Pumped Storage Hydropower Valuation Guidebook

A Cost-Benefit and Decision Analysis Valuation Framework

March 2021

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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 (INL), National Renewable Energy Laboratory (NREL), Oak Ridge National Laboratory (ORNL), and Pacific Northwest National Laboratory (PNNL).

The project team collaborated with Absaroka Energy and Rye Development, 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 (NOTA) process. For these two projects, the project team conducted various techno-economic 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:

Denis Bergeron (Maine Public Utilities Commission)
Norman Bishop (Knight Piesold)
Brent Buffington (Southern California Edison)
Wei Dang (Puget Sound Energy)
Peter Donalek (Stantec)
Christine Ericson (Illinois Commerce Commission)
Donald Erpenbeck (Stantec)
Robert Fick (Los Angeles Department of Water and Power)
Scott Flake (Scott Flake Consulting)
Levi Gilbert (Pacific Gas & Electric)
Edward Hansen (Pacific Gas & Electric)
Elaine Hart (Portland General Electric)
Udi Helman (Helman Analytics)
Michael Manwaring (McMillen Jacobs Associates)
Jay Mearns (Pacific Gas & Electric)
Denis Obiang (Los Angeles Department of Water and Power)
Aidan Tuohy (Electric Power Research Institute)
Bruno Trouille (Mott McDonald)
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 (NHA's) Water Power Week and at the HydroVision International conference. The main purpose of these events was to disseminate information on the development of a valuation framework for PSH projects and obtain feedback from the industry. A key objective for the PSH valuation framework developed during this project was to make it 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 industry outreach events, workshops, and webinars, as well as in coordinating and facilitating interactions with the TAG.

Acknowledgments

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The project team would like to express sincere gratitude to the U.S. Department of Energy's Water Power Technologies Office (WPTO) for recognizing the need for this type of research and for funding this effort. Alejandro Moreno, Timothy Welch, Samuel Bockenhauer, Marisol Bonnet, and others at WPTO have been instrumental in guiding and supporting the project team and coordinating 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 PSH project, and with Rye Development and Copenhagen Infrastructure Partners, 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, and others on the Goldendale team.

The project team would also like to thank the members of the Technical Advisory Group—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 was invaluable for this project and for the development of the PSH Valuation Guidebook.

During the course of the project, the project team was also supported by staff and consultants from the National Association of Regulatory Utility Commissioners (NARUC). Special thanks go to Kerry Worthington, Danielle Sass Byrnett, and Christopher Villarreal, for their kind collaboration throughout the project.

The project team would also like to thank Stephanie Lenhart (Senior Research Associate, Boise State University) and Dakota Roberson (Assistant Professor, University of Idaho) for their contributions to Section 4.5 on valuing power system stability.

HydroWIRES

In April 2019, WPTO launched the HydroWIRES Initiative[1] to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well suited to providing a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

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 trade-offs 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 by 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.

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

Pumped Storage Hydropower Valuation Guidebook

A Cost-Benefit and Decision Analysis Valuation Framework

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Executive Summary

Objectives

As an energy storage technology, pumped storage hydropower (PSH) supports various aspects of power system operations. However, determining the value of PSH plants and their many services and contributions to the system has been a challenge. While there is a general understanding that PSH resources provide many services and benefits for the operation of power systems, estimating the value of these services—and especially the monetary value of some of those services—has been a challenge. The objective of this project, 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 goal is to develop detailed, step-by-step valuation guidance that PSH developers, plant owners or operators, and other stakeholders can use to assess the value of existing or potential new PSH plants and their services.

The specific goals of this project are: (1) to develop comprehensive and transparent valuation guidance that will support consistent valuation assessments and comparisons of PSH projects or project design alternatives, (2) to test the PSH valuation guidance and its underlying methodology by applying it to two selected PSH projects, and (3) to transfer and disseminate the PSH valuation guidance to the hydropower industry, PSH developers, and other stakeholders.

The authors believe that the application of a consistent, transparent, and repeatable valuation process will advance valuation assessments and allow stakeholders to compare valuation analyses performed for different PSH projects or design alternatives. It will also increase the acceptance of valuation results and enable better understanding of the true value that PSH technology brings to the grid.

Technical Approach

To accomplish the goals and objectives of this project, as illustrated in Figure ES-1, the project team first developed a draft PSH valuation guidance that accounts for a full range of PSH services and contributions to the grid. The team then applied the valuation guidance to two proposed PSH projects that were competitively selected by DOE WPTO through the Notice of Opportunity for Technical Assistance (NOTA). Two proposed PSH projects, Banner Mountain PSH (Absaroka Energy, LLC) and Goldendale Energy Storage Project (Copenhagen Infrastructure Partners and Rye Development, LLC), were competitively selected by DOE WPTO through the NOTA process. The project team engaged with the NOTA selectees and performed various techno-economic studies to assess different aspects of the value of these two projects. These analyses also served as the real-world test cases for the proposed PSH valuation framework. Based on the experience gained during the techno-economic and valuation studies, the project team revised and improved the valuation guidance before its public release for use by hydropower industry and stakeholders.

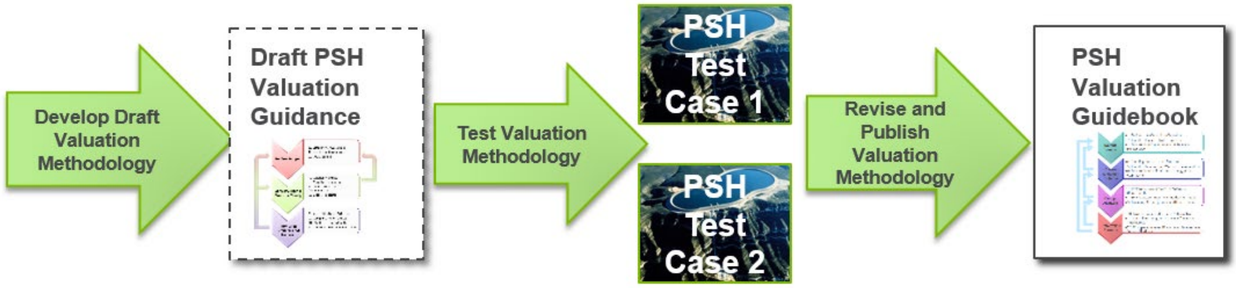

Figure ES-1: Key Project Activities

The techno-economic studies performed during the course of this project included various analyses in support of the valuation process. The key techno-economic studies carried out for the two selected PSH sites included the following analyses:

- Value of bulk power capacity
- Value of energy arbitrage
- Value of PSH ancillary services
- Power system stability benefits
- PSH impacts on reducing system cycling and ramping costs
- Reduction of system production costs and other portfolio effects
- PSH transmission benefits
- PSH non-energy benefits

These analyses provided inputs for the valuation process, specifically the estimated values of different PSH services and contributions. The overall valuation framework was designed as a 15-step valuation process, which is illustrated in Figure ES-2.

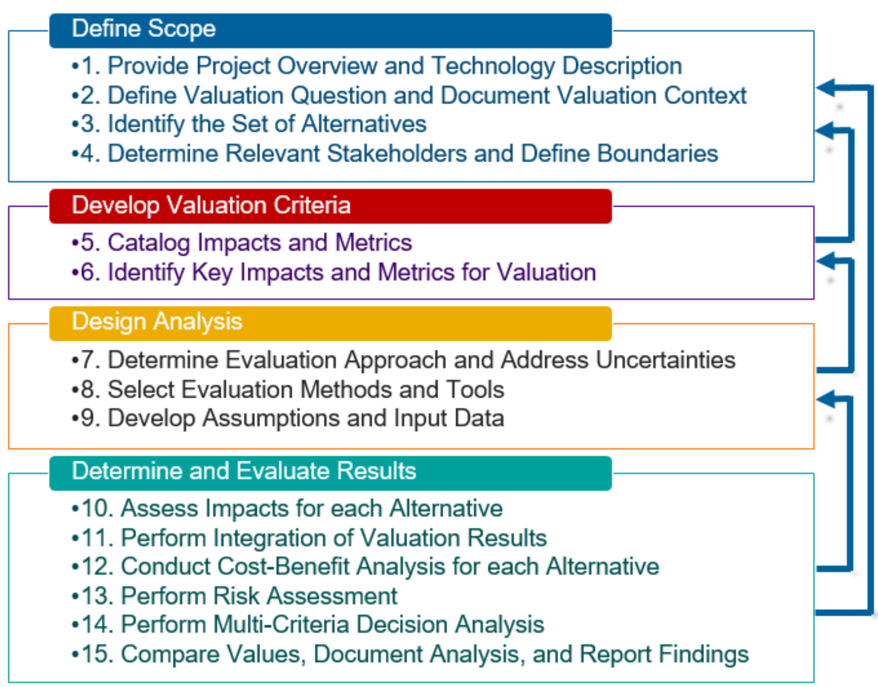

Figure ES-2: Proposed PSH Valuation Process

The steps are grouped into four main activities—the key stages of the valuation process. The valuation process is not linear, and some of the steps may be executed in parallel. Also, based on the results and findings of some steps, there may be a need to go back and revisit previous steps. This is illustrated by the feedback loops on the right side of the chart.

The PSH valuation framework developed during this project utilizes a traditional cost-benefit approach to compare the expected cost and benefit streams over time. In addition, if non-monetized project impacts also need to be taken into account for valuation purposes, the proposed valuation framework allows for multi-criteria decision analysis (MCDA) to be utilized. An MCDA approach can be used to compare different alternatives described with both monetized and non-monetized attributes and explore the trade-offs among different attributes.

The PSH valuation framework was designed to allow for an economic valuation of PSH projects. The economic analysis accounts for all costs and benefits of the project, regardless of who is incurring the costs or is receiving the benefits. In a most general way, the framework allows for a cost-benefit analysis to be performed from a societal perspective, thus helping the analyst determine the economic value of the project for the society as a whole. In addition to the societal cost-benefit analysis, the framework also allows for so-called targeted cost-benefit analyses to be performed by taking into account the perspectives of different stakeholders.

Finally, much of the data and information developed while applying the valuation framework for the economic cost-benefit analysis can also be used to perform a detailed financial analysis of the project. To determine the financial viability of the project, the financial analysis normally takes into account only project costs and benefits that are relevant for its developer or investor.

Intended Audience and Users

The authors believe that the valuation framework and the proposed PSH valuation process described in this Guidebook will be of interest to a variety of stakeholders. PSH developers may use the valuation framework and apply the valuation process presented in the Guidebook to assess the value of their project. Owners and operators of existing PSH plants can also use the Guidebook to assess the value of their project or potential project upgrades. Other stakeholders, such as regulators and financial lending organizations, may not necessarily use the Guidebook to perform their own valuation analysis, but will benefit from understanding the valuation framework and valuation methodology that was applied by PSH developers (e.g., utilities), consulting organizations, and other users. A common benefit for all these stakeholders is that the valuation framework and methodology presented in the Guidebook will help with their decision-making: whether to invest in a project, approve a project, or finance a project.

How to Use this Guidebook

This Guidebook describes a cost-benefit and decision analysis valuation framework and provides guidance how to perform a PSH valuation process. The Guidebook also describes various valuation methodologies and modeling tools that can be used to estimate the value of different PSH services and their contributions to the grid.

The Introduction section provides a brief background for the project, while Section 2 introduces the reader to a general overview of various valuation methods and approaches. The proposed cost-benefit and decision analysis framework for the valuation of PSH projects is described in Section 3, which provides detailed step-by-step guidance on how to perform the valuation.

The proposed PSH valuation process consists of 15 steps that are grouped into four main activities. Some of the steps in the valuation process are relatively simple and straightforward, while others may require complex modeling and analysis (for example, the applications of detailed modeling tools to simulate the operations of PSH plant and the power system in which it is located or to determine the values of its services and various contributions to the grid). Valuation methodologies and approaches that can be used to estimate the value of various PSH services are presented in Section 4, which also provides guidance to users related to appropriate modeling tools and metrics that can be used to estimate the impacts and values of different PSH services. A list of various metrics that could be used to measure the impacts of PSH services and contributions is provided in Appendix A, and a catalog of computer models and tools that could be used for various types of analyses is provided in Appendix B.

While performing the techno-economic studies of various PSH services and contributions, the user should also refer to Section 5, which discusses some of the issues related to the integration of results and how to avoid double-counting costs and benefits. The estimated costs and benefits are then projected over the years to develop expected cost and benefit streams over the time period of the cost-benefit analysis. These cost and benefit streams serve as input to the cost-benefit analysis model (Step 12 of the valuation process) to determine the economic value of the project. Appendix E provides an overview of the cost-benefit analysis and discusses the choice of discount rate and other factors important for this analysis.

If both monetized and non-monetized costs and benefits of a PSH project need to be taken into account for decision-making, an MCDA (Step 14) can help decision-makers determine the best project alternative. Appendix F provides a description of the MCDA process and shows the user how to apply it using a simple but illustrative example.

Finally, in the last step of the valuation process (Step 15), the analyst compares the values obtained for different alternatives, summarizes the results, and presents the findings to decision-makers. While the analyst performs the analysis, it is decision-makers who are making actual decisions related to the project being evaluated.

Methodology Limitations

Analysts should be aware of the limitations of the proposed valuation methodology. The key limitations of 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 MW 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-taker approach, which assumes that the operation of a PSH plant will not have a significant impact on system operations and prices, is valid only for smaller PSH projects (e.g., less than 10 MW). For most other PSH projects, a system analysis that simulates the operation of the entire system and captures the influence of the PSH project on system operations and prices is needed to properly evaluate the costs and benefits of the project. In contrast to the price-taker approach, this system analysis is often referred to as price-maker (or price-influencer) approach, as it tries to capture the impact of the PSH project on system prices. This price-maker or price-influencer approach should not be confused with the market power analysis, as the PSH project is not assumed to perform any strategic bidding in order to exercise market power. Rather, the price-influencer approach acknowledges and tries to capture the impacts of a PSH project that, because of its large size, will inevitably affect supply and demand curves as well as the resulting market clearing prices.

Therefore, 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 need to be performed using multiple computer models and tools. This presents a significant analytical burden for the application of the valuation process, as 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. The case studies for the Banner Mountain and Goldendale projects provide a good example of system analysis approach and illustrate its complexities when dealing with the valuation of PSH projects of larger size. These case studies are documented in two technical reports that accompany this Guidebook and serve as examples of how the valuation methodology presented in this Guidebook can be applied for valuation of actual PSH projects.

Another key limitation of the valuation process is the uncertainty related to the value of PSH services and contributions over time. PSH plants are projects with a very long lifetime (50-60 years or longer), and attempting to estimate any value over such a long time period is inevitably dealing with 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 make estimates of project value streams over such a long period. Evolving power systems, new generation and demand-side technologies, and a rapidly changing generation mix all contribute to these uncertainties. The scenario analyses and sensitivity to key parameters studies may help the analyst capture some 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 this Guidebook are still very useful in estimating the potential value of a PSH project, as they provide valuable information to decision-makers. Of course, with changing system conditions, the valuation analysis may need to be occasionally updated to reflect the new developments and information that was not previously available.

PSH Valuation Tool

Given the complexities of the PSH valuation analysis, the project team is currently developing an online PSH Valuation Tool to help users navigate through the valuation process presented in this Guidebook. The development of the PSH Valuation Tool is also funded by DOE WPTO, and the tool is intended to be publicly available. The tool will employ a decision tree structure to guide users through the steps of the PSH valuation process and the activities and types of analyses to be performed at each step. The PSH Valuation Tool will have the analytical capabilities to be able to perform the price-taker valuation analysis. For system analysis (i.e., price-influencer analysis), the tool will indicate at certain points in the decision tree that the user needs to apply external models to perform system simulations and then return with the results in order to continue the valuation process. The tool will also refer the users to appropriate types of external models that could be applied for system analysis.

Project Team

This project was funded by the DOE's Water Power Technologies Office (WPTO) and carried out in 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 Absaroka Energy and Rye Development, 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, which included prominent experts from the hydropower industry, grid operators, regulatory agencies, and other stakeholders.

Acronyms and Abbreviations

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

ABMS	Agent-based modeling and simulation
ABS	Agent-based simulation
AC	Alternating current
ACE	Area control error
AGC	Automatic generation control
AMES	Agent-based modeling of electricity system
AMI	Advanced metering infrastructure
AMIGA	All-modular interindustry growth assessment
ASAI	Average service availability index
ASIDI	Average system interruption duration index
ASIFI	Average system interruption frequency index
AS PSH	Adjustable-speed pumped storage hydropower
AVERT	Avoided emissions and generation tool
AVR	Automatic voltage regulator
BAU	Business as usual
BCR	Benefit-cost ratio
BPA	Bonneville Power Administration
BSET	Battery storage evaluation tool
BSS	Black start service
Btu	British thermal unit
CAES	Compressed-air energy storage
CAIDI	Customer average interruption duration index
CAIFI	Customer average interruption frequency index
CAISO	California Independent System Operator (ISO)
CAMD	[EPA] Clean Air Markets Division
CBA	Cost-benefit analysis
CCB	Conventional cost-benefit analysis
CCDF	Composite customer damage function
CCS	Carbon capture and storage
CCT	Critical clearing time
CDF	Customer damage function
CE	Cost effectiveness
CELID	Customers experiencing long interruption durations index
$CEMI_n$	Customers experiencing multiple interruptions index
$CEMSMI_n$	Customers experiencing multiple sustained and momentary interruption events index
CFSM	Converter-fed synchronous machine
CHEERS	Conventional Hydropower Energy and EnviRonmental Systems model
CIC	Customer interruption cost
CIP	Critical infrastructure protection
COI	Center of inertia

CONE	Cost of new entry
ConEd	Consolidated Edison
CPS1	Control performance standard 1
CPUC	California Public Utilities Commission
CRM	Capacity remuneration mechanism
CRR	Congestion revenue rights
CTAIDI	Customer total average interruption duration index
CVaR	Conditional value-at-risk
DC	Direct current
DER	Distributed energy resource
DER-CAM	Distributed energy resources—customer adoption model
DFIM	Doubly fed induction machine
DOE	United States Department of Energy
DP	Dynamic programming
DR	Demand response
DSA	Dynamic security assessment
DSS	Decision support system
E4ST	Engineering, economic, and environmental electricity simulation tool
EGEAS	Electric generation expansion analysis system
EIA	Energy Information Administration
ELCC	Effective load carrying capability
EMCAS	Electricity market complex adaptive system
EMM	Electricity market module
EPA	United States Environmental Protection Agency
EPPA	Economic projection and policy analysis
EPRI	Electric Power Research Institute
EPS	Electric power system
ERCOT	Electric Reliability Council of Texas
ESR	Energy storage resource
ETAP	Electrical transient analyzer program
ETSAP	Energy technology storage analysis program
EUE	Expected unserved energy
EUR	Expected unserved ramping
FACTS	Flexible alternate current transmission system
FERC	Federal Energy Regulatory Commission
FESTIV	Flexible energy scheduling tool for integrating variable generation
FTR	Financial transmission rights
GADS	Generating availability data system
GE	General Electric Company
GHG	Greenhouse gas
GIS	Geographic information system
GMI	[DOE] Grid Modernization Initiative
GMLC	Grid Modernization Laboratory Consortium
GU	Generating unit
GW	Gigawatt
GWh	Gigawatt hour

HEC	U.S. Army Corps of Engineers Hydrologic Engineering Center
HEC–ResSim	Hydrologic Engineering Center's reservoir system simulation
HIL	Hardware-in-the-loop
IAEA	International Atomic Energy Agency
IEAR	Interrupted Energy Assessment Rate
IEEE	Institute of Electrical and Electronics Engineers
IO	Input-output
IPP	Independent power producer
IRP	Integrated resource planning
IRR	Internal rate of return
IRRE	Insufficient ramp resource expectation
ISO	Independent system operator
ISO-NE	Independent System Operator–New England
JEDI	NREL jobs and economic development impact models
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt hour
kW-yr	Kilowatt-year
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized cost of electricity
LMP	Locational marginal price
LOLE	Loss-of-load expectation
LOLEV	Loss-of-load events
LOLH	Loss-of-load hours
LOLP	Loss-of-load probability
LP	Linear programming
LSE	Load-serving entity
MA	Mitigating attributes
MAIFI	Momentary average interruption frequency index
$MAIFI_E$	Momentary average interruption event frequency index
MAPS	Multi-area production simulation
MASCEM	Multi-agent system that simulates competitive electricity markets
MCDA	Multi-criteria decision analysis
MGD	Million gallons per day
MILP	Mixed-integer linear programming
MIRR	Modified IRR
MISO	Midcontinent Independent System Operator
MHK	Marine and hydrokinetic (energy)
MW	Megawatt
MWh	Megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEMS	National Energy Modeling System
NEMSIM	National electricity market simulation system
NERC	North American Electric Reliability Corporation
NOTA	Notice of opportunity for technical assistance
NPV	Net present value

NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
O&M	Operation and maintenance
PCM	Production cost model
PFD	Periods of flexibility deficit
PI	Profitability index
PJM	PJM Interconnection (RTO)
PMU	Phasor measurement unit
PNNL	Pacific Northwest National Laboratory
PNUCC	Pacific Northwest Utilities Conference Committee
PPA	Power purchase agreement
PRM	Planning reserve margin
PROMETHEE	Preference ranking organization method for enrichment evaluations
PSH	Pumped storage hydropower
PSS	Power system stabilizer
PTO	Participating transmission owner
PUC	Public utilities commission
PV	Photovoltaic
QSE	Qualified scheduling entity
ReEDS	Regional energy deployment system
RFF	Resources for the Future
RFI	Request for information
RFP	Requests for proposal
RIM	Renewable integration model
RIMS II	Regional input-output modeling system
RMS	Root mean square
ROCOF	Rate of change of frequency
ROI	Return on investment
RTO	Regional transmission organization
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SARFI	System average RMS frequency index
SARI	System average restoration index
SCADA	Supervisory control and data acquisition
SCED	Security-constrained economic dispatch
SCUC	Security-constrained unit commitment
SDP	Stochastic dynamic programming
SIARFI	System instantaneous average RMS frequency index
SF	Shift factor
SMARFI	System momentary average RMS frequency index
SMIB	Single machine infinite bus
SOC	State of charge
SPP	Southwest Power Pool
STARFI	System temporary average RMS frequency index
T&D	Transmission and distribution
TAG	Technical advisory group

TCB	Targeted cost-benefit analysis
TCC	Transmission congestion charge
TO	Transmission owner
TRC	Total resource cost
TS	Transmission services
TVA	Tennessee Valley Authority
UFLS	Under frequency load shedding
UNFCCC	United Nations Framework Convention on Climate Change
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
US-REGEN	U.S. regional economy, greenhouse gas, and energy model
VaR	Value-at-risk
VAR	Volt-ampere reactive
VER	Variable energy resource
VoLL	Value of lost load
WASP	Wien automatic system planning model
WECC	Western Electricity Coordinating Council
WPTO	Water Power Technologies Office
WRAP	Water rights analysis package
WRIMS	Water resource integrated modeling system

Contents

Figures

Tables

1. Introduction

Pumped storage hydropower (PSH) plants are a sizable part of the energy mix in the U.S., with 40 PSH plants in operation in 2015, totaling about 22 GW in installed capacity (DOE 2016) and an estimated 553 GWh of energy storage (Uria-Martinez et al. 2021). About 1,333 MW of PSH capacity was added in the U.S. from 2010 to 2019, which is almost as much as the combined installed capacity of all other energy storage technologies added during the same time period (Uria-Martinez et al. 2021). In 2015, PSH provided about 97% of utility-scale electrical storage in the U.S. (DOE 2016). The interest in PSH development has been high in recent years. At the beginning of 2020, 40 proposed PSH projects had active preliminary permits approved by the Federal Energy Regulatory Commission (FERC), with 14 preliminary permits pending.[1]

In general, electric grid and power system operations have been gradually changing in recent years, influenced largely by the integration of variable renewable generation from wind and solar resources. In addition, aggressive greenhouse gas (GHG) reduction goals adopted by many states have resulted in reduced operation of thermal plants and restricted permitting opportunities for conventional fossil fuel technologies. In the future, electric vehicles, distributed generation, microgrids, smart grids, and other emerging technologies could further affect grid operations. As these changes impact the power system, maintaining a balance between electrical supply and demand and broader power system stability requires support from ancillary grid services to ensure that electricity is provided safely, reliably, and economically.

The role and value of PSH resources in such an evolving electricity grid is 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. While PSH is highly flexible, emerging changes to the power system may require existing PSH facilities to operate in ways that incur costs that were not considered when the facilities were originally designed. Meanwhile, the provision of ancillary services to meet changing power system realities may have economic values above and beyond the financial compensation offered in present-day markets.

As determined by the Hydropower Vision study (DOE 2016), the development of new PSH projects in the future may support the integration of variable renewables, such as wind and solar generation, yet the extent of the value that PSH can provide and how these storage resources should be compensated in electricity markets are not fully understood. This lack of understanding of the benefits and values that PSH projects provide to the grid is one of the key barriers to the development of new PSH projects. Large project sizes (typically several hundred MW), which require significant capital investment costs as well as very long permitting, construction and commissioning times (typically 7–10 years or longer) explain why there was only one new PSH projects constructed in the United States in the last twenty years, despite significant interest by PSH developers and availability of excellent project sites. In addition to

[1] FERC provides information on active and pending preliminary permits for PSH projects at: https://www.ferc.gov/industries-data/hydropower/licensing/pumped-storage-projects

Lake Hodges PSH plant (40 MW), which was commissioned in 2012, several existing PSH plants have been refurbished and repowered, which increased the total PSH capacity in the U.S.

A better understanding of the values and benefits PSH projects provide to the grid, in addition to techno-economic analyses of potential PSH sites, improved quantification and valuation of PSH operational flexibility, analyses of new potential market structures, and an understanding of the effects of flexible operation on plant components are needed to ensure PSH continues to play a significant role in the nation's evolving grid.

1.1. Project Purpose and Context

The main purpose of this project was to develop a valuation framework to assess the economic value of PSH plants by accounting for and estimating the value of various services they provide to the grid. The goal was to develop a valuation framework as a detailed step-by-step methodology that would be publicly available and could be used by PSH developers, plant owners and operators, and other stakeholders to assess the value of existing or potential new PSH projects. One of the objectives for the valuation framework was that it be general, so it could be applied to different types and sizes of PSH plants operating in different market environments (e.g., traditionally regulated or restructured competitive markets), while being detailed enough to account for various services and contributions that PSH plants provide to the grid. Another objective for the valuation framework was to provide a comprehensive, repeatable, and transparent valuation process that would allow for comprehensive and consistent assessments of potential new PSH projects or project design options. Potential use cases for the PSH valuation framework include assessments of value and economic/financial feasibility of existing and new PSH projects by PSH owners/operators and project developers, both electric utilities and independent power producers (IPPs). The application of a standardized and transparent valuation process will also enhance the understanding of results among different stakeholders and provide relevant inputs and information to regulatory agencies (e.g., public utility commissions [PUCs]) and financial organizations for their use in the decision-making process.

The valuation framework developed in this project was tested with 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 DOE WPTO through a Notice of Opportunity for Technical Assistance (NOTA) process. Prior to issuing the NOTA, a request for information (RFI) 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)
- Goldendale Energy Storage Project (Copenhagen Infrastructure Partners and Rye Development, LLC)

Almost a dozen techno-economic 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 techno-economic studies served as inputs into the valuation framework to provide an overall assessment of the economic value of these two PSH projects. These techno-economic studies are documented in two companion technical reports with the purpose of illustrating the valuation methodologies and analyses presented in this Guidebook.

