difference between the value of building the transmission line now and the value of building the transmission line later. The amount of deferred time is based on the amount of time the PSH project can delay the transmission line project by determining when congestion is no longer tolerable.

The annual revenue requirement for PSH is the annual amount of revenue needed to cover costs incurred for the transmission upgrade. Typically, the annual revenue requirement is calculated by multiplying the installed cost for the transmission equipment by a utility-specific “charge rate.” The charge rate reflects all elements of the carrying charges: annual payments for return of principal, interest, and dividend payments plus annual income tax, property tax, and insurance payments.

8.6.3 Analysis

8.6.3.1 Overall Design of Study

The detailed flow chart of the designed simulation can be seen in Figure 8-65. The ACOPF is formulated and solved by using a GAMS platform. The GAMS platform uses the PSSE PF RAW file as input. The ACOPF solution is also written in an updated RAW file format such that the optimization solution could be evaluated in PSSE.

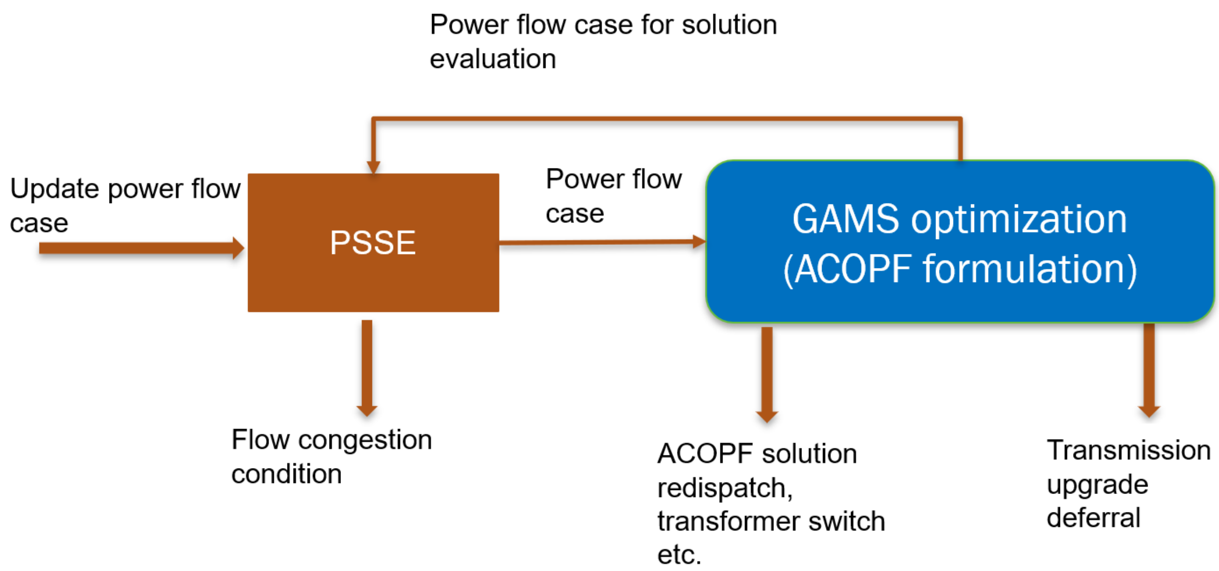


Figure 8-65 Data Exchange between Different Modules of Transmission Upgrade Deferral

8.6.3.2 Data Needs and Sources

In PLEXOS, the entire WECC region was modeled in the study by taking advantage of the nodal and zonal settings in the model. Areas of high interest, in this case west of Wyoming, the PNW, and California, were modeled nodally, allowing us to have higher resolution geographical outputs. The areas outside of this footprint were modeled zonally, meaning they will have the same temporal resolution but less geographical resolution, allowing for a faster solve time. WECC's Transmission Expansion Planning and Policy Committee database for the planning year 2024 (TEPPC, 2024) was used as the base case of PLEXOS.

There is no direct PF case corresponding with the TEPPPC 2024 PCM model; therefore, we used the 2025 Heavy Summer 1 PTI PSS/E case as the base case, because it is the PF model closest to the 2024 TEPPC PCM model. Starting from the base PF case, the generator, lines, and loads are revised in the PF case to match the PCM model from NREL. We used the PSSE model to run the PF analysis to analyze the value of the proposed PSH plant's contribution to transmission congestion relief and transmission upgrade deferral. To simplify the PF case, we extracted the whole Pacific Wyoming area from the PF case.

The PSH model and transmission network model required the following information:

- The PSH plant and connecting transmission line data, which were obtained from the data questionnaire provided to the PSH project personnel.
- The nodal LMP congestion cost, and all generator commitment status and dispatch schedule for the scenarios evaluated, which were provided by PLEXOS runs.

8.6.3.3 Scenarios

This project analysis uses the PCM base year 2028 as a starting point. The first scenario is a BAU case. The base scenario will represent the most likely capacity buildout and use average conditions for factors such as hydro and natural gas prices. The BAU model with and without the additional PSH plants are the two cases simulated in this study.

The impacts of a PSH plant on transmission congestion relief and upgrade deferral can be assessed by comparing the avoided cost of the two cases. As we can see in Figure 8-66, two different scenarios were developed for each case. The first scenario was designed to simulate the system operator's reaction to congestion relief by minimizing all branch congestion. In contrast, the second scenario has the objective of minimizing all congestion LMPs in the system. In both scenarios, the transmission congestion benefit is calculated by comparing the results of generation cost from the ACOPF optimization. The difference between the present value of building the system today and the present value today of delaying the project to the end of the deferral period represents the avoided costs for the transmission upgrade deferral period that can occur with the addition of the PSH plant under consideration.

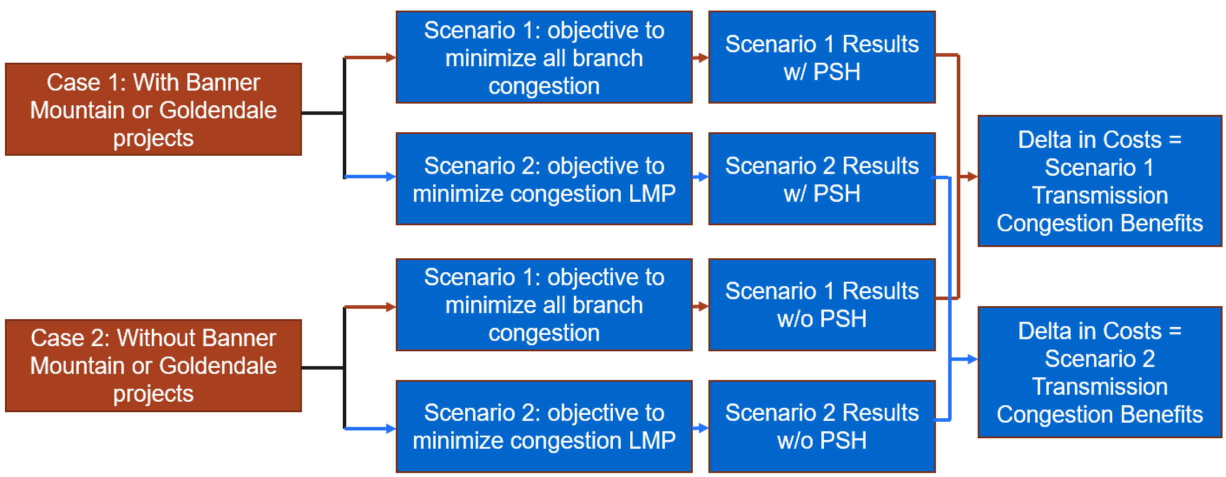


Figure 8-66 Two Cases and Two Scenarios for Calculating Congestion Relief

8.6.3.4 Modeling Runs and Results

The solution of the PLEXOS DA hourly PCM results includes all LMPs at all nodes in the Pacific Wyoming area. The direct comparison of whole-year probability density functions of LMPs with and without the BMSP is shown in Figure 8-67. As we can see, during most hours of the year, the LMPs are between \$0 and \$20/MWh. The BMSP will pump during low LMP periods and generate during high LMP periods. Compared with the case without the BMSP, the BMSP will decrease the probability of LMPs at higher prices and increase the probability of LMPs at lower prices.

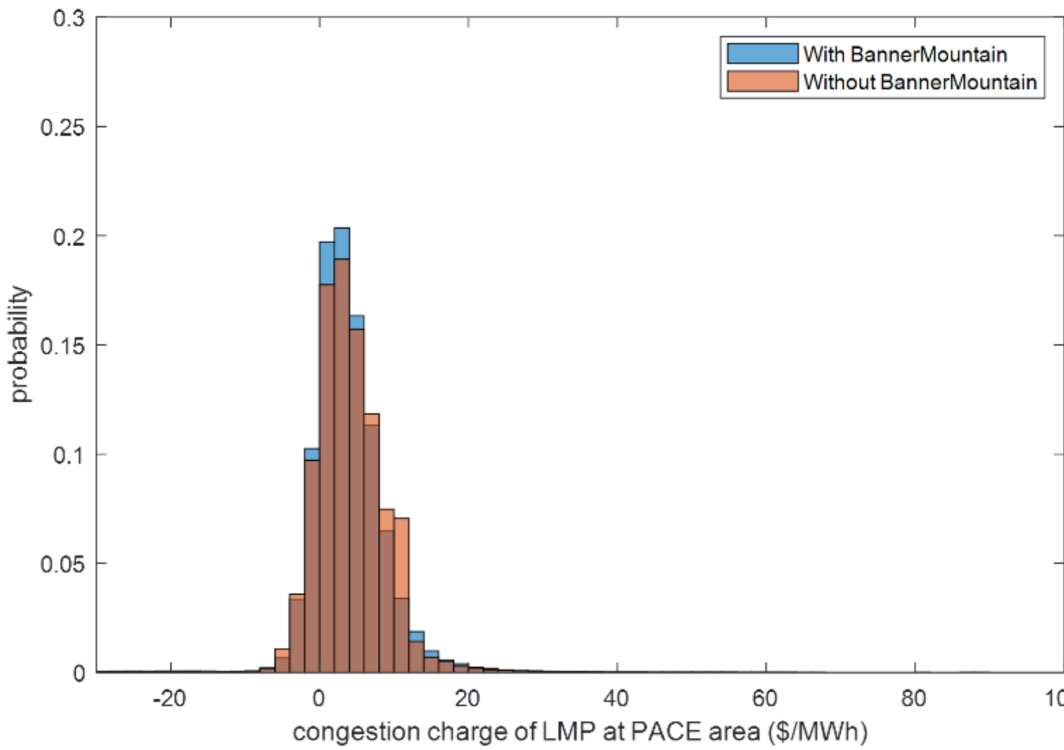


Figure 8-67 Congestion Charge LMP in the Pacific Wyoming Area

Figure 8-68 plots the duration of case 2 (without BMSP) of the 1-year average congestion LMPs of all nodes in the Pacific Wyoming area. As shown in Figure 8-68, the congestion LMPs are less than $100 for most of the year.

Based on the average LMP duration curve in Figure 8-68, we can select the representative hours to run the ACOPF simulation to calculate the detailed congestion relief. The 4 hours selected were 100%, 50%, 25%, and 5% of the peak LMP, respectively, in Figure 8-68.

The ACOPF simulation was run with and without BMSP to identify the line congestions that can be relieved by BMSP. As shown in Figure 8-69, there are four congested lines identified in the study.

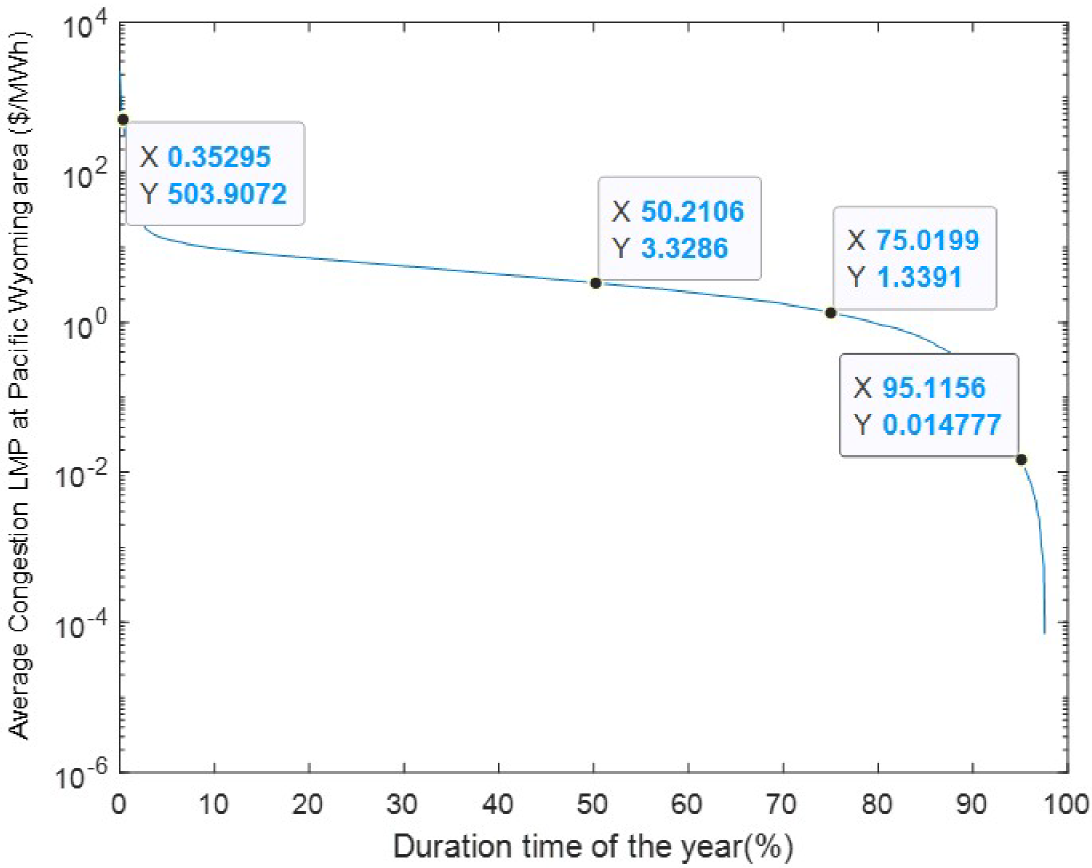


Figure 8-68 Congestion Charge LMP Duration Curve in the Pacific Wyoming Area

From bus	To bus	Voltage class	Line rating (MVA)	Line length (km)	Congestion in MVA
65172	65554	69	45	2.1	0.908827
65174	65554	69	45	1.2	0.659709
65467	66557	69	28	0.8	0.606367

Figure 8-69 Congested Lines that Can Be Relieved by the Banner Mountain Energy Storage Project

The average congestion charge of LMPs in the PACE area for the selected hours are compared in Figure 8-70. As shown by the blue and red curves in Figure 8-70, the existence of the BMSP can always decrease the average congestion LMP in the Pacific Wyoming area. Starting from the representative hours selected for the year, we can calculate the sum of congestion relief for the whole year by using linear regression. Based on the simulation results, Case 2 (without Banner Mountain) has total congestion costs of $148.53 million. In comparison, Case 1 (with Banner Mountain) has total congestion costs of $146.45 million, which is 1.42% lower than case 2 without the PSH facility. The total transmission congestion benefits of Banner Mountain were estimated at $2.1 million annually.

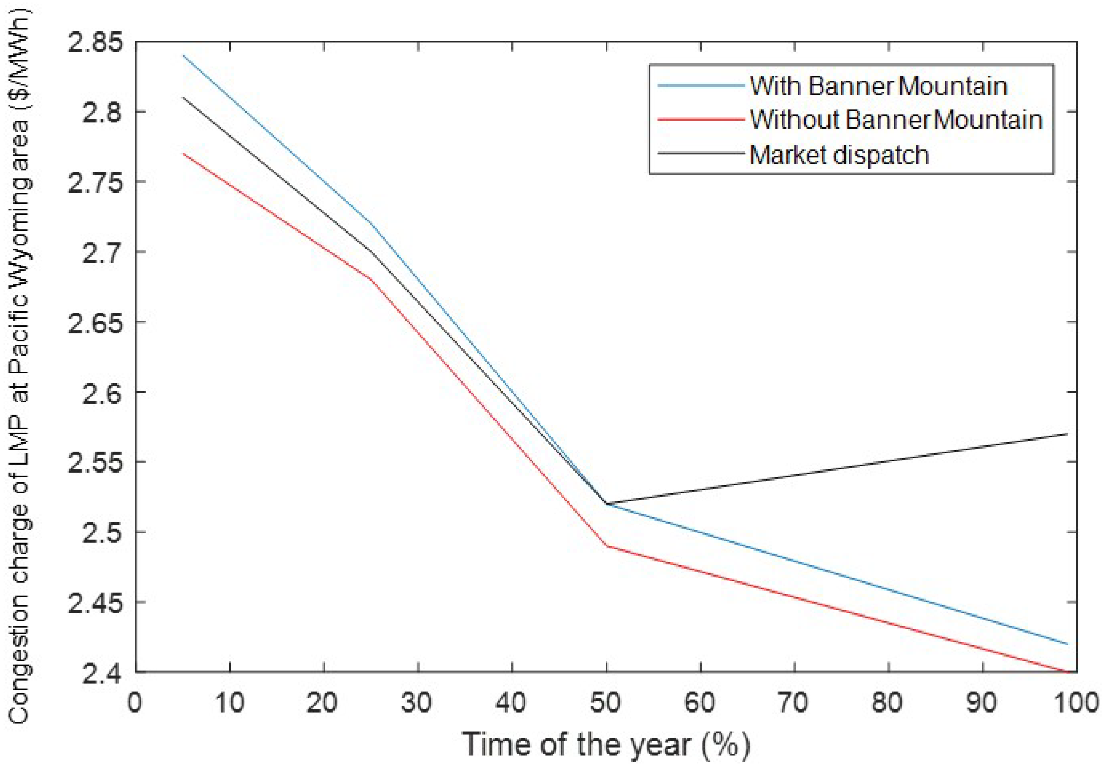


Figure 8-70 Congestion LMP Duration Curve Calculated from ACOPF Formulation in the Pacific Wyoming Area

The 1.42% decrease in congestion cost represents the value the BMSP could bring to the system operator through the calculation of the ACOPF. However, the PSH plant will pump during low LMP periods and generate during high LMP periods based on market energy prices. Therefore, we plug in the charging–discharging cycles for the PSH unit throughout the year, and then recalculate how the congestion component of LMPs throughout the region would change based on the addition of that unit's participation from market dispatch. To do this, we plug in the PSH charging–discharging cycles generated from PMAT from Argonne and rerun the ACOPF simulation to minimize the systemwide congestion costs at selected representative hours.

The generated ACOPF results (black curve in Figure 8-70) represents the average LMP in the Pacific Wyoming area through market participation. As shown in Figure 8-70, in 50% hours of the year with relatively high LMPs, the PSH decreases the average congestion LMP when the Banner Mountain project is generating power to the grid due to market participation. In another 50% of the hours with relatively low LMPs, the Banner Mountain PSH increases the average congestion LMP in case 2 from $2.42 per MWh to $2.57 per MWh, when the Banner Mountain project is pumping due to market participation at low LMP hours. The final calculated Case 3 (market participation) has total congestion costs of $147.72 million (0.6% lower than $148.53 million in case 2).

The WECC 2019 Transmission Capital Cost Tool can estimate the transmission line installation costs by line length, land and right-of-way, structures, and foundations. The estimated installation cost for the three lines is shown as:

- 65172 to 65554, line length 2.1 km ($5.5 million)
- 65174 to 65554, line length 1.2 km ($2.7 million)
- 65467 to 66557, line length 0.8 km ($1.5 million)

We assumed a 2% annual load growth rate. At that rate, there is a 2-year deferral time for the three congested lines. The sum installation cost for the transmission upgrade is $9.7 million. Using the representative FCR of 0.11, the annual charge (and revenue requirement) to own the upgraded equipment is $1,067,000. We assume the transmission line will be a 30-year project and use an annual discount rate of 6.9%. The detailed deferral benefits of the installation cost are shown as Figure 8-71.

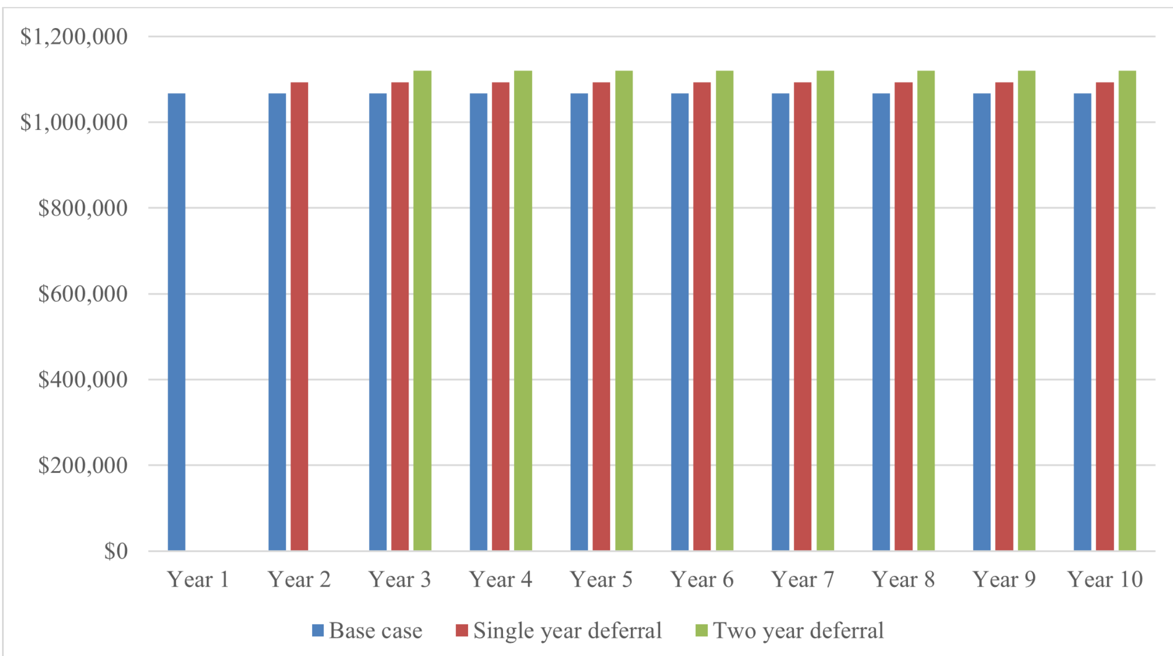


Figure 8-71 Annual Deferral Benefit of the Three Congested Lines

The present value of the 30-year project can be compared to the NPV of the 2-year deferral period. Therefore, we compare the present value of the base case with the 1-year deferral period and the 2-year deferral period in Figure 8-72. The calculated 2-year deferral benefit is $1.1 million.