It should be noted that the developers of these two selected projects are planning on using different PSH technologies than those that are currently utilized by the existing PSH plants in the U.S. While the 1,200 MW Goldendale project will use the adjustable-speed technology that employs doubly fed induction machines (DFIMs), the 400-MW Banner Mountain project will use the "quaternary" technology, which is similar to the ternary PSH technology. Like the ternary units, the quaternary units can also be designed to operate in a hydraulic short circuit (HSC) mode, which provides them with excellent flexibility and a continuous operating range from full generating to full pumping mode of operation. At present, both of these technologies are new to the U.S., since all of the existing PSH plants currently use the conventional single-speed (or fixed-speed) PSH technology. The adjustable-speed PSH technology was developed in Japan in 1990s, and since then it has also been used in Europe and other regions. On the other hand, the quaternary technology with HSC is a new design and the planned installations at the Gordon Butte and Banner Mountain PSH projects in the U.S. would the first applications of that technology in the world.

While developing the valuation framework, the project team also performed a comparative analysis of the costs and performance characteristics of PSH and several competing technologies, including various energy storage technologies such as electro-chemical storage (various chemistries, including flow batteries), flywheels, supercapacitors, and compressed-air energy storage (CAES), as well as conventional electricity generating technologies (e.g., gas turbines). These technologies are often considered able to provide services and contributions to the grid similar to those provided by PSH, but so far a comprehensive analysis of how their costs and benefits compare to those of PSH plants has not been conducted. For this study, a conventional single-speed PSH plant was used to represent the PSH technology. The results of this analysis showed that PSH is very competitive with other energy storage technologies and is one of the lowest cost options on both a $/kW and a $/kWh basis (Mongird et al. 2019).

1.2. Methodological Approach

In developing the valuation framework for PSH plants, the project team leveraged and built upon existing applicable DOE-funded work in this area, including the Grid Modernization Laboratory Consortium (GMLC) projects (GMLC 1.1 Metrics Analysis and GMLC 1.2.4 Grid Services and Technologies Valuation Framework Development) and several DOE WPTO-funded studies focusing on the economic and financial feasibility of new and innovative PSH technologies. The project team also leveraged the PSH and hydropower valuation studies performed by the Electric Power Research Institute (Key 2013), the Brattle Group (Ruiz et al. 2018), Argonne National Laboratory (Botterud et al. 2014; Koritarov et al. 2014), NREL (Ibanez et al. 2014), Pacific Northwest Utilities Conference Committee (PNUCC 2016), International Energy Agency (Huertas-Hernando et al. 2017), and others. A comprehensive literature review process was conducted to inform the development of the PSH valuation framework.

The valuation framework developed in this project allows for the accounting of PSH costs and benefits over the project lifetime. It uses a cost-benefit approach to compare the annualized project investment costs to the annual values of expected benefits and value streams. Since PSH projects typically have a relatively long lifetime—50 years or more—this provides for a fair estimate of their economic value and allows for objective comparison with competing energy storage technologies that have shorter project lifetimes.

In accounting for potential benefits and value streams of PSH projects, the analysis should take into account which services and value streams can be provided in parallel and which are mutually exclusive and cannot be performed at the same time. The framework allows for "stacking" of value streams, but the analyst has to be sure to avoid double-counting of benefits by performing a careful integration analysis.

The valuation framework and analysis also includes the estimation of so-called system-wide or portfolio benefits provided by PSH plants to the power system as a whole. Some of these benefits (e.g., inertial response, flexible ramping, reduced curtailments of variable renewables, and other portfolio effects) are expected to increase in the future, especially in areas with a higher penetration of wind and solar generation.

The valuation framework is also designed to allow both monetized and non-monetized benefits to be considered in the valuation analysis. If both monetized and non-monetized benefits are considered in the decision-making process, then a multi-criteria decision analysis (MCDA) can determine the trade-offs among different types of benefits and compare alternatives. The MCDA is optional, and the analyst may perform the valuation analysis using the traditional cost-benefit analysis if only monetized value streams are considered.

To determine the estimated value of various PSH services and contributions to the grid, a number of techno-economic studies need to be performed, including various analyses to support the valuation process and provide inputs to the valuation framework. Key techno-economic studies that should be carried out in the PSH valuation process include the following analyses:

- Value of bulk power capacity and energy arbitrage
- Value of PSH ancillary services
- Power system dynamic performance stability benefits (e.g., power system stability, inertia, and voltage support)
- PSH impacts on reducing system cycling and ramping costs
- Reduction of system production costs and other portfolio effects
- PSH transmission benefits
- PSH non-energy benefits (e.g., jobs, economic development, etc.)

In addition, power market analyses need to be performed to analyze the market conditions in which the PSH project under consideration will be operating and to assess potential revenue streams for various market services or products. The power market analysis should also include an analysis of new trends and developments in market structures and the potential impacts of new market rules on the PSH project and its future market revenues.

PSH developers should also perform economic and financial analyses to determine the economic viability and financial feasibility of the PSH project and calculate various economic and financial ratios and parameters. Sensitivity studies should be performed for key cost factors and value streams that influence PSH feasibility.

1.3. Main Project Outcomes

An objective and comprehensive valuation framework for PSH plants will establish a consistent and repeatable method for assessing the value that PSH technology brings to the power grid. While 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 in turn to assess the total benefits of PSH for the system and provide appropriate compensation to PSH owners and operators.

As an energy storage technology, PSH supports all aspects of power grid operations and spans major power grid components, including electricity generation, delivery, and demand sub-systems. Developing a valuation framework specifically designed to enable the analyst to include all services and contributions PSH plants provide to the power system represents a big step forward in understanding the true value that this technology brings to the grid, thus removing one of the obstacles faced by PSH operators and developers.

1.4. Organization of the Guidebook

Section 2 provides a general overview of methods and approaches typically used in valuation analyses of various grid technologies. Section 3 provides an overview of the proposed PSH valuation framework and describes in detail the 15-step valuation process. Section 4 provides extensive technical detail on various methods and approaches that can be used to assess, quantify, and estimate the value of different PSH services and contributions to the grid. Section 5 discusses how to integrate the results of valuation assessments for various PSH services in a comprehensive and consistent manner and develop the resulting value streams for use in the cost-benefit analysis.

This report also includes several Appendices that will be useful to the reader. Appendix A provides a list of metrics that can be used in the valuation process. Appendix B provides a catalog of computer models and tools for the assessment and valuation of various PSH services and contributions to the grid. Appendix C provides an overview of the integrated resource planning (IRP) process, which is commonly used for capacity expansion planning but can also serve to provide insights into the long-term values of PSH resources. Appendix D provides a high-level description of the cost-benefit analysis that is typically used to determine the economic value of projects or investments. Appendix E gives an overview of multi-criteria decision analysis and illustrates the process through a simple numerical example. Finally, Appendix F provides a comprehensive glossary of valuation terms.

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2. General Overview of Valuation and Decision Analysis Methods and Approaches

2.1. A Summary of Valuation Techniques

Valuation analysis is frequently used in many industries to determine the estimated value of a project, system component, technology, or service. Given the widespread need for this type of analysis, there is a wide range of different valuation approaches and techniques that can be potentially relevant and applicable for estimating the value of PSH projects and the various services that they provide to the grid. Selection of the appropriate valuation approach is important, as different valuation methods may be more or less suitable for different types of services or technologies. Valuation analysis often supports decision-making, e.g., whether to go ahead and develop a proposed new project or not. Therefore, valuation and decision analyses are often combined in the same analytical framework. At the highest level, the valuation analysis aims to support decision-making and facilitate the selection of the most appropriate option.

Because the valuation analysis normally involves estimating the value of various services that a proposed project or technology can provide, different valuation approaches and techniques may need to be applied to estimate the costs and revenues of individual services. While these valuation approaches and techniques provide good estimates of the value and potential revenue streams that can be expected from different services, they do not provide complete information on the overall value of the project or guidance for making a "go" or "no-go" decision. The valuation analysis then integrates individual value streams that are quantified using different techniques and synthesizes them to obtain the value of the overall project.

Valuation analysis typically includes a cost-benefit analysis, which provides information for decision-making. As mentioned above, the cost-benefit valuation analysis can be used in combination with the decision analysis to support the decision-making process through, for example, the application of a multi-criteria decision support tool. As the estimates of the values of individual services are the basis for the valuation of a project or technology, proper selection of appropriate valuation approaches and quantification techniques for their estimation is fundamental to developing a representative valuation and decision analysis.

2.1.1. Valuation and Decision Methods

The following section outlines the valuation and decision methods most commonly used in the power industry along with their corresponding assumptions, strengths, and weaknesses. It is important to note that while the sections outlined below are separated into distinct sections, the application of these principles within the industry is less defined, with attributes of different applications being included or omitted as necessary to provide the desired insight that is relevant to a particular industry group or stakeholder.

Cost-Benefit Analysis

The most commonly used valuation method is the conventional cost-benefit (CCB) valuation technique. The CCB method involves identifying all of the possible consequences of the project and establishing whether the net impact will have a positive (benefit) or negative (cost) effect. Once this is done, all of the consequences are then valued to a common metric (typically currency) and then summed up to determine both whether the project represents a net benefit or a net cost and the ratio of the net benefit to net cost (known as the benefit-cost ratio or BCR).

Despite the pervasiveness of the CCB method, there have been several proposed modifications to the method to 1) enable greater flexibility in both identifying and valuing project impacts, 2) enhance the ability to specify non-market values, and 3) allow for targeting of the cost-benefit analysis to answer a specific question (Woolf et al. 2014). It should be noted that non-market values specifically refer to services that, while having value, are not traded in the market and thus are more difficult to value.

The first modification is a variation on CCB that, instead of holistically assessing the costs and benefits to determine the general value to the system, uses a targeted assessment of costs and benefits to answer specific questions. These specific questions can be ones relevant to certain stakeholders or valuation perspectives. Developing a targeted cost-benefit (TCB) analysis initially requires that the specific question as well as the costs and benefits specifically affecting that question be defined. The specified costs and benefits for the TCB are then valued and tabulated to answer the question (California Public Utilities Commission 2001). The most common TCB analyses performed in the power sector and their corresponding benefits and costs when applied to a distributed energy analysis can be seen in Table 2.1 and Table 2.2 (Woolf et al. 2014).

Table 2.1: Summary of Targeted Cost-benefit Analyses

TCB Analysis	Question Answered	Summary	Implications
Societal cost test	Will total societal costs decrease?	Costs and benefits experienced by all members of society.	Most comprehensive test, as it includes utility system impacts, participant impacts, and societal impacts (e.g., environmental externalities, economic development, etc.).
Total resource cost (TRC) test	Will utility system costs plus program participant cost decrease?	Costs and benefits experienced by the utility system and program participants.	Less comprehensive than the societal cost test as it focuses on utility and program participant impacts. The TRC test includes participant costs, but does not include any relevant non-energy benefits.
Utility cost test	Will utility system costs decrease?	Costs and benefits experienced by the utility system.	Limited to impacts on utility revenue requirements.
Participant cost test	Will program participant cost decrease?	Costs and benefits experienced by participating customers.	Useful in developing program design and for customer information purposes (e.g., participation improvement programs).
Rate impact measure test	Will utility rates decrease?	Costs and benefits that will affect utility rates.	Does not demonstrate rate impacts or customer equity.

Table 2.2: Costs and Benefits Included in Targeted Cost-benefit Analyses

	Participant Cost	Rate Impact Measure	Utility Cost	Total Resource Cost	Societal Cost
Benefits					
Avoided energy cost	No	Yes	Yes	Yes	Yes
Avoided capacity costs	No	Yes	Yes	Yes	Yes
Avoided transmission and distribution cost	No	Yes	Yes	Yes	Yes
Wholesale market price suppression effects	No	Yes	Yes	Yes	Yes
Avoided environmental compliance costs	No	Yes	Yes	Yes	Yes
Utility non-energy benefits	No	Yes	Yes	Yes	Yes
Participant non-energy benefits	Yes	No	No	Yes	Yes
Societal non-energy benefits	No	No	No	No	Yes
Customer bill savings	Yes	No	No	No	No
Costs					
Program administration	No	Yes	Yes	Yes	Yes
Program financial incentive	No	Yes	Yes	Yes	Yes
Participant contribution	Yes	No	No	Yes	Yes
Non-energy costs (utility, participant, societal)	No	Yes	Yes	Yes	Yes
Lost utility revenue	No	Yes	No	No	No

Cost-Effectiveness Analysis

Although the CCB and TCB methods are the most prevalent, there are several other techniques used to valuate technologies or services that focus on countering the weaknesses of the cost-benefit techniques, such as pricing non-market values, binary trade-offs, assessment uncertainty, discount rate selection, cost exaggeration, and accurate system representation (Ackerman 2008).

One of the most common alternative techniques is the cost-effectiveness (CE) analysis. This method relies on a comparative analysis similar to the cost-benefit method outlined above, but it represents a ratio of an *individual unit* of product or service to the costs associated with it. This analysis type has two primary advantages over the cost-benefit applications: its ability to target a specific attribute of interest, and its ability to limit the number of non-market costs that must be assessed in the valuation. The latter is a function of the former, because the number of specific value streams that must be assessed is limited due to the targeted nature of the analysis. One of the most common applications of this type of analysis is the levelized cost of electricity (LCOE) analysis, which is typically used to compare the cost-effectiveness of different electricity generation technologies. The LCOE analysis is specifically designed to enable the comparison of different generation sources characterized by a wide range of lifespans, capacities, financial characteristics, and capital and maintenance costs.

With its relative analytical simplicity and ease of use, CE analysis is widely used in the energy industry and research community for initial screening of various technology options and to provide insights during the resource selection process (Namovicz 2013; Pawel 2014; Ueckerdt 2013). In addition, CE analysis has been leveraged to document the cost drivers of specific technologies to better target cost reduction research and policies. This is exemplified by efforts of Jenne, Yu, and Neary (2015) and Rubin, Davison, and Herzog (2015), who used CE principles to better understand the price dynamics of marine and hydrokinetic (MHK) systems and carbon capture and sequestration (CCS) technologies respectively (Jenne, Yu, and Neary 2015; Rubin, Davison, and Herzog 2015). It should be noted, however, that despite its variations from the CCB and TCB analysis, CE analysis still must contend with many of the same concerns associated with consolidating the economic and financial aspects of a technology or service into a singular value. These include both representing complex, multi-year cash flows accurately as well as accurately quantifying the value streams that are included in the analysis.

Multi-Criteria Decision Analysis

Multi-criteria decision analysis, which includes benefits expressed in different units (e.g., monetized and non-monetized benefits), is often used in the valuation process to help determine the relative values of alternatives. Multi-criteria decision analysis allows comparisons and ranking of alternatives by establishing trade-offs among different benefits or value streams. This valuation and decision-support technique builds on the difficulty of converting non-market costs and benefits and, instead of forcing the conversion to common currency, enables the user to select multiple comparison criteria among alternatives. The weights of the comparison criteria for each alternative considered are ranked on a scale, e.g., from zero to one, where the total of the individual comparison criteria weights is equal to one (Diakoulake and Karangelis 2007).

This is seen as a more viable approach in situations where multiple, often conflicting, criteria are being evaluated, and it has been leveraged numerous times in the power sector (Behzadian et al. 2010; Klein and Whaleey 2015; Maxim 2014). Within the general category of multi-criteria decision analysis, there are numerous methods of application, with the most common in the energy sector being the preference ranking organization method for enrichment evaluations (PROMETHEE). The specifications of the PROMETHEE method along with its numerous applications are addressed in a survey paper developed by Oberschmidt et al. (2010).

Real Options Analysis

Real options analysis was developed for financial options and has been extended from its application in finance to engineering projects and other real-life decisions. This valuation approach is well suited to investment in an uncertain environment. One of the advantages of this method is that it deals with uncertainty and provides decision-makers with flexibility in their investment decisions. The traditional net present value (NPV) method assumes two options: (1) to make an investment (if NPV >0), or (2) not to make the investment (if NPV < 0). In other words, if the company does not make the investment now, it will lose the opportunity forever (Wang 2005). Unlike the traditional NPV valuation tool, real options analysis gives decision-makers more options, such as investment deferral, abandonment, or expansion—the realistic options in most situations and engineering planning problems. The most common categories of real options include option to defer, time to build option, scaling option, option to abandon, option to switch, growth option, and multiple interacting options (Wang 2005).

Real options analysis is suitable for energy projects since many variables—the cost of equipment, the market price for wholesale ancillary services, energy market prices, the social cost of carbon, the growth of distributed generation—are uncertain and can vary significantly. Much research has been conducted in the energy sector. For instance, some researchers (Zhou et al. 2007) used real options analysis to investigate the value of a generation asset in a spot market with operation constraints. Others (Pringles, Olsina, and Garcés 2015) applied the method to power transmission investment in uncertainty. For example, flexible alternating current transmission systems (FACTS) devices are an effective way to adding flexibility to the transmission system, and another study (Moon 2014) presented an investment valuation approach to assessing the option value of deferring transmission lines investments by applying FACTS devices. The authors also applied real options theory to determine the optimal time to invest in energy storage systems in uncertainty conditions. The real options analysis has also been applied to distributed generation. In "Flexible Distributed Multienergy Generation System Expansion Planning Under Uncertainty" (2016), Ceseña, Capuder, and Mancarella proposed a unified operation and planning optimization methodology for distributed multi-energy generation systems with the aim of assessing flexibility embedded in both operation and investment stages subject to long-term uncertainties.

Real options analysis typically includes an assessment of potential risks associated with different options. To assess risk, value-at-risk (VaR) and conditional value-at-risk (CVaR) are two commonly applied indices. VaR measures the potential loss in value of a risky asset or portfolio over a defined period for a given confidence interval (Wilson 1999). There are three key elements of VaR: (1) a specified level of loss in value, (2) a fixed time period over which risk is assessed, and (3) a confidence interval. Variance-covariance method, historical simulation, and

Monte Carlo simulation are the three most commonly applied approaches for computing VaR. CVaR, also known as average VaR, expected shortfall, or tail conditional expectation, is a risk assessment tool that quantifies the losses associated with the tail of the profit distribution (Jabr 2005). It is defined as the conditional expectation of the loss, given that the loss is beyond the VaR level. For the same confidence level used for VaR, CVaR provides an estimate of the average loss exceeding the VaR value. Therefore, it gives a better understanding of risk than VaR, since VaR provides no indication of the extent of losses that might be suffered beyond the VaR value (Jabr 2005). Several studies have been performed with VaR and CVaR in energy related projects. For instance, in "Optimal Hydro Scheduling and Offering Strategies Considering Price Uncertainty and Risk Management" (Catalão, Pousinho, and Contreras 2012), the authors proposed a framework for optimal hydro scheduling and bidding strategies. In this work, market uncertainty was introduced in the model via price scenarios, and risk management used CVaR to limit profit volatility. In addition, Botterud et al. (2012) in "Wind Power Trading Under Uncertainty in LMP Markets," presented a model for optimal trading of wind power in the electricity market given uncertainty in wind power and electricity market prices.

Real options analysis can be applied as a valuation or a decision-making approach. For example, in "Comparing Hedging Methods for Wind Power: Using Pumped Storage Hydro Units vs. Options Purchasing" (Hedman and Sheblé 2006), the authors used real options analysis to compare two methods, using pumped storage hydro units and options purchasing, to handle the uncertainty and variability of the wind energy.

2.1.2. Quantification of Value Streams

In addition to the selection of the appropriate valuation technique, the accuracy of the analysis is also heavily dependent on how the individual value streams are quantified. While there are several different classes of quantification, the common initial step in this process is to make sure that the scope and scale of the value streams are appropriately established. It’s important to take into account the scale of the value stream to ensure a level of resolution that can capture the necessary subtleties of the system without imposing an excessive burden on the valuation process. A notable example of this in energy systems modeling is temporal resolution, in which variations in energy prices and system dynamics must be captured to accurately represent the technology or service in question. The scope of the value streams must also be appropriately determined to ensure that the resulting valuation reflects reality. This is particularly important when taking into account multiple value streams, such as energy and various ancillary services, in order to avoid double counting. While mutually exclusive services can be used in the analysis, they cannot all be simultaneously fully utilized, as that would be outside of the operational capabilities of the system in question (Ecofys 2014). Once the value streams have been appropriately defined, it is then possible to evaluate them in a standardized fashion using one or a combination of the techniques outlined below.

System Analysis

One of the most common means of assessing the value of an individual benefit is through quantifying its effect on the broader system in which it exists. In the case of power systems, the technology or service being evaluated primarily interacts with the electrical system, and therefore this will be the focus of our discussion. It should be noted, however, that the principles outlined below could be applied to other systems, such as environmental and socio-economic systems. In the case of power systems, the relative impact of the asset being investigated is also dependent on the market environment.

In the U.S., energy markets are broadly categorized as (1) whether or not they are operated by Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), and (2) whether they are dominated by vertically integrated utilities or largely restructured, which is a state policy and legal decision. Their key characteristics and differences are discussed in the following sections. In principle, the valuation approach used for system analysis is focused on a simulation of power system operation for two cases: with and without the technology or service being evaluated. In this analysis, the role of the technology or service is assessed within the power system and then compared to a similar analysis of the system without the technology or service in question. The differences between the two cases are then quantified and assessed to determine the impacts and the value of the technology or service. In general, the quantification mechanisms range from relatively simple techniques, which require minimal levels of calculation and associated assumptions, to more complex analytical methods that require a more significant investment in both calculation and assumptions (Denholm et al. 2014).

Vertically Integrated Utilities

In the case of traditionally regulated utilities, whether in or outside ISO/RTO regions, the electric utility is vertically integrated and therefore owns and manages generation, transmission, and distribution assets within its footprint and serves a captive customer base. Outside ISO/RTO regions, the utility also operates the transmission system, while within those regions the ISO/RTO operates the transmission system. Vertically integrated utilities are responsible for meeting energy demand and traditionally do so by performing economic dispatch and unit commitment. Established value quantification mechanisms in these markets therefore rely on assessing how the service or technology under consideration affects the operating and investment costs of the utility.

One of the common quantification approaches in vertically integrated utilities is the avoided cost approach. It estimates the benefit of technology or service based on whether its use reduces system costs. This quantification technique was popularized by the Public Utility Regulatory Policies Act of 1978, which required that utilities must interconnect with “qualifying facilities” and pay a rate equivalent to the avoided costs associated with utility generation (Federal Energy Regulatory Commission 1978). Ostensibly, the avoided costs represent the savings that utilities incur because they produce less energy due to available external generation, and, due to the focus of the regulation, these costs are traditionally only evaluated for qualifying capacity and energy. These avoided costs are a function not only of reduced energy costs but of avoided capacity investment costs (Flaim 1983). The process of quantifying these specific costs is more difficult, as they interact with the internal operations of the utility. In the short term, the avoided generation costs are calculated using either the instantaneous or the increment/decrement method, as appropriate. The instantaneous approach formulates the utility cost curve and assesses the value, based on the reduction of marginal electricity production cost as a function of the available generation. The increment/decrement method expands on this process and leverages the change in marginal electricity production cost based on a fixed permutation upward and downward. The incremental cost slope is then used to more accurately calculate the impact of qualifying facility generation. The avoided capacity costs provided by the qualifying facility are assessed based on their ability to improve reliability outcomes and reduce capacity investment requirements on behalf of the utility. For example, the traditional target of utilities in the U.S. is to limit the total duration of outage events to a maximum of one day in ten years of operation, and therefore they have to maintain an appropriate amount of capacity reserve in the system (planning reserve margin) (Busch and Eto 1996). The ability of qualifying facilities to provide capacity with this degree of reliability then defers the need of utilities to develop new generation capacity to meet the demand.

The other quantification approach typically used in regulated market environments for quantifying the value of a service or technology is the replacement cost analysis. It estimates the value of a service or technology by analyzing how much it would cost if it needed to be provided by alternative means or technology. The replacement cost analysis estimates the value of a technology or service based on the corresponding replacement cost, using the least-cost alternative available in the open market (such as replacing one source of generation with another type). In cases where the service cannot be directly replaced with an open market product, the conditions provided by the service in question must be replaced with alternative technologies. This approach is often used in situations with significant non-market costs that must be taken into account to fully capture benefits such as environmental or societal valuations (Allsopp, Lange, and Veldtman 2008; Paoli and Vassallo 2013). Full replacement cost analysis of a system or service requires not only that all benefits be assessed in this manner but also that the effects of this replacement effort on market prices be taken into account.

Restructured Energy Markets

In restructured energy markets, the costs or benefits of individual value streams can be assessed in numerous ways. They roughly fall into two general categories: price-taker methods and system analysis (or price-maker) models (Ecofys 2014). The price-taker methods take the characteristics of the technology or service associated with the value stream and assign a certain multiple based on a market price. While assessment of the market price multiple has the potential to induce a significant level of complication to the quantification mechanism, these techniques are simpler than the system models. This is largely a result of the one-way interaction of the valuation model, as the associated characteristic simply accepts the multiple taken from the larger system. This simplicity is exemplified by the price-taking model often utilized in power system modeling, where historical energy prices are used to multiply the output of the plant using a specified output assumption.

The price-taker model assumption is used when the technology or service in question would not have a sufficient impact on the market to significantly affect the product price and thus would be forced to accept the market price (Stoft 2002). The system analysis quantification method, however, unlike the price-taker model, assumes that the operation of the asset being valued influences the market prices in the system in which it exists.

The system analysis method leverages mechanisms that enable the user to simulate the power system with and without the technology or service being evaluated to determine its value through differences in the results of the two simulations. This valuation approach takes into account the influence of the technology or service on market prices and is analytically more complex than the price-taker approach. There is a wide range of system models that can be utilized to study the value of a service or technology characterized by different analytical approaches, assumptions, and corresponding levels of applicability. Appendix B provides an overview of production cost and market simulation models that can be applied for this analysis.

Cost of Service Provided

The cost of service provided quantification approach is similar to the cost-effectiveness analysis described above; however, the focus of this analysis is specifically on assessing the cost of producing a unit of a service. While this is a straightforward concept, the economy of scale coupled with complex supply chains, varying timelines, and non-scalable costs and benefits makes realization of this principle more difficult. Efforts in this area can be separated into understanding how much of a service must be developed to produce a single benefit unit (i.e., a unit of service) and comprehensively determining the cost to produce this unit. To determine the former, the interaction between the service and the benefits it provides must be quantitatively established. In the case of electricity generation, this includes factors such as minimum operational levels, changes in efficiency, and system scaling (Bean, Blazquez, and Nezamuddin 2017). In the case of secondary benefits associated with the primary service, the scale and characteristics of the relationship between the primary and secondary benefits must be understood as well as other relationships (Buonocore et al. 2015; Mc Laughlin et al. 2002). Similarly, the costs associated with each of these individual benefits must be established, and the internal relationships, such as cost-scaling and fixed system costs, must be determined. These factors can then be used to help understand and accurately assess the cost of a single benefit unit (Kellogg et al. 1998; Poonpun and Jewell 2008).

Physical Unit Impact Analysis

When evaluating the impact of a project or policy, some costs and benefits are hard to monetize, and it would be easier to determine the impact in physical units. For example, the deployment of distributed generators, such as photovoltaic (PV) and wind power at the distribution system level, may decrease the lifetime of voltage regulators due to the increase in voltage fluctuations (e.g., increased number of tap-changes). If a facility (e.g., an energy storage system) is applied at the distribution system level to reduce voltage fluctuations, the number of tap-changes of the regulator can be reduced, thus extending its lifetime (Tian et al. 2018). However, this impact is hard to monetize and thus it is easier to evaluate the benefit directly by assessing the decrease in the number of tap changes.

There are many other examples of costs and benefits that may be difficult to monetize, but their impacts in physical units are easier to quantify. For instance, the impacts related to fossil fuel emissions from thermal power plants are a significant environmental policy concern. However, to evaluate the true cost of emissions is not an easy task, since the emission cost varies with the location, fuel source, environmental regulations and other factors. Therefore, quantifying emissions reduction in physical units (e.g., tons of pollutant) is frequently used to estimate the impacts of a service or technology on emissions.

Evaluating reliability impacts in physical units is also commonly done. One of the goals of utilities is to provide their customers with a reliable power supply. But numerous factors may affect system reliability, such as the outages of generating units, system faults and other equipment failures. All these factors may lead to loss of load and cause power interruptions. To measure the reliability of an electric power system, several indices could be applied. For example, loss-of-load probability (LOLP), loss-of-load expectation (LOLE), and expected unserved energy (EUE) are normally utilized for the bulk power system. The system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) are commonly evaluated when quantifying reliability at the distribution level. This does not mean that reliability impacts cannot be monetized. Indices such as customer damage functions (CDFs), composite customer damage function (CCDF), and interrupted energy assessment rate (IEAR) can indicate the estimated value of reliability changes in dollars. However, to obtain the interruption cost data, numerous studies and surveys are needed, and the data are not regularly updated. Thus, the value may be outdated or not be able to represent the interruption cost in the area under study. Hence, in many studies, the impact of reliability is evaluated in physical units (e.g., reduction in SAIFI and SAIDI values).

Qualitative Assessment

Qualitative analysis, unlike the quantitative techniques assessed above, focuses on assigning a relative scoring or assessment of a technology or service. This type of analysis is traditionally employed when the other techniques listed above cannot be used. While all of the qualitative techniques utilize some kind of a categorization system (such as low, medium, high) these values are typically assigned using one of two techniques: (1) expert opinion or (2) binning.

As the name suggests, expert opinion quantification involves leveraging the experience of industry experts to assess the performance of the system based on a predetermined scale. In these instances, a rationale is typically supplied by the expert developing the analysis (DOE 2016). The binning qualitative assessment is a further extension of the process, in which the technique or technology is assessed via an expert-established rubric designed to formally outline the quantification criteria. While the development and use of this rubric system is more time and resource intensive than the straightforward expert opinion process, this technique enables further insight into grading dynamics and also allows for the potential later expansion of the analysis. Brown et al. (2008), who developed a six-scale rubric system specific to 27 different categories of hydropower facilities, exemplifies the use of the binning technique. In this process, industry experts were consulted to develop important distinctions between the different scales for each category (Brown et al. 2009).

2.2. Gaps in Valuation Analysis

An analysis of the literature revealed several common gaps in the valuation process across industries and technologies. These gaps are typically a result of either the inherent difficulty of fully evaluating the attribute under consideration, or an assessment or determination that the service is beyond the scope of the valuation process. The latter is typically justified by stating that some services or attributes may be very difficult to evaluate or estimate with the available modeling tools, while some benefits or contributions may not be that relevant for the valuation process as they do not directly contribute to revenue streams (e.g., there is no appropriate market product). Overall, the gaps can be categorized as functions of temporal resolution, value stream consistency, valuation strategy and quantification mechanism, and non-market cost evaluation.

Temporal Resolution

Temporal resolution plays an important role in the effective valuation of an energy system as it allows both costs and benefits to be fully taken into account over varying time scales. Unfortunately, for accurate valuation, electric power systems and their operations have a wide range of temporal resolution:

- The dynamic system performance of the electrical grid (i.e., transients which occur on the level of microseconds to minutes)
- Scheduling and dispatch of generating units (which occurs on the level of minutes to days)
- Integrated resource planning and development of generation resources (which occurs on the level of years)
- The lifetime of plants (which occurs on the level of decades)

In addition, the operations of power systems are also influenced by external factors such as extreme weather events and climate change, which may affect the value of generation resources in both the short and long term.

Selection of the appropriate temporal resolution must balance the need for accuracy with ensuring that the valuation process is achievable within limited resources. Currently, there are no best practices when considering this in the valuation structure, and a majority of these decisions appear to be made on a case-by-case basis. The PSH valuation framework provides guidance on the appropriate computer models and temporal resolution for evaluating different services to ensure consistency and accuracy.

Value Streams

Consistency in the selection and application of the value streams used for the valuation of a technology or service are also critical in assuring the validity of the research results. It can be seen in the literature that a wide range of different value streams have been used for the assessment of the same technology or service. If the technology is being assessed using a conventional cost-benefit analysis, then as many value streams as possible should be taken into account to provide an accurate assessment of its value. The impact of value stream selection is exemplified by an effort by Keyes and Rabago in 2013 to assess different valuations of distributed solar by varying parties. Based on the value streams taken into account, the net benefit ranged from $0.04/kWh to $0.21/kWh (Keyes and Rabago 2013). The PSH valuation framework should provide the user with guidance on how to assess the relative importance and merit of different value streams.

Valuation Strategy and Quantification

The selection and implementation of the valuation strategy and quantification of the individual value stream is also extremely important, as this is how the relative impact of the value streams are assessed. As outlined above, there are several methodologies by which value can be assessed; however, it is important to note that the quantification of value streams is subject to a further range of methods. Each of these methods has implications regarding its accuracy and ease of use. The result of this disparity is demonstrated in the review report by Keyes and Rabago (2013) referred to above, which investigated the research results of the value of solar energy in Arizona.

In rapid succession, two reports studying the value of solar were released—but with starkly different findings. A utility-funded study found the value of solar to be $0.04/kWh, whereas an industry-funded study found the value of solar to be $0.21/kWh, a more than fivefold variation in results (Keyes and Rabago 2013). A key takeaway from this review report is how the value is perceived from different perspectives and whether and how much the end user wishes to pay for a specific service.

Non-Market Cost Evaluation

Evaluation of non-market costs and benefits represents the last gap common to most of the valuation studies examined in the literature review. By their very definition, non-market costs and benefits cannot be easily valuated as a function of money through the marketplace. As such, these streams must be quantified through another, analogous manner. While these methods enable the assessment of non-market costs and benefits, they are traditionally performed via a custom analysis technique that precludes the ready comparison of results between different valuations of the same technology or service. Multi-criteria decision analysis can help the analyst take into account both monetized and non-monetized value streams in presenting different options to decision-makers.

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3. Valuation Guidance for Pumped Storage Hydropower

3.1. Key Steps in the PSH Valuation Process

The overall structure and key steps in the PSH valuation process are shown in Figure 3.1. The proposed valuation guidance provides a comprehensive cost-benefit and decision analysis framework that can be used for the valuation of existing or new PSH projects, project design alternatives, and potential upgrades or repowering of existing projects. In developing the valuation guidance, the key goals and objectives were to design a valuation framework that will have the following attributes:

- Objective, comprehensive, and transparent valuation methodology
- Consistent and repeatable valuation approach
- Applicable to different types and sizes of PSH plants
- Accounts for various services and contributions that PSH plants provide to the grid
- Applicable to both traditional and restructured market environments
- Usable by various stakeholders
- Publicly available for use by hydropower industry and stakeholders.

The proposed valuation framework is based on a detailed analysis of the findings from an extensive literature review, which covered hundreds of valuation papers and studies, dealing not only with the valuation of PSH and hydropower technologies but with valuation studies and analyses performed for various other power system technologies, including energy storage, wind, solar, distributed energy resources, and others. Some of the main findings related to the key valuation methods and approaches used in different studies are summarized in Section 2.

The proposed valuation framework also leverages past efforts of several organizations and their work in either developing valuation guidelines or performing actual valuation studies for various technologies. In this chapter, we will mention just a few whose work most significantly influenced the development of the PSH valuation framework.

The Electric Power Research Institute (EPRI) has done a significant amount of research in the area of valuation of grid services and technologies (EPRI 2010, 2012). In addition to conducting valuation studies for grid technologies (e.g., energy storage), EPRI has also conducted research on developing valuation frameworks for different grid and distributed energy resource technologies (EPRI 2015a). The proposed PSH valuation framework draws heavily on EPRI's work on developing cost-benefit valuation frameworks for the integrated grid and for smart grid technologies (EPRI 2015b).

The proposed PSH valuation framework also draws on the efforts of the Brattle Group, which has conducted numerous valuation studies of energy storage and other grid technologies. Like EPRI, the Brattle Group utilized a cost-benefit valuation framework that is able to take into account the perspectives of different stakeholders, including system-wide and societal perspectives (Chang et al. 2015).

Finally, the development of the PSH valuation framework was most significantly influenced by the work of several DOE national laboratories developing a general valuation framework for valuing grid services and technologies. This work was funded by DOE in its Grid Modernization Initiative (GMI) and carried out by several national laboratories organized into the Grid Modernization Laboratory Consortium (GMLC). The goal of GMLC Project 1.2.4 was to develop a general valuation framework for the assessment of the value of different grid-related technologies and services (GMLC 2018). This general valuation framework was developed as an eleven-step process that starts with documenting the valuation context and purpose and ends with a comparison of results and recommendations based on the information developed during the valuation process (GMLC 2019a, 2019b). An important part of the valuation process is the identification and prioritization of impacts and metrics to measure those impacts. In this context, it should also be mentioned that in developing the PSH valuation framework, we also leveraged the work performed on another GMLC project (GMLC Project 1.1 – Metrics Analysis), which selected, described, and defined metrics for the purpose of monitoring and tracking power system properties. GMLC Project 1.1 focused on the following six attributes that characterize the electric grid: reliability, resilience, flexibility, sustainability, affordability, and security (GMLC 2020).

We have also built on the previous work performed by DOE national laboratories in analyzing the role and value of PSH technologies (Koritarov et al. 2014) and their benefits for grid reliability and integration of variable renewables (Botterud, Levin, and Koritarov 2014).

Based on these and other works, we have developed a cost-benefit and decision analysis framework that includes a fifteen-step valuation process consisting of four main activities:

1. **Define Scope:** Includes four steps that provide the overall context of the valuation. It starts with providing a project overview, defining the valuation question (i.e., why is valuation analysis performed?), identifying alternatives, and determining relevant stakeholders.
2. **Develop Valuation Criteria:** Includes two steps dealing with the identification of key impacts and metrics for valuation.
3. **Design Analysis:** Includes three steps dealing with designing the analysis that will enable the analyst to assess and measure the key impacts identified in the previous activity.
4. **Determine and Evaluate Results:** The fourth activity includes running the models and performing simulations to assess and evaluate the impacts, performing the cost-benefit and risk assessment analyses, conducting an optional multi-criteria decision analysis and comparing the results for various alternatives, and documenting the results of analysis and reporting findings to decision-makers.

The fifteen-step valuation process is not typically linear, and some steps often need to be performed in parallel. Also, in many cases the results and findings of some steps will require the analyst to go back to previous steps and make necessary adjustments or perform additional analysis. That is illustrated by feedback loops on the right-hand side of the valuation process illustrated in Figure 3-1. Detailed descriptions of each of the fifteen steps are provided in the following sections.

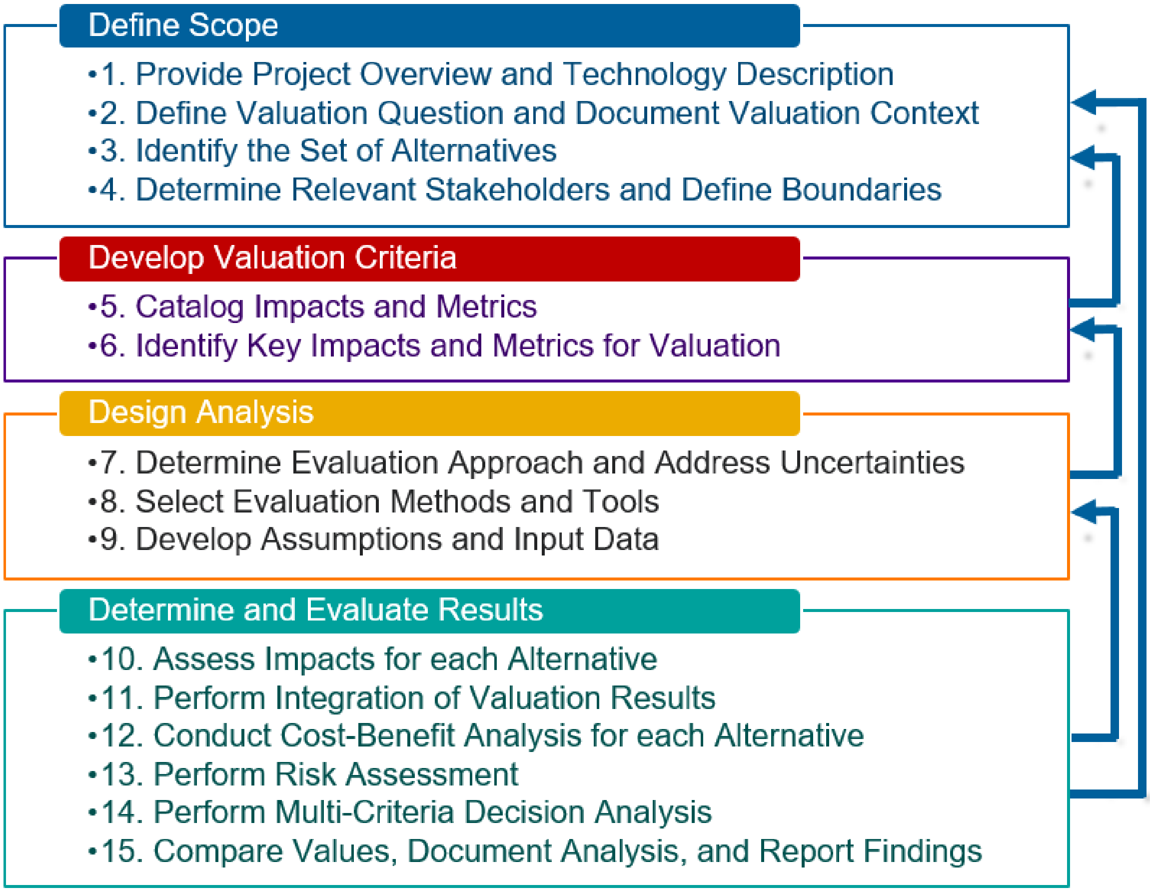

Figure 3.1: Key steps in PSH valuation process.

3.2. Define the Scope of Analysis

The first four steps of the valuation process provide 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.

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/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 3.1.

Table 3.1: Project Characteristics and Parameter Summary

Name of Project	Name of existing or proposed PSH project
Project Location	Geographical location, transmission connection, 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.

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 who is the entity or organization asking the question (e.g., project owner or developer, market operator, regulatory agency, etc.) 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, etc.) as 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, location, and other relevant considerations.

There are numerous potential aspects of the valuation purpose as well. Examples of this 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 whether another location would be more beneficial, and a PSH developer may want to determine which of several potential project designs is likely to provide the highest value. Some of the typical purposes for the valuation assessment are summarized in Table 3.2.

Table 3.2: Purposes of a PSH Valuation Assessment

Existing PSH Project	• Assess the value of the project. The valuation analysis can be conducted from different perspectives (e.g., project owner/operator, market operator, utility, regulatory agency, etc.) • 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 some other project's (e.g., another PSH project or some competing technology)
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 (e.g., using fixed-speed or adjustable-speed units) • Compare the project value to alternative projects or investments • Scale the power/energy capacities 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 takes into account the purpose and context of the valuation process, including the primary perspective from which the valuation should be constructed, 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. A valuation question can be as general as "What is the economic value of the proposed PSH project?" or it can be formulated to be more specific. For example, a PSH developer may ask "What is the value of choosing this project alternative?" or "Should we invest in this PSH project, assuming that current regulatory, environmental, and market conditions in this region will likely remain the same over the next 10-15 years?"

Step 3: Identify the Set of Alternatives

Identification of project 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 whether to build the project or not, there are only two options. 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 under consideration, including a "do nothing" alternative.

There are also potentially many alternatives that depend on the project options and potential actions or decisions that can be taken. For example, many 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. Also, project alternatives can potentially include other technologies that could provide services similar to those of PSH plants. In principle, the set of alternatives should include a baseline to serve as a reference for the comparison of other 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, etc.).

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

Step 4: Determine Relevant Stakeholders and Define

The purpose of Step 4 is to identify stakeholders that will or might be impacted by the projects being considered, determine boundaries of project impacts, and plan relevant stakeholder engagement. The activities in this step are closely related to those in Steps 2 and 3, and they sometimes need to be performed in parallel. For example, the identification of relevant stakeholders may be important to identifying the full set of alternatives that should be considered during the valuation study. Then again, sometimes the valuation question itself may need to be revised to include the perspectives of and potential impacts on all relevant stakeholders that have been 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, location of the project, 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 3.3.

Identifying all relevant stakeholders is key to a successful valuation process, as different stakeholders provide correspondingly different perspectives and so 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 and location dependent. For example, if an independent PSH developer is performing a valuation of a proposed merchant PSH project to determine whether or not to build it, 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 PUC is approving the PSH project, the perspective of ratepayers and corresponding impacts on electricity rates may be of highest importance, balanced with the interests of the local utilities. Literature provides a robust series of case studies that can be leveraged to assess stakeholder inclusion; however, it should be noted that each analysis is case-dependent, and care should be taken when developing the scope.

Table 3.3: 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 (LSEs)	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 governmental territories (municipalities or utility districts), or state authorities. In competitive electricity markets, LSEs also include load aggregators (e.g., community choice 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 just and reasonable electricity rates, approving electricity projects, and setting general policies for electricity markets.
Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)	ISOs and 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, including venture capital groups, investing in or providing loans for the development of a new PSH project.
Other Interest Groups and Regulators	These include various interest groups within society, such as environmental, consumer, cultural, and other groups. Local

	Native American tribes, landowners, and non-governmental organizations (NGOs) can also be included in this group.
Government	Includes various governmental entities such as federal, state, municipal, and other entities that set policies and laws. Also included are various government agencies, such as environmental protection agencies, consumer protection agencies, urban planning agencies, land-use agencies, Native American bureaus, and others.
Broader Society	Provides a public opinion and a general perspective on the project from the point of view of society as a whole. Helps determine the societal view of the project.

Defining Boundaries

Selection of relevant stakeholders can be facilitated by determining the type of authority or impact that they may have on the project. For example, certain stakeholders may have a decision-making and/or jurisdictional authority (e.g., government and regulatory agencies). On the other hand, some stakeholders may not have a decision-making authority but still may influence or have an impact on the project through their advisory or market authority (e.g., transmission system and electricity market operators).

The selection of relevant stakeholders should also include determining their boundaries. Typically, there are two main types of boundaries that should be considered: decision boundaries and jurisdictional boundaries.

Decision boundaries identify relevant stakeholders whose perspectives and actions may have an impact on decision-making (e.g., regulatory agencies). Jurisdictional boundaries identify which stakeholders have jurisdictional or other authority over the area where the project is located, or in which it will be operating. For example, jurisdictional boundaries help identify municipal, state, and federal authorities, as well as relevant utility, ISO/RTO, or electricity market authorities. Note that some stakeholders may have both decision and jurisdictional authority.

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 perspective on the valuation process. Engaging with major stakeholders at the very beginning of the valuation study is recommended; this will facilitate the process and help develop 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 input 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 ways to engage with stakeholders during the valuation process.

3.3. Develop Valuation Criteria

The purpose of Steps 5 and 6 is to catalog all PSH impacts and identify those that are most relevant for the valuation of the PSH project under consideration. In addition to the impacts themselves, Step 5 also includes the identification of metrics that can be used to measure those impacts and their costs and benefits. While 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 3.2 provides an illustration of relationships and terminology for PSH project services, impacts, metrics, and costs and benefits. The process starts with the identification of 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.

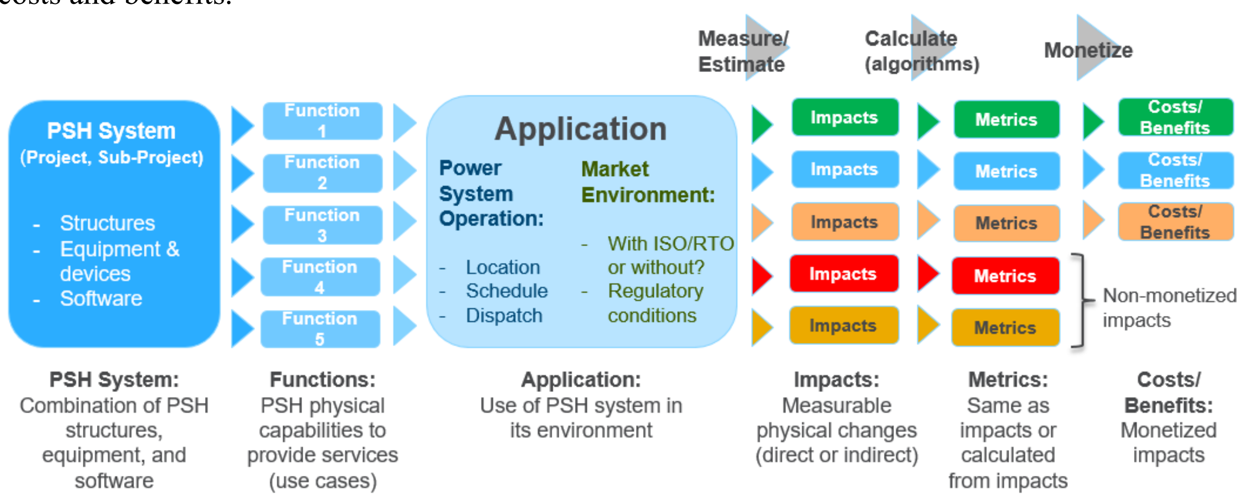

Figure 3.2: Terminology and relationships connecting PSH services, impacts, metrics, and benefits.
(Adapted from EPRI (2015b): *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects*.)

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 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 include the creation of jobs and economic development, water management services, environmental changes, and other 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. Also, it should be noted 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 attributes in 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 typically associated with a large grid-scale PSH project is provided in Table 3.4. The table lists the types of metrics typically used for assessing services or impacts. Note that the valuation approaches in Section 4 provide specific metrics that can be used to assess different services or impacts. A full list of metrics is also provided in Appendix A.

Table 3.4: List of Potential Services and Impacts for Inclusion in Valuation

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

Beneficiary	Cost/Benefit Category	Service or Impact	Types of Metrics Used to Describe Services/Impacts
Society	Non-energy services	Water management services	Physical, qualitative and monetary
		Socioeconomic impacts (e.g., jobs, economic development, recreation)	Physical, qualitative and monetary
		Environmental and health impacts	Physical, qualitative and monetary
	Energy security benefits	Fuel availability, savings, and diversification	Physical, qualitative and monetary
		Major blackouts avoided	Physical, qualitative and monetary

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 depend on many factors, including the PSH technology (e.g., fixed-speed, adjustable-speed, ternary, or quaternary 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 vs. small-scale distribution resource PSH project), market environment (e.g., traditional regulated vs. competitive market), and many others. For example, a list of services and impacts typically associated with a small distribution resource PSH project is shown in Table 3.5.

Table 3.5: Illustrative List of Services and Impacts of a Small-Scale Distribution Resource PSH Project

Beneficiary	Cost/Benefit Category	Service or Impact	Types of Metrics Used to Describe Services/Impacts
End User	Customer energy management services	Time-of-use energy charge management	Physical and monetary
		Demand charge management	Physical and monetary
		Power quality	Physical and monetary
		Power reliability	Physical and monetary
Utility System	Distribution infrastructure services	Distribution voltage support	Physical and monetary
		Distribution upgrade deferral	Physical and monetary
		Distribution losses	Physical and monetary
		Integration of variable generation	Physical and monetary
Utility or ISO Market	Ancillary services	Frequency regulation	Physical and monetary
		Spinning reserve	Physical and monetary
		Non-spinning reserve	Physical and monetary

For each particular PSH project analyzed, the analysts should develop a comprehensive list of various services and impacts the project is capable of providing. The lists of services and impacts provided in Table 3.4 and Table 3.5 are an effective starting point, but are by no means exhaustive. Depending on the techno-economic 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 Table 3.4 and Table 3.5, as well as some 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 being analyzed, the analyst's task in Step 5 is to develop a list of appropriate metrics to be used to measure the impacts. In principle, depending on the type of units, the metrics can be categorized into three broad groups: (1) monetary, (2) physical or numerical, and (3) qualitative.

> *Monetary metrics:* Monetary metrics are used to describe services and impacts that can be directly 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 and in so doing may assist in removing regulatory and market barriers to PSH deployment in that region.
>
> *Physical metrics:* Most often, services and impacts are expressed in physical units. Services and impacts expressed in physical units can sometimes be easily monetized, while at other times it is very difficult or even impossible to explicitly monetize their value. Products or services with an established market can use relevant historical market prices to monetize the past[1] value stream in question. One example of an easily monetized service that is expressed in physical units is electricity generation in megawatt hours (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 per 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 difficult 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 it is difficult to estimate the value of its benefits (e.g., system reliability).

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[1] It should be noted that the "price-taker" approach has significant limitations if the goal is to estimate potential future revenues, because the market prices in the future may be quite different from those in the past.

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 used are purely numerical. One example is the planning reserve margin, which describes the amount by which the available system capacity needs to exceed the system peak load. Although both the available capacity and system peak load are expressed in MW, the planning reserve margin is expressed as a percentage of the available system capacity that exceeds the peak load. Another example is the commonly used reliability metric LOLP (loss-of-load probability), which is also expressed as a percentage. While LOLP is a purely probabilistic metric, it is derived from the LOLE (loss-of-load-expectation) parameter, which has a physical background as it describes the target reliability value for long-term expansion planning of power systems. In the U.S., the target LOLE value is less than one day of outage in ten 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 a certain service or impact. Obviously, since the quality or value of services and impacts is judged by experts performing the analysis, this is a very subjective process. Typical examples of qualitative units include fuel diversity, resilience, and environmental sustainability. To expand 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 having low, medium, or high diversity.

An extended list of metrics that can be used to measure the impacts of PSH services and contributions is provided in Appendix A. In addition, a compilation of metrics developed by GMLC Foundational Project 1.1 (Metrics Analysis) for monitoring and tracking power system properties is also provided. GMLC Project 1.1 focused on general attributes characterizing 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 sub-project that is being evaluated.

Step 6: Identify Key Impacts and Metrics for Valuation

The purpose of Step 6 is to identify key impacts and metrics important for the valuation of 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 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).

The services and impacts to be assessed in the valuation study also depend 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 wholesale 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 vertically integrated 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 are usually assessed through the impacts of PSH plant capabilities on the overall system operation (e.g., reduced electricity generation costs, reduced cycling and ramping of thermal units, reduced curtailments of variable generation, etc.). The business model of the existing or planned PSH project should be taken into account 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 other potential value streams in addition to the PPA, those opportunities should be considered as well.

The list of key impacts and metrics for valuation should include all important services, both those 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 the 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. The design of the analysis is addressed in the next group of steps.

3.4. Design the Analysis

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

Step 7: Determine Evaluation Approach and Address

Selection of the appropriate evaluation approach depends on the types of impacts and metrics identified in Step 6 and 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 a number of different impacts for which the value streams need to be assessed, and they 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 that utilizes 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 projects of relatively small size (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, as the revenues can be estimated using the historical or forecasted market prices. However, if the PSH project being evaluated is a large, grid-scale project, it is likely that its operation will significantly influence 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 located 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 modeling and dynamic simulation analysis may need to be used to assess the value of short-term impacts, such as fast inertial response and power system stability.

Therefore, a number of 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 taken into account 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 to 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 utilize less detailed, simplified analytical approaches as they may be constrained in their access to sophisticated power system modeling tools, data, and time.

In addition to determining the appropriate evaluation approaches and the level of detail, the potential uncertainties in assessing the value of various PSH impacts should also be addressed. There are numerous uncertainties that affect the value of PSH impacts, in both the short and long term. Electricity market prices and the prices of ancillary services vary on a sub-hourly, hourly and daily basis and are extremely difficult to predict even for the next few days, let alone over the lifetime of the PSH project. The same situation exists with many other PSH services and impacts. There are several ways to deal with the uncertainties in the valuation process; here we will describe scenario analysis and sensitivity studies.