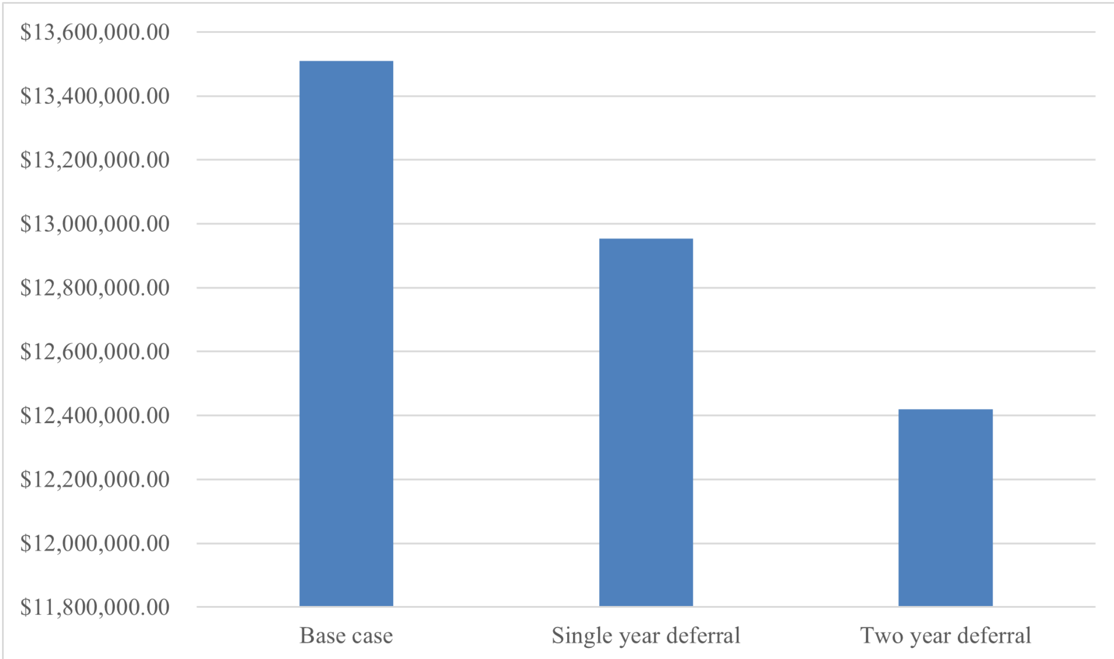


Figure 8-72 Comparison of the NPV of 1-year and 2-year Deferral Benefit

8.6.4 Conclusions

This study estimates the potential transmission benefit value of the BMSP project in the Pacific Wyoming area. Three PF cases (i.e., base case without BMSP, the base case with BMSP, and the base case with BMSP under market dispatch) are simulated and compared by using the ACOPF analysis performed at PNNL by using the production cost simulations results conducted by NREL.

This result shows that the BMSP project can provide transmission congestion relief with decreased congestion LMPs in the Pacific Wyoming area under market dispatch. The final calculated case 3 (with market participation) has a total annual congestion cost that is 0.6% lower than the base case without BMSP. The results further demonstrate that when PSH operators earn profit through market participation, they also produce some external benefits to the market (in the form of congestion relief at other adjacent nodes).

With DA PCM results from NREL, we do not see significant line congestion in the Pacific Wyoming area. There are three minor lines with congestion that could be relieved by the BMSP. Under a 2% annual load growth incremental rate, there was just a 2-year transmission upgrade deferral period for those three congested lines in the grid. The calculated 2-year deferral benefit is $1.1 million.

8.6.5 References

Black & Veatch, 2019, "WECC 2019 Transmission Capital Cost Tool - with E3 Updates." Available at https://www.wecc.org/Administrative/TEPPC_TransCapCostCalculator_E3_2019_Update.xlsx.

CAISO (California Independent System Operator), 1998, "ISO Tariff." Available at http://www.caiso.com/.

8.7 Non-Energy Services

8.7.1 Overview of the Analysis

The technoeconomic study in this section explores non-energy benefits of a PSH plant based on services that are traditionally attributed to conventional hydropower, such as flood control, water supply, navigation, recreation, greenhouse gas (GHG) emission offsets, and economic effects with respect to BMSP construction and operations. Based on configurations and operations of PSH, we found that some of these benefits may not be applicable (e.g., flood control, navigation), while others such as recreation may depend on the site and currently existing recreation (e.g., situated at an existing dam and major river).

Where applicable, we used existing studies to ascertain applicability of benefits to a project. Engineering judgment is used for assessing applicability of benefits because there are no existing studies and surveys for services pertaining to recreation, water supply, and similar benefits. Environmental effects of reduced GHG emissions are determined with respect to natural gas and coal. An economic study performed by a third-party consultant for Goldendale was used to estimate the economic effects for Banner Mountain. We use a benefits transfer approach, calculating jobs per megawatt of power capacity as our metric.

Based on our assessment, we find that services such as navigation, flood control, and water supply are not attributable to the PSH based on configuration, operation, and existing resources being used in the area. Fishing and boating recreation on the reservoirs is not expected due to pool fluctuations and safety concerns. Because Banner Mountain is located mostly on private land, it is estimated that the only applicable recreation would be hunting. Hunting on private lands is allowed in Wyoming in Hunter Management Areas (HMAs) and Walk-in Hunting (WIH) programs. We estimate that hunting on the private lands surrounding Banner Mountain would yield just over roughly $37,000 of annual benefit. Total economic impacts for Banner Mountain are estimated at $47.3 million and $4.7 million of annual income during the construction and operation phases, respectively.

8.7.2 Background on Service

Much like hydropower reservoirs, which can provide a multitude of services or benefits beyond generation (i.e., non-power benefits), we investigate PSH reservoirs to ascertain whether similar types of benefits are applicable. The potential benefits investigated are flood control, water supply, navigation, recreation, and environment.

For hydropower systems, flood control pertains to use of reservoir storage volume and flow releases to accommodate incoming floods. Water supply is provided as withdrawal from a reservoir and is typically based on an agreement of volume and rate of water withdrawal from the reservoir or river. This withdrawal can supply a multitude of uses including domestic and commercial, irrigation and livestock, thermal electric power, and industrial and mining. Water not consumed for these purposes is typically returned to the water body.

Navigation at and through reservoirs is supported by locks, which provides a means for watercraft to travel along waterways separated by dams. Recreational activities such as sight-seeing, boating, and swimming occur at reservoirs associated with dams and hydropower facilities. These activities can take place in the vicinity of the dam and miles up- and downstream of a facility, and can be beneficial to local and regional economies.

Environmental issues are typically concerns for open-loop PSH projects, because they connect to open rivers and waterways. However, environmental issues are minimized for closed-loop systems.

The economic benefits of a PSH project are realized through the creation of jobs associated with the construction and operation of the facility. Merchandise, retail, restaurants, and other public services in the area realize increases in revenues to support the increase in the local population.

8.7.3 Valuation Methodology

A combination of engineering judgement and assessment of traditional applications of potential services (flood control, navigation, water supply, etc.) was used to first assess the applicability of the potential benefits at the PSH facilities. Requests were made to the BMSP team to identify any previous studies that may have been conducted or knowledge of specific applications and potential uses such as water supply and/or irrigation that may be of interest for these projects, as well as projections of recreation. Studies regarding the economic impact due to direct, indirect, and induced impacts such as jobs and economic benefits were also requested.

8.7.4 Analysis

Each of the non-energy benefits for Banner Mountain was assessed to determine its applicability for the project. Although PSH and conventional hydropower facilities share mutual operations (i.e., generation based on head differences and use of reservoirs), the differences in configurations are relevant for assessing differences for most of the benefits.

Engineering judgement and knowledge gained from existing PSH facilities were used to assess applicability of benefits for flood control, water supply, and navigation. Assumptions for recreational use were made based on characteristics of the site and information available for similar projects. Environmental benefits for GHG emission reduction were estimated based on formulation. Economic benefits such as direct, indirect, and induced impacts resulting from construction and operation of a facility were determined.

Requests for information such as existing studies and/or surveys that could be useful for assessing benefits were sent to the BMSP team. An Impact Analysis for Planning (IMPLAN) economic study performed for Goldendale was used to inform the economic benefits for Banner

Mountain. No other studies and/or surveys were received that could be used to inform the assessment of benefits.

8.7.4.1 Overall Design of Study

To assess any potential benefits, we first determined each service's applicability to a PSH facility in general and specifically to Banner Mountain. Engineering judgement and precedence of existing applications of services were used to determine applicability for a PSH facility. If applicable, existing studies and/or surveys informed particulars such as quantities and needs specific to the facility and site and used to calculate benefit metrics. If no study was available, we attempted to gather information and characteristics of similar sites using internet searches of other facilities to inform an extrapolation.

8.7.4.2 Scenarios, Assumptions, Data Needs and Sources

This section evaluates the economic and environmental benefits of flood control, water supply, navigation, recreation, GHG emissions reductions, and PSH plant construction and operations. Based on the findings of the analysis presented in Section 8.7.4.5, we estimate that there would be no direct benefits associated with flood control, water supply, and navigation for the BMSP. The remainder of this section outlines the scenarios, assumptions, and data used in estimates the benefits associated with recreation, GHG emissions reductions, and plant construction and operations at Banner Mountain.

For recreation at Banner Mountain, we defined a scenario based on similarities to assumptions for recreational services and benefits at the Gordon Butte PSH facility in Montana. That scenario is defined as hunting on private land as a recreation service to the area. Because no actual survey data is available pertaining to the number of hunters on the private land at Banner Mountain, we used online data pertaining to the total number of hunters and the private land area in Wyoming to roughly define the number of hunters per private land area. We used this metric along with an area calculation for private land at Banner Mountain; estimated 2011 total expenditures for hunters were adjusted with the consumer price index (CPI) Inflation Calculator to 2021 dollars. This estimate is a rough approximation, because the approach equally distributes the number of total hunters throughout the specified private land area.

For Banner Mountain, no information (e.g., construction/operation timeframes, estimates for distribution/migration of direct construction/operation workers and laborers across and from counties and local regions, local salaries/benefits) was received pertaining to or supporting an economic analysis (e.g., IMPLAN, RIMS II). Therefore, we created a rough estimate of the economic benefits using a benefits transfer approach for Banner Mountain based on the results of Goldendale. Although such an estimate is not as accurate as a site-specific analysis using IMPLAN or RIMS II, we expect it to provide an order of magnitude comparison and some basis for assessment. Goldendale and Banner Mountain site characteristics and construction approaches are similar (i.e., both require construction of upper and lower reservoirs, operation as a closed-loop facility, and installation of three units). However, there are some differences in unit sizes and configurations (Goldendale installs 3 × 400 MW at 2,360 ft head and Banner Mountain at 3 × 133 MW in a Quaternary configuration at 1,175 ft head), which may produce differences in the number of construction jobs and timeframes between the two projects.

The metric of jobs per megawatt (power capacity) is used to estimate a benefits transfer for Banner Mountain. The jobs estimated in the Goldendale analysis refer to a mix of full- and part-time jobs and, as best as can be determined, represents full-time equivalents (FTEs) of work. The metric of FTE per megawatt of power capacity is a similar approach used in a Hydropower Workforce Report to estimate O&M employment based on installed capacity. An FTE of 1.0 equates to a single full-time worker. In the context of the referenced Workforce Report the metric is isolated to actual O&M direct jobs at the hydropower facility; here, it is used to roughly capture total (direct, indirect, and induced) impacts based on megawatt capacity between the two similar facilities and employment regions. Note that this is a crude approximation that can be affected by site characteristics, project configuration differences, and population of the local communities. Based on 2019 U.S. Census Bureau estimates, the population of Klickitat County, WA for Goldendale is 21,721 and is 13,921 for Converse County, Wyoming, for Banner Mountain. Although these populations are not the same, they both represent urban clusters defined by the Census Bureau as fewer than 50,000 people, and can be considered a classification just beyond "rural." The two counties are also both located in the northwest region of the United States.

The population of major towns within driving distance (around 90 minutes) include Casper, Wyoming (2019 Census data = 58,446), which is located just outside of the county where Banner Mountain will be located and Yakima, Washington (93,413), located near the Goldendale PSH site. Based on the similar characteristics of the populations near the two PSH facilities, it is not infeasible to draw comparisons between the two projects.

8.7.4.3 Modeling Runs and Results

We determined that there are no flood control, water supply, or navigation benefits for Banner Mountain, because as PSH facilities are not typically used for flood control or navigation. Discussions pertaining to these assumptions are provided in Section 8.7.4.5.

For recreation, we use the approach outlined in Section 8.7.4.2 to estimate that there are approximately 66,000 hunters on private lands, who spend on average $1,979 per hunter (adjusted to $2,351 in 2021 dollars). Based on 2011 estimates, we identified 1,176,497 acres of HMAs and 706,253 acres of WIH areas, totaling 1,882,750 acres. This equates to roughly 0.035 hunters per acre. Applying this to the roughly 453 acres of private land at the Banner Mountain site equates to an estimated 16 hunters and $37,616 (2021 dollars) of yearly benefit for recreational hunting.

For GHG determination at Banner Mountain, low and high emission offsets are determined corresponding to natural gas and coal, respectively. The CO_2 emission factors used for natural gas and coal are 544.1 kg CO_2/MWh and 943.8 CO_2/MWh, respectively. Yearly generation at Banner Mountain is estimated to be 1,300 GWh (1,300,000 MWh) based on project data.

The yearly avoided emissions in metric tons for Banner Mountain for the low offset (i.e., natural gas offset of 544.1 kg CO_2/MWh) for 1,300 GWh is 707,330 tCO_2. The avoided emissions in metric tons for Banner Mountain for the high offset (i.e., coal offset of 943.8 kg CO_2/MWh) for 1,300 GWh is 1,226,940 tCO_2.

These results are based on a simplified approach and assumption that all of the yearly generation is attributed to offsets in coal and natural gas, respectively, along with average values for offsets. A more detailed approach for assessing generation patterns accomplished with PCM reflects a more accurate representation of yearly generation and associated offsets for coal and natural gas. This approach yields a yearly generation of 667,691 MWh and uses offset rates of 953.2 and 392.4 kg/MWh for coal and natural gas, respectively. The offset value for coal is slightly higher (by about 1%) and for natural gas is lower (by about 28%) as compared to the value in the PSH Valuation Guidebook (943.8 kg CO_2/MWh for coal and 544.1 kg CO_2/MWh for natural gas) (Koritarov et al., 2021). The results based on values used in the PCM yield 636,443 and 262,002 tCO_2 per year for coal and natural gas, respectively. For comparison, results based on average offset values presented in the PSH Guidebook, using the more accurate yearly generation of 667,691 MWh as compared to the 1,300 GWh assumed in the simplified analysis, are roughly 630,167 and 363,291 tCO_2 per year for coal and natural gas, respectively.

We were unable to secure any information regarding the direct, indirect, and induced economic impacts of the BMSP. We therefore relied on the Goldendale Impact Analysis, which was adapted for Banner Mountain using the benefits transfer method (Highland Economics, LLC, 2019). There would be 1.27 jobs per MW of power capacity for Goldendale (based on total jobs supported in Washington and Oregon) during the construction phase and 0.108 during the operation phase. This equates to an average annual impact of $144.4 million. When divided by 1,550 jobs, the impact is measured as $93,161 per job during the construction phase. During the operations phase, $14.2 million in annual benefits is spread across 130 jobs, which totals $109,231 per job. Using these metrics to transfer and determine the economic impacts of Banner Mountain (400 MW) yields 508 jobs during the construction phase and 43 during the operations phase. This results in estimated annual income of $47.3 million and $4.7 million during the construction and operation phases, respectively.

8.7.4.4 Sensitivity Studies

No significant sensitivity studies were performed to assess service benefits.

8.7.4.5 Discussion and Valuation of "Service"

The non-energy benefits and their applicability to the PSH facilities and respective valuation of services/benefits are as follows:

- **Flood Control**—This is not applicable to Banner Mountain or for PSH facilities in most cases. Although upper reservoirs (in an open-loop case) and lower reservoirs (in a closed-loop case) could *theoretically* be used for flood storage, the amount of storage would be minor compared to the storage capabilities of the reservoir system used for the respective lower water body supply at or near a PSH facility.

- **Water Supply**—In general, drinking water supply is derived from an open continuous source system such as a river or reservoir. In most cases for PSH facilities, whether they are open- or closed-loop systems, the water used in the initial filling and subsequent operation of the generation and pumping sequences are obtained from local rivers, reservoirs, or streams that may already serve as water supply sources for local communities. The use of PSH reservoirs for water supply would require continual replenishing of makeup water that would interrupt the operation of a facility and would not represent a feasible solution for a water supply. For Banner Mountain, the local community of Casper, Wyoming, currently purchases water from the Central Wyoming Regional Water System, which is sourced from the North Platte River aquifer and surface withdrawals. The town of Douglas, Wyoming, sources its drinking water from the North Platte River, Little Boxelder Creek, and Sheep Mountain Well, with additional wells evaluated in a 2010 study. The town's average daily water use is on the order of 1.4 million gallons per day, which is roughly 0.10% of Banner Mountain's storage capacity. If daily operations of the PSH did not interfere with peak water supply demands and agreements were made, the reservoir could hypothetically be used as a water supply but would require a 30-mile closed-conduit water conveyance. Such a scenario is most likely not warranted, and would be cost prohibitive given the current infrastructure and supply available at the local towns. The nearby areas of Casper and Douglas derive irrigation water from the North Platte River, a source different than the one used for initial filling and makeup water. Although the reservoir water could theoretically reduce the need for local pumping stations, it would require facility infrastructure and a closed conduit pipeline that could exceed lengths beyond which it would be economically feasible for use. Further, it would necessitate provisions and agreements for operational adjustments and makeup water at the PSH facilities.

- **Navigation**—This benefit is associated with reservoirs and rivers that provide enough water draft depth to facilitate watercraft transportation along a river. Navigation locks at dam facilities facilitate passage of craft across adjacent different pool levels. PSH reservoirs do not provide this benefit because their configuration and operation do not support or control depth for watercraft in corresponding reservoirs or rivers used in open-loop systems. Navigation is essentially nonexistent for closed-loop systems.

- **Recreation**—For the Banner Mountain PSH project, no recreation surveys or studies are known to have been conducted. The majority of the site's land is private and a minority is associated with the Wyoming State Trust Land. No federal lands are associated with the project. A project similar to the Banner PSH is Gordon Butte PSH. Based on the FERC environmental assessment documentation for Gordon Butte (FERC project 13642-003), no recreational facilities at the PSH are proposed due to large reservoir fluctuations associated with project operation, which would make angling difficult and dangerous. Outfitter-guided hunting on private land associated with Gordon Butte may provide a potential for recreation at Banner Mountain. Yearly benefits (in 2021 dollars) for hunting of private land equates to roughly $37,616.

- **Environment**—Closed-loop PSH projects like Banner Mountain are generally associated with fewer environmental issues relative to open-loop systems because they are separated from open natural bodies of water. Like conventional hydropower, PSH facilities contribute to GHG reduction. This is determined as a reduction of the CO_2 to offset a mix of generation due to coal, natural gas, and lignite. For Banner Mountain, reduced yearly emissions estimates that take annual production values and apply them to emissions offsets for natural and gas and coal are 707,330 and 1,226,940 tCO_2, respectively. Results based on more accurate methodologies reflected in the PCM analysis yield 636,443 and 262,002 tCO_2 per year for coal and natural gas, respectively.

- **Economic Impacts**—A simple benefit transfer approach for estimating total economic benefits at Banner Mountain using an FTE per MW (power capacity) metric yields approximately 508 jobs and an annual \$47.3 million in the construction phase, and 43 jobs and an annual \$4.7 million in income during operation phase.

8.7.5 Summary of Results

No benefits pertaining to flood control, water supply, or navigation are expected for Banner Mountain. Recreational benefits for Banner Mountain were extrapolated from similar recreational benefits at Gordon Butte PSH, totaling \$37,616 annually. For Banner Mountain, reduced yearly emissions range are 707,330 and 1,226,940 tCO_2 when using natural gas and coal offsets, respectively. Results based on more accurate methodologies reflected in the PCM-based analysis yield 636,443 and 262,002 tCO_2 for coal and natural gas, respectively. Total economic impacts for Banner Mountain are estimated based upon a job per MW (power capacity) metric and results barrowed from an economic impacts analysis conducted for the Goldendale PSH plant result in economic impacts of \$47.3 million and \$4.7 million annually during the construction and operation phases, respectively.

8.7.6 Conclusions

Significant non-energy benefits are attributed to the economic effects of the jobs created for the respective regions due to the construction and continued multi-year operation of Banner Mountain. Discretion should be used as it was found that values for the jobs per MW (power capacity) metric as mentioned in other studies reviewed for this analysis vary compared to that based on the economic analysis performed by Highlands Economics for Goldendale. Thus, there is uncertainty when estimating economic impacts. Services often found at conventional hydropower plants like flood control, water supply, and navigation are generally not applicable to PSH due to their configuration and operational parameters.

8.7.7 References

Henningson, Durham and Richardson (HDR), 2017, *JD Pool Pumped Storage Hydropower Project – Conceptual Study*, Klickitat County, WA, June 9.