> *Scenario analysis:* A common way of addressing uncertainties, especially in the long term, is through a scenario analysis, in which key factors change over time throughout the study period. Scenario analysis can be designed to capture many different uncertainties that affect the value of PSH impacts in those potential futures. For example, different scenarios can be developed regarding load growth, penetration levels of variable generation, resource mix in the system, and other factors that may affect the value of PSH services and impacts. Scenario analysis should also take into account the potential changes in PSH plant operations in the future, due to evolving resource mix, potential market changes, and other factors. To the extent possible, the construction of plausible future scenarios should be internally consistent.
>
> *Sensitivity studies:* Another way of dealing with uncertainties is to perform sensitivity analyses around key factors that may impact the value of PSH projects and their services. Sensitivity studies are typically performed by varying the value of a single factor, running the analysis again, and then observing the changes in the results. Very often sensitivity studies are performed to assess the potential impacts of uncertainties in technology capital costs, fuel costs, discount rates, and other key factors.

The main outcome of Step 7 is the selection of appropriate evaluation approaches for assessing the value of key PSH services and impacts identified in Step 6, including a plan for addressing the short- and long-term uncertainties that may affect the value of the PSH project being analyzed and its services.

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 that will be used 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. Since 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.

Or, 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 this 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 (ABMS) 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 3.6 illustrates categories of analytical models and tools that are commonly applied for the valuation of various PSH services and impacts.

Table 3.6: Commonly Applied Models and Tools for Assessment of Services and Impacts

Beneficiary	Cost/Benefit Category	Service or Impact	Commonly Applied Models and Tools
PSH Owner or Operator	Bulk energy services	Electricity price arbitrage	Production cost or electricity market model
		Bulk power capacity	Capacity markets or IRP analysis
	Ancillary Services	Regulation	Production cost or electricity market model
		Spinning reserve	Production cost or electricity market model
		Non-spinning reserve	Production cost or electricity market model
		Supplemental reserve	Production cost or electricity market model
		Voltage support	Power flow model or contractual agreement
		Black start service	Contractual agreement
Power System	Power system stability	Inertial response	Dynamic simulation model
		Governor response	Dynamic simulation model
		Flexibility (e.g., load following and ramping)	Production cost model

Beneficiary	Cost/Benefit Category	Service or Impact	Commonly Applied Models and Tools
	Power System Reliability and Resilience	Reduced sustained power outages and restoration costs	Production cost model (short-term analysis) or IRP (long-term analysis)
	Power System Indirect Benefits	Reduced electricity generation cost	Production cost model
		Reduced cycling and ramping (wear and tear costs) of thermal units	Production cost model
		Reduced curtailments of variable generation	Production cost model
	Transmission infrastructure benefits	Transmission upgrade deferral	IRP and transmission planning
		Transmission congestion relief	Production cost model and power flow model
Societal Costs and Benefits	Non-Energy Services	Water management services	Water use model
		Socioeconomic benefits (e.g., jobs, economic development, recreation)	Socioeconomic model
		Environmental impacts	Environmental model
	Energy security benefits	Fuel availability, savings, and diversification	Production cost model (short-term) and IRP (long-term)
		Major blackouts avoided	Dynamic simulation model, system restoration model, macroeconomic model

Appendix B provides a list of representative models and tools for the above categories, and an overview of the IRP process and applications is provided in Appendix C.

The outcome of Step 8 is the specific list of methods, models, and tools that will be used for the valuation analysis of each of the key PSH services and impacts that were identified in Step 6.

Step 9: Develop Assumptions and Input Data

With the evaluation methods and tools selected in Step 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. As 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 sets of data may need to be put together 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. In addition, a set of sensitivity studies that will be carried out for each scenario should also be defined. For example, suppose that two scenarios have been defined with regard to 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. A preliminary list of key drivers and factors that are likely to influence the value of PSH services should be prepared during this step. 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 in an iterative fashion. The analyst should revisit the previous steps and reevaluate previous decisions. For example, if a selected methodology requires data at a five-minute time step, and only hourly data are available, either the modeling approach needs to be adjusted or five-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 of the alternatives defined in Step 3. In addition, a preliminary list of parameters and key drivers for which sensitivity studies will be performed should be developed for each scenario. Finally, a set of input data for each of the modeling tools that will be used in the valuation analysis should also be prepared.

3.5. Determine and Evaluate Results

The final group of steps in the valuation process—Steps 10 through 15—includes assessment and quantification of the key PSH impacts defined in Step 6, including an analysis to determine which PSH services can be performed in parallel and which ones are mutually exclusive, as well as conducting a cost-benefit analysis to determine the economic value of each of the alternatives defined in Step 3. When several alternatives are examined during the valuation process, multi-criteria decision analysis can explore trade-offs among different impacts and develop a ranking of alternatives. The decision analysis approach is typically applied when several alternatives are characterized by both monetized and non-monetized costs and benefits (quantitative and/or qualitative metrics). Finally, the last step in the valuation process is to compare the valuation results, document the analysis, and report findings.

Step 10: Assess Impacts for Each Alternative

The valuation methods and tools selected in Step 8 are applied in Step 10, including the analysis of PSH services and impacts and quantifying their corresponding value streams. This step can include a significant amount of modeling and simulation, as the analysis should cover all of the alternatives identified in Step 3, including all scenarios and sensitivity studies defined in Step 9.

All key impacts identified in Step 6 should be assessed for each alternative. The level of detail and methodological approaches for assessing impacts should be the same for each alternative.

Step 10 is by far the most computationally intensive step in the valuation process and, as such, significant time and effort should be allocated for its execution. The analytical process is unlikely to be straightforward, so analysts should be prepared to perform additional analyses not originally foreseen, or to go back and modify or adjust the plan of analysis to capture or address certain aspects that may arise during the analysis process.

It should be noted that it will not be possible to asses all PSH impacts and services at the same level of detail and accuracy. For example, it may be possible to assess and quantify the regulation service in greater detail than the inertial response or transmission investment deferral. The level of detail for the assessment of different impacts and services may vary depending on many factors, including the relative importance or estimated value of the impact, the availability of data for the analysis, the availability of appropriate assessment tools (models, algorithms), and others. Simplifications and approximations are sometimes inevitable. In such cases, the analyst should be aware of the approximations made and their potential impacts on results.

Modeling Framework

In principle, Step 10 involves running different models and tools to assess and quantify the impacts for each alternative. Various impacts are quantified using appropriate metrics that were selected in Step 6. Different analytical tools and models may be needed to assess and measure different impacts, and different time scales (e.g., short-term and long-term analysis) and different time steps may need to be applied. Often, several modeling tools must be used to assess specific impacts. Various analytical tools can be used in combination by sharing the data and results with each other, or they can be combined in an integrated modeling framework. A list of representative modeling tools that can be used for different types of power system analyses is provided in Appendix B.

As it is likely that multiple models and tools will be used for the assessment of various PSH services and impacts, possibly performed by different teams of analysts, this step requires a high level of coordination to make sure that various alternatives and scenarios are analyzed in a consistent manner and that all key PSH impacts identified in Step 6 are evaluated. Information flows among the analytical tools in the modeling framework may need to be refined, and modeling inconsistencies or incompatibilities in terms of component/object representation, function, and temporal and spatial resolution must be resolved.

On the one hand, models that run at a fine level of granularity can inform broader-scope models. For example, a model that is run at a four-second time step to simulate regulation signals provided by automatic generation control (AGC) and generating unit responses should set regulation requirements and parameters for a model that simulates real-time market operations using a five-minute time step. On the other hand, broader-scoped models should provide longer-term direction and power system evolution. For example, capacity expansion models can inform detailed production cost models with information about what technologies will be included in the dispatch in the future as new units are constructed and old ones retired.

As discussed in Step 7, the modeling framework applied in Step 10 should also be able to address various uncertainties. The uncertainties can be dealt with in different ways:

(1) intrinsically, within the modeling tool (e.g., probabilistic or stochastic simulation),
(2) scenario analysis, and (3) sensitivity studies.

This step also includes a careful review of analyses and results obtained from the modeling and simulation of various PSH services and impacts. The goal is to confirm that the valuation assessments were done properly and that the results obtained provide reasonable estimates of the value of PSH services and impacts. A cross-comparison of results obtained for different alternatives and scenarios, as well as the comparison of results of different sensitivity studies, may provide additional insights into the values of certain PSH services and how those values may be affected by the change of key parameters.

Opportunities to reduce the number of model runs and speed up the modeling process while still retaining sufficient modeling accuracy should also be considered in Step 10. For example, it may be sufficient to run a parameter sweep of a detailed model and create a multi-dimensional surface of results. Instead of running the detailed model in an integrated framework, it may be more computationally efficient and sufficient to use a set of equations that represent the model response surface.

Modeling time requirements can also be significantly reduced by distinguishing those aspects of the modeling process that can take advantage of parallel processing from those modeling tasks that must be run sequentially.

The outcome of Step 10 is the set of results that provides estimated values of key PSH services and impacts, assessed through the application of various valuation methods and tools. Specifically, for each of the analyzed alternatives, the results of this step include a set of assessed impacts or their estimated values, described either quantitatively in monetary or physical units or qualitatively using a constructed scale.

Step 11: Perform Integration of Valuation Results

While PSH plants can provide many different services, not all of the services can be provided at the same time. The purpose of Step 11 is to determine which of the services can be performed in parallel and which are mutually exclusive and cannot be performed at the same time. Effectively, there is competition for the energy of the PSH unit on at least two dimensions: intertemporal and between services. That is, if the PSH unit provides power for one hour, there is less of it available for the next. The use of the PSH unit for one service may preclude it from being used by another.

Next, based on the results of Step 10, PSH services can be assessed according to their estimated value and revenue stream potential. The goal is to determine the highest-value services and maximize their provision (or utilization) relative to other services that have smaller estimated value. Obviously, the highest-value services may not be possible to provide all the time, may not be needed by the system at all times, or may need to be limited by mandated site operational characteristics. Therefore, a co-optimization analysis should be performed to determine the optimal mix of services that will result in the highest value or benefit for the PSH project. The optimal mix of services will represent a combination of PSH services that provides the highest overall benefit, and this analysis is sometimes referred to as "stacking of benefits" (Hledik et al. 2017).

Typically, stacked benefits comprise those PSH services that are not mutually exclusive and can be performed in parallel. However, if the value streams are estimated for a longer time period, e.g., on an annual basis, it is possible to have even mutually exclusive PSH services in the combined stack of benefits. This is because one service can be performed at certain hours or periods during the year, while the conflicting other service can be performed at other hours or time periods. Therefore, to estimate the total possible revenue streams from these two services on an annual basis, it is necessary to determine how much of each service can be performed during the year. The relative values and the needs of the power system for these mutually exclusive services can then be used to estimate their shares in the annual provisions of PSH services.

Note that some co-optimization of PSH services may have already been performed in Step 10. For example, if a production cost model or electricity market simulation model used in Step 10 has the capability to co-optimize the provisions of energy and ancillary services, there is no need to co-optimize them again in this step.

The key output of Step 11 is the optimal mix of PSH services that maximizes the value of stacked benefits. The integration analysis should take into account the relative values of PSH services, which ones can be performed in parallel, and the relative shares of mutually exclusive services if they can be provided at different times. The principles of integration analysis are described in Section 5.

Step 12: Conduct Cost-Benefit Analysis for Each Alternative

In Step 12, cost-benefit analysis (CBA) is used to determine the economic value of each alternative identified in Step 3. Using the assessed values of PSH services that were developed in previous steps, CBA is used to calculate the NPV and BCR parameters for each alternative as well as the associated payback periods (Boardman et al. 2006).

More details on the theoretical background of CBA are provided in Appendix D. Here we will outline just a few of the main aspects of this analysis.

> *Scoping the cost-benefit analysis*: This includes determining which components will be included and the extent of the study period for the CBA. Ideally, from an economic standpoint, the length of the time period for the CBA should be equal to the project's useful service life. However, that is often not practical for projects that, like PSH plants, have a very long lifetime. In those cases, a shorter time period can be selected for the CBA; however, the remaining costs and benefits until the end of the useful service life of the project should be estimated and accounted for in the analysis.

Extrapolating PSH impacts over the life of the project: The mix of various services provided by a PSH plant is likely to change over the project lifetime. As the power system evolves over time, the needs for different services change as well. Utilizing the available projections for the long-term evolution of the power system and the insights gained through the scenario analyses and sensitivity studies performed in Step 10, the optimal mix of PSH services can be extrapolated over the project lifetime.

Extrapolating costs and benefit streams over the CBA period: The cost and benefit streams associated with the projected PSH impacts should be extrapolated over the CBA period. Escalation rates, which can be different for different services, should be applied to express the values of costs and benefits in different years of the CBA period.

Discounting costs and benefits: An appropriate discount rate should be applied to bring the costs and benefits from different years of the CBA period to reference year or present year values. The choice of discount rate is discussed in Appendix D.

Calculating economic parameters: The present values of project costs and benefits can be used to calculate the NPV and BCR for the project—the key parameters determining the economic viability of the project.

A project is considered to have positive net economic benefit if its NPV is greater than zero, meaning that the total project benefits over its lifetime are greater than total project costs. Similarly, the project is considered to be economical if its BCR is greater than 1. It should be noted that, in addition to NPV and BCR, there are other factors that are important for decision-making. If the project provides some important benefits that could not be monetized and applied in the CBA, a project may go forward even if the calculated NPV is negative and/or the BCR is less than one (e.g., 0.9). Likewise, a project with a positive NPV may be rejected because negative externalities not incorporated into the CBA are judged to outweigh the positive NPV. The use of decision analysis tools may help ensure that final decisions involving the consideration of non-monetized impacts are based on a sound and consistent approach. Multi-criteria decision analysis and its application for decision-making are discussed in Step 13 and Appendix E.

CBA may also include certain sensitivity analyses to determine the impacts of various factors on the values of NPV and BCR. Very often, sensitivity analyses are performed to examine the impacts of the discount rate, as a change in discount rate may have a significant impact on the valuation results. Sensitivity analyses are also performed to examine the impacts of changes in other key factors, such as project capital costs, escalation rates, and others. Evaluating costs and benefits in a wide range of plausible alternative futures is useful for identifying situations that result in both positive and negative NPVs. It is also useful for assessing project risks.

CBA can take into account different valuation perspectives. It is normally performed to determine the value of a project to society as a whole in what is called a system wide or societal perspective (Chang et al. 2015). The societal CBA reflects the true economic value of the evaluated project, as it takes into account all costs and benefits that the project brings to society.

In addition to the societal CBA, there are variations of CBA that focus on the valuation perspectives of certain stakeholders and are called targeted CBAs. A targeted CBA takes into account only the costs and benefits that are relevant for the stakeholder whose perspective is being used for the valuation analysis. For example, various types of targeted CBAs can be performed by focusing on the perspectives of PSH owner or developer, electric utility, electricity consumers, regulatory authority, or public interest.

The key outcomes of this step are the results of the CBA, including the resulting NPV and BCR values calculated for each of the alternatives identified in Step 3.

Step 13: Perform Risk Assessment

The purpose of Step 13 is to perform an objective risk assessment of the alternatives analyzed during the valuation process. The primary concern is to identify and evaluate potential risks that may impact the value of the project being evaluated or the alternatives.

The cost-benefit analysis performed in Step 12 is subject to numerous uncertainties and short- and long-term projections (e.g., fuel price projections, revenue projections, etc.) made during the valuation process. For this reason, the cost-benefit analysis is typically followed by a risk assessment to evaluate which factors and uncertainties may have the greatest impact on the NPV, BCR and other parameters.

In principle, risk assessment and evaluation should be part of all steps in the valuation process, especially designing the analysis (Steps 7-9) and performing the analysis (Steps 10-11). The goal of the risk assessment in Step 13 is to summarize the potential risks that may have a significant impact on the value of the project and present the results. The key objectives are:

- Formulate, assemble, and present a list of potential risks
- Estimate the likelihood of potential risks (if that is possible to quantify)
- Assemble and present the results of various risk analyses conducted during the valuation process
- Conduct any additional risk analyses deemed necessary
- Present the overall results of risk assessment to decision-makers

Risk assessment is obviously very important for making decisions on any new project development, as potential risks may significantly affect the economic and financial feasibility of the investment. However, risk assessment is also important for the valuation of existing projects or project upgrades. For example, the value of an existing project is subject to many potential risks, including changes in government regulations, energy and environmental policies, market rules and market structure, fuel prices, and many others. All these risks may impact the value of an existing project and may result in different decisions: for example, to continue to operate the project, to mothball it, to retire the project early, or to put it up for sale.

Risk assessment is also important if several projects or project alternatives are being compared. It is possible that two or more alternatives have approximately the same NPV, but may have different risk profiles. In such cases, minimizing the risk or risk exposure may be a prudent objective. The main deliverable of Step 13 is a clear and transparent risk assessment presented to decision-makers. It should summarize the key potential risks and their possible impacts on the project or its alternatives.

Step 14: Perform Multi-Criteria Decision Analysis

If the alternatives identified in Step 3 are characterized by both monetized and non-monetized impacts, CBA may not provide a clear answer to the question of which alternative has the highest value. This is because CBA addresses the monetized value streams, and it is inherently difficult to account for the value of impacts or attributes that are not easy to quantify or monetize. Often the non-monetized impacts or attributes of certain alternatives are very important and need to be also taken into account in the valuation process and the comparison of alternatives (Keeney and Raiffa 1976).

The situation described in the preceding paragraph is illustrated in Figure 3.3, which shows three hypothetical alternatives characterized by different attributes, of which only the NPV is monetized (the others are not monetized). While Alternative 1 has the highest NPV and the highest estimated socioeconomic benefits, Alternative 2 is the best with regard to system reliability and support for (fewest curtailments of) variable energy resources (VER), and Alternative 3 is the best with regard to environmental characteristics. If the only factor considered for the ranking of these three alternatives was the NPV, then Alternative 1 would be a clear winner. However, as each of the alternatives has certain advantages and disadvantages, it is difficult to determine which alternative is the best if other attributes are also considered.

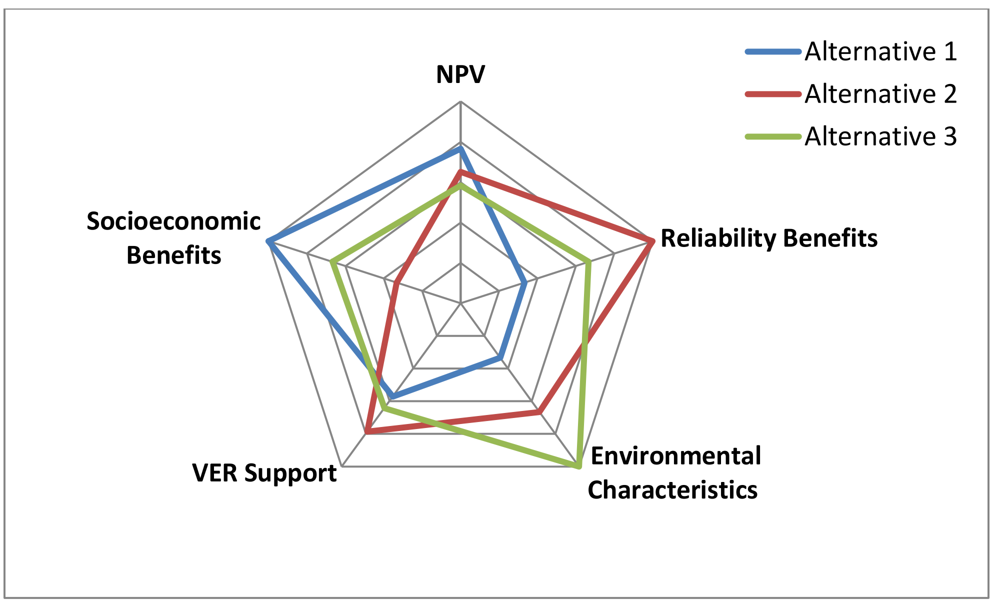

Figure 3.3: Hypothetical alternatives characterized by monetized and non-monetized attributes.

When alternatives are characterized by a variety of attributes, both monetized and non-monetized, a MCDA approach can be applied to prioritize various alternatives. MCDA allows for the value of non-monetized attributes to be expressed in any type of units (e.g., physical, numerical, or qualitative).

In principle, MCDA is a decision support system that allows for the valuation and ranking of alternatives that are described by various characteristics or attributes. The MCDA approach involves a trade-off analysis in which the relative importance of different attributes is determined and trade-off coefficients are established. This approach allows the analyst to take into account both qualitative (i.e., typically non-numerical) and quantitative (i.e., typically numerical and based on quantifiable information) attributes. To do so, decision analysis typically uses three types of measurement scales:

- *Natural*, such as metrics used to express the value of different attributes (e.g., NPV in $)
- *Constructed,* typically a several-point or several-level scale (5 or 7 levels is common) with a precise definition for each level, such as "low," "medium," and "high"
- *Proxy,* or indirect measurement, such as tons of pollutant emissions instead of a specific human health effect

MCDA involves normalizing the values for different attributes and determining the relative importance of each attribute to reach a specific objective. This relative importance constitutes a trade-off weight, which is then used to multiply the values of the attribute to calculate a single composite score for each alternative.

The following are the key steps in the MCDA process:

1. Define the set of objectives and goals to be achieved with the valuation process (e.g., maximize NPV, minimize negative environmental impacts).
2. Select attributes to be used for decision analysis. A list of attributes to be used in the MCDA, along with their values expressed in appropriate metrics, is prepared for each alternative.
3. Specify measurement scales. For each attribute, a measurement scale that specifies a range of possible values for that attribute must be determined. For example, a measurement scale for certain attributes can be from 0% to 100%. For attributes expressed in monetary or physical units, the measurement scale typically includes the range from the minimum to the maximum possible value that a particular attribute may have. A proxy scale is typically constructed for attributes that are expressed qualitatively.
4. Normalize attribute values. The attribute values for each alternative are normalized using the measurement scales developed in the previous step. The normalization provides an indication of how the value of an attribute for a particular alternative compares to the same attribute of other alternatives.
5. Characterize attribute importance. The relative importance of various attributes to decision-makers needs to be determined. This is typically done through an elicitation process.
6. Determine weight coefficients, based on the relative importance of each of the attributes. The weight coefficients allow for trade-offs among different attributes, and the sum of these coefficients is equal to one.

7. Calculate the composite score. A utility function is developed, based on the normalized values for each attribute and their respective weight coefficients, to obtain the composite score for each alternative. The composite scores allow for the prioritization of alternatives considering the objectives defined during the first step.

The key steps in the MCDA process are 4 and 5—normalization of impact or attribute values and determining the relative importance of various attributes characterizing each alternative. The normalization can be done in different ways, such as defining the range of possible values for a certain attribute (e.g., minimum and maximum boundaries), or by using the minimum and maximum values that were observed for a specific attribute in a given set of alternatives to represent the lower and upper boundaries of the range for that attribute. In the latter case, the normalization is simply performed by dividing the attribute value for each alternative by the sum of the values for all alternatives (Woolf et al. 2014).

Characterization of attribute importance is normally done through an elicitation process, that is, by surveying the decision-makers about their views of the relative importance of the different attributes. This is a subjective process that reflects different preferences of different decision-makers. To help determine the relative importance of various attributes, the analyst may also elicit decision-makers' views on the trade-offs among different attributes. The results of this analysis are then used to determine the relative importance of each attribute and its respective weight coefficient.

Appendix E provides a brief overview of the MCDA approach and illustrates a simplified MCDA process using the hypothetical example shown in Figure 3.3.

The key outcome of Step 14 is the ranking of alternatives using the MCDA approach by taking into account their monetized and non-monetized attributes. Given that certain steps in the MCDA process are based on the subjective views and preferences of decision-makers, a sensitivity analysis should be performed to determine how the changes in relative importance and weight for certain attributes may affect the overall ranking of alternatives.

3.6. Results Analysis and Reporting

Step 15: Compare Values, Document Analysis, and Report

The final step, Step 15, 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. If one of the alternatives looks like a clear winner, the analysts should be able to understand which impacts or attributes make that alternative preferable to the others. If there are several alternatives that are very close to each other, the analysts should develop a good understanding of how their relative values may change if some of the key valuation parameters change.

To better understand what other factors may affect the values of alternatives, additional sensitivity studies and risk assessments may need to be performed. The types of risks that could be analyzed include the risk of potential regulatory changes, technology evolution and obsolescence risks, extreme weather and climate risks, market variability risk, financial risk, and other risks that may not have been explicitly captured in the valuation analysis.

In addition, it is important to review the underlying assumptions associated with the valuation process to take into account the impact that this may have on the results. A careful review of the inputs and analytical results is required in each step of the valuation process, not just in the final step. As mentioned earlier, the valuation process often may not be linear and may require the analyst to revisit prior steps and make necessary adjustments and modifications. That is illustrated with the feedback loops in Figure 3.1.

Once all the checks and reviews have been made, the valuation analysis report should be prepared to document all key inputs, assumptions, and results of the analysis. The report should provide sufficient information for a clear and transparent understanding of the valuation process.

Finally, the key findings of the valuation process should be summarized for decision-makers and relevant stakeholders. If the valuation analysis was performed to inform a specific decision-making process, the analysts should present the decision-makers with all the information that is necessary to support their decision-making, but should refrain from making recommendations on the course of action. The information delivered to decision-makers should be presented in a form that would allow even non-experts to fully understand the valuation process and results.

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4. Methodological Approaches for Valuation of PSH Services

The previous sections of this report presented a high-level overview of a cost-benefit and decision analysis valuation methodology for PSH plants. Section 3 presented fifteen unique steps for conducting PSH valuation, beginning with the definition of fundamental project components (e.g., scope of the analysis, project purpose, context of the project valuation, and identification of relevant project stakeholders) and ending with the discussion of methods to develop valuation criteria, analysis design, and presentation of results. With the fundamental overview complete, this section presents detailed methods and approaches for estimating the value of various PSH services and contributions to the power system. Each sub-section includes the following components:

- *Methodology and approach* section, providing an overview of methods proposed here for valuing the benefits delivered by each service.

- *Key features and assumption* section, which defines the key features and assumptions underpinning a given valuation methodology. It can include complex modeling requirements, assumptions governing electricity market interactions, applicability of the methodology to systems of varying scales, and other key details.

- *Modeling tools* section, providing guidance on power system models and analytical tools that can be used to estimate the costs and benefits of PSH services or use cases. A detailed catalog of power system modeling tools and their key characteristics is provided in Appendix B. In principle, for the valuation of many (but not all) PSH services, the modeling approaches can be categorized as either price-taker modeling or system analysis (price-maker or price-influencer) modeling. The key differences between the two and their applicability to various PSH cases can be summarized as follows:

  Price-taker model estimation: The price-taker approach and tools are used to estimate the historical or future value of PSH plants using historical or forecast future market prices. These models offer a more flexible and simplified approach: measuring plant revenues under the assumption that the PSH unit does not significantly affect electrical grid operations or change market prices. This type of model can be used to benchmark the historical value of existing PSH or new projects which are sufficiently small not to affect future prices, which is a function of the regional market size.

  System analysis (price-maker or price-influencer) model estimation: The system analysis approach (also referred to as the price-maker or price-influencer approach) and tools are used to estimate the value of PSH plants that are assumed to be large enough to affect grid operations and influence market clearing prices. This model can often provide the most information about system effects; however, it is more complex to implement than a price-taker model and can be difficult to use for valuation of certain PSH services, such as ancillary services like frequency regulation, spinning and non-spinning reserves, etc.

- *Metrics and units* section listing and describing key parameters commonly used in the valuation of each PSH service and the units in which they are typically measured.

- *Limitations* section, which provides an overview of the limitations of each approach, including those related to co-optimization challenges, data shortcomings, and uncertainty.

- Prior studies section presenting an overview of relevant literature for each PSH service or use case.

Energy storage is able to provide flexible capacity and energy to grid operators in a way that can set it apart from traditional power generation assets. It is capable of responding quickly when called upon to support grid reliability while also accumulating a range of benefits that are not necessarily attainable through alternative resources. The ability to define those benefits and the total potential value that a PSH resource can bring to a system is, however, dependent on ensuring that it has been correctly evaluated. The remainder of this section provides a few additional kernels of information to consider while reviewing the methods outlined for each PSH service or use case.

Benefits are typically monetized in the valuation process either in terms of direct revenue (e.g., selling a service in an electricity market) or as an avoided cost. An example of the latter case would occur when a vertically integrated utility that does not participate in an electricity market must procure assets to provide ancillary services within its own system. The value of the PSH plant for providing ancillary services in this scenario would be tied to the avoided cost of procuring an alternative asset to provide the same service. While this value is demonstrable, it may or may not result in a PPA or some other revenue mechanism that yields revenue to the PSH operator. The valuation method that applies to the PSH plant under evaluation—revenue or avoided cost—is often variable and dictated by such factors as utility structure and market accessibility.

It is important to note that it can also be valuable to assess benefits to the system that do not necessarily generate any immediate revenue to project investors. These use cases and their value can instead be used to influence markets and regulators through the demonstration of the benefit to the system. This is done to contribute to the ongoing development and optimization of the policy and rulemaking that surrounds energy storage and its role in the grid of the future. Ultimately, the results of comprehensive PSH valuation studies could be used to obtain PPAs or to remove market and regulatory barriers.

To accurately quantify the value that PSH plants provide to the grid, their characteristics and features must be reflected through the models capable of simulating the operation of the asset and its various services and use cases. Operation of the PSH plant can vary significantly depending on the topology of the grid, the location of the project, and the environment or market in which the benefits are realized. There are specific and varying rules and requirements that must be met to accurately simulate the capabilities of the storage resource and to avoid under or overvaluation. Furthermore, PSH plants are energy limited and cannot provide all potential services simultaneously. Due to these restrictions, services provided by the PSH plant must be co-optimized. This process involves simulating the operation of the asset in a manner such that the optimal operation is chosen at each time step while also limiting asset operation only to that which is physically achievable, subject to the present technological and system limitations. Understanding which benefits can be obtained in parallel and which are mutually exclusive is key to correct valuation.

The technical characteristics of the PSH plant determine which model should be used when conducting an analysis. Smaller systems that have low to negligible impacts on the market clearing prices within the power grid can be evaluated using price-taker models. The term price-taker means that the PSH plant operator has no control over market prices. Price-taker models allow greater flexibility when evaluating PSH services, are often more flexible, require fewer computing resources, and are less complicated and costly to administer. Large PSH systems, on the other hand, cause shifts in market clearing prices and alter grid dynamics. These effects must be accounted for through a system model or production cost tool that can simulate operation for the relevant power system. While this model loses some of the flexibility offered in a price-taker model, it can more accurately demonstrate how operation of the PSH unit impacts the grid, provides more resolution with respect to competing assets, and ultimately provides a more dynamic understanding of price shifts caused by PSH operation.

Armed with this background information, which includes valuation fundamentals and additional points covering the differences between the competing modeling frameworks, the remainder of Section 4 presents an overview of valuation approaches for various PSH services and use cases.

4.1. Capacity Value Evaluation

4.1.1. Overview

The value of generation capacity is primarily derived from its contribution to resource adequacy and system reliability. PSH plants typically provide peaking capacity since they are very flexible and can be quickly dispatched with a high ramp rate to meet peak demands. The peaking capacity of PSH plants can also replace or reduce the need for new peaking thermal resources. The capacity value of PSH can be high when there is a shortage of peaking capacity in the system and low if the system already has sufficient peaking capacity. Therefore, as Huertas-Hernando et al. (2017) and Balducci et al. (2018b) discussed, the correct valuation of generating capacity is complex and requires detailed analysis.

As stated above, the value of generation capacity is directly related to resource adequacy and the reliability of power system operation as a whole. The reliability of system operation can be considered in the short term (operations) and in the long term (expansion planning).

In the short term, if the power system is overbuilt, there is a surplus of generation capacity, so the value of capacity is rather low. On the other hand, if the power system currently experiences shortages of capacity (e.g., the operating reserve margin is low), then the value of capacity is high. In both cases, the value of capacity is driven by reliability factors that may include so-called scarcity prices and/or avoided outage costs (e.g., avoided energy-not-served costs). It should be noted that in the short term, power system operators can rely only on the existing generating capacity connected to the system, flexible demand-side resources (e.g., demand response), and potential imports from surrounding areas. It is assumed that no new generation capacity can be constructed to help meet the system demand in the short term.

In the longer term, resource adequacy can be achieved by adding (i.e., constructing) new generating units, so that in the long run system capacity can be maintained at the desired level relative to the system load. Of course, due to seasonal patterns of system loads, hydropower generation, and variable renewable generation, operating reserve margins are not likely to be the same in every hour of the year. For this reason, resource adequacy in the long term is measured using the planning reserve margin (PRM). The PRM is usually expressed as the percentage of total system capacity that exceeds the annual peak load for the system; thus, it represents the relative difference between the system available capacity and the system load during the critical period of the year. If the PRM is too small, system operation may be less reliable, especially in cases of multiple forced outages of generating units or other adverse reliability events. On the other hand, if the PRM is too high, the system may be overbuilt, which is economically suboptimal. Therefore, power system planning entities in the U.S. typically set target PRM values between 12% and 18% in their planning process. The North American Electric Reliability Corporation (NERC) publishes a reference reserve margin level for each NERC assessment area, shown in Figure 4.1, in the annual long-term reliability assessment report (NERC 2018a).[1]

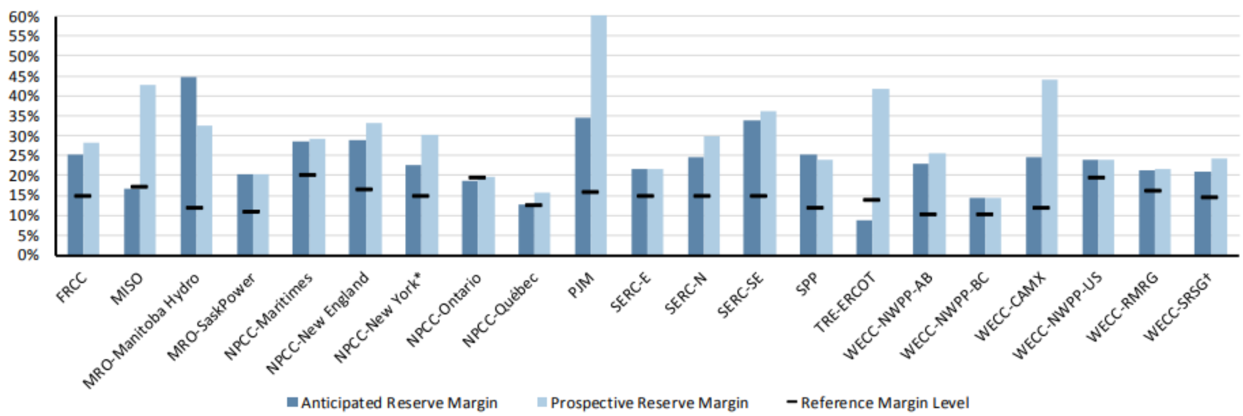

Figure 4.1: Anticipated and prospective reserve margins for 2023 peak. (NERC 2018a)

While PRM is sometimes calculated using the installed capacity of generating units, it is more correct to use the total net available capacity of generating units. The net available capacity of conventional thermal and nuclear units is straightforward to calculate, as their fuel supply is typically always available and does not vary from hour to hour. For these units, the net available capacity is calculated as the installed capacity de-rated by the equivalent forced outage rate (EFOR) of the generating unit. The EFOR is called equivalent because it includes both the full and partial outages of a generating unit. The planned outages (e.g., for regular annual unit maintenance) are not used for the calculation of net available capacity, because the maintenance

[1] A reference reserve margin level can be provided by a regional planning entity. In this case, the reference reserve margin level is equivalent to the target reserve margin level of the planning region. If that is not provided, NERC applies a 15% reserve margin for predominately thermal systems and a 10% reserve margin for predominately hydro systems (NERC 2018a)

of these units is normally not scheduled during the critical period (e.g., summer peak load period).

The power output of conventional hydropower plants depends on the hydrology and availability of water inflows, which are driven by seasonal and climatological patterns. Because of this, the net available capacity is determined as the average hourly output that can be produced by a generating unit during the critical period. Hydropower plants with large reservoirs and PSH plants are typically able to generate at full capacity during the peak hours, even during the critical period. For example, the upper and lower reservoirs of closed-loop PSH plants are not connected to other water bodies and their power output does not depend on water inflows,[1] so it can be assumed that these plants have a constant net available capacity throughout the year.

The generation and power output of variable renewable energy sources (e.g., wind and solar) vary not only from season to season but also from day to day and hour to hour. Therefore, to determine their net available capacity, it is necessary to first determine their firm or dependable capacity in the critical period. This firm capacity is typically referred to as capacity credit. Capacity credit is determined based on how much firm capacity a variable resource can provide in a specified time period or point in time (e.g., peak hours during the critical period). Typically, in ISOs and RTOs capacity credit is determined as the historic (i.e., 1–5 prior years) average output during the critical period defined by the ISO or RTO. Another measure for capacity credit is the effective load carrying capability (ELCC), which represents how much system load (in MW) can be covered by the variable resource (California Public Utilities Commission, 2014). Due to the high intermittency and temporal variability of wind and solar generation, their capacity credits are often estimated to be rather low, just a fraction of their total installed capacity (e.g., 10%–30% for wind and 40%–100% for solar) (Bothwell and Hobbs 2017). Table 4.1 presents a comparison of the capacity credit determination methods for different technologies.

Table 4.1: Capacity credit determination method comparison
(Byers, Levin, and Botterud 2018; CPUC 2017; ERCOT 2018; SPP 2019)

ISO	Wind	Solar	Hydro	Battery Storage
PJM	Average hourly output during the peak period[2]	Average hourly output during the peak period	Reservoir, pumped storage, and run-of-river: average hourly output during the peak period	Average hourly output during the peak period
ISO-NE	Average of five prior years of median net outputs during the peak period[3]	Average of five prior years of median net outputs during the peak period	Reservoir and pumped storage: Audited output over 2-hour period Run-of-river: Same as wind, solar	Audited output over 2-hour period

[1] There may be some loss of water due to evaporation and leakage, which occasionally requires make-up water to be provided.

[2] PJM defines the peak period as 6:00 a.m. to 9:00 a.m. and 6:00 p.m. to 9:00 p.m. in January and February and 2:00 p.m. to 8:00 p.m. from June through August.

[3] ISO-NE defines the peak period as 1:00pm to 6:00pm in summer (June to September) and 5:00pm to 7:00pm in winter (October to May) plus shortage events.

ISO	Wind	Solar	Hydro	Battery Storage
MISO	ELCC based on 8 highest coincident-peak load hours of the preceding year	Average hourly output during the peak period[1] for prior 3 years	Reservoir and pumped storage: Median head in prior 5–15 years during the peak period converted to expected output Run-of-river: median output from prior 3–15 years during the peak period	Not defined
NYISO	Average output during the peak period[2] of preceding delivery period	Average output during the critical period of preceding delivery period	Reservoir and pumped storage: average output over 4-hour period with average stream flow and storage conditions Run-of-river: average output during 20 highest load hours in prior five capability periods during the peak period	Not defined
CAISO	ELCC for each month	ELCC for each month	Dispatchable resource: the most recent maximum capacity test Non-dispatchable resource: 3-year rolling average of production during the peak period	Dispatchable resource: the most recent maximum capacity test Non-dispatchable resource: Not defined
ERCOT	Weighted average of the previous 10 eligible years of seasonal peak average values, which is average capacity during the 20 highest system-wide peak load hours	Weighted average of the previous 10 eligible years of seasonal peak average values, which is average capacity during the 20 highest system-wide peak load hours	Average hydro capacity available during the highest 20 peak load hours for each of the preceding three years	0% of rated capacity; resources assumed to provide regulation reserves rather than sustained capacity available to meet peak loads
SPP	Weighted average historic peak hour performance in July and August over three years	Weighted average historic peak hour performance in July and August over three years	Not defined	Not defined

[1] MISO defines the peak period as 2:00pm to 5:00pm in January-August.
[2] NYISO defines the critical period as 1:00pm to 5:00pm in summer (June to August) and 5:00pm to 8:00pm in winter (December to February).

Given the values in Table 4.1, clearly power systems with a larger share of variable generation will need to have installed capacity much higher than the peak load, as much of the installed variable generation capacity may not be available during the critical period. Because of this uncertainty with regard to variable generation, these systems will typically set a higher target value for PRM, say 16%–18%, rather than the target value of PRM of systems that have little or no variable generation capacity, where it typically ranges from 12% to 14%.

In addition to PRM, the reliability of power system operation in the long term can also be measured probabilistically, using LOLP, LOLE, EUE, and other parameters. LOLP is calculated using probabilistic simulation methods to take into account the impacts of stochastic unit outages on the reliability of system operation. LOLP is defined as the probability of system daily peak load or hourly demand exceeding the available system capacity during a given period (NERC 2018b). The Monte Carlo simulation and probabilistic simulation using the equivalent load duration curve (ELDC) convolution analysis are typically the methods used to calculate the LOLP. LOLE is a related reliability parameter that is derived from LOLP and represents the expected number of days within a given time period (usually a year) for which the available capacity is insufficient to serve the demand at least once per day (NERC 2018b). Neither LOLP nor LOLE provides information about the quantity of energy that may not be supplied to meet the demand. This information is provided by the EUE parameter, which represents the expected total MWh of demand that will not be served in a given time period as a result of power demand exceeding the available system capacity across all hours (NERC 2018b). In long-term system capacity expansion planning (e.g., IRP), LOLP is typically used directly as a hard reliability constraint or translated into a PRM for the optimization of power system development over the study period. The IRP system planning analysis is typically performed for a 10to 30-year study period, and reliability criteria (i.e., PRM, LOLP, and EUE) are used to ensure system resource adequacy and reliability of operation in the long-term.

Since the value of generation capacity is related to short- and long-term resource adequacy and system reliability, capacity valuation approaches can be categorized into the following three groups:

Long-term resource planning method: The capacity value of PSH plants can be assessed in terms of their contributions to long-term resource adequacy. The avoided construction of new generating resources in the long term can be evaluated by conducting IRP studies with and without the specific PSH plant of interest. The differences in total investment and fixed operation and maintenance (O&M) costs between the two studies can be interpreted as the capacity value of the PSH plant. This type of approach can be applied for the evaluation of new PSH projects.

Short-term system operations method: The value of avoided peaking capacity in the near future (e.g., 1–5 years) can be assessed by capturing how much peaking thermal capacity the PSH plant of interest can replace while maintaining the same system reliability. The most common approach is to compare the cases with and without the PSH plant to determine how much thermal peaking capacity is avoided due to the PSH plant. The cost of new entry (CONE) approach can then be applied to calculate the value of avoided generation capacity. CONE represents the cost of building new generating capacity in the short term, typically peaking capacity such as gas turbines. The CONE approach would involve calculating the incremental capacity equivalent (ICE) of the next-best alternative (e.g., simple cycle or combined cycle gas turbine) that is avoided by having the PSH capacity in the system. The reliability of operation of the PSH and the CONE resource are taken into account when calculating ICE. The avoided capital cost of ICE is then reduced for any benefits that this capacity may provide to the system (e.g., energy and ancillary services). The annual fixed O&M charges are typically added as avoided cost. This type of approach can be applied to capture the benefits of new PSH projects as well as existing PSH plants.

Capacity remuneration method: This capacity valuation approach mainly focuses on monetized benefits in the near future (e.g., 1–5 years) that a PSH plant can achieve from the perspective of asset owners or investors. Various capacity remuneration mechanisms (CRMs) have been introduced in restructured markets to provide appropriate market signals for capacity investment and to achieve desired resource adequacy. In the U.S., several ISOs and RTOs operate centralized forward capacity markets, though in different ways, to provide additional revenue and price signals that would ensure resource adequacy. The capacity value assessment approach in this category typically includes an estimate of potential capacity payments from different CRMs.

Figure 4.2 illustrates a framework for the analysis of the value of PSH generation capacity that accounts for different factors such as market structure (traditionally regulated and various types of competitive markets), perspective (PSH developer, utility, system operator, or regulatory agency), context (new or existing project), and the analysis purpose. The following sections will provide an overview of capacity valuation approaches in regulated and restructured market environments.

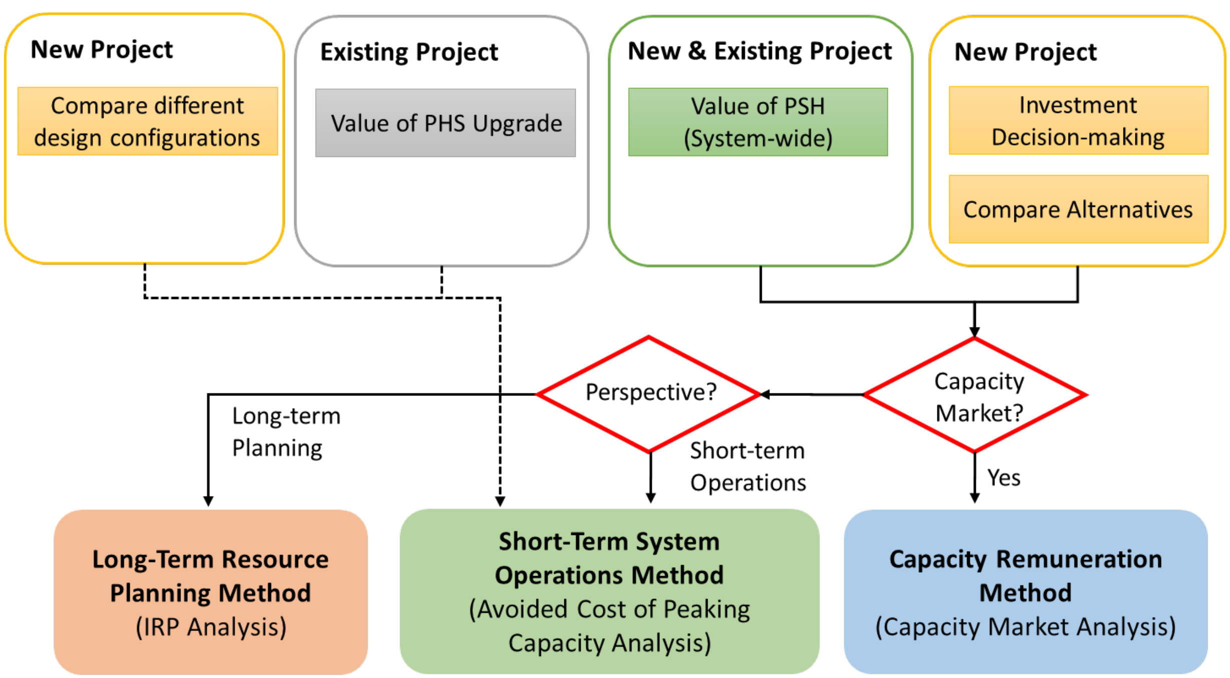

Figure 4.2: Process for evaluation of PSH capacity value.

4.1.2. Methodological Approaches for Capacity Value Assessment

Long-Term Resource Planning Method: Integrated Resource Planning Analysis

Methodology Description

Capacity value assessment quantifies the value of PSH capacity in providing long-term resource adequacy using IRP studies. IRP is a quantitative modeling approach that determines the least-cost future portfolio for power systems. It considers the time, type, and size of all supply and demand options to serve projected future demand and satisfy reliability and other constraints.

To evaluate the capacity value of a PSH plant, two IRP scenarios are created: one with and one without the PSH plant under consideration. The IRP study with the PSH plant may provide a system expansion portfolio with a reduced need for the construction of other generating capacity, and the expansion plan may show that the commissioning dates of some new capacity additions have been postponed by a year or two because of the PSH capacity. Therefore, the long-term impacts of a PSH plant on resource adequacy can be assessed by comparing the optimal expansion plans. First, the NPV of the differences in capital investment costs between these two cases should be calculated for each year of the study period. Next, the NPV of differences in annual fixed O&M costs between these two cases should be calculated. The sum of differences in capital investment and fixed O&M costs over the study period provides an estimate of the avoided costs for alternative generating capacity that is replaced by the PSH plant under consideration. These avoided generating capacity costs, or savings, can be interpreted as the capacity value of the PSH plant in the long term. To be comparable, both expansion cases should be developed using the same reliability criteria (e.g., PRM, LOLP, EUE, etc.) to provide the same level of reliability.

Key Features and Assumptions

Capacity value assessment requires the use of complex IRP models with the capability to simulate and optimize the future resource portfolio, taking the detailed operation of the entire system, including both power supply and demand options, into consideration. IRP models have the following characteristics:

- Typically applied in a traditionally regulated market environment in which a utility performs investment decision-making and optimizes its portfolio.[1]
- Assume centralized power system operations; therefore, the optimization model will minimize total planning costs, including investment costs and overall production costs of the system over the entire study period.
- Are applicable for various purposes, including investment decision-making for a new PSH project as well as for system-wide valuation of existing PSH resources.
- Require an extensive set of input data and parameters. Most commercial IRP models provide a set of default design parameters. The design parameters can have a direct and significant impact on the valuation study results. Thus, user-defined design parameters may be required for accurate and appropriate study results. Key analysis design parameters include current and planned generation portfolio, current and planned

[1] Note that IRPs can be applied in a deregulated market environment as well. For instance, CPUC implemented a process for IRP to ensure that load serving entities procure resources adequately in a long-term perspective (see https://www.cpuc.ca.gov/irp/).

transmission network, growth of distributed energy resources on the distribution network, utilization of energy efficiency and demand response as supply solutions, technical and economic information for different technologies, and other planning environment parameters.
- Can be used with sensitivity studies using scenarios that capture various market conditions and planning environments. Potential scenarios for a capacity valuation of a PSH plant include carbon restriction, renewable policies, water availability, and natural gas prices.
- Can consider scenario-based stochastic modeling to capture uncertainties associated with other stochastic variables.

Modeling Tools
Capacity expansion planning tools, such as Aurora (Energy Exemplar), EGEAS (EPRI), Haiku (RFF), MARKAL (ETSAP), PLEXOS (Energy Exemplar), ReEDS (NREL), Strategist (ABB), and WASP (IAEA), can be used to conduct IRP studies. Further details about these tools can be found in Appendix B.

Metrics and Units
Some of the key metrics used in IRP studies are listed below. Further details regarding metrics and units can be found in Appendix A.
- LOLP/loss-of-load probability (%)
- LOLE/loss-of-load expectation (days/year)
- EUE/expected unserved energy (MWh)
- Investment costs ($)
- Fixed O&M costs ($/kW-yr)
- Avoided capacity construction cost ($)

Limitations
- Optimization of a long-term system expansion planning exercise can be very complex, due to the level of detail needed for system representation as well as the computational complexities related to the number of potential expansion options and system configurations in the future (e.g., integer variables associated with the investment status of each candidate resource and potential combinations of various capacity expansion options).
- This type of capacity value assessment may not be sensitive enough to valuate different PSH design configuration or technology upgrades because the impact of such enhancements may not be large enough to affect the optimal solution of IRP studies. In that case, instead of the system-based IRP approach, a project-based approach would be more applicable.
- The details of the representation of system operation and PSH plant operational characteristics can affect the capacity value assessment significantly. Due to computational challenges, many IRP models simulate the system over selected representative days instead of considering all days during the planning horizon. This approach basically prevents the model from representing inter-temporal constraints and may prohibit the realistic operation of a PSH plant.

- The publicly available long-term system expansion planning tools may have limited ability to consider ancillary services, ramping requirements, transmission congestion, and input uncertainties, so additional ad-hoc analyses may be required.

Prior Studies

- Cooke, Twitchell, and O'Neil (2019) review 21 recent integrated resource plans in the U.S., focusing on the treatment of battery energy storage and pumped storage hydropower.
- Energy Storage Association (2018) presents an overview of how to effectively include advanced storage resources in long-term IRP studies. The report also summarizes recent utility IRP practices that consider advanced storage resource.
- In Teng et al. (2018), a deterministic system planning tool combined with a stochastic system operation tool is used to investigate the benefits of PSH in the future European electricity system. However, this study does not explicitly assess the PSH capacity value.
- Xu et al. (2017) introduces an energy storage planning problem formulated as a bi-level model to optimize the location and size of energy storage. This study could be used in an IRP study, along with a traditional system expansion planning tools, to provide input for the deployment of energy storage resources.

Short-term System Operations Method: Avoided Cost of Peaking Capacity Analysis

Methodology Description

Avoided cost of peaking capacity analysis aims at quantifying the PSH capacity value by estimating the avoided capital costs of alternative peaking capacity (avoided due to the peaking capacity of the PSH plant of interest) without using an IRP model. Most often, simple-cycle combustion turbines are considered as the alternative peaking capacity for this analysis. The first step is to estimate how much new thermal peaking capacity is avoided or, alternatively, how much existing capacity can be replaced by the PSH plant. This can be done by comparing system operating conditions with and without the PSH plant using production cost simulation models.

Production cost simulation models reflect system operations with the objective of minimizing system operating costs while taking various system constraints into account. Therefore, the scheduling solution of the case with the PSH plant will include discharging (i.e., generation) during peaking hours and charging (i.e., pumping) during off-peak periods from the PSH plant. The avoided thermal peaking capacity can be obtained by comparing the total capacity of committed thermal peaking plants from both cases. As with the IRP analysis, the cases with and without PSH should satisfy the same reliability criteria for system operation as well as other operational constraints. This will ensure that the PSH capacity can be considered to be equivalent in terms of its load carrying capabilities (i.e., ELCC) to the alternative thermal peaking capacity.

Second, once the corresponding amount of thermal peaking capacity has been determined, then the avoided capital cost can be determined using the CONE approach. CONE represents the annual revenue that a new generation resource would need to earn in the markets to recover its costs, including capital investment and fixed costs, over the economic life of the facility (Newell et al. 2018). Generally, the avoided capital cost can be assessed using the CONE of a reference resource, such as a simple-cycle combustion turbine. The fixed O&M costs for the thermal peaking capacity should also be added to obtain the total avoided cost of peaking capacity. The avoided peaking capacity cost due to having the PSH plant in operation can be interpreted as the value of peaking capacity that PSH plant provides to the system.

While in principle both the IRP analysis and the avoided cost of peaking capacity analysis estimate the value of PSH capacity by analyzing the avoided costs of alternative capacity, there are some key differences. First, the IRP analysis determines the value of PSH capacity as its contribution to resource adequacy in the long term, over a 20–30 year horizon, while the avoided cost of peaking capacity approach focuses on the resource adequacy in the short term, from one to several years. Note that the results from the avoided cost of peaking capacity analysis can be extrapolated to a longer time period, if desired. Second, in the IRP analysis the alternative capacity mix can include different types of resources and can vary over time. In contrast, the avoided cost of peaking capacity analysis approach is typically applied for a single type of avoided peaking capacity using a fixed resource mix. In all of the above approaches, the analyst should be sure to exclude the energy and ancillary services benefits from the estimate of capacity benefits.

Key Features and Assumptions
Avoided cost of peaking capacity analysis is characterized by the following features and assumptions:

- It can be applied in a traditionally regulated market as well as a restructured market environment for various purposes, including: 1) investment decision-making for a new PSH project, 2) valuation of different PSH design configurations or technology upgrades, and 3) system-wide valuation of existing PSH resources.
- It requires the use of complex production cost simulation models with the capability to simulate and optimize the scheduling of the entire power system.
- It assumes centralized power system operations; therefore, the optimization model will minimize total production cost.
- It can consider scenario-based stochastic modeling to capture uncertainties associated with the operation of the power system, variable generation resources, and other stochastic variables.
- It can be performed over various time horizons from days to years.