Highland Economics, LLC, 2019, "Appendix I: Socioeconomics Report for Federal Energy Regulatory Commission Project No.14861" in *Economic and Fiscal Impact Analysis of the Goldendale Pumped Storage Project for ERM*, Final License Application.

Koritarov, V., P. Balducci, T. Levin, M. Christian, J. Kwon, C. Milostan, Q Ploussard, M. Padhee, Y. Tian, T. Mosier, S.M.S. Alam, R. Bhattarai, M. Mohanpurkar, G. Stark, D. Bain, M. Craig, B. Hadjerioua, P. O'Connor, S. Mukherjee, K. Stewart, X. Ke, and M. Weimar, 2021, *Pumped Storage Hydropower Valuation Guidebook: A Cost-Benefit and Decision Analysis Valuation Framework*. doi:10.2172/1770766.

8.8 Step 11: Integration of Valuation Results

Energy storage systems (ESSs) face a significant challenge when attempting to assign value to the services they provide. ESSs have several unique attributes that differentiate them from traditional generators: they can act as both generation and load, have the ability provide benefits at multiple points in the grid, and have the capacity to be more effective than conventional generation in meeting ramping requirements and responding to frequency regulation signals. These systems, including PSH, have operational limitations that are not entirely captured with nameplate ratings or single value specification. Unlike traditional generation technologies, an ESS's current state is influenced by all previous states. Thus, it can be challenging to schedule and dispatch PSH in a manner that provides the highest value.

This study addresses grid services that can be provided by PSH systems and defines approaches for assigning value to each of these services. However, as is the case with every other energy storage technology, PSH is energy limited and cannot meet the requirements of every service simultaneously. There is competition for the energy in the PSH unit. There is intertemporal competition in that if energy is supplied in an hour, there is less of it available in the next. There is also competition for the energy between services. The provision of one service (e.g., frequency regulation) may preclude or reduce the capability of the PSH unit to provide another (e.g., energy arbitrage). Thus, the complexity of correctly valuing PSH comes not only from the devices themselves, but also from the potentially competing methods of gaining value from a given set of use cases.

The PSH unit can be charging or discharging (i.e., pumping and generating) at different points in time throughout each day, and determining the optimal current and future power exchanges is complex. Each value stream or use case has a set of requirements and limitations that must be addressed for the value to be captured. Furthermore, physical and market characteristics may limit operational value at certain times. Gaining value from a broad spectrum of services therefore requires extensive consideration. A co-optimization procedure and valuation model is therefore necessary when stacking benefits to avoid double counting.

An accounting framework must also be established to determine the perspective from which value accrues. For example, the analysis of transmission system operations has determined that both PSH systems could provide both transmission congestion relief and the ability to defer investments in the transmission system. While this represents a benefit to the system and therefore society, monetizing this benefit through a market or bilateral contract appears unlikely for the Banner Mountain system. Further, monetizing transmission benefits in isolation is unrealistic because the operation schedules for PSH systems are principally dedicated to other, higher value use cases. This integration assessment addresses both these issues.

The remainder of this section presents an overview of our approach for integrating the individual use case studies and our results. We define the approach used to estimate system- and operator-based benefits for each use case, define our integration approach, discuss other key considerations, and outline scenarios evaluated for each use case. We then describe our integration and modeling approach in more detail and present results.

8.8.1 Modeling Flow and Coordination of Technoeconomic Studies

The technoeconomic studies defined in Section 8.7 were conducted by the project team and the responsibilities of different labs are indicated in Figure 8-73. While each analysis has a clearly defined lead lab, the lab teams collaborated closely; certain analyses need to be coordinated and use the same baseline and scenario assumptions to ensure that the results are consistent across various analyses and so the team can avoid double counting of benefits. For example, Argonne used the AURORA model to develop capacity expansion builds for several scenarios as defined in Figure 8-73. The NREL team then used the results of those capacity expansion runs to run production cost simulations for 2028 and 2038 using the PLEXOS model. The results of the production cost runs were then passed on to the INL team to analyze potential benefits of the BMSP on power system stability, and to the PNNL team to study potential benefits on transmission congestion and deferrals. The PLEXOS runs prioritize energy and ancillary services. The power system stability analysis reserves capacity for primary frequency response and voltage support using only the capacity unused by those prioritized services. Transmission services monetize value based on the impact of all other operations on transmission congestion. Figure 8-73 illustrates this modeling flow and how the labs coordinated different analyses.

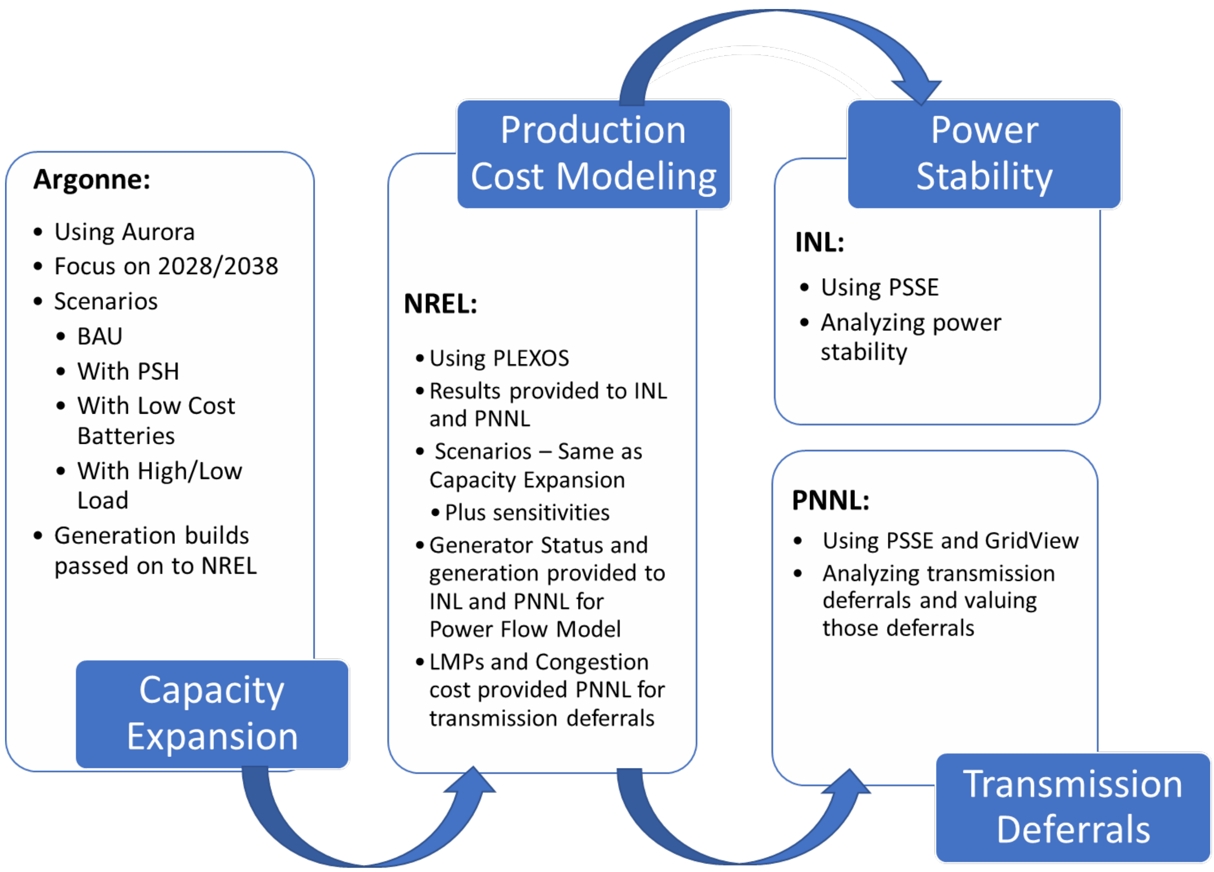


Figure 8-73 Modeling Flow and Coordination of Technoeconomic Studies

8.8.2 Basis of Integration

The basis of use case integrations is summarized at a high level in Table 8-26. As noted in Section 8.1, AURORA modeling was used to define WECC-wide generation portfolios for several scenarios in future years 2028 and 2038. PLEXOS, using these generation portfolios as inputs to the PCM process, then co-optimized system operations to minimize energy generation and ancillary service costs throughout the WECC. These costs were estimated with and without the availability of Banner Mountain PSH, with the difference in costs being used to define value. For the owner-operator analysis, operations were still optimized for system benefits, but the value of arbitrage was estimated based on local LMPs evident when the PSH unit was charging (purchasing energy) and discharging (selling energy) while accounting for RTE losses. Black start, voltage support, and primary frequency response values were estimated using the PSH capacity remaining after co-optimizing for energy and ancillary services, while transmission benefits were estimated assuming that any benefits accrued as a byproduct or positive externality of plant operations. That is, transmission services are not prioritized in the co-optimization procedures, but the system benefits associated with the transmission congestion component of regionwide LMPs or the deferral of transmission investments can be quantified. Note that transmission benefits register no monetized value to the owner-operator due to an absence of direct market or non-market funding mechanisms. The remainder of this section provides more detail concerning the approaches used to integrate the results for each use case and reports the co-optimized values by use case when stacked.

Table 8-26 Summarizing the Basis of Use Case Integration

Use Case	System	Owner-Operator
Capacity, Generation Costs/Arbitrage, Spin Reserve, Frequency Regulation	AURORA and PLEXOS Co-optimization	Co-optimized with respect to system benefits but value based on relevant prices (e.g., LMP for arbitrage)
Black Start	Evaluation of exceedance curves demonstrates that 1.73 GWh of firm storage is available for black start service	Evaluation of exceedance curves demonstrates that 1.73 GWh of firm storage is available for black start service
Voltage Support, Primary Frequency Response	Analysis performed by INL found up to 5% (20 MW) of Banner Mountain capacity can be committed to primary frequency response and 15 mega volt ampere reactive (MVAr) can be committed to voltage support without conflicts with primary services	Analysis performed by INL found up to 5% (20 MW) of Banner Mountain capacity can be committed to primary frequency response and 15 MVAr can be committed to voltage support without conflicts with primary services
Transmission Congestion Relief	PLEXOS runs establish dispatch and ACOPF model determines reduction in congestion component of LMPs	Positive externality to system but not monetized benefit
Transmission Deferral	ACOPF program used to alleviate congestion along targeted lines	Positive externality to system but not monetized benefit

8.8.2.1 Capacity

Resources that provide capacity to a power system will typically be compensated for the value of capacity by agreeing to make themselves available to generate energy when called upon, particularly during peak load conditions. If they are called upon to do so in system operations, they are separately and additionally compensated for the energy that they can generate. Similarly, they can also receive separate and additional revenues for providing reserve capacity in RT operations. The capacity value reflects the availability of a resource, not actual delivery of energy. Therefore, the capacity value can be considered separately and independently in the integration task.

AURORA, a commercial power system expansion model, was used to simulate generation expansion and retirement throughout the entire WECC from 2019 through 2038. We used AURORA to simulate the value of capacity as a service in the RMRG from the perspective of a neutral system planner. The value of capacity was estimated based on the marginal resource's revenue requirement in terms of satisfying the PRM in the RMRG. The capacity supply curve was developed for the RMRG each year by ordering all the resources in the RMRG according to their revenue requirement, normalized by their peak capacity contribution. The capacity demand curve was developed as a vertical curve. The value of capacity was then determined by the intersection of these supply and demand curves. The future power system generation portfolios were therefore defined using AURORA and then carried forward to the PCM simulations where PLEXOS was used to define energy and ancillary service benefits.

8.8.2.2 Energy and Ancillary Services

Resources that provide energy to a power system are compensated for the energy they generate. Similarly, resources that consume energy are required to pay the value of energy that they consume. Unlike the capacity value, there is an interdependency between the value of energy and other services, particularly ancillary services, because not all services can be provided simultaneously due to physical constraints and because different services require different outputs from the generating units. There is a temporal dependency as well, due to the impacts of previous uses of stored energy on the available energy in the next hour.

For a cost-based system-oriented valuation, the optimal dispatch schedules from the PLEXOS runs already consider the interdependency between services and the temporal dependency. Therefore, the dispatch schedule and the marginal costs of electricity generation and ancillary services, including frequency regulation and spin/non-spin reserve, were used to calculate the system value of the Banner Mountain PSH plant.

In this approach, we use production cost simulation results to assess the value of PSH energy arbitrage operations from the system perspective. The value of energy (i.e., production cost savings) can be estimated by comparing the total system production costs in two cases: (1) with and (2) without the Banner Mountain PSH plant. The results show that the BMSP can provide production cost savings in all future cases. This approach also established the basis for defining the value of energy arbitrage from the perspective of asset owners based on the difference between the value of PSH electricity generation, using local LMPs rather than systemwide costs, and the cost of energy used for pumping while accounting for RTE losses.

8.8.2.3 Power System Stability and Black Start Services

The value of voltage support is estimated by assessing the quantity of reactive power capable of being contributed by the Banner Mountain PSH unit during widespread voltage events. Based on a review of PSH unit operation modeled in PLEXOS, the study authors use 15 MVAr as the voltage capacity for the Banner Mountain PSH unit. Based on a review of PSH unit operation modeled in PLEXOS, the INL team determined that 5% of system capacity (20 MW) could be reserved for primary frequency response. Further market analysis would be required to establish the optimal reserve level. The PSH units were modeled to respond to 200 frequency events annually.

With respect to black start, in addition to the ability to "self-start" there are a variety of other requirements, which typically include: (1) the capability to accept instantaneous demand blocks, (2) the ability to provide sufficient generation for the duration of the restoration plan (typically between 7 and 16 hours); and (3) the ability to maintain a high service availability (typically 90%). The last requirement is most significant in determining a firm capacity dedicated to the provision of black start services because it requires capacity that is available at least 90% of the time.

It is not necessary to consider the black start service in a co-optimization for the integration task because the value of the potential black start service is relatively small. Instead, the black start service value was assessed based on the remaining capacity that could be used for black start. This value was determined by creating an exceedance curve using the dispatch schedules from the power system production cost simulation results (i.e., PLEXOS study results from NREL). Evaluation of exceedance curves demonstrates that 1.73 GWh of firm storage is available for black start service. Then the annual black start cost-of-service was estimated by leveraging the subcomponents values (i.e., the values for the fixed black start service compensation, variable cost compensation, and the training cost compensation) in combination with the cost-of-service equation defined in Section 8.5.3.

8.8.2.4 Transmission Services

One of the constituents of LMPs is the cost of transmission congestion. If market participants are able to alleviate the congestion by providing energy in RT, the LMP drop provides value to consumers and transmission authorities. This value, which can be counted in a system benefit–cost analysis, does not typically result in compensation directly to the operator. With that noted, there are mechanisms for monetizing the value of transmission congestion relief. Based on the outcome of the analysis performed by PNNL and discussions held with the Banner Mountain PSH team, no revenue associated with transmission congestion relief is envisioned at this time.

Transmission congestion relief is a cost driven activity, meaning that transmission congestion relief service is tightly coupled with other ancillary services that can be provided by PSH. There is interdimensional competition for the energy stored by the PSH unit. Therefore, not all services can be provided simultaneously and use of stored energy in one hour can reduce the amount of energy stored in the PSH unit and available in the next hour.

Because the transmission congestion relief value is very low and non-monetizable from the perspective of the operator, it would not be a primary driver in the dispatch schedule. With that noted, PSH generation during peak periods would alleviate transmission congestion during the highest value hours and yield significant reductions in the congestion component of LMPs. Energy generation cost reductions are realized in the PLEXOS model through reductions in startup and fuel costs. Therefore, reductions in the congestion component of LMPs would not already be embedded in those cost savings and can be counted here from a system cost perspective. From an owner-operator perspective, there would be no direct value in the absence of congestion revenue rights, transmission congestion contracts, or some other compensation mechanism. It would rather be a positive externality associated resulting from other operations, such as arbitrage.

To determine the value of this external benefit, the dispatch schedule from the NREL PCM was used to define the annual charging/discharging profile of the PSH. This profile was modeled in the PF model using the ACOPF for congestion relief to determine the marginal benefit of transmission congestion relief while engaged in other operations. The modeled hours were fitted to the PCM LMP congestion cost curve to determine the annual benefit of transmission congestion relief.

The PF model was used to define the number of hours during which load would exceed transmission capacity of the congested lines identified in Figure 8-69. Peak load hours were defined for each line and the dispatch schedule from the NREL PCM was consulted to determine whether the high-load hours are addressed through other energy and ancillary service operations. We found that when operated primarily for energy and ancillary services, the impact of Banner Mountain PSH plant operations did not reduce load below transmission capacity limits along the congested lines. Therefore, no transmission deferral value was obtained after the co-optimization procedure was completed.

8.9 Step 12: Cost-Benefit Analysis for Each Alternative

In this step, the CBA is utilized to define the economic value of each use case over the economic time horizon of the project and to compare the value of each alternative evaluated in common across all use cases. Using the results for the assessed values of PSH services that were developed in the previous steps, the CBA is conducted to calculate several performance metrics, including NPV, payback period, and IRR. These metrics are reported in Step 15.

The Argonne team developed a CBA model and set of financial worksheets to perform the financial analysis for the Banner Mountain PSH plant. The CBA calculator runs the user through a series of data input fields to acquire all information needed to perform the financial calculations. The model enables the user to define alternative scenarios, evaluate many use cases, and consider alternative debt structures, varying depreciation methods, tax implications, salvage value, all capital and O&M costs, and all refurbishment costs over a defined CBA period. The CBA model then uses these inputs to define an NPV, benefit–cost ratio (BCR), payback period, and IRR for each case under consideration.

The CBA model requires detailed information for several key financial parameters. These parameters, including the defined value and basis of each value are presented in Table 8-27. Key inputs include project cost at $1.12 billion, a 10-year project development period but 5-year construction period, a 50-year CBA period, a 6.98% discount rate, and a 2% escalation rate for value of service and capital/O&M costs. The values were obtained primarily through a data questionnaire completed by the Banner Mountain project team and through a series of follow-on conversations. Additional data were obtained from WECC (weighted average cost of capital for the project sponsor).

Table 8-27 Key Financial Parameters

Key Financial Data Requirements	Value	Basis
Project development period (years)	10	Absaroka Energy
Project construction period (years)	5	Absaroka Energy
CBA period (years)	50	Equal to plant economic life
Plant depreciable lifetime	30	Absaroka Energy
Plant economic life (years)	50	Absaroka Energy
Total cost	$1.12 billion	Absaroka Energy
Amount financed	70%	Absaroka Energy
Year of financial closure on loans (when funds are available and interest starts to accrue)	As required	Standard assumption
Repayment period (years)	30	Absaroka Energy
Interest rate on debt financing (%)	4% (long-term treasure rate plus 200 basis points)	Absaroka Energy
Type of payment schedules	Even Payments	Standard assumption
Weighted average cost of capital for sponsor—discount rate for owner-operator (%)	6.98%	WECC-wide IOU rate
Federal tax rate (%)	21%	WECC cost calculator
State tax rate (%)	0%	Wyoming state income tax rate
Recurring capital investment	$100 million in year 30	Absaroka Energy
Annual O&M costs	$6 million	Fixed for 10 years, then grow at 2%
Escalation rate for value of service and capital/O&M (%)	2%	Absaroka Energy
Insurance cost (annual as % of capital investment) (%)	0.20%	Absaroka Energy
Property tax and other cost rates (%)	0.01%	Absaroka Energy
Expenditure pattern during construction period	$0.5, $2, $2, $5, $5, $465, $180, $180, $180, $100.5 (millions)	Absaroka Energy
Non-depreciable investment costs	$11.5 million	Land and site prep costs in Banner Mountain data questionnaire

8.10 Step 13: Perform Risk Assessment

The purpose of this step is to identify and evaluate potential risks that may impact the value of the project being evaluated. The CBA performed in Step 12 is subject to numerous uncertainties and short- and long-term projections (e.g., fuel price projections, revenue projections) made during the valuation process. Therefore, the cost benefit analysis is typically followed by a risk assessment to evaluate which factors and uncertainties may have the greatest impact on NPV, benefit–cost ratios, and other parameters.

For this analysis, we evaluated the sensitivity of the results with respect to a few key parameters, varying them as follows:

- Vary discount rate by ±1%
- Vary cost and revenue escalation rates by ±1%
- Add 30% investment tax credit
- Property taxes increased to 0.5%
- Compare to RT high renewable energy case
- Compare to DA high renewable energy case
- Compare to DA baseline case
- Economic lifetime extended to 100 years

These alternatives are compared against the RT baseline case to measure the range of potential impacts on NPV for each sensitivity analysis. Results are presented in Section 8.12.

8.11 Step 14: Perform Multi-Criteria Decision Analysis

MCDA is a decision support tool that enables diverse stakeholders to consider a variety of concurrent goals when deciding on energy policies, initiatives, and infrastructure investments. MCDA provides a flexible method for analyzing complex multi-objectives (e.g., sustainability, resilience, reliability, flexibility, affordability) and priorities that are hard to quantify in monetary terms (e.g., climate equity, social equity, resilience) with a structured decision-making process. MCDA also accounts for stakeholder-specific weighting of considered objectives. With appropriate weighting to reflect the relative importance of competing objectives, MCDA can be applied for valuation assessments and decision support focused on transition to equitable, resilient, and sustainable energy.