Modeling Tools
Production cost simulation tools, such as Aurora (Energy Exemplar), CHEERS (Argonne), GE MAPS (GE), GridView (ABB), GTMax (Argonne), PLEXOS (Energy Exemplar), PROMOD (ABB), and UPLAN (LCG), can be used.

Metrics and Units
Further details regarding metrics and units can be found in Appendix A.

- ELCC/effective load-carrying capability (MW)
- Total system operating costs for the period ($)
- Total system operating cost savings for the period ($)

Limitations

- The optimization of electrical power system operations can be very complex, depending on the level of detail used for system representation. For instance, binary variables can be used to represent the on/off status of individual generators, which makes the optimization problem a mixed-integer linear programming (MILP) problem. MILP problems are non-convex and harder to solve than linear programming (LP) problems.
- The complexity of the model can increase rapidly, leading to high computational time and often requiring some high-performance computing (HPC) capacity, particularly in stochastic approaches using a large number of scenarios to represent the uncertainty of wind, load, outages, etc. The more scenarios that are introduced, the more accurate the capacity value that can be captured—at the cost of higher computational requirements. Moreover, the limited capability of publicly available modeling tools to handle uncertainties requires users to perform additional ad-hoc analyses.

Prior Studies

- In Tuohy and O'Malley (2011; 2019), system operation with and without a PSH unit is examined using production cost models to investigate PSH capacity value at different wind penetration levels. The results show that PSH resources reduce curtailment and increase the use of baseload plants in the system. This study also introduced a simple capacity credit determination method for energy storage resources.
- In Brown, Peas Lopes, and Matos (2008), the capacity value of PSH is assessed for a small island system that has rich renewable energy potential available. The study optimizes the operation of PSH within the production cost model and shows that including PSH can allow better utilization of renewable energy resources (with fewer curtailments) while meeting the security criteria.
- In P. J. Balducci et al. (2018), capacity addition cost is defined as an increment of net installed cost and annual fixed O&M cost of the next-best alternative technology, considering offsets from energy and ancillary service benefits.
- In P. Balducci et al. (2018), the capacity value of a small closed-loop PSH was investigated, based on the market services offered in several electricity markets in the United States. In this study, which applied the price-taker approach, the capacity value was assessed by conducting an optimal scheduling of the PSH unit of interest during peak demand periods to supply energy and shave peak energy demand. The capacity payments were used to monetize the PSH capacity value.
- In PNUCC (2016), the cost of a new natural-gas-fired gas turbine was used as the avoided peak capacity value proxy and was estimated at $100/kW-year. Natural-gas-fired gas turbines were used and defined as the next capacity resource of choice.
- Koritarov et al. (2014) used various simulation tools including PLEXOS, FESTIV, and CHEERS to conduct different studies with and without PSH plants in operation. In addition, this study introduces two capacity valuation methodologies, including long-term system expansion studies and the value of peaking capacity in the capacity markets.

Capacity Remuneration Method: Capacity Market Analysis

Methodology Description

The objective of capacity market analysis is to evaluate the capacity payments that could be received by a PSH project in a capacity market. Capacity markets and other CRMs have been introduced in some restructured electricity markets to provide proper market signals for capacity investment by market participants and to achieve desired resource adequacy. In these markets, LSEs are required to meet their share of the region's capacity requirements by procurement, through centralized auctions or bilateral contracts, and by self-supply. In the U.S., several ISOs and RTOs operate forward-capacity markets. ISO-NE, MISO, NYISO, and PJM operate centralized capacity markets which utilize capacity auctions to procure capacity for resource adequacy in the next one to three years. Both supply and demand resources can participate in capacity auctions and are eligible for capacity payments. Energy storage resources are also eligible, except in MISO where storage is currently not eligible to participate in the capacity market. However, FERC Order 841 (2018) has mandated that all ISOs/RTOs should remove barriers to the participation of energy storage resources in competitive wholesale markets.[1] Presently, CAISO and SPP do not have capacity markets, but they require LSEs to maintain resource adequacy through bilateral contracts and self-supply. ERCOT does not operate a capacity market either, as it is an energy-only market, but rather relies on scarcity pricing mechanisms to maintain system reliability and resource adequacy. More details about how various electricity markets in the United States procure generating capacity and maintain resource adequacy are provided below.

- *California Public Utilities Commission(CPUC)/CAISO:* CPUC implements the state's resource adequacy policy for investor-owned utilities in the CAISO footprint with less direct authority over the community choice aggregators, and the California Energy Commission provides oversight over compliance by the state's publicly owned utilities. Resource adequacy requirements are set by these and other local regulatory authorities, mostly at 15%–17% reserve margin (Bushnell, Flagg, and Mansur 2017). The CPUC capacity procurement structure is based on bilateral resource adequacy requirements that LSEs can meet through bilateral contracts (many of which bundle energy and capacity) or self-supply. If conditions warrant, CAISO can also procure additional resource adequacy capacity on a "backstop" basis via auction (pay as bid) subject to a soft-offer cap (Jenkin et al. 2016). Since both CPUC and CAISO utilize the bilateral resource adequacy procurement framework, capacity prices are not transparent as in centralized capacity markets, which regularly publish capacity prices that were cleared during the auctions. However, CPUC periodically publishes statistics on contract prices.

- *ERCOT*: As mentioned above, ERCOT does not operate a capacity market and relies on energy prices to maintain an adequate supply of electric generation to meet demand and capacity reserves to help support grid reliability if shortfalls occur.[2] In 2014, ERCOT implemented the operating reserve demand curve, which creates a real-time price adder to reflect the value of available reserves in the system. It is based on the LOLP calculation and reflects the value of lost load (VoLL). The maximum VoLL at ERCOT is administratively set to $9,000/MWh, which is reached if the available reserve capacity

[1] "The Federal Energy Regulatory Commission (Commission) is amending its regulations under the Federal Power Act to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by Regional Transmission Organizations and Independent System Operators (RTO/ISO markets)." (FERC 2018)

[2] http://www.ercot.com/gridinfo/resource

drops below 2,000 MW. Even though this market does not have, strictly speaking, any resource adequacy requirements, it has a target reserve margin set to 13.75%.

- *ISO-NE*: Resource adequacy is procured through a centralized capacity market called forward capacity auctions. The base forward capacity auction is conducted for a one-year delivery period that is three years in the future. Annual reconfiguration auctions (ARA1, ARA2, ARA3) and monthly reconfiguration auctions are conducted as the delivery year approaches. The auction price is formed using the sloped demand curve, utilizing LOLE resource adequacy requirements and CONE estimates for capacity pricing of different asset classes. Even though ISO-NE states that energy storage resources (ESRs) are allowed to participate in the capacity market, they did not create specific rules for them, stating that they may qualify for a forward capacity auctions as a generator or a demand resource.

- *MISO*: In MISO, the capacity is procured through bilateral resource adequacy requirements or through the voluntary centralized capacity market called the planning resource auction. System-wide and zonal resource adequacy requirements are set utilizing LOLE studies. The planning resource auction is conducted immediately prior to the delivery year.

- *NYISO*: Resource adequacy is procured through a centralized capacity market called installed capacity auctions. The capacity auctions are held a month before the 6-month delivery period. Additional auctions are conducted on monthly basis during the delivery period. As in ISO-NE, the auction price is based on the sloped demand curve using LOLE resource adequacy requirements and CONE price estimates. Following FERC Order 841 (2018), NYISO has clearly defined specific qualification and obligation rules for ESRs.

- *PJM*: PJM operates a centralized capacity market called the reliability pricing model. It is a forward capacity market with a base residual auction conducted three years in advance of the delivery year. Incremental auctions are held 20, 10, and 3 months prior to the commitment period. The auction prices are based on a sloped demand curve, taking into account capacity requirements, CONE price estimates, and demand reservation prices. PJM allows ESRs to combine with other resources in its capacity market.

- *SPP*: As in CAISO, in SPP capacity requirements are procured by LSEs through bilateral resource adequacy contracts or by self-supply. SPP sets a minimum required planning reserve margin which must be met by all LSEs. A proposal is being considered for a planning reserve margin assurance mechanism that would penalize LSEs that are not maintaining the required reserve margin. The proposed penalty would be based on the CONE estimate and a multiplier that would be based on the region-wide reserve margin level. The critical period for planning reserve margin is the peak summer season. In August 2018, SPP proposed requiring a 9.89%, rather than 12%, planning reserve margin for those LSEs that have a 75% or more hydro-based resource mix.

Figure 4.3 shows a chart of historical capacity prices for auction-based centralized capacity markets in the U.S. (Byers, Levin, and Botterud 2018). It can be observed that capacity prices vary significantly from year to year and from market to market.

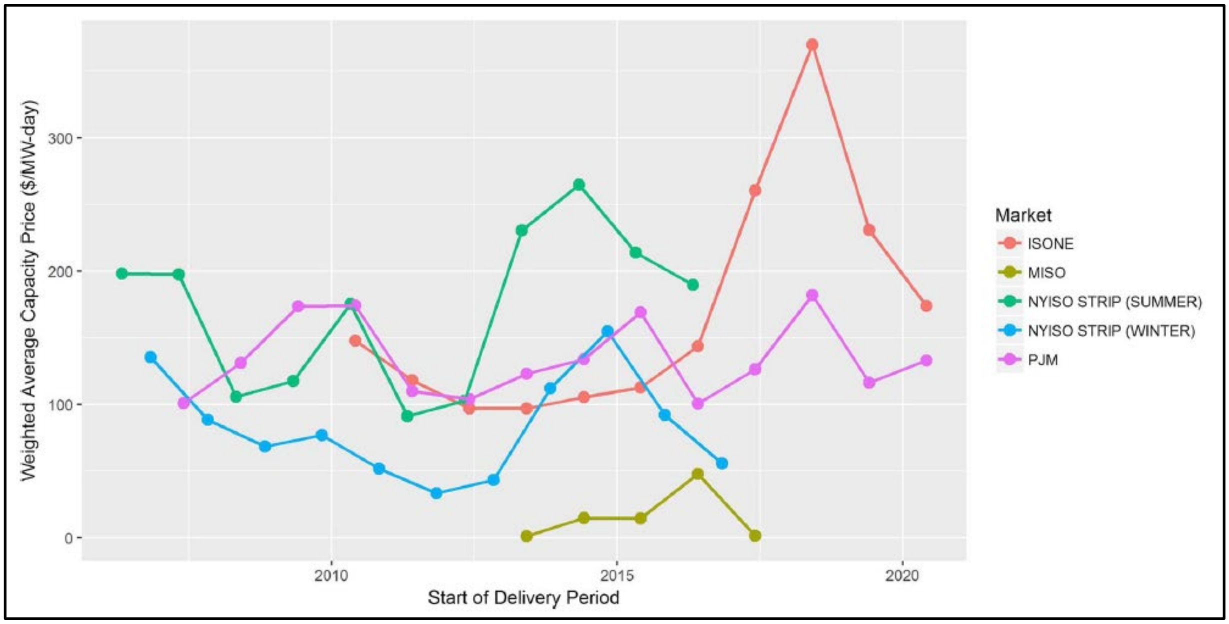

Figure 4.3: Historical capacity prices in United States markets.
(Byers, Levin, and Botterud 2018)

In principle, in the capacity market analysis approach the value of PSH capacity can be estimated using historical market prices without considering the impact of PSH capacity on market prices. Alternatively, model-generated price information can be used, which requires specific modeling and market assumptions. The model-generated capacity prices are typically used to project future capacity prices. This approach can also include stochastic modeling to consider potential impacts of uncertainties (e.g., wind forecasts, demand levels, and others) on capacity prices.

Key Features and Assumptions

Capacity market analysis is characterized by the following features and assumptions:

- It assumes a centralized forward capacity market where ISO/RTOs operate auctions on behalf of consumers.
- The historical capacity market prices analysis typically does not take into account the potential effect that a PSH plant may have on market prices; that is, it is assumed that the installation is marginal and does not exert any influence on the price levels (i.e., a price-taker approach). This assumption can be justified for a small PSH installation; however, an analysis for larger PSH plants would need to consider the impact of PSH size on capacity prices.
- The analysis can be deterministic or consider various uncertainties by using stochastic approaches.
- It can support investment decision-making process for a new PSH project.

Modeling Tools
Typically, assessments of capacity payments are based on historical capacity market prices or future projections of capacity prices.

Metrics and Units
- Capacity payment ($/MW-day) or $/kW-year.

Limitations
- Capacity market clearing prices are determined by supply and demand and represent only the marginal capacity costs (system-wide or local). The capacity prices provide limited insight into the condition of the system and, more significantly, the potential changes caused by the introduction of new PSH plants or other changes in the system capacity or plant mix.
- In the U.S., there is no consensus on how or whether capacity markets should be implemented. Byers, Levin, and Botterud (2018) studied centralized capacity markets in the U.S. and concluded that there are substantial differences in capacity market design and market rules concerning operational performance incentives, treatment of variable renewable energy resources, capacity demand curves, and others. This study also showed that the divergence in capacity market designs may affect the resulting capacity market clearing prices.

Prior Studies
- In P. Balducci et al. (2018a), the capacity value of a small closed-loop PSH was investigated based on market services offered in several electricity markets in the United States. This study provides four capacity valuation approaches from the Pacific Northwest region, CAISO, NYISO, and Hawaii. In the Pacific Northwest region, capacity value can be estimated based on the amount of capacity requirement, i.e., provision of capacity assigned to the PSH unit during peak demand events. In CAISO, the bilateral capacity contract prices from CPUC are used, and in NYISO, reference capacity prices for winter are used. Lastly, in Hawaii, the capacity value was assumed to be equal to the estimated levelized annual cost for the least expensive new peaking plant.
- In Mills et. al. (2018), marginal impacts were estimated using recent historical prices and emission rates for 2007–2016. This study considers energy value (i.e., locational marginal prices for energy), capacity value (i.e., capacity price), REC value, avoided emissions, and natural gas price. This study also provides a sensitivity analysis with temporal wind generation across sites and prices.
- Sioshansi, Madaeni, and Denholm (2010) examined incentives (e.g., capacity value) for the use of energy storage by different agents (operators, consumers, generators, etc.) in an electricity market. It was found that consumers will generally overuse storage compared to the social optimum, whereas merchants and generators will tend to underuse their assets. As the market becomes increasingly competitive with more agents, storage use will approach the social optimum. However, with a finite number of agents, the welfare losses can be substantial.
- Hledik et. al. (2017) conducted various sensitivity studies related to the CAISO market, which show that the uncertainty about the capacity value of storage could significantly impact estimates of total value. In the short run, excess supply means that the capacity

value of energy storage in California will be modest unless there are local needs for resource adequacy. In the longer term, as planning reserve margins tighten, the system-wide capacity value could approach the levels quantified in this study. Aside from sensitivity to generation capacity cost assumptions, the base case results are fairly robust across a range of assumptions about transmission and distribution (T&D) capacity costs, location, and historical study year. The study shows that, with perfect foresight, up to $300/kW-year of value, which includes $106/kW-year of capacity value, can be obtained from PSH.

- E3 (2014) conducted various sensitivity studies related to the Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric regions that show that uncertainty exists about the capacity value of storage that might significantly impact estimates of total value. Using E3's stochastic production simulation model REFLEX, E3 quantified the capacity value of energy storage in the California grid in 40% and 50% renewable penetration scenarios. REFLEX is specifically designed to investigate flexible capacity needs and value with VER. E3 also used the energy storage valuation tool to co-optimize the dispatch of energy storage across capacity, energy, and ancillary service markets and calculate the total value provided, on a $/kW-Yr. basis, by each respective system configuration.
- European Academies' Science Advisory Council (2017) conducts studies similar to E3's (2014) but for markets in Europe, such as those in Germany and the United Kingdom.

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4.2. Value of Energy Arbitrage

Like all energy storage technologies, PSH has roundtrip efficiency losses so it consumes more energy than it generates. Therefore, instead of estimating the value of energy generation, it is more correct to estimate the value of energy arbitrage for PSH projects. Energy arbitrage refers to the operation of energy storage facilities that generate electricity when the demand and/or electricity prices are high and consumes electricity when the demand and/or prices are low. Since this type of energy storage 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 can be performed in both a vertically integrated system and in wholesale electricity markets. In vertically integrated systems, energy arbitrage involves pumping during off-peak periods and generating during peak periods. In the literature, dispatch strategies for storage devices are based on optimization approaches for maximizing revenue. Some studies co-optimize PSH energy arbitrage with the provision of frequency regulation and/or contingency reserves, thus reducing the energy available for providing arbitrage services.

The modeling approaches to evaluating the energy arbitrage value of PSH can be classified based on the market environment in which the PSH plant operates and on the level of detail with which the energy system surrounding the storage (grid or power system) is represented.

4.2.1. Methodological Approach for the Valuation of PSH Energy Arbitrage

Production Cost Approach

Methodology Description

The production cost approach estimates the value of energy arbitrage by determining the difference in the value (i.e., revenue) of PSH energy generation compared to the cost of energy used for pumping. This can be done by simulating power system operation for two cases: with and without the PSH plant under consideration. This is a system analysis approach that requires a simulation of the entire utility system to determine the value of energy arbitrage. As a result of the optimized system operation, PSH plants are typically dispatched to generate electricity (i.e., generation mode) during the periods of high demand, and to consume electricity (pumping mode) when the system demand is low. The key driver for the optimization of PSH plant operation is the marginal cost of electricity generation at different hours of the day. The production cost simulation and optimization models will try to dispatch PSH plants as peaking capacity when the marginal costs of electricity generation in the system are high and use the PSH plant as load in pumping mode when the marginal costs of electricity generation are low.[1]

Since the operation of PSH plants as peaking capacity will reduce the need for expensive peaking generating units to operate, PSH operation during peaking hours will significantly

[1] This is similar to the optimization of PSH dispatch in restructured electricity markets, where the locational marginal prices (LMPs) of electricity are the key drivers for the operation of PSH plants.

reduce the cost of electricity generation during those hours. The cost savings during the 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, since pumping energy is 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 taking into account the 20%–25% energy losses due to PSH round-trip cycle efficiency. Therefore, by using a production cost optimization model to simulate system operation with and without the PSH plant, and determining the difference in electricity production costs and the value of PSH generation and pumping between the two cases, the value of PSH energy arbitrage can be estimated.

Key Features and Assumptions

The production cost approach is characterized by the following:

- It requires the use of a sophisticated production cost model with the capability to simulate and optimize the operation of the entire utility system. Variations from the optimization assumption resulting from regulatory or contractual requirements (such as "must run" cases) should be taken into account. In addition, the model needs to be able to properly simulate and optimize the operation of PSH plants.
- It assumes centralized power system optimization and dispatch, thus minimizing the overall production costs of electricity for the system as a whole.
- It is applicable to any size of PSH plant, including potential power upgrade or technology conversion of existing PSH plants.

Modeling Tools

High-resolution production cost simulation and optimization models are preferred for this type of analysis. Applicable tools include PLEXOS (Energy Exemplar), PROMOD (ABB), Aurora (Energy Exemplar), and others. A list of selected production cost simulation models and their key characteristics is provided in Appendix B.

Metrics and Units

- System marginal operating costs ($/MWh)
- Total system operating costs in each time step ($)

Limitations

- The key factor influencing the quality of this valuation approach is how realistically the operation of the PSH plant under consideration and the power system in which it operates can be simulated. This is directly related to the production cost model's ability to simulate the entire time spectrum of scheduling resources to satisfy the energy and reliability needs of the bulk power system. For example, a production cost model with a multi-cycle and multi-timescale can be used to consider intra-hourly plant operations and system dynamics. However, many production cost models simulate system operations on an hourly basis; thus, it does not capture intra-hour price volatilities and scarcity events. In addition, a production cost simulation with an hourly time resolution does not properly reflect the flexible operation capability of PSH. Finally, most commercial production cost

models do not allow for modifications (functional or modeling formulation) to account for unique factors of the study under consideration.
- The analysis is typically performed for a period of one year, rarely for several years. While this approach may provide a good estimate of the value of PSH energy arbitrage for simulated years, it does not provide the value of energy arbitrage over the PSH's lifetime. To estimate the value over the PSH's lifetime, which can be 50 years or longer, a post-analysis projection needs to be made. Projecting the value over the long term is rather uncertain since it depends on the evolution of system plant mix, fuel prices, and many other uncertainties.

Prior Studies
- Most studies that determined the value of energy arbitrage in regulated market environments used the production cost approach. One recent example is the study in Koritarov et al. (2014), which determined production cost savings due to the operation of PSH plants in the Western Interconnection. The study utilized the PLEXOS model to perform a production cost-based simulation of the entire Western Interconnection with and without PSH plants. The difference in results was used to determine the production cost savings that can contribute to the operation of PSH plants. The analysis was performed for existing fixed-speed PSH plants and three potential new adjustable-speed PSH plants (Iowa Hill, Eagle Mountain, and Swan Lake North).

Price-Taker Approach with Perfect Forecast

Methodology Description
The price-taker approach with perfect forecast is the most common method of valuating energy arbitrage that is suitable for small PSH plants (e.g., less than 10 MW) for which a reasonable assumption can be made that their operation will not significantly impact market clearing prices for electricity. In addition, it is assumed that electricity market prices are known in advance using historical price information, so a deterministic optimization of PSH plant operation is performed with perfect foresight. This is obviously the best possible case that would provide maximum energy arbitrage benefits. The actual energy arbitrage benefits that can be expected in the real world PSH operation are likely to be lower. The benefit of using the deterministic price-taker approach is its simplicity of use and design.

The size of the PSH plant that can be considered small enough and suitable for the price-taker approach will vary from market to market. Conceivably, in some large markets, a case can potentially be made that even a 50 MW PSH plant can still be considered relatively small and not able to significantly affect the market prices, therefore rendering it suitable for a price-taker approach.

Key Features and Assumptions
The price-taker with perfect forecast approach is characterized by the following:
- It is typically applicable to small projects, such as batteries and some other types of energy storage, rather than to PSH plants, which are typically larger projects of several hundred megawatts. However, this approach can provide information on an upper bound of potential energy arbitrage value for large PSH plants. In addition, recent trends in the research and development of innovative PSH technologies, including small modular PSH

plants, have the potential to improve the technical and economic feasibility of small PSH projects for which the price-taker approach would be appropriate.

- The perfect price forecast assumption has been given more attention in the literature (see Section 4.2.3), and its impact is well known. The key limitation of such an assumption is the fact that the model assumes perfect foresight of market prices, which is unrealistic. The total energy arbitrage revenues obtained from the model are therefore overestimated as compared to what can be captured in reality. Perfect foresight would be more applicable if storage were dispatched by a market operator (e.g., ISO/RTO), rather than through a bidding process by market participants.

Modeling Tools

Some of the modeling tools that can be used in this approach include StorageVET by EPRI, Energy Storage Computational Tool by Navigant (now Guidehouse), ES-GRID by DNV GL, GridStore by Integral Analytics, BSET by PNNL, and ReEDS by NREL. Further details regarding these tools are found in Appendix B.

Metrics and Units

- Electricity market prices ($/MWh)

Limitations

- Market clearing prices are determined by supply and demand and represent the marginal costs of generating electricity. These prices provide limited insight into the condition of the market and the potential changes that may happen because of the redispatch that would occur with the introduction of new PSH plants or other changes in the system configuration.
- Wholesale electricity market prices may include scarcity pricing, which raises energy prices during shortages. This may distort the energy arbitrage analysis, since in some markets, like ERCOT, scarcity pricing is supposed to provide resource adequacy signals and is a substitute for capacity prices.

Prior Studies

- He et al. (2012) modeled an optimization strategy for energy arbitrage in the day-ahead market. First, they developed a retrospective price forecast method for simulating an arbitrage strategy based on imperfect foresight over market prices. Second, the actions of energy storage were integrated into the market clearing algorithm to establish the final market clearing price. The arbitrage profit calculated as such represents the maximum value that a PSH plant can realize because of the perfect foresight assumption.
- Drury, Denholm, and Sioshansi (2011) developed a co-optimized energy storage dispatch model to characterize the value of providing operating reserves in addition to energy arbitrage in several U.S. markets. The model was used to quantify the added value of providing operating reserves in addition to energy arbitrage. They found that arbitrage-only revenues are unlikely to support an energy storage investment in most market locations, and modifying energy storage design and performance parameters primarily impacts arbitrage revenues. They simulated two storage dispatch methods: (1) dispatch to maximize net revenue from energy arbitrage, and (2) co-optimized dispatch to maximize net revenue from both energy arbitrage and providing contingency reserves.

- He et al. (2011) proposed a model that allows accumulating several services of energy storage in a non-conflicting way and performs a global value assessment of second generation gas-fired CAES plants. The analysis was done for the French electricity market and includes both regulated and deregulated sources of revenue. One of the CAES's value chains is composed of several elements, including arbitraging on the spot market by using the residual capacities of storage after fulfilling the contract with the transmission system operator for the programmed product. Excluding the periods reserved for the programmed product, the storage unit can realize arbitrage profits in the day-ahead market. An arbitrage period is defined as the period between two neighborhood periods reserved for the programmed product. The annual profits from arbitrage in both the day-ahead spot market and the balancing market are obtained through the maximization of two objective functions.
- In PNUCC (2016), the value of energy arbitrage was quantified using a Mid-Columbia wholesale market price forecast. In addition, the hourly and seasonal hydro generation profile was estimated based on a monthly on and off-peak forecast paired with a historical hydro generation profile.

Price-Taker Approach Without Perfect Forecast

Methodology Description

The price-taker approach without perfect forecast utilizes non-deterministic approaches and scenario-based deterministic approaches for production cost simulations and analyses of power system operations. The objective is to propose realistic dispatch strategies without a perfect forecast assumption, that is, facing uncertainty on price levels and potentially on other parameters such as wind forecasts, natural gas prices, demand levels, etc.[1] Like the previous approach in 4.2.2.2, this approach does not take into account the effect that an electricity storage system may have on electricity market clearing prices. The key rationale for the application of this approach is that the perfect forecast approach might not be appropriate in increasingly volatile markets. This valuation approach can use various modeling and simulation methods including stochastic programming, (stochastic) dynamic programming, Monte Carlo simulation, and others.

Key Features and Assumptions

The price-taker approach without perfect forecast is characterized by the following:

- It shares the key features and assumptions of the approach described in Section 4.2.2.2.
- The potential revenues for PSH from energy arbitrage are studied without considering the impact of PSH capacity on the market clearing prices (marginal analysis) while considering imperfect forecasting and uncertainties in the electricity price levels.
- Modeling of uncertainty comes with increased computational complexity and lack of scalability. Scenario-based stochastic simulation, dynamic programming, and Monte Carlo simulation are the most common approaches used in the literature.

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[1] However, it is appropriate to separate the studies dealing with hybrid system (e.g., wind combined with energy storage) from stand-alone energy storage capturing value in different markets.

Modeling Tools

Some of the modeling tools that can be used in this approach, with appropriate modification and ad-hoc analysis, include PROMOD by ABB, PLEXOS and Aurora by Energy Exemplar, GridStore by Integral Analytics, and ReEDS by NREL. Further details on these tools are found in Appendix B.

Metrics and Units

- Electricity market prices in each time step ($/MWh)

Limitations

- The use of stochastic programming divides the time horizon into several stages. At each stage, the energy storage operation is optimized based on several price expectation trends and the expected optimal value for future time stages, introducing recourse in the problem formulation (a scenario tree). The more stages that are introduced, the more energy arbitrage revenues can be captured at the cost of higher computational requirements.
- Dynamic programming (DP) does not have any limitation related to the number of stages, but it does need to limit the number of operation possibilities (actions) at each stage to overcome the curse of dimensionality.[1] A basic prerequisite for DP optimality is that optimization of future actions is not dependent on the past actions. This may not be compatible with power exchange rules in which day-ahead bids are placed.

Prior Studies

- Xi et al. (2013) proposed a stochastic dynamic programming (SDP) model for optimization of distributed energy storage. The paper provides a very clear presentation of the model and of the assumptions used, which could allow replicating their approach. The problem is solved in two stages. First, discretization of exogenous and state variables allows solving the discretized SDP using backward induction, then a mixed-integer program is solved in which the value of the true SDP is approximated. A use case combining several services (energy arbitrage, regulation, and backup capacity) is then studied, using PJM data over one week. The main conclusion of the authors concerns the occurrences of trade-offs between services when they are jointly optimized.
- Keles et al. (2012) propose a modeling framework that includes a deterministic optimization model and a financial mathematical model: the core of the model is still based on an optimization problem with a perfect price forecast, but the procedure is carried out on 1,000 price paths (Monte Carlo simulation), generated by a stochastic process. The authors emphasize that ongoing and further future work should concentrate on the formulation of a stochastic optimization model instead of the time-consuming Monte Carlo simulation.
- Qin et al. (2012) state that the control and optimization of storage in a spot market could, in theory, be assessed through a naive Monte Carlo approach, but that the important number of scenarios needed would imply very high computational time. Estimating the arbitrage value of storage is an important problem in power systems planning. The authors review numerical approaches such as scenario selection, approximate dynamic programming, and parametric linear programming. Then an analytical solution is

[1] The exponential increase in complexity because of additional dimensions or variables.

proposed for the storage operation problem — the optimal control rule compares the current price with a pre-calculated threshold value (formulae are specified) to decide how to buy and to sell.

- Mokrian et. al. (2006) propose several models for optimizing the operation of a storage facility over a 24-hour period. The optimization problem is framed as a linear program, a multi-stage stochastic program, and a dynamic program. Two storage technologies are modeled and analyzed within the separate optimization frameworks.

System Analysis (Price-Influencer) Approach

Methodology Description

The system analysis or price-influencer approach assumes that the operation of a PSH could influence the market clearing prices in the system, so this approach requires an electricity market simulation model to be used. These models aim at simulating the operation of an electricity market and determining the market clearing prices in each time period based on electricity supply and demand. For this reason, the entire power generation value chain—power generation, transmission, and demand—is typically modeled. Models for generation scheduling and transmission power flows can be coupled and include storage in one or several value chain steps, but the objective of these models is not to provide detailed analyses of the transmission grid. Thus, the level of detail for a power flow calculation varies between studies, from a few regions with some interconnection capacity to a detailed node-by-node power flow calculation. On the demand side, power flows and storage dispatch are usually modeled using a zonal representation rather than representing every node and often analyze only one snapshot in time (e.g., peak day). The energy storage dispatch and capabilities on the demand side are typically represented in an aggregate manner, for example by zone, by distribution substation (or feeder), or by customer group. The "downstream" benefits of storage thus always represent some aggregated value (e.g., a representative customer) while the "upstream" benefits can be quantified for a specific asset.

Key Features and Assumptions

The system analysis or price-influencer approach is characterized by the following:

- Optimization of electrical power system operation considering power generation, transmission, and demand for electricity
- Consideration of scenario-based stochastic modeling
- Higher time resolution requirements

Modeling Tools

Tools such as PLEXOS (Energy Exemplar), Aurora (Energy Exemplar), PROMOD (ABB), and FESTIV (NREL) have been used in prior studies. Further details regarding the various features available in these packages and the description of the algorithms used are found in Appendix B.

Metrics and Units

- Market clearing prices of electricity in each time step ($/MWh)

Limitations

- Models can be very complex, non-linear and non-continuous, depending on the constraints that are considered for electricity market simulation.
- The number of variables can increase rapidly, leading to high computational time, often requiring high-performance computing capacity, particularly in stochastic approaches using a high number of scenarios to represent the uncertainty of wind and solar generation, load variability, generating unit outages, etc. This also acts to limit the time resolution and number of time steps that can be effectively simulated based on computational resources.
- The amount of data needed is also an important challenge.

Prior Studies

- In Teng et. al. (2018), the deterministic system planning tool (WeSIM) and stochastic system operation optimization tool advanced stochastic unit commitment are employed for different studies. The approach decouples the planning problem, which considers a large number of snapshots in a year (or multiple years) to determine the impact of certain technologies on the system capacity requirements, from the operational problem, which explicitly considers uncertainty, especially with respect to renewable energy output.
- In Denholm et. al. (2013), the PLEXOS tool is used to conduct the various studies. Storage devices are added to a utility system in the western United States, and the production cost of electricity generation is compared to the same system without the added storage. The studies in the report analyze individually and in combination the potential market value of load shifting/arbitrage and two classes of operating reserve products: regulation reserves and spinning contingency reserves.
- In EPRI (2013), the UPLAN tool is used along with a security-constrained unit commitment and economic dispatch model to quantify the role of hydropower for several future energy scenarios up to 2020. This approach to electric system modeling first estimates the capacity expansion and generation mix, and then runs a production simulation with economic dispatch. The modeling analysis provides an assessment of value derived from hydropower resources in the provision of services such as energy to meet the electricity demand, including the ability to arbitrage energy prices. The hourly model does not, however, capture the benefits of deployment of reserves within the hour.
- Sioshansi et al. (2009) performed research to better understand the value of energy arbitrage for a price taking energy device located in PJM. The research specifically focused on load shifting; however, social welfare was also included in the valuation of the technology.

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4.3. Value of Ancillary Services

Values and costs associated with operations are usually calculated together in that they are very tightly coupled (e.g., the amount of regulation provisioned limits the amount of energy that can be sold). Energy, either directly (e.g., generation) or indirectly (e.g., demand response), can be provided by most assets on the grid, while ancillary services have traditionally been provided by dispatchable resources (e.g., hydro or fossil-fired generation) that are characterized by the ability to vary generation output in timescales necessary for grid support. However, the question of which technologies are allowed to provide ancillary services is in flux; for example, in some areas variable energy resources, including demand response and distributed energy resources, are approved to provide ancillary services. Analysts should confirm the current balancing authority practices and available value streams before starting their valuation work.

What follows is a brief discussion of the types of services that are often modeled when estimating ancillary service values as well as the types of metrics that are often calculated as part of this type of work.

Two approaches to modeling the value of these services are reviewed: system analysis, using detailed production cost models, and price-taker modeling. System production cost modeling is also referred to in valuation studies as the price-maker or price-influencer approach. Since the types of services and metrics used in these two types of evaluations are common across both types of models, this information is presented prior to the discussion on the individual methodological approaches.

In this section, four types of ancillary reserves are discussed:

- Regulation (secondary frequency control)
- Spinning (contingency or tertiary frequency control)
- Non-spinning (supplemental)
- Flexibility (load following)

Similarly, there are two primary metrics by which these ancillary services can be assessed:

- Provision (MW)
- Cost ($)

4.3.1. Methodological Approaches for the Assessment of the Value of Operations

Two methods of estimating ancillary service value are provided—production cost modeling and price-taker modeling—and each has its own benefits and limitations. Production cost models can be used to calculate valuation from both the system and an individual unit's perspective but are complex (and sometimes costly) to implement, while although price-taker models can only be used to calculate revenues from the individual unit perspective, they can provide quick insight as to whether a project would have been financially viable based on historical market prices.

Note that while the section below is written from the perspective of assessing value in a competitive wholesale market, the approach for modeling traditionally regulated vertically integrated markets is similar—both have the challenge of committing slow-to-start generation ahead of time (typically, a day ahead), both need to dispatch fast-start generation in real time, and both are focused on about costs to provide services (energy and ancillary services). Unfortunately, energy and especially ancillary service prices are seldom available for traditionally regulated non-competitive markets, limiting the valuation approach that can be used in these areas to production cost modeling.

Estimation Using Production Cost Model

The methodology described here consists of a simplified two-part approach: security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED). For purposes of discussion, the SCUC model will be referred to as the unit commitment model and the SCED model as the economic dispatch model.

Modeling Approach

The unit commitment model and economic dispatch model can be used together to provide an improved estimate of value streams. These value streams are derived by comparing the results of a model that includes the proposed PSH facility to those of a baseline model that does not include the new facility.

> *Unit commitment model:* As the name implies, the unit commitment model is used to commit slow-starting generation (coal, nuclear, combined cycle) so that slow-starting generation will be available when needed. The model is typically run with an extended look-ahead period to help ensure that slow-starting (and often costly to start) generation is used long enough to make economic sense to start it and so that assets with multi-hour energy storage capability (e.g., pumped storage hydro) can be optimized across interval seams (e.g., across nighttime and into the following morning ramp-up in the case of day-ahead unit commitment modeling).
>
> *Unit commitment hydro modeling:* Hydro modeling should be planned and performed so that it is consistent with interconnection convention. For example, in the Western Interconnection, monthly hydro constraints are used for each major reservoir, and then medium-term optimization software is used to assign daily allocations that are used in the production cost modeling software.
>
> *Unit commitment forecasts:* An added benefit of the two-part production cost model approach is that it can be used to estimate the value that storage can provide in mitigating load and variable generation-related forecast errors. For example, load forecasts are helpful in estimates of the value of grid-connected storage in areas where there is a significant amount of behind-the-meter generation, and they should be used when available. If load forecasts are not available, current best practice is to use a perfect forecast (i.e., use the load actuals as if the actuals were the forecast), noting that the final simulation results will overestimate the value that storage will provide to the system; that

is, load variability and storage's ability to mitigate load variability-related effects will not be captured.

Similarly, the use of variable generation (e.g., wind and solar) forecasts can help stakeholders better understand the value of storage for integrating variable renewable assets into the grid. On their website, NREL provides hourly resolution, day-ahead forecasts (and 6-, 4-, 3-, 2-, and 1-hour ahead forecasts) and 5-minute resolution real-time data for wind and solar PV to help simplify this task (please see the Resources section below for the web addresses of the wind and solar toolkits).

Economic dispatch model (typically 5-minute resolution): Unit commitments for slow-starting, fossil-fired generation (coal, nuclear, combined cycle) are typically passed from the unit commitment model results (i.e., their operational status as to whether they are on or off is determined in the unit commitment model), and these commitments determine which low-cost, slow-start generation is available for dispatch. Other, faster-start generation, such as combustion turbine-based technologies, is both started and dispatched in the economic dispatch model.

Economic dispatch hydro modeling: Hydro is dispatched according to local convention. For example, in some areas, hydro dispatch is fixed in the unit commitment model, and in others it is dispatched in real time.

Pumped storage hydro can be dispatched in in multiple ways. Two of the more common are:

- Fix the dispatch (and pumping) levels to those that were calculated in the unit commitment.
- Dispatch (and recharge) the pumped storage hydro based on how real-time energy prices compare with the prices predicted in the unit commitment model: If the real-time prices are much lower than what was predicted in the unit commitment, pump rather than generate, and if prices are much higher, generate rather than pump.

Model Design

This section highlights the main aspects of model design. For additional information, please see the Prior Studies section below, especially Lew (2013).

Capacity constraints: In balancing areas where capacity constraints are based on generation being available at designated times, those constraints should be entered into both the unit commitment and real-time models.

Reserves provisioning: Where the reserves provisioning mechanisms for the area of study are known, use those mechanisms in the modeling work. Where the provisioning mechanisms are not known, a reasonable starting point for areas with low to moderate amounts of variable generation is 1% of instantaneous load for regulation, 3% of load for contingency (spinning) reserves, and 3% of load for supplemental (non-spinning) reserves. For areas with significant amounts of variable generation, better results (e.g., less unserved energy) can be achieved by adding flex reserves and by modifying the regulation methodology so that it includes a term for the ten-minute variability of the variable generation (Lew 2013).

Key features and assumptions: The key feature of the production cost modeling approach is that it provides a time series of operating metric estimates for both unit commitment and dispatch operations. These estimates can be extremely valuable in assessing cost savings (and associated valuation) in a variety of operation conditions. Typically, a baseline scenario is configured (e.g., the existing system), and other scenarios (e.g., the existing system with the addition of the storage asset) are compared to the baseline. By comparing the cost differences among various scenarios (as well as other parameters such as curtailment and emissions), the relative value of a storage device can be determined.

The primary assumption in current production cost models is that DC power flow provides an accurate estimate of actual power flows. While this assumption has limited impact on operating costs, inaccuracies associated with this assumption can significantly affect the model's ability to provide accurate price predictions and transmission flows at the nodal level. Also important is that production cost models operate on the assumption that generator operation can be modeled by piece-wise linear approximations.

Limitations
In order to solve larger models (e.g., interconnection-wide) in a reasonable period of time, transmission constraints are usually not enforced below a threshold (e.g., 69 kV).

Modeling Tools
Numerous production cost modeling tools are available in the marketplace. Some examples include GridView (ABB), PROMOD (ABB), Aurora (Energy Exemplar), PLEXOS (Energy Exemplar), Multi Area Production Simulation Software program (GE MAPS; GE), and Power System Optimizer (Polaris Systems Optimization).

When deciding which tool to use, it is essential to find one that provides sub-hourly simulations (typically 5-minute). Hourly simulations, while often adequate for system-wide questions, can miss some of the value that is provided by an individual storage asset in areas with high amounts of variable generation. More details on the characteristics of various modeling tools are provided in Appendix B.

Resources
For forward-looking studies that assess how storage performs in areas with increased variable generation, the National Renewable Energy Laboratory provides the following tools:

- NREL WIND Toolkit (https://www.nrel.gov/grid/wind-toolkit.html) — provides wind power forecasts and real-time power data
- NREL SIND Toolkit (https://www.nrel.gov/grid/solar-integration-data.html) — provides solar power forecasts and real-time power data

The WIND Toolkit provides nationwide estimates of wind power on a two-kilometer grid with 5-minute resolutions. Wind data is provided for seven exemplar years. Day-ahead as well as sub-day (e.g., four-hour ahead) forecasts are also provided.

The SIND toolkit development work is currently in progress, with data and features similar to that described for the WIND Toolkit.

Prior Studies

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Estimation Using Price-Taker Model

Price-taker models optimize a plant's operations across energy and ancillary services to maximize the plant's net revenues. To do so, price-taker models are based on the assumption that a plant's operations does not affect system energy and ancillary service prices, allowing the models to use exogenous price time series, such as historic prices. This assumption holds better for larger power systems and smaller power plants, as smaller plants' operations have limited effects on market prices.

For larger storage plants (those that are large enough to impact market prices), the price-taker model provides an upper bound on revenues, with actual revenues expected to be lower and pumping costs higher.

Because price-taker models optimize operations against a price signal, they are better suited for analyses in competitive wholesale electricity markets. In these markets, storage plant operations are driven by their own and other plants' bids, which are closely related to marginal costs and which set electricity prices. For vertically integrated utilities outside the competitive market regions, the same market dynamics do not exist, so a plant's value is better determined with another model, such as a production cost model. However, in vertically integrated utilities, a hybrid approach that combines a production cost model and a price-taker model is possible, as discussed below.

Modeling Approach

Four major modeling decisions must be made for a price-taker model: (1) the services the plant will provide, (2) the electricity markets it will participate in, (3) whether the model assumes perfect or imperfect foresight of prices, and (4) the source from which prices are obtained.

> *Provided services:* In addition to electricity generation, the main types of services relevant to a price-taker model for ancillary services include regulation, spinning, non-spinning, and, in some markets, flexibility reserves. To provide regulation, spinning, and flexibility reserves, pumped hydropower plants must be “online,” i.e., either generating electricity, pumping, or idling (e.g., in a condensing mode of operation). Consequently, reserve provision in a price-taker model also requires optimizing electricity generation.
>
> Compensation schemes vary among services, and price-taker models should capture those differences. Compensation for regulation provision poses a special challenge. Under FERC Order 755 (2011), all ISO and RTO-run regulation markets (except ERCOT) have “pay for performance” rules, meaning regulation compensation consists of capacity and mileage payments and varies with a unit’s performance in following the regulation AGC signal. Capacity indicates the total MW of regulation reserves provided by a unit, and mileage quantifies the absolute value of the total change in each unit’s response to the regulation AGC signal. How markets quantify mileage and a unit’s performance varies among markets. Yu et al. (2016) provide a discussion of regulation modeling approaches for several of the more common U.S.-based regulation markets as of early 2016. In most markets, provision of energy and other ancillary services are compensated based only on the energy or ancillary service price in the relevant time period.
>
> Finally, price-taker models should reflect changes in state-of-charge (SOC) due to provision of ancillary services. This is less important for spinning and non-spinning reserves, which are deployed in contingency situations (e.g., unexpected generation or transmission outages), than for regulation and flexibility reserves, which are frequently deployed. The total change in the \a storage device’s SOC due to regulation provision will depend on the AGC signal for that time period, which is rarely published (PJM being a notable exception). In the absence of real signal data, an assumption must be made regarding the net loss in SOC per unit of regulation capacity provided. The price-taker model should then be run across different assumed values to test the sensitivity of the results.
>
> *Market participation:* Competitive wholesale electricity markets run several markets each day, including a day-ahead and one or more real-time markets. PSH plants can participate in all these energy markets, based on financial settlement rules, although day-ahead ancillary services are typically treated as physical commitments. Price-taker models can be applied to both markets, but special caveats pertain to the real-time markets, which are thin markets as they only provide for limited balancing of deviations from the day-ahead schedules. In both cases, the price-taker model should be run with a look-ahead period (e.g., 24 hours and 1 hour for day-ahead and real-time markets, respectively) to capture the value of storing energy beyond the optimization period.

To run a price-taker model for the day-ahead market, the day-ahead price time series for each selected service (see prior section) must be input to the model. The model runs for a single day (plus a look-ahead period), then rolls forward a day. To run a price-taker model for the real-time market, two special considerations apply. First, in ISOs and RTOs with capacity obligations, all capacity resources must offer into the day-ahead market, so skipping this market is not an option. Second, in areas where there is the option to skip the day-ahead market, and a generator elects to participate only in the real-time market, real-time prices are more volatile and uncertain than day-ahead prices.

To account for these considerations, day-ahead and real-time operations can be either sequentially or simultaneously optimized, although this is rarely done in storage valuation studies. In the sequential approach, the price-taker model optimizes generator operations against day-ahead prices, and then uses remaining capacity, if any, in the real-time market, while respecting committed day-ahead energy and ancillary services. In the simultaneous approach, the price-taker model optimizes across day-ahead and real-time prices concurrently. However, given the volatility and uncertainty of real-time prices, significant caution should be used when interpreting price-taker model results against real-time price time series, because optimizing across historic prices can significantly overestimate actual revenues. For the same reason, we caution against running a price-taker model run directly on real-time prices to optimize operations assuming real-time market participation only. Instead, we recommend using forecasted real-time prices (e.g., those obtained through a price forecasting algorithm) in the price-taker model, as explained in the next section.

Perfect versus imperfect foresight: A price-taker model can assume perfect or imperfect foresight of electricity prices. In the perfect foresight assumption, the model optimizes operations of the power plant for the input time series of prices without heuristics. To capture imperfect foresight, two options exist. First, the model can determine operations using a set of price-based heuristics: The unit should pump if prices are below certain level and provide services if prices exceed certain level. Second, a price forecasting algorithm (separate from the price-taker model) can forecast prices. The price-taker model can optimize operations against those prices, and then remuneration can be determined with the actual (i.e., historic) prices. This method approximates real-world operations in which generators submit bids based on their expectation of future prices, and then are compensated based on market-clearing prices. Perfect foresight does not exist in reality, so assuming it will tend to overestimate potential real-world revenues.

Source of prices: Price-taker models require an exogenous time series of energy and ancillary service prices. These prices can either be historic observed data or be generated using another model or series of models. Historic observational data, e.g., published energy and ancillary service prices from ISOs and RTOs, provide the best estimate of how a facility would have operated in the past and how it would have been paid for those operations. However, such operations and compensation have limited applicability to the future, and increasingly limited applicability the further out in time the future extends. Consequently, an alternative source of price time series is needed to generate prices. One option is to generate them using a production cost model that can simulate power system operations in the future or power systems without historic prices (e.g., vertically integrated utilities). However, production cost models often do not accurately capture prices. Thus, several caveats apply to using production cost model outputs in a price-taker model. First, prices from the production cost model should be validated against historic data by running the model for a historic period. The validation can not only indicate the general accuracy of the production cost model in estimating prices, but can indicate whether the production cost model performs poorly in certain ways, such as missing high price periods that are particularly valuable to facilities. Second, depending on the results of the validation, statistical analysis can be used to better align the production cost model outputs with historic prices and then applied to subsequent production cost model runs. Standard good practice in statistical analysis applies, such as using out-of-sample testing and selecting an appropriate statistical model. Third, based on the results of the first two steps, care should be taken in interpreting the price-taker model results when run on production cost model prices, and the limitations of the approach should be clearly communicated.

Model Constraints

In addition to the above model design issues, two key types of constraints that should be included in price-taker models are capacity and reserve provision constraints.

If the plant provides capacity to the system, such as through a contractual agreement or a capacity market, that capacity requirement should be enforced in the price-taker model. To enforce the requirement, the plant's capacity that is available to participate in day-ahead and real-time markets should be reduced by its capacity commitment. Time periods in which capacity commitments are triggered vary by system, but typically correspond to peak load periods.

When the reserves provisioning mechanisms for the area under study are known, use those mechanisms in the modeling work. For instance, reserves in a given balancing area are typically distributed over multiple assets; therefore, a constraint for the maximum amount of reserves that the unit under study can provide should be entered into the model (e.g., up to 10% of a machine's capacity can be used for regulation). Additionally, to strengthen the assumption that a plant's operation does not affect reserve prices, constraints should limit the reserves provided by the plant to a fraction of the total system reserve requirement. Constraints should also limit reserves provided by the plant to the plant's reserve provision capabilities over the reserve timeframe.

Key Features and Assumptions

The key feature of the price-taker approach is that it can provide a quick estimate of the potential revenues for storage project if prices for the area of interest are known and the size of the project is such that it is unlikely to affect local energy and ancillary services prices. Additionally, like production cost models, price-taker models can be used to test the sensitivity of net revenues and operations to plant design and operational parameters, such as wet, typical, and dry hydrological years, variable O&M cost, and energy storage capacity.

The main assumption underlying price taker models is that the plant's operations do not affect market prices. This assumption holds better for smaller plants and for market products with large volumes and shallow or flat supply curves. Such products include electricity in off-peak hours and reserves with large requirements. In peak electricity demand periods and for reserves with small requirements, though, small supply changes can result in large price changes, so results driven by revenues obtained in a very small number of hours should be regarded carefully.

Price-taker models are linear models, so plants' operations must be able to be accurately represented with convex, piecewise linear functions. Increasing the number of linear segments in the piecewise linear approximation can improve the approximations' accuracy.

Limitations

Price-taker models have several limitations. First, due to the underlying assumption that the facility operates in response to price signals only, price-taker models are more applicable to areas with market-clearing prices, e.g., competitive wholesale electricity markets. As discussed above and in the next paragraph, they can be run in other areas, e.g., in vertically integrated utilities, using a hybrid approach combining a production cost and price-taker model. However, in these situations, it is important to note that prices from the production cost model do not necessarily indicate remuneration but signal scarcity, which in turn drives the facility's operations.

A second limitation is that price-taker models require an exogenous time series of prices. Consequently, they can only be run for regions with a historic or generated price time series. This means that to estimate revenues in the future or in regions without electricity prices (e.g., in vertically integrated utilities) using a price-taker model, either another model must first create a time series of prices or, in the case of future prices, historic prices must be assumed to be indicative of future prices. The latter assumption is increasingly tenuous, though, due to rapid changes in the composition of the electric power sector nationwide and other key uncertainties, such as natural gas prices. The former approach, using another model to generate future prices, is typically done with a production cost model. However, production cost models do not accurately reproduce historic market prices, particularly peak price periods, so their output should be first validated against historic prices and used with caution, based on the results of the validation.

Third, price-taker models more accurately estimate revenues when more support exists for the assumption that the plants' operations do not affect system prices. As discussed in the prior section, this assumption is stronger for large power systems and small power plants.

Modeling Tools

A common approach for price-taker modeling is to build the models using either an open source or commercially available mixed-integer linear programming environment. A few of the software packages are General Algebraic Modeling System (GAMS; GAMS Development Corporation), juMP/Julia/ (NumFOCUS) and Pyomo (Center for Computing Research at Sandia National Laboratories).

4.3.2. References

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Yu, B., Y. Dvorkin, D. Kirschen, C. Silva-Monroy, and J-P Watson. 2016. A Comparison of Policies on the Participation of Storage in U.S. Frequency Regulation Markets. Presented at 2016 IEEE Power and Energy Society General Meeting (PESGM), Boston, MA. https://doi.org/10.1109/PESGM.2016.7741531.4.4

4.4. Value of Black Start Service

A black start is the process of restoring an electric power station or a part of an electric grid without relying on the external power transmission network. Black starts often follow a severe system event causing a blackout of certain parts of the grid. In normal grid operation, it is possible to provide the requisite energy to start up the onsite electric generators by drawing power from the grid through the plant's transmission line. However during a wide area outage, off-site power from the broader grid is unavailable to enable the start-up, and therefore energy to restart the broader grid must be provided in a systematic way via individual plants that are capable of providing the necessary power to electrify themselves. NERC defines a “black start resource” as “A generating unit(s) and its associated set of equipment which has the ability to be started without support from the system or is designed to remain energized without connection to the remainder of the system, with the ability to energize a bus, meeting the transmission operator’s restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the transmission operator’s restoration plan” (NERC 2018). Previous studies have revealed that power systems can benefit from new black start generators to reduce the restoration time. There is, however, a point beyond which system restoration time cannot be further reduced, even with additional black start capability.

In order to provide black start service, power stations are equipped with small diesel generators, called black start diesel generators (BSDG), which can be used to start larger generators. Hydroelectric power plants are prime candidates to be black start resources given their relatively small start up power requirements to (enough to energize controls, communications and relays and to open intake gates and provide excitation current to the generator field coils) and their ability to provide a substantial block of power on line in minutes. This can be compared to other sources of generation, such as coal or nuclear stations, which not only require a significant start-up level of energy but also have a significant cold start-up period.

The advantageous characteristics of hydropower which make it an attractive black start resource can also be found in other sources of generation (primarily diesel generators, combustion turbines, and combined cycle turbines). This similarity in black start performance can be observed in both their similar ramping rate (15%, 20%, 20%, and 8% of full load per minute for hydropower, diesel, combustion turbine and combined cycle units, respectively) and in the generating availability data system (GADS), which lists hydropower, natural gas and oil generation as providing over 90% of the listed black start availability (by plant). Hydropower has the advantages of a relatively fast ramping capability and a generally larger size. Further specifics on black start dynamics, timing and energizing requirements can be found in Garcia et al. 2019, Gonzalez-Salazar, Kirsten, and Prchlik 2018, Qiu et al. 2016, and Sun, Liu, and Zhang 2011.

It should be noted that due to the national security nature of black start generation, there are both strict performance requirements for black start designated units and limited information about the amount and characteristics of black start designated units. A series of national level black start NERC requirements, in their Emergency Preparedness and Operations standards (EOP-005-03), place a series of reliability obligations on transmission operators to ensure black start preparedness rather than providing a prescriptive series of actions. These national level requirements are typically supplemented with additional requirements based on the transmission operator's specific needs. The only publicly available data on black start generation can be collected from the GADS database by querying cause code 9998. This is intentionally left vague to ensure confidentiality by keeping disclosed data at a high regional level and omitting the number of plants in a region when that number is below a specific threshold.