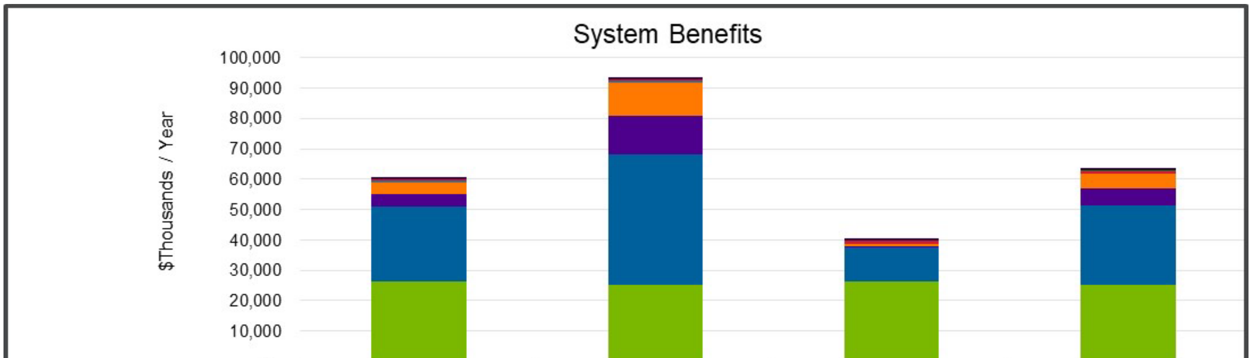
MCDA is a systematic and local set of procedures for analyzing complex, multi-objective problems. MCDA enables the analyst to evaluate competing investment opportunities while considering a broader set of policy and stakeholder priorities. Because we only consider the lone investment option comprised of the proposed Banner Mountain PSH plant in this study, there were no multiple project investment alternatives suitable for comparison using MCDA, so we did not perform an MCDA and this step can be skipped.

8.12 Step 15: Compare Values, Document Analysis, and Report Findings

The final step in the valuation process includes comparing the values obtained for different alternatives, documenting the valuation analysis results, and reporting the key findings to decision-makers and stakeholders. The comparison of results obtained for different alternatives is essential for understanding the valuation process. Results based on the procedures defined for all previous steps are presented here.

8.12.1 Annual System and Owner-Operator Values

Results of the system analysis are presented in Figure 8-74. It shows the co-optimized value of system services by use case in the first year of Banner PSH operations for four scenarios: RT (5-minute) operations under a baseline scenario, RT operations under a high renewable energy case, DA (hourly) operations under the baseline scenario, and DA operations under the high renewable energy case. The annual system value of the Banner Mountain PSH plant ranges from $40.5 million (DA, baseline) or $101/kW-year, to $93.7 million (RT, high renewables) or $234/kW-year. The vast majority of the value is tied to capacity and energy services (84% of RT base case). Unserved energy and other societal benefits are excluded from the analysis. The transmission deferral value is eliminated in the co-optimization process.

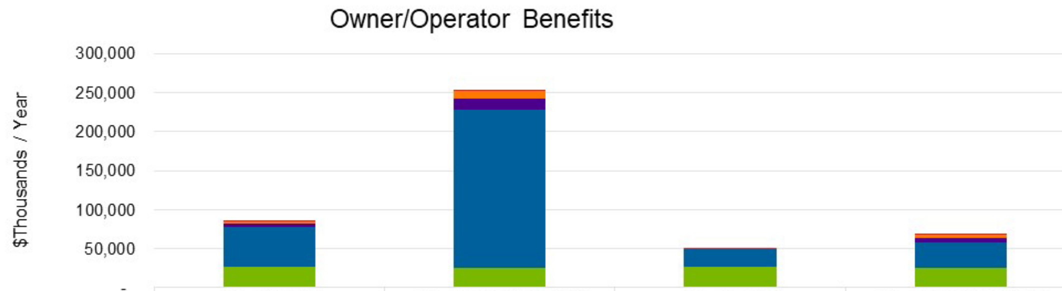


	RT - Baseline	RT - High Renewables	DA - Baseline	DA - High Renewables
Unserved Energy	-	-	-	-
Transmission Congestion Relief	810	810	810	810
Transmission Deferral	-	-	-	-
Voltage Regulation	52	52	52	52
Primary Frequency	960	960	960	960
Black Start	152	152	152	152
Frequency Regulation	3,761	10,750	600	4,501
Spin	4,124	13,014	481	5,606
Generation/Arbitrage	24,800	42,900	11,300	26,400
Capacity	26,184	25,100	26,184	25,100

Figure 8-74 Annual System Value of Services Provided by Banner Mountain PSH Plant

The results show the increasing value of long-duration energy storage when the system has high VRE resource capacity. In addition, the cases with the 5-minute time resolution show the importance of considering a finer time resolution in assessing the value of energy storage that has a high ramping capability in a system with high VRE resource capacity.

Figure 8-75 presents the co-optimized value of services accruing from an owner-operator perspective for the same four scenarios. Annual estimated revenue under the owner-operator scenario ranges from $50.9 million (DA, baseline) or $127/kW-year to $253.3 million (RT, high renewables) or $633/kW-year. The vast majority of the revenue is tied to capacity and energy services (90% of RT base case). RT and high renewable cases yield much higher values to the owner-operator. Unserved energy, voltage regulation, and all transmission services yield no revenue due to an absence of financial mechanisms for monetizing the value of these services.



	RT - Baseline	RT - High Renewables	DA - Baseline	DA - High Renewables
Unserved Energy	-	-	-	-
Transmission Congestion Relief	-	-	-	-
Transmission Deferral	-	-	-	-
Voltage Regulation	-	-	-	-
Primary Frequency	960	960	960	960
Black Start	152	152	152	152
Frequency Regulation	3,761	10,750	600	4,501
Spin	4,124	13,014	481	5,606
Generation/Arbitrage	51,210	203,350	22,560	32,640
Capacity	26,184	25,100	26,184	25,100

Figure 8-75 Annual Owner-Operator Value of Services Provided by Banner Mountain PSH Plant

8.12.2 Results of the Benefit Cost Analysis

The results of the benefit–cost analysis from a system perspective are presented in Table 8-28. For this analysis, we employed five metrics, defined as follows:

- NPV (end-of-the-year and mid-year methods)—The difference between the present value of cash inflows (benefits) and the present value of cash outflows (costs) over the benefit-cost analysis period. A positive value demonstrates that present value inflows exceed outflows.
- BCR—Discounted total revenues or benefits for the project divided by discounted total costs. A BCR of more than 1.0 demonstrates a positive return on investment.
- IRR—Highest discount rate for which the NPV of the project would be positive.
- Discounted payback period (years)—Number of years it takes to break even from undertaking the initial expenditure when discounting future cash flows and accounting for the time value of money.

Using these five metrics, we see that under three scenarios of the system analysis, costs exceed the value of services provided to the electrical grid with NPV metrics (mid-year method) ranging from -$149 million (DA, high renewables) to -$523 million (DA, baseline). Among these scenarios, BCRs range from 0.33 to 0.81, and IRRs range from 1.9% to 5.6%. Under the RT high renewables scenario, the NPV (mid-year method) is positive at $301 million. The RT high renewables scenario produces a BCR of 1.38 and IRR of 9.4%. A BCR of 1.38 indicates that for every dollar invested in the project, benefits in present value terms would be $1.38. Discounted payback periods are not measured for the three scenarios with negative returns but for the RT high renewables scenario, the discounted payback period is 23 years.

Table 8-28 System Analysis Results

Metric	RT Baseline	RT High Renewables	DA Baseline	DA High Renewables
NPV (end-of-year-method), $	$(184,661,570)	$290,733,699	$(505,794,685)	$(143,993,215)
NPV (mid-year method), $	$(190,997,560)	$300,709,169	$(523,149,191)	$(148,933,819)
BCR	0.76	1.38	0.33	0.81
IRR	5.2%	9.4%	1.9%	5.6%
Discounted Payback Period (years)	N/A	23	N/A	N/A

System results explore the benefits of the BMSP across the western United States. The analysis compares the numbers with versus without Banner Mountain, where value is derived from the avoided startup and fuel costs of other units that would have otherwise been employed to address system needs. Because the scale is so large, it affords maximum flexibility in the system response, thus dampening the impacts and system value of BMSP services.

The results of the analysis from the perspective of the owner-operator are presented in Table 8-29. With the owner-operator serving as the beneficiary of plant operations, value is lost for some use cases (e.g., transmission congestion relief, voltage regulation) because there is no mechanism for monetizing the value of the service. However, Banner Mountain is more profitable under each of these cases largely because the arbitrage value—which is calculated using local LMPs—produces much higher value captured in the form of revenue. The RT scenarios produce positive returns on investment ranging from $191 million (RT baseline) to $2.6 billion (RT high renewables). BCRs for the RT baseline and RT high renewables scenarios are 1.24 and 4.41, respectively. Both the DA baseline and DA high renewables scenarios fail to produce positive returns on investments with BCRs registering at 0.56 and 0.91, respectively. Under the RT high renewables case, the IRR is 22.4% and the payback period is 11 years. Under the only other scenario yielding positive returns on investment (RT baseline), the IRR is 8.6% and the payback period is 31 years.

Table 8-29 Owner-Operator Analysis Results

Metric	RT Baseline	RT High Renewables	DA Baseline	DA High Renewables
NPV (end-of-year-method)	$184,934,365	$2,588,855,940	$(337,287,745)	$(66,092,447)
NPV (mid-year method)	$191,279,715	$2,677,683,121	$(348,860,548)	($68,360,169)
BCR	1.24	4.41	0.56	0.91
IRR	8.6%	22.4%	3.7%	6.4%

Metric	RT Baseline	RT High Renewables	DA Baseline	DA High Renewables
Discounted Payback Period (years)	31	11	N/A	N/A

8.12.3 Evaluation of Alternative Scenarios and Sensitivity Analysis

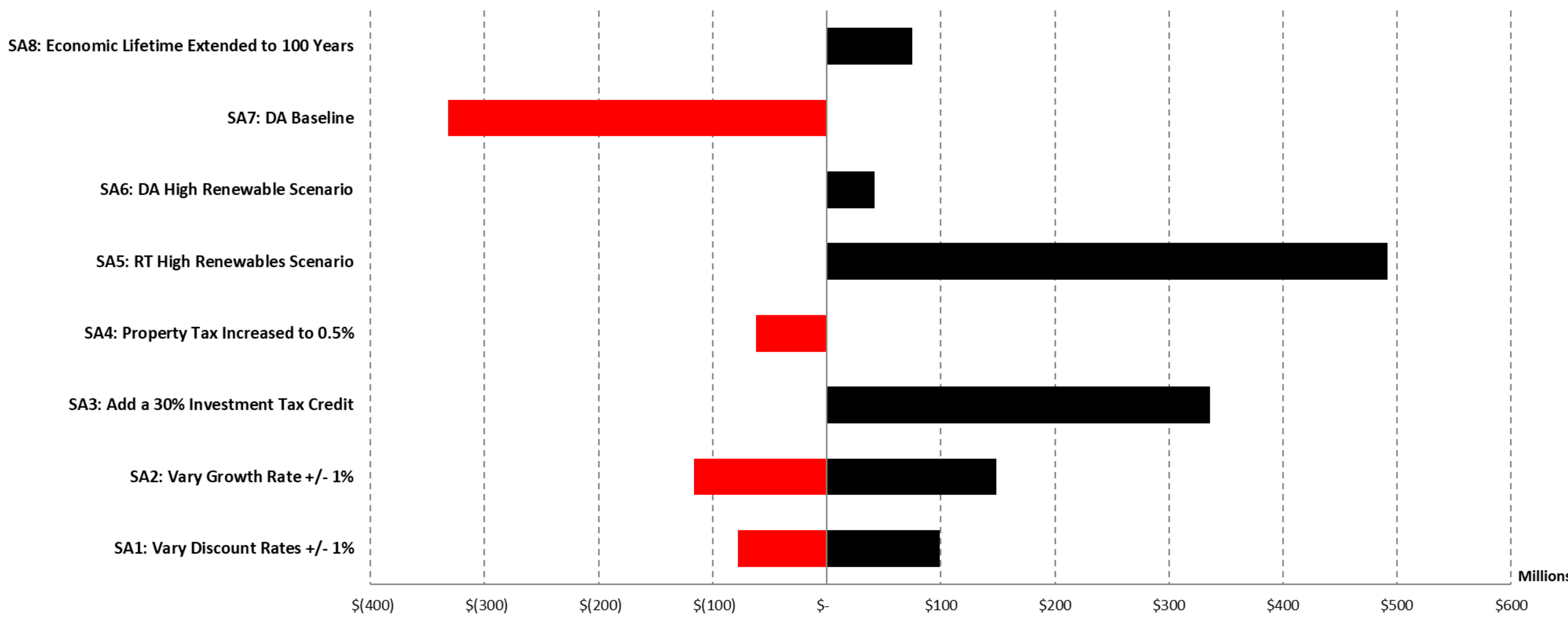
We evaluated the sensitivity of the results with respect to changes in a number of key assumptions and parameters. These scenarios and their impacts are outlined in this section as compared to the system and owner-operator RT base cases. The following adjustments to the assumptions were made:

- Vary discount rate by ±1%
- Vary cost and revenue escalation rates by ±1%
- Add 30% investment tax credit
- Property taxes increased to 0.5%
- Compare to RT high renewable energy case
- Compare to DA high renewable energy case
- Compare to DA baseline case
- Economic lifetime extended to 100 years

The results of each sensitivity analysis for the system analysis are presented in Figure 8-76. Note that the table below the figure presents the corresponding values numerically. As shown, 6 of the 8 evaluated scenarios yield either entirely or mostly positive impacts on the financial results when compared to the RT base case. The effects of extending the economic lifetime of the PSH plant and increasing the property tax rate to 0.5% are not significant. Due to the long life of the PSH plant, a 1-percentage-point increase in the cost/value escalation rate or reducing the discount rate by one percentage point would have a moderate impact on financial results, yielding higher PV benefits of roughly $149 million and $99 million, respectively. Reducing the cost/value growth rate by 1 percentage point and increasing the discount rate by 1 percentage point reduces the NPV (mid-year method) by $117 million and $78 million, respectively.

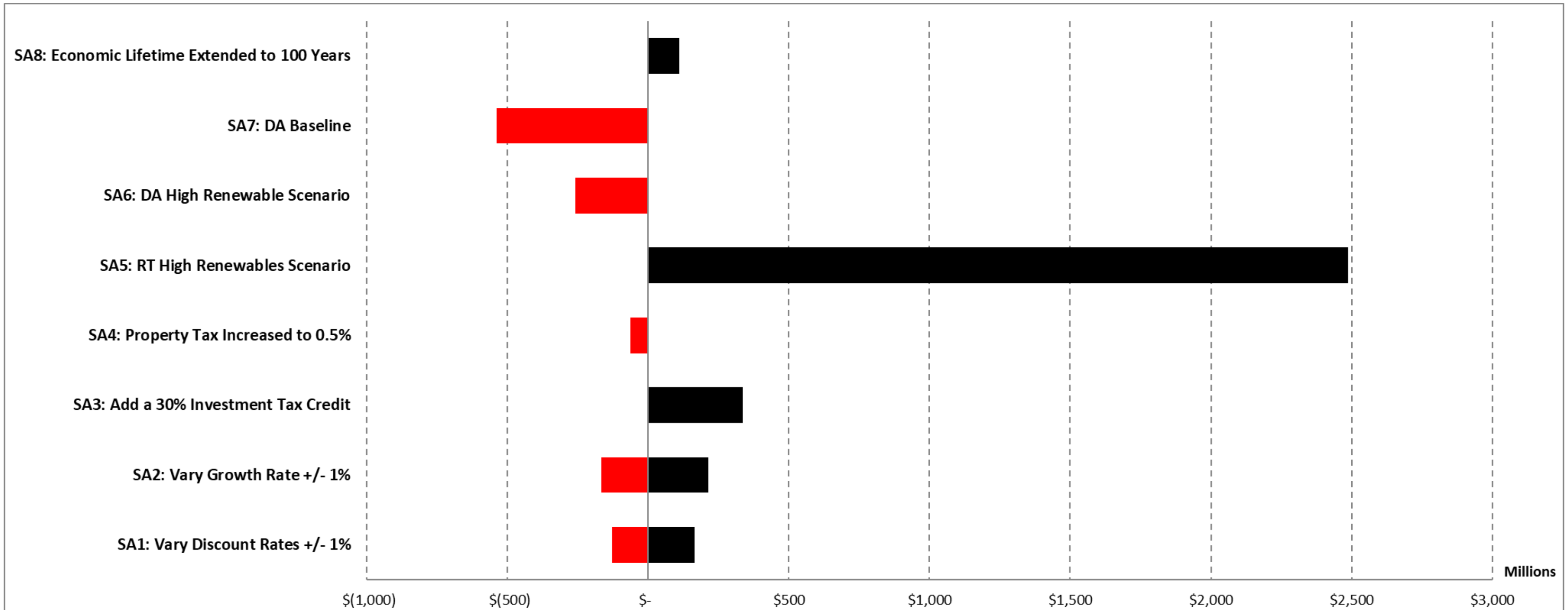
As noted previously, high renewable energy scenarios yield higher revenue while DA scenarios reduce value compared to the equivalent RT scenarios. The most significantly positive scenario is RT high renewables, which increases the NPV by roughly $492 million. The 30% ITC improves the NPV of the BMSP investment by $336 million. The results of the sensitivity analyses performed for the owner-operator analysis are presented in Figure 8-77. Directionally, the results are identical to those presented in Figure 8-76, with the exception of the DA high renewables scenario, but differ in terms of magnitude.

The results of all scenarios evaluated in this study are presented in Table 8-30. Under the system-based analysis, the RT base case does not produce positive economic returns. While most of the scenarios evaluated as part of the system analysis produce BCRs below 1.0, there are two scenarios (add a 30% ITC and RT high renewable) that produce positive economic returns. The majority (9 of 11) scenarios evaluated from an owner-operator beneficiary perspective yield positive economic returns that reach as high as $2.5 billion under the RT high renewable scenario.



	SA1: Vary Discount Rates +/- 1%	SA2: Vary Growth Rate +/- 1%	SA3: Add a 30% Investment Tax Credit	SA4: Property Tax Increased to 0.5%	SA5: RT High Renewables Scenario	SA6: DA High Renewable Scenario	SA7: DA Baseline	SA8: Economic Lifetime Extended to 100 Years
Low	$(77,757,955)	$(116,624,836)		$(62,390,591)			$(332,151,631)	
High	$99,290,093	$148,677,294	$336,000,000		$491,706,729	$42,063,741		$75,197,595

Figure 8-76 Sensitivity Analysis Results (System Analysis)



	SA1: Vary Discount Rates +/- 1%	SA2: Vary Growth Rate +/- 1%	SA3: Add a 30% Investment Tax Credit	SA4: Property Tax Increased to 0.5%	SA5: RT High Renewables Scenario	SA6: DA High Renewable Scenario	SA7: DA Baseline	SA8: Economic Lifetime Extended to 100 Years
Low	$(127,897,093)	$(167,229,182)		$(62,390,590)		$(259,639,884)	$(540,140,263)	
High	$163,829,088	$213,557,658	$336,000,000		$2,486,403,406			$110,293,789

Figure 8-77 Sensitivity Analysis Results (Owner-Operator Analysis)

Table 8-30 BCR Results for All Evaluated Scenarios

Scenario	System		Owner-Operator	
	Low	High	Low	High
Base Case	0.76	0.76	1.24	1.24
SA1: Vary Discount Rate by 1%	0.65	0.89	1.08	1.44
SA2: Vary Growth Rate by ±1%	0.61	0.95	1.03	1.52
SA3: Add a 30% Investment Tax Credit	–	1.20	–	1.69
SA4: Property Taxes Increased to 0.5%	0.68	–	1.16	–
SA5: RT High Renewable Scenarios	–	1.38	–	4.41
SA6: DA High Renewable Scenario	–	0.81	0.91	–
SA7: DA Baseline	0.33	–	0.56	–
SA8: Economic Lifetime Extended to 100 Years	–	0.85	–	1.38

9.0 Conclusions and Recommendations

In this study, the research team demonstrated the validity of the methods, modeling techniques, and 15-step framework for PSH valuation documented in the *PSH Valuation Guidebook* (Koritarov et al., 2021). In preparing the guidebook and conducting the technoeconomic studies of the BMSP, the project team learned several lessons. Here we share some of those lessons and provide suggestions related to modeling approaches, tools, and analyses.

9.1 Conclusions Drawn from the Technoeconomic Studies

The technoeconomic studies followed a step-by-step integration approach designed to ensure internal consistency between them while avoiding double counting of benefits. AURORA modeling was used first to define WECC-wide generation portfolios in future years 2028 and 2038. Our analysis arrives at a range of potential future capacity valuations in the RMRG under four different future scenarios, but it also highlights the inherent challenge and complexity involved in forecasting future capacity valuations. The concept of capacity value is inextricably linked to the RA framework in each system, the system operator's explicit or implicit demand for capacity, and the specific market mechanisms that are used to value other grid services. In some U.S. power markets, these valuation frameworks and processes are formalized through a regular auction process that clears at the intersection of well-defined supply and demand curves, while other markets use different mechanisms.

The RMRG does not have a capacity market. Therefore, capacity values are defined in the IRPs of the vertically integrated utilities and other load-serving entities based on implicit prices or the cost of the next-best alternative for building or procuring a capacity resource. The value of capacity to utilities differs based on system needs, capacity requirements, rules governing provision of capacity services, and several other factors.

We adopted a system-oriented approach for capacity valuation analysis for the BMSP. We first use AURORA, a commercial power system planning and operations tool widely used throughout industry, to simulate the value of capacity as a service in the RMRG from the perspective of a neutral system planner. This resource revenue requirement-based approach to capacity valuation simulates a competitive capacity market clearing process under the assumptions that (1) every unit offers capacity at their true revenue requirement each year, and (2) the RMRG has a vertical capacity demand curve at its target PRM. Although this approach represents market clearing under a competitive capacity market framework, it still provides valuable insights in systems that are vertically integrated or do not operate a competitive capacity market.

The PRM target selected for each pool implies that there is a tangible system value associated with maintaining a certain level of UCAP in the operating pool. In a vertically integrated system, this capacity valuation may not be formally calculated or made explicit as a direct payment, but it would still be implicit in a central planning process that selects these units for development and guarantees their cost recovery. Some vertically integrated utilities may enter into bilateral contracts with resources to secure firm capacity during periods of peak demand. It is not possible to consider the specifics of individual contract negotiations in a system-level capacity expansion analysis, but these valuations still provide a proxy for the revenue streams that resources would require in to provide capacity.

For energy and ancillary services, including frequency regulation and spin reserve, this study ran a least-cost optimization using mixed integer linear programing in the PCM PLEXOS. The PLEXOS database was built using the WECC TEPPC 2024 database as a base but was updated with inputs from the capacity-expansion model AURORA and used to run production cost simulations for 2028 and 2038. By using the AURORA model as the basis for capacity expansion in PLEXOS, we ensured that the results between capacity and energy, which together comprised 84% of the value of the system RT base case, were internally consistent and fully integrated.

In PLEXOS, we modeled the entire WECC region, taking advantage of the nodal and zonal settings in the model. Areas of high interest—in this case the PNW, Wyoming, and California—were modeled nodally, allowing us to have higher resolution geographical outputs. The areas outside of this footprint were modeled zonally, meaning they had the same temporal resolution but less geographical resolution, which allows for a faster solve time.

The analysis found a consistent reduction of production costs, made up of start costs and fuel costs, as well as reduction in curtailment with the inclusion of the Banner Mountain PSH plant. The use of Banner Mountain increased in the high renewable scenario. These benefits increase in the RT runs as well as in the high renewable scenario. Although this study only evaluated scenarios with renewables comprising up to about 40% of total generation, the evidence suggests that Banner Mountain could increase its benefit to the system under higher renewable penetrations such as those required in the next 20–25 years under RPSs in California, Oregon, and Washington.

We estimate the potential energy arbitrage value of the BMSP in the future power system. Argonne quantified the energy arbitrage values using the generation and pumping schedules and LMPs for energy from the PCM results. Although our models do not co-optimize for all services simultaneously, results are integrated as one technoeconomic study builds on the next. The PCM study considers both hourly and 5-minute time resolutions, the same as those for the DA and RT markets. The results show the increasing value of long-duration energy storage when the system has high VRE resource capacity. In addition, the cases with 5-minute time resolution show the importance of considering a finer time resolution in assessing the value of energy storage that has a high ramping capability in a system with high rates of renewable penetration.

A power stability study that considered several benefits—including transient stability, small-signal stability, inertial frequency response, primary frequency response, and voltage support—was conducted for the BMSP. From the analysis performed, we can see that with operation of the Banner Mountain PSH unit, the small signal stability and transient stability of the system is improved, irrespective of operating scenarios. In terms of frequency stability, even though the ROCOF of the system increases with the addition of the Banner Mountain PSH unit in the system, improvements are visible in other stability metrics, including the frequency nadir, frequency arresting period, and settling frequency. In addition, the turbine mode of operation of the Banner Mountain PSH unit during the high-wind scenario is beneficial to overall system frequency stability as compared to the pump mode of operation. In terms of voltage stability, the results demonstrate that the local reactive power support from the Banner Mountain PSH unit in either turbine mode or pump mode significantly improves the voltage recovery of the system following a disturbance. This leads to a larger amount of load and generators that continue to remain online, which has a positive impact on overall system stability.

The cost evaluation of the services provided by the Banner Mountain PSH unit demonstrates that it can generate a significant amount of revenue from the primary frequency response and voltage support it can provide. In addition, operation of the Banner Mountain PSH unit can lead to cost savings in operation of the grid, because it minimizes the loss of load in the system and hence the amount of unserved energy in the system. From the analysis of multiple fault cases, we observed that for the extreme cases about 7 MW of load continues to remain online compared to the cases without the Banner Mountain PSH unit. Assuming it takes 10 minutes for the loads to be restored, the total unserved energy for the base case was equal to 1.2 MWh. Assuming there will be 100 such events in a year, total unserved energy in a year will be ~120 MWh. Assuming that the average cost of unserved energy is $12.5/kWh (in 2016 dollars), the economic loss avoided by stability services from Banner Mountain PSH could be up to approximately $1.75 million in 2020 dollars. Note that the cost computed does not include additional cost to possibly dispatch operators for load restoration and equipment such as reclosers to bring loads back online.

The value of voltage support is estimated by assessing the quantity of reactive power the Banner Mountain PSH unit can contribute during widespread voltage events. Based on a review of PSH unit operation modeled in PLEXOS, the study authors use 15 MVAr as the voltage capacity for the Banner Mountain PSH unit. Based on a review of PSH unit operation modeled in PLEXOS, the INL team determined that 5% of system capacity could be reserved for primary frequency response. Further market analysis would be required to establish the optimal reserve level. The PSH units were modeled to respond to 200 frequency events annually.

The BMSP is not located within a structured market. When valuing black start, the cost-of-service approach was therefore deemed most appropriate given insufficient access to information around unstructured black start markets. The primary implication of this methodology is that the resulting values should reflect the minimum revenue the facility should be compensated for its service, because this value indicates the cost to provide black start service. This methodology was selected because it uses a reasonable set of assumptions by the industry, and because there is sufficient information within the public domain for the user of this methodology to either leverage their own internally established values or use information within the public domain. The specific cost-of-service format applied in this analysis leverages the one created by PJM. The rationale for this is that the other markets that use this approach (MISO, CAISO, and NYISO) use formulas that require detailed system knowledge or variables that are subject to negotiation. The desire to make this a generally applicable methodology and somewhat limited system information prevents these other market equations from being included in this analysis.

We found that it was not necessary to prioritize black start in our integration formulation because it generally captures a relatively small value. Instead, this value was determined by creating an exceedance curve using the dispatch schedules from the power system production cost simulation results (i.e., PLEXOS study results from NREL). Evaluation of exceedance curves demonstrates that 1.73 GWh of firm storage would be available for black start service.

This study estimates the potential transmission benefit value of the Banner Mountain PSH project in the Pacific Wyoming area. Three PF cases (i.e., base case without Banner Mountain project, the base case with Banner Mountain project, and the base case with Banner Mountain project under market dispatch) are simulated and compared by using the ACOPF analysis using results from the production cost simulations.

This result shows that the Banner Mountain PSH project can provide transmission congestion relief with decreased congestion LMPs in the BPA area under market dispatch. The final calculated Case 3 (with market participation) has a total annual congestion cost that is 1.4% lower than that of the base case without the Banner Mountain project. The results further demonstrate that when the PSH operators earned profit through market participation, they also produced some external benefits to the system, in the form of congestion relief at other adjacent nodes.

With DA PCM results, line congestion in the Pacific Wyoming area was not significant. There are three lines with congestion observed that could be relieved by the BMSP. Under a 2% annual load growth incremental rate, there was just a 2-year transmission deferral period for those three congested lines in the grid. However, when the PCM optimized for high-value energy and ancillary services instead of transmission services, our model registered no transmission deferral benefits.

9.2 Conclusions Drawn from the Financial Analysis

For this study, we evaluated multiple scenarios while varying key parameters related to discount rates, cost/value growth rates, tax rates, renewable penetration, and market structure (DA versus RT). We also varied the beneficiary, performing the assessment from both system and owner-operator perspectives.

The system analysis yielded three scenarios where costs exceed the value of services provided to the electrical grid, with NPV metrics (mid-year method) ranging from -$149 million (DA, high renewables) to -$523 million (DA, baseline). Among these scenarios, BCRs range from 0.33 to 0.81, and IRRs range from 1.9% to 5.6%. Under the RT high renewables scenario, the NPV (mid-year method) is positive at $301 million. The RT high renewables scenario produces a BCR of 1.38 and an IRR of 9.4%. A BCR of 1.38 indicates that for every dollar invested in the project, benefits in PV terms would be $1.38. Discounted payback periods are not measured for the three scenarios with negative returns, but for the RT high renewables scenario the discounted payback period is 23 years.

With the owner-operator serving as the beneficiary of plant operations, value is lost for some use cases (e.g., transmission congestion relief, voltage regulation) because there is no mechanism for monetizing the value of the service. However, Banner Mountain is more profitable under each of these cases largely because the arbitrage value—which is calculated using local LMPs—produces much higher value captured in the form of revenue. The RT scenarios produce positive returns on investment ranging from $191 million (RT, baseline) to $2.6 billion (RT, high renewables). BCRs for the RT baseline and RT high renewables scenarios are 1.24 and 4.41, respectively. Both the DA baseline and DA high renewables scenarios fail to produce positive returns on investments with BCRs registering at 0.56 and 0.91, respectively. Under the RT high renewables case, the IRR is 22.4% and the payback period is 11 years. The RT baseline case produces an IRR of 8.6% and the payback period is 31 years.

We evaluated the sensitivity of the results with respect to changes in a number of key assumptions and parameters. For the system analysis, 6 of the 8 evaluated scenarios yield either entirely or mostly positive impacts on the financial results when compared to the RT base case. The effects of extending the economic lifetime of the PSH plant and increasing the property tax rate to 0.5% are not significant. Due to the long life of the PSH plant, a 1-percentage-point increase in the cost/value escalation rate or reducing the discount rate by 1 percentage point would have a moderate impact on financial results, yielding higher PV benefits of roughly $149 million and $99 million, respectively. Reducing the cost/value growth rate by 1 percentage point and increasing the discount rate by 1 percentage point reduces the NPV (mid-year method) by $117 million and $78 million, respectively. The results of the sensitivity analyses performed for the owner-operator analysis are directionally identical to those calculated for the system analysis, with the exception of the DA high renewables scenario, but differ in terms of magnitude.

While the financial results presented here mostly show negative returns for the system analysis, it is important to note that the BMSP will produce several non-energy benefits, serving as a key enabler of vast future VRE deployments in the region that will be necessary for complying with high renewable portfolio standards in California (100% by 2045), Oregon (100% by 2040), and Washington (100% by 2045) (National Conference of State Legislators, 2022). This conclusion is supported by the results of the PLEXOS analysis, which found that the BMSP would avoid renewable curtailments ranging from 186 to 479 GWh annually. The BMSP produces tremendous environmental benefits in terms of reduced emissions. The results based on values produced by the PCM yield carbon reductions of 636,443 and 262,002 tCO_2 per year for coal and natural gas, respectively.

9.3 Methodology Limitations

Analysts should also be aware of the limitations of the proposed valuation methodology. The key limitations for the practical applications of the proposed PSH valuation process include the complexity of the analysis and various uncertainties. Because PSH projects are typically large (e.g., several hundred megawatts total capacity), they inevitably have an impact on power system operations and production costs, as well as on the market clearing prices in organized wholesale markets. Therefore, a price-influencer approach was used to study the BMSP.

The research team performed a system analysis, which simulates the operation of the entire system and captures the influence of the PSH project on system operations and prices. To properly perform system analysis and capture the interactions between the PSH project and the power system in which it operates, detailed modeling and simulations of system operations were performed using multiple computer models and tools. This presents a significant analytical burden for the application of the valuation process, because the system analysis requires modeling and simulation of multiple potential future scenarios and using different models to address various PSH services and contributions. It also requires the analysts to have access to sophisticated modeling tools and be trained in their use.

Finally, a modeling flow or design must be established to integrate the results between models to ensure internal consistency of results and avoid double counting of benefits. The case studies for the Banner Mountain and Goldendale projects provide good examples of a system analysis approach and illustrate its complexities when dealing with the valuation of large PSH projects.

Another key limitation of the valuation process is the uncertainty related to the values of PSH services and contributions over time. PSH plants are projects with a very long lifetime (50–100 years) and attempting to estimate any value over such a long time inevitably involves huge uncertainties. Even if a shorter time period (e.g., 20–30 years) is selected for the CBA, it is still very challenging to estimate project value streams over such a long period. The evolving power systems, new generation, demand-side technologies, and rapidly changing generation mix all contribute to these uncertainties. The scenario analyses and sensitivity studies to key parameters may help the analyst capture some of the possible future developments, but many uncertainties will still remain.

Despite these and other limitations of the valuation process, the valuation framework and methodology presented in the guidebook and applied to evaluate the BMSP is still very useful in estimating the potential value of a PSH project, because it provides valuable information to decision makers. Of course, as system conditions change, the valuation analysis may need to be occasionally updated to reflect the new developments and information that was not previously available.

9.4 References

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Appendix A: Worksheet for Valuation Steps 1–4

The proposed valuation process for pumped storage hydropower (PSH) projects includes 15 steps, as illustrated in Figure A-1. Each step involves certain actions, considerations, or analyses that need to be performed as part of the overall valuation process. The steps are arranged in four groups, based on the types of activities being performed.

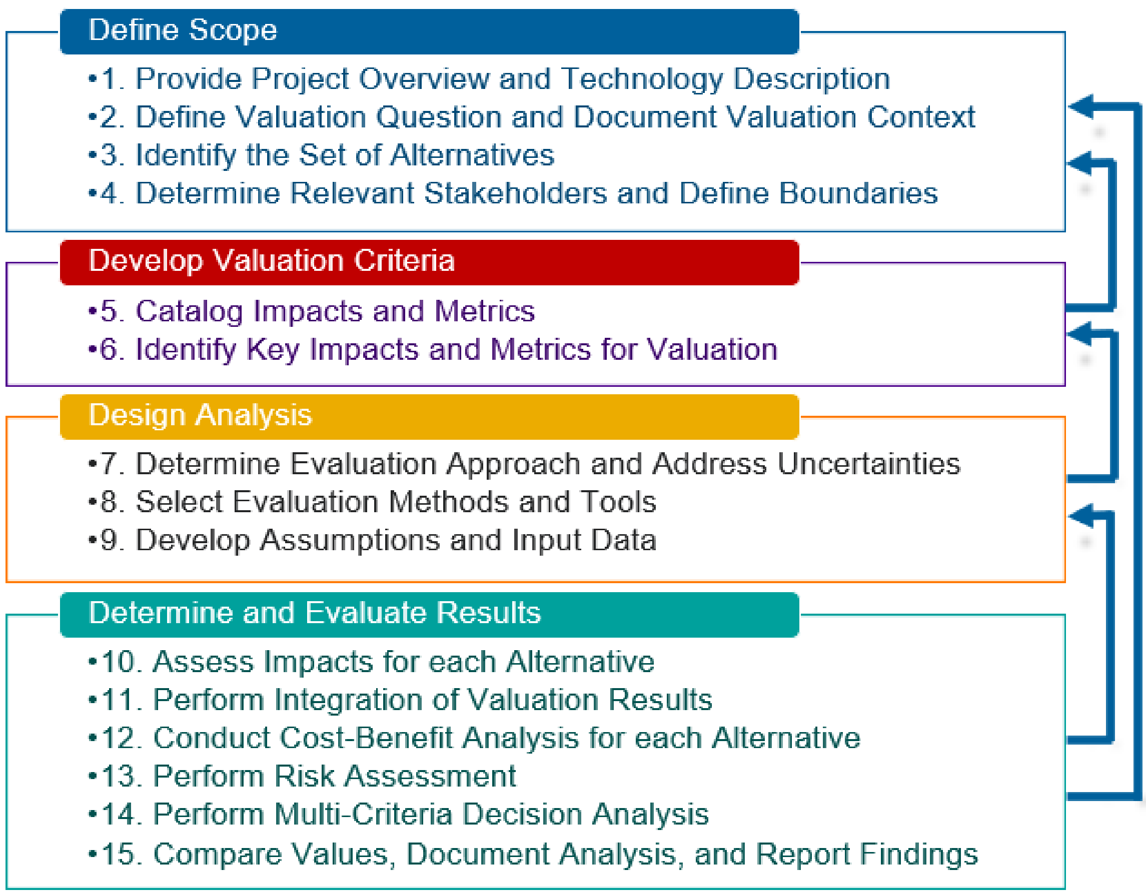

Figure A-1 Key Steps in PSH Valuation Process

The following exercise is meant to guide the analyst through a practical application of the valuation process. The goal is to go through each step and perform the necessary actions required or recommended for that step. By going through the valuation process systematically, the analyst will ensure that no actions or considerations were forgotten or not given due diligence. Although not all of the actions may be applicable or necessary for a particular PSH project, this step-by-step valuation process will ensure that all recommended actions and analyses receive proper consideration before determining whether they are needed or not.

The first six steps of the PSH valuation process are presented in this appendix. As guidance to the analyst, a general description of the step and its key actions and objectives are presented first, followed by the space reserved for specific inputs for the PSH project being evaluated.

Define the Scope of Analysis

The first four steps of the valuation process provide a brief overview of the PSH project under consideration, describe its technology, formulate the valuation question by considering the valuation context and purpose, identify the set of alternatives or alternative solutions, determine all relevant stakeholders, and define the boundaries of the analysis.

Step 1: Provide Project Overview and Technology Description

A brief project overview should describe the PSH project or subproject, including its key parameters and characteristics, and identify its owners/operators (for existing projects) or developers (for new projects). Relevant technical information should be provided as well. The project overview narrative should typically include, but should not be limited to, the following types of information found in Table 1.

Table 1 Project Characteristics and Parameters

Name of Project	Name of existing or proposed PSH project
Project Location	Geographical location and electricity markets served
Lead Organization	Company name (e.g., project owner or developer)
Other Project Participants	Collaborating organizations
Project Manager	Project Manager name and contact information
Project Size and Number of Units	Project total capacity (MW) and number of units (e.g., for baseline alternative)
In-Service Date	Actual in-service date for existing PSH or expected in-service year for new or proposed projects
Project Type	Type of PSH project (e.g., closed-loop or open-loop)
Technology Type	Types of turbines (e.g., Francis, Pelton, etc.), motor/generators (e.g., fixed-speed, adjustable speed, ternary), etc.
Technical and Operational Characteristics	Energy storage, nominal head, nominal flow, ramp rates, minimum generating capacity, etc.
Other Relevant Project Information	Estimated project costs, key project advantages or disadvantages, operational constraints, etc.

The project overview should also include any other relevant project information or data that is deemed necessary for understanding the PSH project and its characteristics. For example, if an upgrade or conversion (e.g., from fixed-speed to adjustable-speed technology) of an existing PSH project is being considered, the project overview should provide enough details to describe the proposed upgrade or conversion.

PROJECT INPUTS FOR STEP 1:

Name of Project	
Project Location	
Lead Organization	
Other Project Participants	
Project Manager	
Project Size and Number of Units	
In-Service Date	
Project Type	
Technology Type	
Technical and Operational Characteristics	
Other Relevant Project Information	

Step 2: Define the Valuation Question and Document the Valuation Context

The valuation question should be defined with careful consideration of the valuation context, purpose, and objectives. Proper formulation of the valuation question is essential for the successful application of the valuation process. In formulating the valuation question, it is important to understand both which entity or organization is asking the question (e.g., project owner or developer, market operator, regulatory agency) and what perspective(s) will be used in the valuation assessment (e.g., value to PSH owner/operator, to PSH developer, to utility, to ratepayers, to society as a whole), because this impacts the assessment and types of relevant value streams used in the assessment.

Valuation context and purpose play a key role in formulating the valuation question. Many different aspects should be considered to properly understand and establish valuation context such as whether the PSH project currently exists and is operational or is a proposed new one, the regulatory and market environment, relevant policy incentives or disincentives, potential environmental issues, and other relevant considerations.

Many potential factors also contribute to the valuation purpose as well. Examples include the owner or operator of an existing PSH project wanting to assess its full value to the grid or to decide whether to invest in a project upgrade. Similarly, a PSH developer may want to determine whether to invest into the proposed new PSH project or not. Furthermore, a PSH developer may want to determine which of the several potential project designs is likely to provide the highest value. Some of the typical purposes for the valuation assessment are summarized in Table 2.

Table 2 Purposes for a PSH Valuation Assessment

Existing PSH Project	• Assess the value of the project. This valuation analysis can be conducted for different perspectives (e.g., project owner/operator, market operator, utility, regulatory agency) • Assess the value of a proposed project power upgrade or rehabilitation • Assess the value of technology change (e.g., conversion from fixed-speed to adjustable-speed units) • Compare the project value vs. some other project (e.g., another PSH project or some competing technologies)
Proposed New PSH Project	• Assess the economic value of the project to inform the investment decision-making process • Assess the values of different project design configurations • Compare the project value vs. alternative projects or investments • Scale the power/energy capacities in order to maximize the return on investment based on the landscape of economic opportunities

The outcome of Step 2 should be a concise valuation question that considers the purpose and context of the valuation process including: the primary perspective that the valuation should be constructed around, the purpose of the decision, the timeframe and temporal resolution of the question, the performer of the valuation analysis, and the valuation process budget and milestones.

PROJECT INPUTS FOR STEP 2:

Valuation question (a brief, concise formulation of valuation goal – preferably one sentence):

Valuation context, purpose, and objectives:

Other relevant information:

Step 3: Identify the Set of Alternatives

Identification of alternatives is closely related to the valuation question and the understanding of the valuation purpose and context, so often they can be performed in parallel. A properly formulated valuation question and a holistic understanding of the valuation purpose and context are essential for the proper identification of potential alternatives.

Depending on the valuation question, the number of alternatives can range significantly—from a limited number to a wide range of options. For example, if the valuation seeks to inform the investment decision-making whether to build the project or not, there are only two alternatives. Alternatively, if the valuation seeks to answer the question of which project alternative provides the highest value, the number of alternatives is equal to the number of project options being considered, including a "do nothing" alternative.

There are also potentially many different types of alternatives, depending on the project options and potential actions or decisions that can be taken. For example, many different project design alternatives (e.g., with regard to the total project capacity, number of units, or energy storage size and duration) may be considered for a proposed new PSH project. In additional, project alternatives can potentially include other technologies that could provide similar services as PSH plants.

In principle, the set of alternatives should include a baseline alternative to serve as a reference for the comparison of alternatives. This baseline alternative is typically defined as the business-as-usual (BAU) scenario, which assumes current practices will continue in the future or will follow an already known or predefined scenario (e.g., expected technology evolution, known changes in regulatory frameworks).

The outcome of this step should be a comprehensive set of alternatives for the valuation analysis.

PROJECT INPUTS FOR STEP 3:

Alternative 1:

Alternative 2:

Alternative 3:

Alternative N (please limit the number of alternatives to most important ones):

Additional information (e.g., clarifying the rationale for the selection and types of alternatives):

Step 4: Determine Relevant Stakeholders and Define Boundaries

The purpose of this step is to identify stakeholders that will or might be impacted by the considered project, determine boundaries of project impacts, and plan relevant stakeholder engagement. The activities within this step are closely related to Steps 2 and 3, and sometimes need to be performed in parallel. For example, the identification of relevant stakeholders may be important to identify the full set of alternatives that should be considered during the valuation study. In addition, sometimes the valuation question itself may need to be revised to include the perspectives and potential impacts on all relevant stakeholders identified in Step 4.

Defining Stakeholders

The selection of relevant stakeholders is highly dependent on the purpose of the valuation study, type of the valuation question, and the entity or decision maker (identified in Step 2) performing the valuation analysis. A list of stakeholders in the power sector typically includes the entities in Table 3.

Table 3 List of Potential Stakeholders for inclusion in Valuation

Electricity-End-Users (Ratepayers)	Electricity customers who pay for electricity service. Their interests are primarily in affordability, but also in reliability and resilience of the power system. Some customers are also interested in the sustainability of the power system and are willing to trade off some other interests (e.g., affordability) for sustainability (e.g., buying green power).
Load-Serving Entities (LSE)	Electric utilities and other retail energy suppliers that provide electricity to consumers. Utilities can be owned by investors (investor-owned utilities, or IOUs), customers (public utilities and cooperatives), municipal or other political territories (municipals or utility districts), or state authorities. In competitive electricity markets, LSEs also include load aggregators and other retail energy suppliers.
Grid Infrastructure Asset Owners	These entities own generation, transmission, or distribution assets and provide electricity generation and transfer services. They typically operate in wholesale markets and can be investor-owned, customer-owned, or government-owned.
Public Utility Commissions	Public utility or public service commissions are state or federal entities that regulate much of the electricity sector. They are tasked with setting fair and equitable electricity rates, approving electricity projects, and setting general policies for electricity markets.
Independent System Operators (ISOs)	ISOs and regional transmission organizations (RTOs) operate regional transmission systems and coordinate, control, and monitor the use of the grid by utilities, generators, and marketers.
Market Operators	Market operators facilitate and operate wholesale electricity markets, thus allowing generators and LSEs to buy and sell electricity, typically within the ISO/RTO footprint.
Technology Manufacturers	These include entities such as Original Equipment Manufacturers (OEMs) who develop, produce, and supply electrical, mechanical, and other equipment and components necessary for project construction and operation.
PSH Developers	Organizations or entities developing a new PSH project.
Financial Organizations	Investment banks and other financial organizations investing or providing loans for the development of a new PSH project.
Other Interest Groups and Regulators	These include various interest groups within the society, such as environmental, consumer, cultural, and other groups, as well as various government agencies, such as environmental protection agencies, consumer protection agencies, urban planning agencies, land-use agencies, Indian bureaus, and others.
Government	Includes various political entities, such as federal, state, municipal, and other entities that set policies and laws.
Broader Society	Provides a general perspective from the point of view of society as a whole, potentially including future generations. Helps determine the societal value of the project.

Identifying all relevant stakeholders is key to a successful valuation process, because different stakeholders provide correspondingly different perspectives and thereby enable better encapsulation of value. Depending on the perspective of the valuation question or the decision maker, not all of the stakeholders need to be included in the valuation study, as the appropriate scope of perspectives is case dependent. For example, if an independent PSH developer is performing a valuation of a proposed merchant PSH project to determine whether to build it or not, the list of relevant stakeholders may not include the end-users of electricity (ratepayers) or broader society, as their perspectives are not essential for this particular decision-making. On the other hand, if a public utility commission is approving the PSH project, the perspective of ratepayers and corresponding impacts on electricity rates may be of highest importance.

Literature provides a robust series of case examples that can be leveraged to assess stakeholder inclusion. However, note that each analysis is case dependent and therefore care should be taken when developing the scope.

Defining Boundaries

Selection of relevant stakeholders can be facilitated by determining the applicable boundaries first. Typically, two main types of boundaries should be considered: (1) decision boundaries and (2) jurisdictional boundaries.

Decision boundaries identify relevant stakeholders whose perspectives may have an impact on the decision making. Jurisdictional boundaries further refine the stakeholder selection process by identifying which stakeholders have jurisdictional or other authority. For example, jurisdictional boundaries help identify the municipal, state, and federal authorities, as well as the relevant utility, ISO/RTO, or electricity market authorities.

Stakeholder Engagement

Once the relevant stakeholders have been identified, a stakeholder engagement plan should be prepared. The level of collaboration with different stakeholders may vary, depending on the relative impact of their perspectives for the valuation process. It is recommended to engage with major stakeholders at the very beginning of the valuation study to facilitate the process and assist in developing a consensus regarding the valuation procedure. A number of stakeholders can be included in the Advisory Board for the study, while others can be informed about the valuation process through regular workshops, seminars, discussion meetings, and review processes. The purpose of stakeholder engagement is twofold: to keep the stakeholders informed about the valuation process and to obtain inputs and feedback from stakeholders on their specific perspectives and concerns, which may need to be addressed during the valuation process. The key benefit of successful stakeholder engagement is that it increases the transparency of the valuation process and enhances the understanding and acceptance of valuation results.

The outcomes of Step 4 include the identification of relevant stakeholders, their respective areas of interest, and the proposed means to engage with stakeholders during the valuation process.

PROJECT INPUTS FOR STEP 4:

Relevant Stakeholders:

Stakeholder/Organization	Why is it relevant? (Provide a brief rationale)	Type of stakeholder authority (e.g., decision, jurisdictional) or impact (e.g., advisory, market, etc.)

Stakeholder engagement:

Stakeholder/Organization	Engagement actions already performed (what, when, goals achieved, etc.)	Planned engagement actions, if any (what, when, objectives, etc.)

Key issues that need to be addressed with stakeholders:

Other information relevant for stakeholder engagement:

Appendix B: Worksheet for Valuation Steps 5–6

The proposed valuation process for pumped storage hydropower (PSH) projects includes 15 steps, as illustrated in Figure B-1. Each step involves certain actions, considerations, or analyses that need to be performed as part of the overall valuation process. The steps are arranged in four groups, based on the types of activities being performed.

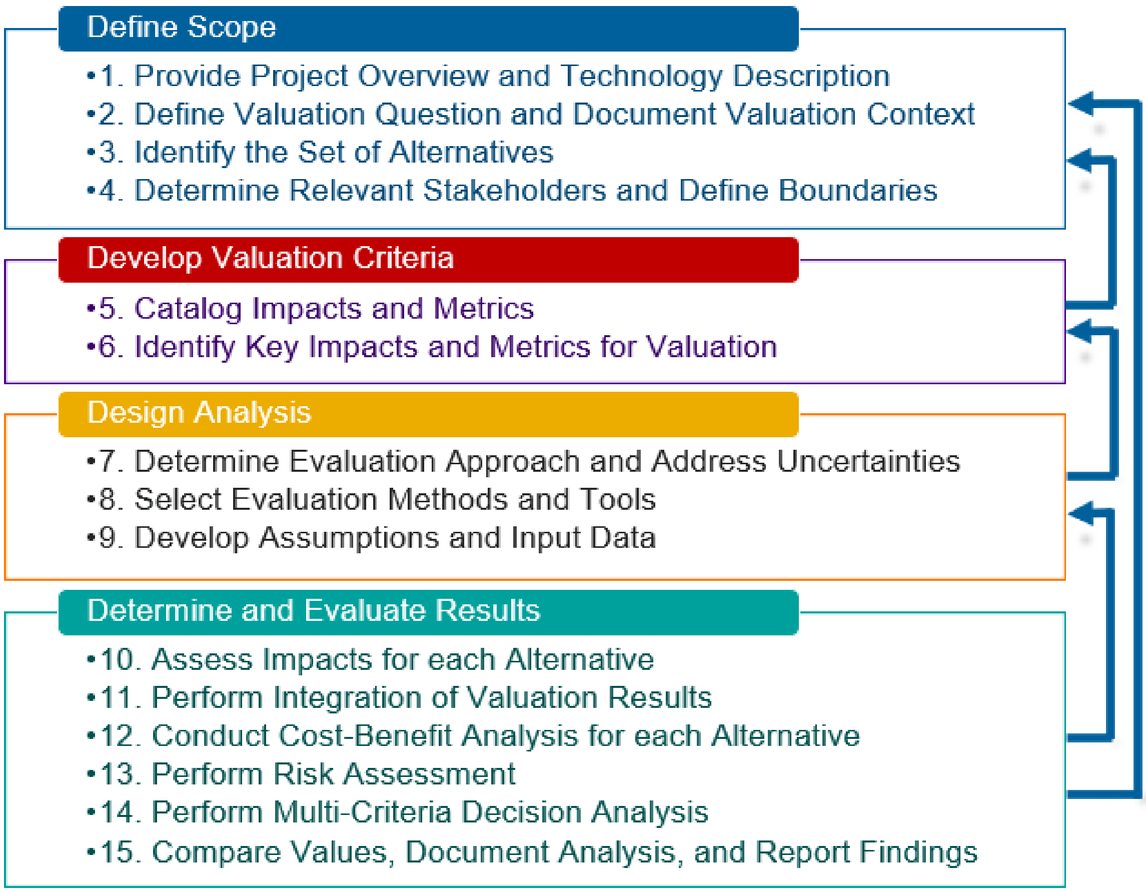

Figure B-1 Key Steps in PSH Valuation Process

The following exercise is meant to guide the analyst through a practical application of the valuation process. The goal is to go through each step and perform the necessary actions required or recommended for that step. By going through the valuation process in a systematic way, the analyst will make sure that no actions or considerations were forgotten or not given due diligence. While not all of the actions may be applicable or necessary to perform for a particular PSH project that is being evaluated, this step-by-step valuation process will ensure that all recommended actions and analyses receive proper consideration before determining whether they are needed or not.

Steps 5 and 6 of the PSH valuation process are presented below. As guidance to the analyst, a general description of the step and its key actions and objectives are presented first, followed by the space reserved for specific inputs for the PSH project that is being evaluated.

Develop Valuation Criteria

The purpose of the following two steps is to catalog all PSH impacts and identify those that are most relevant for the valuation of the PSH project being considered. In addition to impacts, this includes identifying the metrics that can be used to measure those impacts and their costs and benefits. Although some impacts are measured in monetary units and their costs and benefits are easily monetized, other impacts are measured in physical or other units that are not easily monetized. Figure B-2 provides an illustration of relationships and terminology for PSH project services, impacts, metrics, and costs and benefits. The process starts with identifying the project functions (services or use cases), their applications in the power system, measuring their impacts using appropriate metrics, and monetizing the impacts to derive costs and benefits.

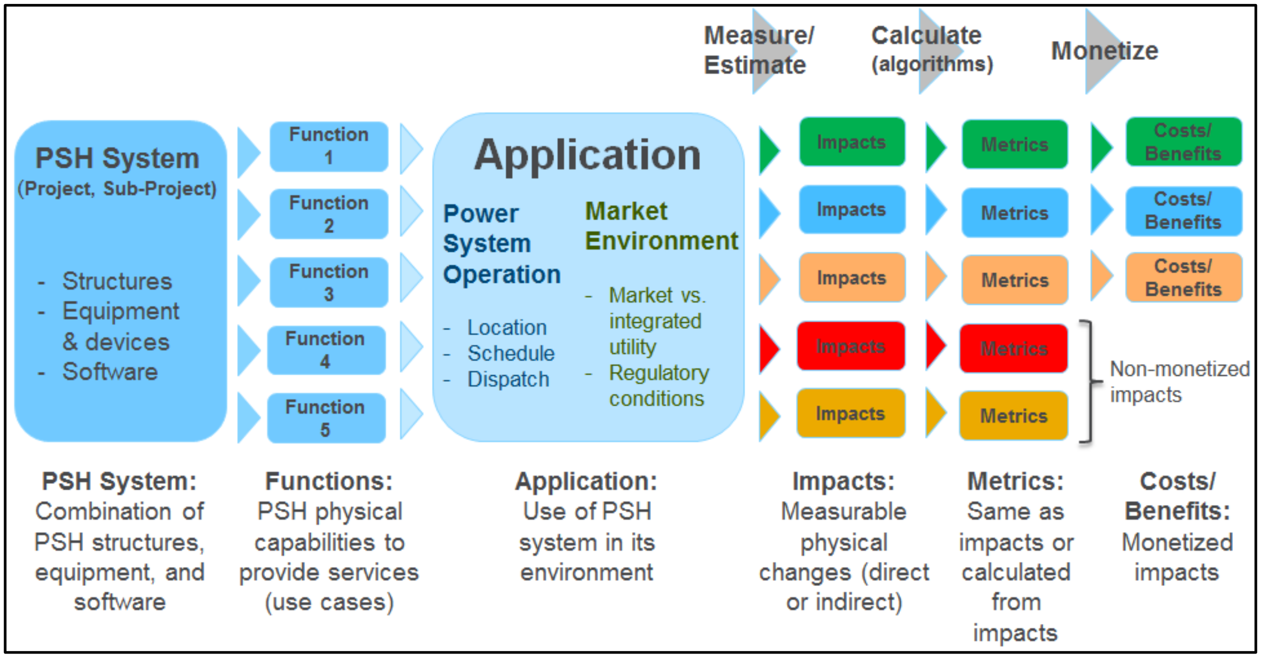

Figure B-2 Terminology and Relationships Connecting the PSH Services, Impacts, Metrics, and Benefits (adapted from EPRI [2015], Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects)

Step 5: Catalog Impacts and Metrics

PSH plants are highly versatile technologies that can provide many grid services and other benefits to the power system. In addition to so-called energy (or power) services, some impacts of PSH plants operations may go beyond the power system and can have wider societal effects. Typical examples of these wider societal impacts are creation of jobs and economic development, water management services, environmental, and security impacts. In principle, both energy and non-energy impacts should be included in the list of impacts relevant for the valuation analysis of the PSH project being analyzed. In addition, note that both energy and non-energy categories can include certain impacts that can be monetized and others that are very difficult or impossible to explicitly monetize. While the monetized impacts can be used directly in the cost-benefit analysis, the non-monetized attributes can still be used in the valuation process as components of the multi-criteria decision analysis. The multi-criteria (or multi-attribute) decision analysis is described in Step 14 and can be used for the valuation of alternatives that are described by both monetized and non-monetized impacts.

Impacts

A list of PSH services and impacts that are typically associated with a large grid-scale PSH project is provided in Table 1. The table presents the types of metrics that are typically used for assessing services or impacts. A full list of metrics is also provided in Appendix A of the *PSH Valuation Guidebook*.

Table 1 List of Potential Services and Impacts for Inclusion in Valuation

Stakeholder/ Beneficiary	Cost/Benefit Category	Service or Impact	Typical Metrics Used to Describe Services/Impacts
PSH Owner or Operator	Bulk Energy Services	Electricity price arbitrage	Physical and monetary units
		Bulk power capacity	Physical and monetary units
	Ancillary Services	Regulation	Physical and monetary units
		Spinning reserve	Physical and monetary units
		Non-spinning reserve	Physical and monetary units
		Supplemental reserve	Physical and monetary units
		Voltage support	Physical and monetary units
		Black start service	Physical and monetary units
Power System	Power System Stability	Inertial response	Physical and qualitative units
		Governor response	Physical and qualitative units
		Flexibility (e.g., ramping and load following)	Physical, qualitative, and monetary units
	Power System Reliability and Resilience	Reduced sustained power outages and restoration costs	Physical and qualitative units
	Power System Indirect Benefits	Reduced electricity generation cost	Monetary units
		Reduced cycling and ramping (wear and tear costs) of thermal units	Physical and monetary units
		Reduced curtailments of variable generation	Physical and monetary units
	Transmission Infrastructure Benefits	Transmission upgrade deferral	Physical and monetary units
		Transmission congestion relief	Monetary units

Table 1 (cont.)

Stakeholder/ Beneficiary	Cost/Benefit Category	Service or Impact	Typical Metrics Used to Describe Services/Impacts
Societal Costs and Benefits	Non-Energy Services	Water management services	Physical, qualitative, and monetary units
		Socioeconomic benefits (e.g., jobs, economic development, recreation)	Physical, qualitative, and monetary units
		Environmental and health impacts	Physical, qualitative, and monetary units
	Security Benefits	Fuel availability, savings, and diversification	Physical, qualitative, and monetary units
		Major blackouts avoided	Physical, qualitative, and monetary units

Naturally, not every PSH project can provide, will be able to provide, or will be operated in such a manner as to provide all of these services. The services that can be provided depends on many factors, including the PSH technology (e.g., fixed-speed, adjustable-speed, or ternary units), plant design and technical performance characteristics, operational and environmental constraints, project size, location, and role in the system (e.g., large grid-scale PSH project versus small-scale distribution resource PSH project), market environment (e.g., traditional regulated versus competitive market), and many others. For example, a list of services and impacts typically associated with a small distribution resource PSH project are shown in Table 2.

Table 2 Illustrative List of Services and Impacts of a Small-Scale Distribution Resource PSH Project

Stakeholder/ Beneficiary	Cost/Benefit Category	Service or Impact	Typical Metrics Used to Describe Services/Impacts
End User	Customer Energy Management Services	Time-of-use energy charge management	Physical and monetary units
		Demand charge management	Physical and monetary units
		Power quality	Physical and monetary units
		Power reliability	Physical and monetary units
Utility System	Distribution Infrastructure Services	Distribution voltage support	Physical and monetary units
		Distribution upgrade deferral	Physical and monetary units
		Distribution losses	Physical and monetary units
		Integration of variable generation	Physical and monetary units
ISO Market	Ancillary Services	Regulation	Physical and monetary units
		Spinning reserve	Physical and monetary units
		Non-spinning reserve	Physical and monetary units

For each particular PSH project analyzed, the analysts should develop a comprehensive list of services and impacts the project is capable of providing. The lists of services and impacts provided in Tables 1 and 2 are an effective starting point but are by no means exhaustive. Depending on the technoeconomic and operating characteristics of a PSH project being evaluated, its purpose and role in the system, and other factors, the list of its services and impacts may include a combination of items listed in Tables 1 and 2, as well as other project-related services and impacts not listed in these two tables.

Metrics

In addition to cataloging the services and impacts for the PSH project analyzed, the analysts' task under Step 5 is to also develop a list of appropriate metrics to be used for measuring the impacts. In principle, depending on the type of units, the metrics can be categorized into three broad groups: (1) monetary, (2) physical and numerical, and (3) qualitative.

Monetary Metrics: Monetary metrics are used to describe services and impacts that can directly be expressed in monetary units (e.g., U.S. dollars). As such, the costs and benefits of these services and impacts are already monetized and can be directly used to develop cost and benefit value streams for the cost-benefit analysis. Services and impacts that are sold and bought in electricity markets are the easiest ones to monetize and are defined in terms of market-based revenue. Other services (e.g., transmission congestion relief) may result in cost avoidance that, while monetizable, fails to generate revenue for the developer. These avoided costs are still quite relevant and worthy of definition. By including them in the valuation process, the analyst can bring the value streams to the attention of regulators and market operators. By doing so, the analyst may assist in removing regulatory and market barriers to PSH deployment in that region.

Physical Metrics: Most often, the services and impacts are expressed in physical units. Services and impacts expressed in physical units can sometimes be easily monetized, while sometimes it is very hard or even impossible to explicitly monetize their value. Products or services with an established market can use the relevant market prices to monetize the value stream in question. Note that this "price-taker" approach has analytical implications that must be considered. One example of easily monetized service that is expressed in physical units is the electricity generation (MWh) or, for PSH plants it would be the value of energy arbitrage (value of electricity generation minus the cost of pumping). For PSH plants, the quantities of electricity (MWh) produced and consumed during the energy arbitrage are multiplied by the respective prices of electricity ($/MWh) in those time periods to derive the value of energy arbitrage in monetary units ($). On the other hand, some services and impacts can be expressed in physical or numerical units, but it is very hard to monetize them and express their value in monetary units ($). That is typically the case when there is no market for a particular service or impact (e.g., inertial response), or when it is hard to estimate the value of its benefits (e.g., system reliability).

In addition to physical units (i.e., those that have a clear physical meaning and background), certain services or impacts can be expressed in numerical or synthetically derived units. Although these units may still describe the physical impacts and services, the units that are used are purely numerical. One example is the PRM, which describes the desired level of available system capacity that needs to be above the system peak load. Although both the available capacity and system peak load are expressed in megawatts, the PRM is expressed as a percentage

(%). Another example is the commonly used reliability metric LOLP (loss-of-load probability), which is also expressed as a percentage (%) but is actually derived from the LOLE (loss-of-load-expectation) parameter. While LOLP is a purely probabilistic metric, it is derived from the LOLE, which has a physical background as it describes the target reliability value for long-term expansion planning of power systems. In the United States, the target LOLE value is less than 1 day of outages in 10 years.

Qualitative Metrics: Some services or impacts can also be described using qualitative metrics. Typically, qualitative metrics use descriptive units, such as low, medium, and high, or a predefined or constructed scale (e.g., from 0 to 1, or from 0 to 100) to describe the quality or benefit provided by certain service or impact. Obviously, because the quality or value of services and impacts are judged by experts performing the analysis, this is a very subjective process. Typical examples of qualitative units are fuel diversity, resilience, and environmental sustainability. Expanding on the first of these, while fuel diversity may not have clearly defined parameters and thresholds, the plant mix and fuel use in the power systems can often be broadly categorized as low-, medium-, and highly diversified.

An extended list of metrics that can be used to measure the impacts of PSH services and contributions is provided in Appendix A of the *PSH Valuation Guidebook*. In addition, a compilation of metrics that was developed by the GMLC Foundational Project 1.1 (Metrics Analysis) with the purpose of monitoring and tracking power system properties is also provided. The GMLC 1.1 project focused on general attributes characterizing the power systems, including reliability, resilience, flexibility, sustainability, affordability, and security.

The main outcome of Step 5 is a detailed list of all services, impacts, and associated metrics for the PSH project or subproject that is being evaluated.

PROJECT INPUTS FOR STEP 5:

In the following table, please provide a list of all potential services, contributions, or impacts of your PSH project, regardless of whether they can be monetized or not. Insert additional lines in the table if needed. For metrics, please enter dollars if the service can be expressed in monetary units or enter appropriate metrics from the Appendix A of the *PSH Valuation Guidebook* (e.g., LOLE or LOLP for reliability impacts). Leave the metric field blank if you are unsure what an appropriate metric would be for that particular PSH service or impact.

List of All Potential Services and Impacts of the PSH Project

Stakeholder/ Beneficiary	Cost-Benefit Category	PSH Service or Impact	Metrics

Step 6: Identify Key Impacts and Metrics for Valuation

The purpose of this step is to identify key impacts and metrics important for the valuation of the PSH project or subproject being analyzed. Starting from the comprehensive list of project services and impacts developed in Step 5, analysts should identify those that will be assessed in the valuation process. The first step is to identify which services are currently provided or may be provided by the PSH project over its lifetime. Then, this subset should be examined to determine which services and impacts should be assessed and used in the valuation study. Ideally, all of the potential services and impacts should be evaluated; however, that is often impractical to do in an actual valuation study. The reasons for omitting certain services or impacts are typically because those value streams are either negligible or their value is difficult to estimate or assess analytically (e.g., the value of inertial response).

Which services and impacts will be assessed in the valuation study also depends on several other factors, such as the electricity market structure, PSH business model, operational and environmental constraints, and others. For example, if the PSH project is operating in a restructured market environment where energy and ancillary services are procured by the market operator through a competitive bidding process, those value streams and their associated costs and benefits should be assessed and included in the valuation analysis. On the other hand, if the PSH project is operating in a traditionally regulated utility environment, where there are no individual value streams established for various ancillary services, the benefits of the PSH plant operation are still there, but they are usually assessed through the impacts of PSH plant on the overall system operation (e.g., reduced electricity generation costs, reduced cycling and ramping of thermal units, reduced curtailments of variable generation, etc.). In addition, the business model of the existing or planned PSH project should be considered as well. For example, if the PSH project is developed as a merchant plant and has a long-term power purchase agreement (PPA) with a utility, this factor represents one of the most important value streams to be considered in the valuation analysis. If there are potential other value streams in addition to the PPA, those opportunities should be considered as well.

Note that the list of key impacts and metrics for valuation should include all important services, both monetized and those that cannot be monetized. Important non-monetized services and impacts should be included as long as they can be expressed in physical units or in qualitative terms. These can be leveraged in the development of a multi-criteria decision analysis to choose among different alternatives described by multiple attributes (e.g., monetized and non-monetized).

The output of this step results in a list that should include all services and impacts that will be evaluated in the valuation study. This list can be prioritized so that higher importance is given to services that are expected to provide higher value streams. This prioritization can be used later for determining the level of detail needed for various modeling and analyses that will be performed to assess the value of each of these services.

The selection of the metrics for evaluation will to some extent dictate the analysis methods that need to be applied in the valuation study, so that the relevant metrics can be utilized for the assessment of PSH services and impacts.

PROJECT INPUTS FOR STEP 6:

Starting from the list of all potential services and impacts that your PSH project may be able to provide, and which was developed in Step 5, in the following table please list only those services or impacts that should be included in the valuation analysis. This list of services and impacts should be a subset of those listed in Step 5. Furthermore, please prioritize these selected services and impacts in order of their importance or perceived value. The ranking can be approximate, and for this purpose you can develop a scale from 1 to 5, or 1 to 10 (with 1 being the highest priority). It is OK if two or more services are given the same priority for valuation (i.e., the same ranking in the table). As in the Step 5, feel free to include any potential services, contributions, or impacts of your PSH project that are important for the valuation, regardless of whether they can be monetized or not. Insert additional lines in the table if needed.

List of Services and Impacts to be Included in the Valuation Analysis

Stakeholder/ Beneficiary	Cost-Benefit Category	PSH Service or Impact	Metrics	Priority

Appendix C: Glossary of Terms

Adequacy
The ability of a bulk power system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, considering scheduled and reasonably expected unscheduled outages of system components.

Advanced distribution management system
Advanced Distribution Management System (ADMS) supports the adoption levels of distributed energy resources (DERs) and assists in maintaining reliability and enhance resilience across the distribution grid. The ADMS adds levels of communication, intelligence, and visibility into the distribution grid for the distribution utility to better understand RT conditions across its distribution service territory. ADMS provides utilities with several specific functions, such as automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction; and volt/VAR optimization. Installing ADMS is not merely about better integrating DER; rather, ADMS will change how a utility operates and where a utility envisions itself and customers in the future. As customers continue to adopt technology and DER continues to grow, having the information about the grid that can be gathered from ADMS investments will help the utility meet customer demands while maintaining reliability, resilience, and flexibility. Functionally, an ADMS integrates several utility systems, such as outage management, geographical information, advanced metering infrastructure (AMI), and customer information systems, into one enterprise-wide system.

Advanced metering infrastructure
An electricity metering system that records a customer's electricity consumption (and possibly other parameters) hourly or more frequently, and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point.[1] Advanced meters can measure consumption in 15-minute to 1-hour increments. The meters are connected to a communications network, which then transmits the consumption information to the utility's back office for billing. This stands in stark contrast to the historical mode of metering, which usually occurred once a month and included either a physical reading of the meter or collecting the information through a local radio network. With the installation of AMI, implementing electric rate designs like time of use (TOU), critical peak pricing (CPP), and real-time pricing (RTP) becomes possible at lower costs than in the past. An integral part of an AMI system is a communications network. That network allows the meter to communicate with the utility and can send information like consumption, but also receive messages like prices or demand response signals. This two-way flow of information means that the utility can provide customers with usage, price, and cost information over the course of the month rather than only once, at the end of the month.

Adverse reliability impact
The impact of an event that results in bulk electric system instability or cascading.

[1] See https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

Affordability
The ability of an electric system to provide electric services at a cost that does not exceed customers' willingness and ability to pay.

Ancillary services
Services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice.

Annualization
The conversion of a series of transactions to an equivalent annuity.

Annuity
A series of equal annual payments occurring over a period of time.

Arbitrage
The purchase of a commodity or derivative in one market and the sale of the same, or similar, commodity or derivative in another market in order to exploit price differentials.

Area control error
The instantaneous difference between a balancing authority's net actual and scheduled interchange, taking into account the effects of frequency bias, correction for meter error, and automatic time error correction (ATEC), if operating in the ATEC mode. (ATEC is only applicable to balancing authorities in the Western Interconnection).

Asset valuation methods
Various methods such as reproduction cost and replacement cost that are used to determine the value of an asset. Other related terms include market value and earnings value.

- *Reproduction cost* is defined as the estimated cost, usually at current prices, of duplicating an existing facility in both its current form and current function. This valuation method requires that costs be based on reproducing facilities using identical replacements; other facilities that perform the same function cannot be used. Precise reproduction costs can be difficult to calculate because some facilities may be custom-made or may be impossible to duplicate.
- *Replacement cost* is the estimated cost, usually at current prices, of duplicating an existing facility in function only. This valuation method allows for the replacement of facilities with others that may vary considerably in form from existing facilities, while still duplicating the existing facilities functions. The new facilities, under this method, may be redesigned to take advantage of new technology or to increase efficiency.
- *Market value* is the value established in the market by exchanges between willing sellers and willing buyers. When a number of similar sales occur, a fairly certain market value can be determined. When a market value cannot be easily determined due to a lack of transactions, other methods such as reproduction cost or replacement cost may be used to estimate the value of property for sale.

- *Earnings value*, also called the income or revenue method of estimating value, estimates the value of property as the present worth of future net earnings that are expected to result from the ownership of that property.
- *Original cost* and *historical cost* also are used sometimes to estimate the value of an asset.

Automatic generation control
A process designed and used to adjust a balancing authority areas' demand and resources to help maintain the area control error within the bounds required by applicable North American Electric Reliability Corporation (NERC) reliability standards.

Average rates
Average electric or natural gas rates paid by customers over a given period of time, usually calculated either for a specific class of customers or for a specific geographic or service area.

Avoided cost
The cost that an electric utility would incur to produce or otherwise procure electric power but does not incur because the utility purchases this power from qualifying facilities.

Balancing
The requirement imposed by electricity grids or natural gas pipelines that supply and demand be equal over a certain time period.

Balancing authority
The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a balancing authority area, and supports interconnection frequency in real time.

Balancing authority area
The collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.

Baseload unit
An electric power plant, or generating unit within a power plant. It normally operates continuously to meet the base load of a utility.

Benefit/cost ratio
The ratio of the sum of all discounted benefits accrued from an investment to the sum of all associated discounted costs.

Blackout
The disconnection of all electrical sources from all electrical loads in a specific geographic area. The cause of disconnection can be either a forced or a planned outage.

Black start capability
The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering electric power without assistance from the electric system.

Black start resource
A generating unit and its associated set of equipment that can be started without support from the electric system.

Book life
Period over which an investment amount is recovered through book depreciation.

Bulk power system
The electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Bulk power market
A market in which large amounts of electricity at high voltages are exchanged, usually from one utility to another for the purpose of resale.

Capacity
In reference to electricity, the maximum load that a generating unit or generating station can carry under specified conditions for a given period of time without exceeding approval limits of temperature and stress.

Capacity charge
The capacity charge, sometimes called demand charge, is the portion of the charge for electric service that is based on the amount of customer's peak load (kW) within the specified billing period.

Capacity credit
The amount of system load that a generation resource can supply during the critical period (e.g., peak load hour). The metric is mostly used to express the "firm capacity" of variable renewable resources, such as wind and solar. It can also be understood as the amount of conventional generation capacity that can be avoided or replaced by a variable generation resource.

Capacity, rated
The maximum capacity that a generating unit can sustain over a specified period of time.

Capacity factor
The total capacity output over a period of time in hours, divided by the product of the period hours and the rated capacity.

Capacity market
A market for the trading of capacity credits (the ability to produce electricity in the market area during a defined period) usually between parties obligated to deliver electricity to customers and power plant owners.

Capitalization
The total of all debt and equity in a company.

Carrying charges
The revenue needed to support an investment. Equal to the sum of

- Return on debt
- Return on equity
- Income taxes
- Book depreciation
- Property tax
- Insurance.

Cascading
Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Cash flow
Net income plus amount charged off for depreciation, depletion, amortization, and extraordinary charges to reserves.

Constant dollar analysis
An analysis made without including the effect of inflation, although real escalation is included.

Coincidental demand or peak load
The sum of two or more demands (or peak loads) that occur in the same time interval.

Congestion
A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.

Congestion costs
Charges assessed and redistributed due to electricity network constraints.

Conservation
A reduction in energy consumption that corresponds with a reduction in service demand. Service demand can include buildings-sector end uses such as lighting, refrigeration, and heating; industrial processes; or vehicle transportation. Unlike energy efficiency, which is typically a technological measure, conservation is better associated with behavior. Examples of conservation include adjusting the thermostat to reduce the output of a heating unit, using occupancy sensors that turn off lights or appliances, and carpooling.

Constraints
Constraints or system requirements are a subset of outcomes that are real-world operational requirements (or their modeling approximations) and bound the valuation process.

Contingency
The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element.

- *Single Contingency*—The loss of a single system element under any operating condition or anticipated mode of operation.
- *Most Severe Single Contingency*—A single contingency that results in the most adverse system performance under any operating condition or anticipated mode of operation.
- *Multiple Contingency Outages*—The loss of two or more system elements caused by unrelated events or by a single low probability event occurring within a time interval too short (less than 10 minutes) to permit system adjustment in response to any of the losses.

Contingency reserve
The provision of capacity that may be deployed by the balancing authority to respond to a contingency (e.g., outage) and other contingency requirements (such as energy emergency alerts) in order to balance system generation and demand and return area control error within the specified range. Contingency reserve is typically deployed within 10 minutes following an outage. Typically, at least 50% of contingency reserve is required to be spinning reserve, which automatically responds to frequency deviations.

Control area
An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchanges schedule with other control areas, and contributing to frequency regulation of the interconnection.

Control performance standard
The reliability standard that sets the limits of a balancing authority's area control error over a specified time period.

Current dollar analysis
An analysis that includes the effect of inflation and real escalation.

Curtailment
A reduction in the scheduled capacity or energy delivery of an Interchange transaction.

Day-ahead markets
Forward markets for electricity to be supplied the following day. This market closes with acceptance by the independent system operator, power exchange, or scheduling coordinator of the final day-ahead schedule.

Debt ratio
The ratio of debt money to total capitalization.

Decision analysis
The evaluation of decision options and the estimation of the value of additional information or testing, using the time and risk preferences of the decision maker.

Decision tree
A decision support tool that uses a tree-like graph or model of decisions, choices, options, or actions, and their possible outcomes.

Demand
The rate at which electric energy is delivered to or by a system or part of a system (at a given instant or averaged over any designated interval of time), or the rate at which energy is being used by the customer.

Demand response
Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[1]

Demand response programs
Incentive-based programs that encourage electric power customers to temporarily reduce their demand for power at certain times in exchange for a reduction in their electricity bills. Some demand response programs allow electric power system operators to directly reduce load, while in others, customers retain control. Customer-controlled reductions in demand may involve actions such as curtailing load, operating onsite generation, or shifting electricity use to another time period. Demand response programs are a type of demand-side management that also covers broad, less immediate programs such as the promotion of energy-efficient equipment in residential and commercial sectors.

Demand-side management
The term for all activities or programs undertaken by an entity (e.g., utility, customers) to influence their demand (e.g., the amount or timing of electricity they use).

Depreciation
The accounting mechanism for the reduction in value of a capitalized item. The precise definition and the schedule of reduction may vary widely, depending on the use and type of asset. Frequently associated with capital cost deductions for income tax purposes.

Depreciation period
The amount of time required for the original capital investment to be fully recovered.

Depreciation, accelerated
Any depreciation schedule that reduces a sum of money more rapidly than would be done with straight-line depreciation.

Depreciation, book
A component of the carrying charge, it is the revenue required to repay the original investment. In the utility industry it is usually calculated on a straight-line basis.

Direct control load management
Demand-side management that is under the direct control of the system operator. Direct Control Load Management may control the electric supply to individual appliances or equipment on

[1] See https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp.

customer premises. Direct control load management as defined here does not include interruptible demand.

Discount rate
The rate used for computing present values, which reflects the fact that the value of a cash flow depends on the time in which the flow occurs.

Discounted payback period
The payback period computed in a way that accounts for the time value of money.

Distributed energy resources
Distributed energy resources include distributed generation and storage technologies, energy efficiency, demand response, demand-side management programs, electric vehicles, and other distributed resources.

Distributed generation
Distributed generation resources provide an alternative approach to large, centralized generation connected to the interstate bulk transmission system, by feeding electricity directly into buildings and end-use customers or into the distribution grid.

Disturbance
An unplanned event which produces an abnormal system condition such as high or low frequency, abnormal voltage, or oscillations in the system.

Dollar year
The year in which constant dollar results of an analysis are reported.

Earnings
The portion of revenue that remains after all charges, including interest, have been satisfied.

Economic dispatch
The allocation of demand to individual generating units online to effect the most economical production of electricity.

Effective load-carrying capability
The amount of additional load that the power system can supply with a particular generation resource of interest, with no net change in reliability. This metric is often used to determine the capacity credit of generation resources.

Electrical energy
The generation or use of electric power by a device over a period of time, expressed in kilowatt-hours, megawatt-hours, gigawatt-hours, or terawatt-hours.

Electric power system
A combination of generation, transmission, and distribution components.

Electric rates
The rates paid by end-use customers for electricity service. In addition to the energy charge (which is based on customers energy consumption in kilowatt-hours), electric rates may also

include a capacity or demand charge (based on customer's peak demand in kilowatts), and a service charge. The following are common types of electric rates:

- *Flat Electric Rate*—A flat rate charges customers per unit of consumption (kWh), at the same rate for all units of consumption. This rate structure (in combination with a monthly customer charge) is commonly used in rates for residential electric customers. It is the most common form of residential rate design used across the country today.
- *Block Electric Rate*—An increasing, inverted, or inclining block rate (IBR) structure is designed to charge customers a higher per unit rate as their usage increases over certain "blocks" within a billing cycle. For example, a three-tier IBR would identify three blocks of usage: block one could be 0–150 kWh, block two could be 150–250 kWh, and block three could be all usage over 250 kWh. For each block, there is a price for all electricity used within it, with the price increasing as a customer moves through the blocks over a billing period.
- *Time Variant Electric Rate*—Time-variant rates (TVRs) are designed to recognize differences in a utility's cost of service and marginal costs at different times (e.g., hour, day, or season). Generally, a TVR design charges customers a higher price during peak hours and a lower price during off-peak hours. Unlike with flat rates, customers need to be aware of usage throughout the day and the month to respond to the price signals in a TVR design. A customer may increase savings under a TVR compared with a flat rate, if that customer uses energy in response to the time-variant price signal, such as shifting usage to lower-cost periods or conservation.
- *Time-of-Use Electric Rate*—A time-of-use (TOU) rate is a specific kind of TVR. TOU rate charges customers different prices according to a predetermined schedule of peak and off-peak hours and rates. For many utilities, TOU rates have been a voluntary option for residential customers for decades, but generally few customers participate. Many commercial and industrial (C&I) electric customers already receive service under TOU rate designs.
- *Real Time Pricing Rate*—Under a real-time pricing (RTP) plan, the customer is charged for generation at the price set by the wholesale market (for deregulated utilities or vertically integrated utilities participating in an organized wholesale market) or at the short-run marginal generation costs (for vertically integrated utilities not participating in an organized wholesale market) by the hour. With advanced metering infrastructure, it is possible to implement real-time pricing for residential and smaller C&I customers.
- *Critical Peak Pricing Rate*—A utility may implement a critical peak pricing (CPP) rate during times of expected shortages or anticipated high-usage days to mimic peak time price increases. The utility will announce, usually the day before, the hours that the CPP rate will be in effect. The CPP rate reflects the higher-generation price of electricity during those CPP hours or the existence of scarcity during the event hours. Generally, the CPP rate is set significantly higher than the non-CPP rate as a means of incentivizing customers to reduce consumption. A CPP can be included with a TOU rate or paired with a demand response (DR) program. A CPP event is usually limited to certain peak hours over a year.

- *Three-Part Rate/Demand Charges*—Because the utility system is built to serve peak loads, the costs of providing electricity at peak hours is higher than during non-peak hours. Part of this reflects the increased costs of having sufficient infrastructure and generation necessary to serve customers during peak demand times. To address this situation, a rate structure option is the three-part rate, which adds a demand charge to the existing fixed charge and volumetric rate. This rate recognizes three of the major contributors to a utility's costs. To the extent that each component of the rate properly reflects its associated costs, the price signal to customers should be improved over the use of flat or block rates. Such rates have been commonplace for C&I customers. The demand charge component usually reflects the costs to provide electricity at the peak hour of the month. In an effort to identify costs associated with peak hours, a "demand charge" is one way for a utility to send a peak pricing signal over a certain time period (such as a month).

Electric utilities
All enterprises engaged in the production and/or distribution of electricity for use by the public, such as investor-owned electric utility companies and government-owned electric utilities (municipal systems, federal agencies, state projects, and public power districts).

Embedded cost
The total current cost of owning, operating, and maintaining an existing electric power system.

Emergency
Any abnormal system condition that requires immediate manual or automatic action to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of the electric system.

Energy arbitrage
In general, storing energy when the electricity prices are low and generating when the prices are high. Typically refers to the mode of operation of pumped-storage hydropower plants in electricity markets when they pump during the hours with low electricity prices and generate during the hours with high electricity prices.

Energy charge
That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy efficiency
A ratio of service provided to energy input.

Energy efficiency programs
Programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided.

Energy intensity
A ratio of energy consumption to another metric, typically national gross domestic product in the case of a country's energy intensity. Sector-specific intensities may refer to energy consumption per household, per unit of commercial floorspace, per dollar value industrial shipment, or another

metric indicative of a sector. Improvements in energy intensity include energy efficiency and conservation, as well as structural factors not related to technology or behavior.

Environmental externality
Health and environmental impacts on society in general that are not internalized in the market price of a good or service.

Equity
That portion of a company's total capitalization resulting from the sale of common and preferred stock and retained equity earnings.

Equity ratio
The ratio of equity money to total capitalization. It is also equal to 1 minus the debt ratio.

Escalation, apparent
The total annual rate of increase in cost. The apparent escalation rate includes the effects of inflation and real escalation.

Escalation, real
The annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, and improvements in design or manufacturing (negative rate). The real escalation rate does not include inflation.

Expected value
The mean or average value of a variable.

Expense
A cost of goods and services that normally are utilized in one year or less (e.g., fuel, operation, maintenance).

Federal Energy Regulatory Commission (FERC)
The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the DOE and is the successor to the Federal Power Commission.

Financial transmission right
A contract that entitles the holder to receive or pay compensation for transmission charges that arise when grid congestions cause price differences due to the redispatch of generators.

Firm power
Power or power-producing capacity, intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

First contingency reliability criteria
The requirement that an electric system be planned and operated so that it can safely withstand the loss of the largest single system element (i.e., power plant or transmission line).

Fixed costs
Costs or expenses that do not depend on the level of production output or operation and are incurred even if there is no production or operation. For example, for generating units fixed costs are mainly the costs of capacity, while variable costs are mainly the costs of operation.

Fixed charge rate
The factor by which the present value of capital investment is multiplied to obtain the annual cost attributable to the capital investment.

Flexibility
The ability of an electric system to respond to future changes that may stress the system in the short-term and require the system to adapt in the long term. Increased variability resulting from the growing share of variable renewable generation, such as wind and solar power, are increasing the need for flexibility in grid planning and operations.

Flexibility reserve
A new type of reserve that is being introduced in some electricity markets, mostly to compensate the variability and uncertainty of variable renewable generation (e.g., wind and solar), and to correct control area exchanges (reduce energy imbalances).

Flow-through accounting
An accounting practice used by regulated utilities in which deferred income taxes are passed on immediately either to the ratepayers through a decrease in rates, or to the stakeholders through an increase in earnings (return on equity). It is the opposite of normalization accounting.

Forced outage
The condition in which the equipment is unavailable for service due to unanticipated failure or the removal of equipment from service for emergency reasons.

Framework
A defined, systematic approach for accounting for and comparing costs and benefits.

Frequency bias
A value, usually given as MW/0.1 Hz, associated with a balancing authority area that relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

Frequency control
Also referred to as frequency regulation, frequency control includes maintaining system frequency within the specified range by continuous regulation of system generation and loads. Typically, a three-stage frequency control procedure (primary, secondary, and tertiary control) is applied:

- *Primary Frequency Control*—The automatic and immediate response of turbine governors and some loads to frequency changes, which assist in stabilizing system frequency immediately following a disturbance. Primary control, also referred to as frequency response, occurs within the first few seconds following a change in system frequency.

- *Secondary Frequency Control*—Balancing services deployed in the “minutes” time frame. Secondary frequency control is accomplished using the automatic generation control and the manual actions taken by the system operator to provide additional adjustments. Secondary control maintains the minute-to-minute balance throughout the day and is used to restore frequency to its scheduled value following a disturbance. Secondary control is provided by both spinning and non-spinning reserves.
- *Tertiary Frequency Control*—Actions taken to provide relief for the secondary frequency control resources, so that they are available to handle current and future contingencies. Reserve deployment and reserve restoration following a disturbance are common types of tertiary control actions.

Frequency regulation
The purpose of frequency regulation, also known as frequency control, is to maintain system frequency within the specified range. Frequency regulation typically refers to both frequency response of turbine governors and to automatic generation control. It is provided by online generating units with frequency responsive governors and by generation and demand resources that can respond rapidly to automatic generation control (AGC) requests for up and down movements to counterbalance minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator outputs.

Frequency response
The ability of a system or elements of the system to react or respond to a change in system frequency.

Governor
The electronic, digital, or mechanical device that implements primary frequency response of generating units or other system elements.

Grid services
The combination and operationalization of performance characteristics to perform a specific action, such as providing spinning reserve or load following. The commonly recognized grid services have evolved through time as new challenges have faced the grid. In a market context, performance characteristics are monetized through the procurement of select services via market products. However, not all services (e.g., inertia) currently have market products and subsequently remain unmonetized.

Heat rate
The amount of input energy (e.g., usually expressed in kilojoules or British thermal units) required to produce a kilowatt-hour of electric energy.

Hurdle rate
The minimum acceptable rate of return on a project.

Imbalance energy
Discrepancy between the amount of energy that a seller contracted to deliver and the actual amount of energy delivered.

Impacts
The changes in outcomes as measured by metrics.

Inadvertent interchange
The difference between the control area's net actual interchange and net scheduled interchange.

Incremental cost
The change in total costs that results when output is increased or decreased by a block or specific increment of units, not just by one unit. If the output is increased or decreased by just one unit (a single kilowatt or kilowatt-hour), the resulting costs are referred to as marginal cost.

Independent power producer
A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.

Independent system operator
An independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system. *(See also Regional transmission organization)*.

Inertia
The property of a mass that resists changes in speed.

Inertial response
The inertial resistance of the rotating mass of turbine generator that resists instantaneous speed changes.

Inflation
The rise in price levels caused by an increase in available currency and credit without a proportionate increase in available goods and services of equal quality. Inflation does not include real escalation. Inflation is normally expressed in terms of an annual percentage change.

Integrated resource planning
A process of analyzing the growth and operation of utilities to ensure that energy needs are met through the optimum mix of supply-side and demand-side resources. IRP approach is also called least-cost planning.

Interchange
Energy transfers that cross balancing authority boundaries.

Interconnected power system
A network of subsystems of generators, transmission lines, transformers, switching stations, and substations.

Interconnection
A geographic area in which the operation of bulk power system components is synchronized.

Internal rate of return (IRR)
The discount rate required to equate the net present value of a cash flow stream to zero.

Internal rate of return, modified
The discount rate required to equate the future value of all returns to the present value of all investments. This metric accounts for reinvestments of cash flows.

Interruptible load or demand
Demand that end-use customer makes available to its load-serving entity via contract or agreement for curtailment.

Investment
An expenditure for which returns are expected to extend beyond 1 year.

Investment useful lifetime
The estimated useful life of a capital investment.

Investment tax credit
An immediate reduction in income taxes equal to a percentage of the installed cost of a new investment.

Investment year
The year in which a capital or equipment investment is fully constructed or installed and placed into service.

Investor-owned utility
A privately owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

Least-cost planning
A process of analyzing the growth and operation of utilities to ensure that energy needs over a specified future period are met through the optimal (least-cost) mix of supply-side and demand-side resources, while satisfying all reliability criteria and other constraints.

Levelization
Conversion of a series of transactions to an equivalent value per unit of output.

Levelized cost of energy
The cost per unit of energy that, if held constant through the analysis period, would provide the same net present revenue value as the net present value cost of the system.

Life-cycle cost
The present value over the analysis period of all system resultant costs.

Load
An end-use device or customer that receives power from the electric system.

Load duration curve
A chart showing electric demand in decreasing magnitude plotted against total duration of occurrence over a specified period of time (usually a year).

Load factor
The ratio of the actual energy consumed during a designated period to the energy that would have been consumed if the peak load were to exist throughout the designated period (i.e., the ratio between the actual and maximum possible consumption in the period). The term is used to describe a characteristic of individual or aggregated load rather than that of generation.

Load following
Increase or decrease in generating unit power output to follow longer term (hourly) changes in electricity demand.

Load levelling
Shifting the load from peak to off-peak periods, which results in a flatter load profile of system load.

Load management
The application of measures to influence customers' use of electricity so as to modify the demand and load factor.

Load profile
A curve depicting aggregated system load of all electricity consumers, typically over a 24-hour period.

Load-serving entity
Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

Locational marginal price
The market-clearing price for electricity at the location the energy is delivered or received.

Long-term transmission planning horizon
Transmission planning period that covers years 6 through 10 or beyond when required to accommodate any known longer time projects that may take longer than 10 years to complete.

Loss-of-load expectation
The expected number of days per year for which available generating capacity is insufficient to serve the daily peak or hourly demand (load).

Loss-of-load probability
The proportion (probability) of days per year, hours per year, or events per season that available generating capacity is insufficient to serve the daily peak or hourly demand (i.e., the proportion of time that the available generation is expected to be unable to meet the system load).

Marginal cost
The economic concept of the change in total costs that results when output is increased or decreased by a single unit. In the electric power industry, marginal costs are the change in total costs resulting from the production of one additional kilowatt or kilowatt-hour of electricity.

Marginal electric generating unit
In organized wholesale markets, the price of the marginal source of electricity (e.g., generating unit providing the next increment or decrement of energy) usually sets the price for all generation.

Market clearing price
The price at which supply equals demand for the day-ahead or hour-ahead markets.

Market-based pricing
Prices of electric power or other forms of energy determined in an open market system of supply and demand under which prices are set solely by agreement as to what buyers will pay and sellers will accept. Such prices could recover less or more than full costs, depending upon what the buyers and sellers see as their relevant opportunities and risks.

Merchant generator
A generating plant built with no energy sales contracts in place.

Metrics
Factors that provide an indication of the extent to which an outcome is achieved. Metrics can be quantitative or qualitative but should provide a reasonably objective means of assessing the outcomes and allow comparisons to be made.

Microgrid
Microgrids are localized grids that can disconnect from the traditional grid to operate independently. Microgrids can strengthen grid resilience and help mitigate grid disturbances because of their ability to continue operating while the main electric grid is down, thereby functioning as a grid resource for faster system response and recovery.

Monetization
Presenting a benefit or cost in terms of monetary value, i.e., in terms of dollars.

Near-term transmission planning horizon
The transmission planning period that covers years 1 through 5.

Net present value (NPV)
The value in the base year (usually the present) of all cash flows associated with a project.

Nominal dollars
The values expressed in nominal or current dollars including inflation.

Non-coincidental peak load
The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating, or cooling season, and usually for not more than 1 year.

Non-energy impacts
Costs or benefits beyond those related directly to energy, capacity, or ancillary services.

Nonfirm power
Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Non-spinning reserve
The portion of operating reserve that is not connected to the system but is capable of serving the demand within a specified time (typically within 10 minutes), or interruptible load that can be removed from the system in a specified time.

Non-utility power producer
A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for electric generation and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers). Non-utility power producers are without a designated franchised service area and do not file forms listed in the *Code of Federal Regulations*, Title 18, Part 141.

Normalization accounting
An accounting practice used by regulated utilities in which deferred income taxes are accumulated in a reserve account and effectively used to purchase new investments. The rate base is reduced by the accumulated reserve. Normalization accounting is the opposite of flow-through accounting.

North American Electric Reliability Corporation
A nonprofit corporation formed in 2006 as the successor to the North American Electric Reliability Council; established to develop and maintain mandatory reliability standards for the bulk electric system, with the fundamental goal of maintaining and improving the reliability of that system. NERC consists of regional reliability entities covering the interconnected power regions of the contiguous United States, Canada, and Mexico.

Open access
FERC Order No. 888 requires public utilities to provide non-discriminatory transmission service over their transmission facilities to third parties to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee. Order 890 expanded open access to cover the methodology for calculating available transmission transfer capability; improvements that opened a coordinated transmission planning process; standardization of energy and generation imbalance charges; and other reforms regarding the designation and un-designation of transmission network resources.

Operating reserve
The capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning reserve and non-spinning reserve.

Opportunity cost
The rate of return on the best alternative investment available.

Outage
The period during which a generating unit, transmission line, or other facility is out of service. A forced or unplanned outage is the shutdown of a generating unit, transmission line or other facility for emergency reasons. A scheduled or planned outage is the shutdown for inspection or maintenance, in accordance with an advance schedule.

Outcomes
The actual or modeled end-state of grid operations, as quantified by metrics.

Overnight construction cost
The value of total plant investment if construction had occurred overnight and all expenditures were made instantaneously.

Payback period
The time required for net revenues associated with an investment to return the cost of the investment. Can be calculated as simple payback period or discounted payback period.

Peak demand
The maximum load during a specified period of time.

Peaking capacity
Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads.

Performance characteristics
The physical and operational attributes of a technology or system. Simple characteristics would include emissions rates, ramp rates, and storage capabilities. More complex characteristics might include transient responses. In a valuation context, performance characteristics must be modeled with varying levels of granularity depending on the metrics to be quantified.

Power purchase agreement
Guarantees a market for power produced by an independent power producer and the price at which it is sold to a purchaser. Such an agreement imposes legal obligations on both the parties to perform previously accepted tasks in a predetermined manner.

Present value
The value in the base year (usually the present) of a cash flow adjusted for the time-value differences in those cash flows between the time of the actual flow and the base year.

Present value dollars
The future amount of money that has been discounted to reflect its present value, as if it existed today. For projects with multiple years of investments and benefits, the costs and benefits in each year of the future are typically presented in present value terms using a constant discount rate per year.

Primary frequency response
The immediate proportional increase or decrease in real power output provided by generating units and the natural real power dampening response provided by system load in response to frequency deviations. This response is in the direction that stabilizes frequency.

Pumped storage hydropower
An energy storage technology that pumps the water into the upper reservoir to store energy and releases water into the lower reservoir to generate electricity.

Qualifying facility
A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the FERC pursuant to the Public Utility Regulatory Policies Act.

Quantification
Presenting a benefit or cost in numerical terms, regardless of the unit used to quantify it (e.g., tons, megawatt-hours, job years).

Ramp rate
The rate at power system load or generator output varies, or the limits to such rates due to mechanical or reliability considerations.

Rate base
The portion of total assets (principally investments in plant and equipment) for regulated utilities, as defined by a regulatory body, upon which a utility is allowed to earn a return.

Reactive power
The portion of electricity that establishes and sustains the electric and magnetic fields or alternating-current equipment.

Real dollars
Real or constant dollars are adjusted to remove the effects of inflation.

Real power
The portion of electricity that supplies energy to the load.

Real-time market
An electricity market that settles—determines the price—for 1-hour periods or less during the day of delivery.

Real-time pricing
The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

Regional transmission organization
A voluntary organization of electric transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate electric transmission planning (and expansion), operation and use on a regional (and interregional) basis. Operation of transmission facilities by the regional transmission organization must be performed on a non-discriminatory basis.

Regulating margin
The amount of spinning reserve required under non-emergency conditions by each control area to bring the area control error to 0 at least once every 10 minutes and to hold the average

difference over each 10-minute period to less than that control area's allowable limit for average deviation, as defined by the NERC control performance criteria.

Regulating reserve
An amount of reserve responsive to automatic generation control, which is sufficient to provide normal regulating margin.

Regulation service
The process whereby one balancing authority contracts to provide corrective response to all or a portion of the area control error of another balancing authority.

Reliability
The ability of an electric power system to meet the electricity needs of end-use customers, even when unexpected equipment failures or other conditions reduce the amount of available power supply.

Reliability must run
A unit that must run for operational or reliability reasons, regardless of economic considerations. Also called a reliability agreement.

Reserve margin (operating)
The amount of unused available capability of an electric power system (at peak load for a utility system) as a percentage of total capability.

Reserve margin (planning)
Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand over a planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy.[1] Planning reserve margin is typically expressed as percentage by which the available generation capacity of existing and new (planned) capacity resources exceeds the net system load.

Resilience
The ability of an electric power system to resist, absorb, or withstand the impact of changes in conditions that have the potential to affect its operation, the ability to adapt in response to the change, and the ability to recover and restore system functionality rapidly.

Resource planner
The entity that develops a long-term (generally 1 year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a planning authority area.

Return on debt
A component of the carrying charge, return on debt is the revenue required to pay for the use of debt money. It is usually stated as a percentage and is applied to unrecovered capital in a particular year. Numerically, it is equal to the cost of debt money times the debt ratio.

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1 See http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx.

Return on equity
A component of the carrying charge, return on equity is the revenue required to pay for the use of equity money. It is usually stated as a percentage and is applied to unrecovered capital in a particular year. Numerically, it is equal to the cost of equity money times the equity ratio.

Revenue allocation
The process of assigning to various customer classes a portion of a regulated utility's revenue requirement.

Revenue requirement
The total amount of money a regulated utility is allowed to collect from customers to pay all approved operating and capital costs, including a fair return on investment.

Risk
There are three key types of risks related to utility resource planning:

- *Financial risk*—Risk associated with the funding (i.e., total cost of capital) used to invest in a new project.
- *Project risk*—Risk associated with planning, constructing, and operating a resource or project. It involves the possibility that the project will not perform as anticipated.
- *Portfolio risk*—Risk experienced by an investor from the total portfolio of investments, projects, or resources. Different combinations of investments, projects, and resources will result in different types of risks for the investor. A common strategy to reduce portfolio risks is to diversify investments.

Risk analysis
Method for quantifying and evaluating uncertainty.

Risk management
The process of analyzing exposure to risk and determining how to best handle such exposure.

Scenario analysis
Evaluation of a set of conditional relationships between variables.

Scheduled frequency
50.0 Hertz in Europe, 60.0 Hertz in North America.

Scheduled outage
The shutdown of a generating unit, transmission line, or other facility for inspection or maintenance, in accordance with an advance schedule.

Security
The ability of electric power system to withstand sudden disturbances such as electric short circuits, unanticipated loss of system components, or switching operations.

Sensitivity analysis
The evaluation of a project under a number of different assumptions on the values of one or more uncertain variables.

Service territory
The area where a utility currently provides service to retail customers, as well as specified areas adjacent to the utility's electric distribution lines or natural gas pipelines in cities and counties where the utility holds franchises.

Simple payback period
The payback period computed without accounting for the time value of money.

Smart inverter
For solar PV installations, an inverter is necessary to switch electricity from direct current (DC) to alternating current (AC). The grid, including the local distribution grid, uses AC power, so before electricity generated by a solar PV installation can be exported onto the grid, it must be changed into AC. More recently, this inverter can now be outfitted with additional software that can accomplish additional services. For example, a smart inverter is capable of actively regulating the voltage of the solar PV's output. As clouds pass over a solar PV unit, the voltage can drop on the electricity that is exported onto the grid, causing drops in voltage at that location. To raise the voltage levels up, the transformer capacitor will step in and provide voltage support. Having a smart inverter address voltage drops before exporting the energy to the distribution grid is a value and service that can be provided by the customer, which can defer or avoid additional distribution upgrades.

Spark spread
A measurement of the difference between the price that a generator can obtain from selling 1 MWh of electricity and the cost of the natural gas needed to generate the megawatt-hour of electricity. Spark spread is a measure of potential profit for generating electricity on a particular day.

Spinning reserve
The portion of operating reserve consisting of the generation that is fully synchronized to the system and available to serve load within the specified period (typically within 10 minutes) following a contingency event.

Spot market
The natural gas market for contractual commitments that are short term (usually a month or less) and that begin in the near future (often the next day, or within days). In electricity, spot markets are usually organized markets for day-ahead and real-time electricity run by an independent system operator or regional transmission organization.

Stability
The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

Sunk cost
Any cost incurred by a prior decision that cannot be affected by the current course of action.

Supervisory control and data acquisition
A system of remote control and telemetry used to monitor and control the transmission system.

Supplemental reserve
The portion of operating reserve consisting of the generation that is capable of being synchronized to the system and available to serve the load within the specified period (typically within 10 minutes) following a contingency event, or the load fully removable from the system within 10 minutes following a contingency event. It is also referred to as non-spinning reserve.

Sustainability
The ability of an electric system to provide electric services to customers with minimal impacts on natural resources, human health, or safety.

System
The integrated electrical facilities, which may include generation, transmission, and distribution facilities that are controlled by one organization.

System characteristics
The current configuration of the power system. These characteristics have physical (i.e., current transmission topology and generators), regulatory (i.e., market structure), and policy (i.e., incentives) dimensions.

System load
Total aggregated demand of all electricity consumers in an electric system at a given time (e.g., instantaneous load, within a certain hour).

System power value
A forecast of the value to an electric system of the next incremental unit of power generation, usually expressed in terms of dollars per megawatt-hour for energy and dollars per kilowatt-hour for capacity.

System requirements
System requirements or constraints are a subset of outcomes which are real-world operational requirements (or their modeling approximations) that bound the valuation process.

Taxable income
That portion of revenue remaining after all deductions permitted under the Internal Revenue Code or a state revenue code have been taken.

Taxonomy of grid services and technologies
A classification scheme for grid-related technologies and services that provides a common language for the discussion of valuation.

Tax preferences
Incentives designed to encourage investment as a stimulus to the overall economy. Examples are deferred income taxes and the investment tax credit.

Tax rate
The rate applied to taxable income to determine federal and state income taxes.

Telemetering
The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.

Time-of-use pricing
A rate design imposing higher charges to customers during periods of the day when higher demand is experienced.

Total plant investment
Total plant costs as modified by escalation and interest during construction.

Tradeoff analysis
Seeks to determine how the value of certain outcomes compares against the value of other outcomes, which are of different nature and measured by different metrics.

Tradeoffs
Provide information on comparative values and possible substitutions among different outcomes of different nature.

Transmission
An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission constraint
A limitation on one or more transmission elements that may be reached during normal or contingency system operation.

Transmission deferral
Deferral of transmission system investments or upgrades.

Transmission loading relief
A NERC procedure that allows reliability coordinators to curtail transactions (among other actions) to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities.

Two-settlement system
A system under which the price for electricity on any given day is established and settled both on a day-ahead and a real-time basis. Day-ahead prices are based on forecasted energy demand and transmission and generation availability. Real-time prices reflect not only day-ahead anticipated events, but what actually occurs in real time—for example, generation or transmission failures, and differences between forecasted load and actual load.

Uncertainty
The range of interval of doubt surrounding a measured or calculated value within which the true value is expected to fall with some degree of confidence.

Uniform capital recovery factor
The uniform periodic payment, as a fraction of the original investment cost, that will fully repay a loan, including all interest, over the term of the loan.

Uplift
Charges from an RTO/ISO collected outside of the market-clearing commodity price. These charges can include payments to reliability must-run units, other out-of-merit-order power purchases, administrative costs of the RTO/ISO, or other cost categories.

Value
The interpretation and weighting of an outcome from a unique stakeholder perspective. Metrics for value can be quantitative or qualitative.

Value of service
A monetary measure of the value customers receive from using or consuming a specific service or product.

Valuation
The systematic process of comparing the difference in current outcomes to those of the potential introduction of a new technology, system, process, or policy. Valuation process accounts for the value of benefits either through market prices, monetization, quantification, the use of a proxy, or some other approach.

Valuation framework
A decision tree/process by which to identify the correct tools, methods, and assumptions to model outcomes. It also provides guidance on the appropriate choice of outcomes on a technology- and stakeholder-specific basis and the level of transparency necessary for comparison and interpretation. Technologies or systems with similar characteristics will require similar quantification methods.

Variable costs
Costs or expenses that increase or decrease along with the increases or decreases in the level of production output or operation.

Virtual bidding
In two-settlement electricity markets, financial transactions that allow participants to hedge against the risk that real-time and day-ahead prices will differ, or to speculate on the difference.

Voltage collapse
A power system at a given operating state and subject to a given disturbance undergoes voltage collapse if post-disturbance equilibrium voltages are below acceptable limits. Voltage collapse may be total (blackout) or partial and is associated with voltage instability and/or angular instability.

Voltage instability
A system state in which an increase in load, disturbance, or system change causes voltage to decay quickly or drift downward, and automatic and manual system controls are unable to halt

the decay. Voltage decay may take anywhere from a few seconds to tens of minutes. Unabated voltage decay can result in angular instability or voltage collapse.

Weighted average cost of capital
The weighted average of the component costs of debt, preferred stock, and common equity. This is sometimes use as a proxy for discount rates in the industrial and utility sectors.

Wholesale electricity markets
The purchase and sale of electricity from generators to resellers (who sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Zonal price
A pricing mechanism for a specific zone within a control area.

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