The next sections provide an overview of black start service compensation mechanisms in both regulated and restructured markets in the U.S.

4.4.1. Traditionally Regulated Markets

Regulatory context strongly shapes how different systems procure black start services. Vertically integrated utilities in the U.S. primarily use administrative tools such as bilateral contracts, requests for proposals (RFPs), and internal acquisitions to procure the black start services they need to balance supply and demand and maintain grid reliability.

- An RFP is a document through which the utility company or an agency interested in the procurement of black start service solicits business proposals, often made through a bidding process, from potential suppliers. It is submitted early in the procurement cycle, either at the preliminary study stage or the procurement stage. An RFP is used when the request requires technical expertise and or specialized capability, or when the service being requested does not yet exist, and the proposal may require research and development to create it.
- A bilateral contract is a reciprocal arrangement between two parties (utility company and black start service provider) by which each promises to perform an act in exchange for the other party's act. Each party is both an obligor (a person who is bound to another) to its own promise, and an obligee (a person to whom another is obligated or bound) on the other party's promise. For one of these contracts to be legally binding, there must be some sort of record that all parties agreed to the terms. This usually takes the form of a signed contract.

If the utility company is not willing to sign a bilateral contract for black start service after going through an RFP process, it usually designates certain generating units from its own fleet as black start units, assuming that they have such capabilities. This is referred to as internal acquisition of black start service.

4.4.2. Organized Wholesale Markets

The appropriate way to estimate the value of black start service in a restructured market is to evaluate the compensation procedure provided by the appropriate RTO or ISO. In general, there are three types of payment mechanisms: cost-of-service payment, flat rate payment, and payment through competitive bidding. PJM, MISO, CAISO and NYISO (units not in the ConEd territory) utilize the cost-of-service type of compensation. Black start units that participate in ISO-NE and the ConEd part of NYISO receive compensation related to a flat rate and the claimed capacity. In ERCOT, black start units are paid an hourly standby fee, which is determined through a competitive bi-annual bidding process. The black start compensation in SPP is not presented in this document since it is not procured through SPP.

4.4.3. Methodological Approaches to the Assessment of Value of Black Start Service in Traditionally Regulated Markets

In traditionally regulated electricity markets in the U.S., procurement of black start service and associated compensation is usually carried out via internal acquisitions, RFPs, and bilateral contracts. The following sections present a more detailed overview of these procurement methods. Note that these approaches require significant insight into regulated market owners and therefore may be prohibitively difficult to perform. However, cost-of-service estimations (outlined in Section 4.4.4) can provide a reasonable indication of the cost to provide black start capabilities, and there is broad industry acceptance of that methodology.

Internal Acquisition

A vertically integrated utility company may opt not to procure black start services from external organizations by going through an RFP process and subsequently signing a bilateral contract with one or multiple entities (e.g., IPPs). Instead, they opt for internal acquisition of black start service: assigning specific generating units from the company's own fleet to provide black start service. The utility must ensure that black start capable units fulfill the various organization-specific technical requirements before starting operation.

Modeling Tools

Commercial tools are not required for evaluating black start service compensation since it is procured within the company.

Metrics and Units

The only relevant metric is the total available black start capacity provided by designated units compared to the needs of the transmission operator to meet critical loads and energize the grid. Metrics associated with black start compensation are not relevant since the service is procured internally.

Limitations

The black start service is provided using internal resources, i.e., company-owned black start capable generating units, which may present a limited set of options.

Request for Proposal and Bilateral Contract

A utility company can create a plan to incrementally request a specific capacity of black start generation over a future time period. Several companies, such as Dominion Energy in Virginia, use the RTO/ISO's (PJM in this case) black start replacement process to solicit additional black start generation to ensure a resilient and robust ability to meet black start and restoration requirements (Dominion Energy 2012). The RTO/ISO will work with the utility company to determine future black start capacity needs and post an RFP for black start service.

Once a set of potential black start service providers has been selected in the RFP process, the company and one or more generation companies (and/or its subcontractors) can sign one or more bilateral contracts for provision of black start services from specific dates. Such contracts will also include information on the location of the two parties in the U.S., specific details regarding the type of ancillary service that is to be provided, term of contract and the capabilities of the generating units to be able to provide the service.

Methodology Description

In collaboration with the RTO/ISO, the utility company typically initiates the RFP process for black start service procurement, which consists of the following tasks:

1. *Develop technical requirements for request for proposal:* The ISO/RTO will coordinate technical requirements for the RFP with transmission owners (TOs), including MW requirements, mega volt amperes reactive (MVAr) capability, and geographic details.

2. *Issue RFP for resources interested in supplying new black start service*: The ISO/RTO will post the black start RFP on their website with notifications to the appropriate stakeholder groups. Interested bidders will review the content guidelines posted on the webpage. The RFP notification will also advise that all bids submitted for black start resources must be cost-based bids consistent with the ISO/RTO's schedule.

3. *RFP proposal evaluation*: The ISO/RTO will work with the TOs to evaluate proposals and select viable black start solutions based on critical load requirements identified by location, cost and operational considerations (amount, start time, etc.). Units on a cost recovery rate would automatically be selected for the length of the recovery period. Units on bilateral contracts with TOs would be automatically selected for use in those zones. The ISO/RTO works in collaboration with TOs to select black start solutions for each zone in accordance with the specific criteria. Preferred black start solutions typically include units located in close proximity (from a transmission topology perspective) to defined critical loads, which are loads to support quicker starting combined-cycle units, nuclear safe shutdown loads, and electric-powered gas compressor stations. In addition, RFP proposals for natural gas black start units with dual fuel capability and/or primary firm gas transportation contracts will be given a higher level of consideration in the RFP evaluation process. If the proposals received do not satisfactorily meet the fuel assurance criteria outlined below, the ISO/RTO will request that the resource owners resubmit proposals with adequate demonstration of dual fuel capability and/or primary firm gas transportation contracts (for natural gas units).

1 Technical feasibility
  a. Reliability analysis/NERC EOP-005 studies
  b. Unit location/characteristics
  c. Operational/environmental restrictions
  d. Black start testing requirements

2 Fuel assurance
  a. Fuel type/fuel diversity
  b. Dual fuel capability/availability, including logistics assessment
  c. Onsite fuel storage
  d. Primary firm gas transportation contract vs. secondary firm or interruptible gas contract, single vs. multiple gas pipeline access

3 Cost/schedule
  a. Annual revenue requirements (capital costs, net present value comparison)
  b. Black start commitment period (20, 15, 10, or 5 years)
  c. Cost recovery method: base formula rate, NERC critical infrastructure protection (CIP) rate, capital recovery factor rate, FERC rate
  d. Proposed black start service date to requested in-service date

4. Verify feasibility of black start units selected: The ISO/RTO, with TO input, will identify black start cranking paths and black start units to source critical loads. The RTO, with TO input, will perform dynamic simulations and reactive/voltage studies on cranking paths, and if issues are identified on cranking paths that would prevent a potential black start unit from performing in accordance with appropriate manuals, other black start units will be considered.

5. Review of cost recovery components: The RTO will perform cost evaluation for each option and review cost recovery components provided for proposed black start solutions in accordance with appropriate schedules. Length of commitment would remain a minimum of two years (or longer based on capital recovery time). Separate compensation schedules and regulations may exist for units electing and not electing to recover black start capital costs. Black start unit owners may also choose to file for recovery of actual costs directly with FERC.

In collaboration with the RTO/ISO, the utility company and black start service provider(s) must subsequently complete the following key sections of the black start service procurement agreement:

- *Details regarding provision of the ancillary service:* Information on the facilities that the black start service provider will utilize as part of the agreement, steps to be undertaken to improve the operational efficiency of those facilities along with repair and maintenance, utility company's right to enter the facilities if the black start service provider fails to adequately maintain and repair the facilities, and so on.
- *Term of contract:* Information regarding effective date and termination date of the contract.
- *Termination:* Information on the methods of terminating the contract (expiration, cancellation or by any other mode mutually agreed on by the parties).

- *Personnel:* Information on the employees, contractors and/or subcontractors working for the black start service provider and the rights of the utility company to revoke the authorization of personnel if applicable laws and regulations are violated.
- *Access to the facilities:* Information on parts of the facilities that are accessible to the black start service provider, and maintenance work to be performed by the utility company and the service provider in the event of any damage to the roads.
- *Compensation, invoicing, and payment:* Information on monthly or annual compensation to be paid to the black start service provider. It also consists of rules for generating the invoice and payment of black start service provider's compensation for the ancillary service.
- *Use or storage of hazardous material:* Rules for storage and disposal of hazardous material and penalties or fines imposed on the black start service provider if any rule is violated.
- *Utilities and other services:* Information on whether the utility company agrees to provide electricity, water, and other utilities required only for the provision of the ancillary services.
- *Permits and licenses:* Information on whether both parties should obtain and maintain all licenses, permits, rights, variances, or other approvals during the term of the agreement.
- *Insurance:* Steps to be taken by the black start service provider to obtain and maintain insurance policies and coverage for its employees, contractors, and subcontractors as required under the agreement.
- *Regulatory changes:* Specifies that if a governmental agency has the authority to regulate the charges for and conditions of the performance of the ancillary services as described, or acquires such authority in the future, the agreement is subject to regulation by that governmental agency. In that event, the agreement between the two parties will be modified only to the extent necessary to comply with the regulations.
- *Modification:* Any amendment or modification of the agreement will be invalid unless in writing and executed by the duly authorized representatives of both parties.
- *Order of precedence:* Information about the parts of the agreement which will have precedence if there is any conflict between the terms and conditions of the agreement and any other related agreement.

Modeling Tools
Commercial tools are not required for evaluating the black start service compensation in the electricity market: Utility analysts and experts follow the procedure outlined in the Methodology Description section to select black start services from the submitted proposals, and bilateral contract(s) that include compensation will be signed.

Metrics and Units
Black start compensation comprises various costs expressed in terms of U.S. dollars. Other metrics are related to MW requirements, reactive power capability and average hourly availability requirements of the selected black start units.

Prior Studies
Following are examples of how companies in the U.S. have used this method for procurement of black start services.

- *RTO-Wide Five-Year Selection Process—Request for Proposal for Black Start Service.* 2018. http://www.pjm.com/-/media/markets-ops/ancillary/black-start-service/pjm-2018-rto-wide-black-start-rfp.ashx?la=en.
- *PJM Manual 14D: Generator Operational Requirements Revision: 44*. 2018. http://www.pjm.com/-/media/documents/manuals/m14d.ashx.
- *National Grid Black Start Procurement Guidelines Version Number: 16.0.* 2018. https://www.nationalgrid.com/sites/default/files/documents/Procurement%20Guidelines%20v16_Effective%20from%201%20April%202018.pdf.
- *Dominion Energy—Application, Appendix, DEQ Supplement, Direct Testimony and Exhibits of Virginia Electric and Power Company.* 2012. https://www.dominionenergy.com/library/domcom/media/about-us/electric-projects/power-line-projects/surry-skiffes-creek/surry-volume-i.pdf.
- *Bilateral contract signed between Dominion Energy in Virginia and Alliance Coal, LLC in Delaware for the provision of ancillary services.* 2007. https://www.sec.gov/Archives/edgar/data/1086600/000119312505131991/dex102.htm.

4.4.4. Methodological Approaches for the Assessment of Value of Black Start Service in Wholesale Electricity Markets

The black start service compensation mechanisms in wholesale electricity markets are generally of three types: cost-of-service, used by PJM, MISO, CAISO and NYISO black start units not participating in the ConEd Plan, flat rate, used by ISO-NE and NYISO black start units participating in the ConEd Plan, and competitive bidding process, used by ERCOT. The following sections present a more detailed overview of each of these black start procurement methods.

Cost-of-Service Compensation Approach

Cost-of-service is the most common approach used by some ISOs/RTOs in the U.S., since it is the simplest and the traditional method. In this approach, a black start generator's annual revenue requirement is generally equal to a specific percentage of the sum of a combination of cost components. Such cost components include the fixed black start service cost, variable black start service cost, training cost, fuel storage cost, compliance cost, fixed operation and maintenance cost, and costs associated with black start capability tests (EPRI 2016).

Methodology Description

The procedures for evaluating black start compensation in the U.S. electricity markets that employ this approach follow:

PJM

According to PJM (2017), "A black start unit owner's annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider Bill for Black Start Service charges and credits."

In the PJM area, black start services are not acquired through a market mechanism, and according to PJM Manual 27, “Each generation owner of black start units that meet the PJM and NERC criteria, receives a monthly black start service credit equal to one-twelfth (1/12) of its annual black start revenue requirement. Revenue requirements for black start service may include the following, where applicable: NERC CIP Capital Costs, Fixed Black Start Unit Costs, Variable Black Start Costs, Training Expenses, Fuel Storage Costs for liquefied natural gas, propane or oil and an incentive factor. Revenue requirements for units with the ability to disconnect from the grid automatically and remain operating at reduced levels (ALR) may only recover Training Costs, NERC Compliance Costs, and an Incentive Factor” (PJM 2018).

According to PJM Open Access Transmission Tariff Schedule 6A, the formula for calculating a generator’s annual black start service revenue requirement is (PJM 2017):

$$\{(Fixed\ BSSC) + (Variable\ BSSC) + (Training\ Costs) + (Fuel\ Storage\ Costs)\} \times (1 + Z)$$

Where $Fixed\ BSSC$ is the fixed black start service cost, $Variable\ BSSC$ is the variable black start service cost and Z is an incentive factor.

For units that have the demonstrated the ability to operate at reduced levels when automatically disconnected from the grid, the annual black start service revenue requirement becomes the following:

$$(Training\ Costs) \times (1 + Z)$$

More details can be found in *PJM Open Access Transmission Tariff Schedule 6A*.

MISO

According to MISO (2016), “Compensation for black start service is based on the annual revenue requirements associated with each black start unit. In accordance with Schedule 33, Section V of the Tariff, a black start unit owner possesses the unilateral right under Section 205 of the Federal Power Act to file to establish or revise its annual cost-based revenue requirement for the provision of black start service. The black start unit owner or transmission operator is thus responsible for making all appropriate filings with FERC, which shall then determine whether such revenue requirement is just and reasonable.”

In the MISO area, the transmission provider pays 1/12 of the black start unit owner’s annual revenue requirement. According to MISO FERC Electric Tariff Schedule 33, the annual revenue requirement is the sum of the following three elements: fixed black start service costs, variable black start service costs and training and compliance costs (MISO 2014). As stated in MISO (2014):

> Fixed Black Start Service Costs shall include the annual amortized fixed costs that a black start unit owner incurs to be able to provide black start service. If the transmission operator terminates a black start unit’s designation pursuant to Section II (and the black start equipment was installed in response to a request

> by a transmission operator to provide black start service under this tariff), the black start unit owner shall be entitled, upon termination, to full recovery over a ten year period of any unamortized fixed capital costs (including its financing costs of capital), that the black start unit owner invested in the black start equipment. A terminated black start unit shall provide information regarding fixed costs to the transmission provider consistent with information filed with the commission in support of its revenue requirements.
>
> Variable Black Start Service Costs: shall include the reasonable operating, maintenance and costs to maintain sufficient fuel inventory that can be attributed to supporting black start service for a black start unit.
>
> Training and Compliance Costs: shall include those training and compliance costs that are reasonably incurred to enable a black start unit owner's employees to efficiently operate the black start service capabilities of the black start unit, including costs incurred to comply with NERC reliability standards applicable to black start units such as, but not limited to, Critical Infrastructure Protection standards (MISO 2014).

CAISO

According to CAISO (2017), "The black start generator will file with the FERC in rates the following categories of incremental costs expected to be incurred for the provision of black start service to the CAISO and Participating Transmission Owners (PTOs). The filed rates will be reflected in Schedule 5 of this Agreement. The black start generator will be compensated as per Section 11 of the CAISO Tariff and applicable CAISO Business Practice Manuals."

According to the CAISO Black Start Service Agreement, the compensation to black start generators includes the fixed black start service costs, variable black start service costs, and training and compliance costs. The following description is from the CAISO sample black start agreement (CAISO 2017);

> Compensation to Black Start Generator. The black start generator will file with the FERC in rates the following categories of incremental costs expected to be incurred for the provision of black start service to the CAISO and PTO. The filed rates will be reflected in Schedule 5 of this agreement. The black start generator will be compensated as per Section 11 of the CAISO Tariff and applicable CAISO Business Practice Manuals.
>
> Fixed Black Start Service Costs: shall include the annual amortized incremental fixed costs that a black start generator incurs to be able to provide black start service. If the CAISO and PTO terminates the agreement pursuant to Section 2.3.3 and the black start generating unit was established as required by this agreement for the purpose of providing black start service under the CAISO Tariff, the black start generator shall be entitled, upon termination, to full recovery over a five (5) year period of any unamortized Fixed Capital Costs (including its financing costs of capital), that the black start generator invested in the black start generating unit. Upon termination, the black start generator shall provide information regarding fixed costs to the CAISO and

PTO consistent with information filed with the FERC in support of its revenue requirements, to support recovery of unamortized capital costs.

Variable Black Start Service Costs: shall include the reasonable incremental operating costs, maintenance costs, and costs to maintain sufficient fuel inventory that can be attributed to supporting black start service for a black start generating unit.

Training and Compliance Costs: shall include those training and compliance costs that are reasonably incurred to enable the black start generator's employees to efficiently operate the black start service capabilities of the black start generating unit, including costs incurred to comply with applicable reliability criteria such as, but not limited to, Critical Infrastructure Protection reliability standard requirements.

NYISO (Bulk Power System Restoration or Transmission Districts Other Than ConEd)

In the NYISO area, the black start capability service settlement for generators providing black start and restoration services are different in the NYISO and TOs' plans and in the ConEd Plan. According to the NYISO Accounting and Billing Manual, payments are calculated as follows (NYISO 2016).

$$\sum_{N_m}^{N} \{(BSOM_{ga} + BSTN_{ga} + BSTS_{ga}) \div N_y\}$$

Where:

N_y = Number of days in the previous year (May 1 to April 30)

N_m = Number of days in the month

a = Annual period ending April 30

$BSOM_{ga}$ = Capital and fixed operation and maintenance costs associated with only the equipment that provides black start and system restoration services

$BSTN_{ga}$ = Annual costs associated with training operators in black start and system restoration services

$BSTS_{ga}$ = Annual costs associated with black start and system restoration services testing in accordance with the NYISO plan or the plan of an individual transmission owner

Key Features and Assumptions

Some of the assumptions in this type of black start service compensation are the following:

- Retirement of certain power generation capacity in the near future
- Allocation of black start cost only to the RTO/ISO's load
- Justifiable variable operation and maintenance cost estimations, typically leveraging historic variable O&M costs for established plants and reasonable estimates for new facilities
- For PSH plants, availability of energy within the upper reservoir to provide black start energy throughout the restoration period.
- Non-escalation of Handy-Whitman indices used for annual adjustment of black start service payments

Modeling Tools
Commercial tools are not required for evaluating black start service compensation in the electricity market; a scientific calculator is sufficient for performing the calculations.

Metrics and Units
No relevant metrics are available. The black start compensation consists of various costs expressed in terms of U.S. dollars.

Flat Rate Compensation Approach

In the flat rate compensation approach, the black start participants in a black start plan receive compensation based on a flat rate, expressed in terms of $/kW-year and referred to as the $Y value, and the claimed capacity. The purpose of using this approach is mainly to simplify procurement and encourage provision of the black start service. Designated black start resources must be eligible to provide black start service and selected by the ISO to provide the service. Designated black start resources are paid the black start standard rate or a black start station-specific rate. Costs include operations and maintenance, capital costs, CIP capital, CIP operations and maintenance costs, and an annual adjustment based on Handy-Whitman indices. Costs for black start payments are allocated to transmission customers based on pro-rata monthly regional load share (EPRI 2016).

Methodology Description
The procedures for evaluating the black start compensation in the U.S. electricity markets that employ this approach follow:

NYISO (*Generators Providing Black Start and System Restoration Services in the ConEd Transmission District)*
In the NYISO area, black start capability service settlements for generators providing black start and restoration services are different in the ISO and TOs' plans and in the ConEd Plan. According to the NYISO Accounting and Billing Manual, the payments in the ConEd Plan are calculated as follows (NYISO 2016).

$$BSCEAct_a \times \frac{BSCESCap_{ga} + BSCESOM_{ga} + BSCEACap_{ga} + BSCEAOM_{ga}}{BSCEDes_a}$$

Where:
a = Annual period ending April 30 of the current year
$BSCEAct_a$ = The number of sole black start units or black start unit groups designated by ConEd as participants in the ConEd plan excluding any units that have withdrawn or failed a black start capability test pursuant to Rate Schedule 5 of the Services Tariff
$BSCESCap_{ga}$ = Annual station-level capital amount (in U.S. dollars) for a sole black start unit or for one unit of a black start unit group based upon their unit size, as specified in the station-level column of the table in Section I.17 (NYISO 2016)
$BSCEACap_{ga}$ = The sum of annual capital amounts (in U.S. dollars) for the remaining units in the black start unit group based upon the unit sizes, as specified in the additional resource column of the table in Section I.17 (NYISO 2016)

$\mathrm{BSCESOM}_{\mathrm{ga}}$ = Annual station-level operating and maintenance amounts (in U.S. dollars) for a sole black start unit or for one unit of a black start unit group based on the unit's size, as specified in the station-level column of the table in Section I.17 (NYISO 2016)
$\mathrm{BSCEAOM}_{\mathrm{ga}}$ = The sum of annual operating and maintenance amounts (in U.S. dollars) for the remaining units in the black start unit group based upon the unit sizes, as specified in the additional resource column of the table in Section I.17 (NYISO 2016)
$\mathrm{BSCEDes}_{\mathrm{a}}$ = Number of units in the sole black start unit or black start unit group designated by ConEd as participant in the ConEd plan(NYISO 2016)

ISO-NE

According to ISO-NE (2018):

> Resources are offered by black start owners to provide black start service and, if selected by the ISO, are modified (if required), maintained, tested and operated by a Market Participant, or its designee, in accordance with this Schedule 16. The ISO shall select those resources whose locations and capabilities support the New England System Restoration Plan. Following agreement between the owner and the ISO, such selected resources shall provide and are eligible to receive compensation for providing black start service. Black start service is provided by black start owners via Designated Black Start Resources, arranged for through the ISO, and utilized by Transmission Customers.

According to ISO-NE Open Access Transmission Tariff Schedule 16, a black start owner is eligible to receive payment for the provision of black start service from a designated black start resource based on either the black start standard rate payment or a black start station-specific rate payment. The description of these two types of payment is as follows (ISO-NE 2018).

Black start standard rate payment: A designated black start resource at a black start station is entitled to black start service compensation in a month based on the following formula (black start owner-submitted data and values from Appendix A of the Schedule 16):

$$\begin{aligned}&\text{Black Start Standard Rate Payment}_{\text{individual}}\\&= \left(\frac{1}{12}\right) \times (\text{Total Black Start O\&M Payment}_{\text{station}}\\&+ \text{Total Black Start Capital Payment}_{\text{station}})\\&\times \left(\frac{\text{Designated black start resource}_{\text{individual}}\ \text{nameplate MVA value}}{\sum \text{Designated black start resource}_{\text{individual}}\ \text{nameplate MVA values at the black start station}}\right)\end{aligned}$$

Where:

$$\begin{aligned}\text{Total Black Start O\&M Payment}_{\text{station}}&\\&= \text{Black Start O\&M Payment}_{\text{station}} + \text{Black Start CIP O\&M Payment}_{\text{station}}\end{aligned}$$

$$\begin{aligned}\text{Total Black Start Capital Payment}_{\text{station}}&\\&= \text{Standard Black Start Capital Payment}_{\text{station}}\\&+ \text{Specified-Term Black Start Capital Payment}_{\text{station}}\\&+ \text{Black Start CIP Capital Payment}_{\text{station}}\end{aligned}$$

Black start station-specific rate payment: Black start station-specific rate payment is calculated as follows:

$$\text{Black Start Station specific Rate Payment}_{\text{individual}} = \left(\frac{1}{12}\right) \times (\text{Total Black Start O\&M Payment}_{\text{station}} + \text{Total Black Start Capital Payment}_{\text{station}}) \times \left(\frac{\text{Designated black start resource}_{\text{individual}}\text{ nameplate MVA value}}{\sum \text{Designated black start resource}_{\text{individual}}\text{ nameplate MVA values at the black start station}}\right)$$

Where:

$\text{Total Black Start O\&M Payment}_{\text{station}}$ = the commission-accepted annual black start O&M payment for the black start station, including O&M compensation for the provision of black start service and for compliance with all associated NERC critical infrastructure protection reliability standards.

$\text{Total Black Start Capital Payment}_{\text{station}}$ = the commission-accepted annual black start capital payment for the black start station, including the black start station-specific rate capital payment and the black start station-specific rate CIP capital payment.

Key Features and Assumptions

Some of the assumptions in this type of black start service compensation are,

- Retirement of certain power generation capacity in the near future
- Allocation of black start cost only to the RTO/ISO's load
- Non-escalation of Handy-Whitman indices, used for annual adjustment of black start service payments

Modeling Tools

Commercial tools are not required for evaluating the black start service compensation in the electricity market; a scientific calculator is sufficient for performing the calculations.

Metrics and Units

No relevant metrics are available. The black start compensation consists of various costs expressed in terms of U.S. dollars.

Limitations

One of the potential disadvantages of flat-fee pricing is that any obstacle that gets in the way of productivity reduces income for the black start equipment owner. Pricing competition might intensify with other companies in the industry competing for the lowest pricing. Inflation can also cause unexpected losses, and companies may need to raise the charge to keep up with costs. In addition, calculation of these factors necessitates a detailed knowledge of the overall black start system characteristics, which provides a barrier to effective valuation and system security.

Competitive Bidding Process Based Compensation Approach

In the competitive bidding approach, the ISO runs a market for black start services. Interested participants submit an hourly standby cost in \$/hr, often termed an availability bid (on a bi-annual basis), that is unrelated to the capacity of the unit. The resources that meet its reliability criteria at minimum cost are selected. These resources are paid an hourly black start "standby fee," which is de-rated when the resource availability is below some threshold (currently at 85%). Qualified scheduling entities (QSEs) representing loads are allocated black start capacity total cost based on their load ratio share (EPRI 2016).

Methodology Description

The procedure for evaluating black start compensation in the ERCOT market that employs this approach is as follows:

As described in the ERCOT Nodal Protocols Section 6:

> Black Start Service (BSS) is obtained by ERCOT through Black Start Agreements with QSEs for generation resources capable of self-starting or generation resources within close proximity of a non-ERCOT control area that are capable of starting from that non-ERCOT control area under a firm standby power supply contract, without support from the ERCOT System, or transmission equipment in the ERCOT System. Generation resources that can be started with a minimum of pre-coordinated switching operations using ERCOT transmission equipment within the ERCOT System may be considered for BSS only where switching may be accomplished within one hour or less (ERCOT 2015; ERCOT 2018).

And according to ERCOT (2018):

> ERCOT shall pay an Hourly Standby Fee to the QSEs representing a black start resource. This standby fee is determined through a competitive bi-annual bidding process, with an adjustment for reliability based on a six-month rolling availability equal to 85% in accordance with Section 22, Attachment D, Standard Form Black Start Agreement. The Black Start Hourly Standby Fee is subject to reduction and claw-back provisions as described in Section 8.1.1.2.1.5, System Black Start Capability Qualification and Testing. ERCOT shall pay a Black Start Hourly Standby Fee payment to each QSE for each black start resource.

The hourly payment can be computed as follows:

$$BSSAMT_{q,r} = (-1) * BSSPR_{q,r} * BSSARF_{q,r}$$

Where $\mathrm{BSSARF_{q,r}}$ is calculated as:

If $(\mathrm{BSSHREAF_{q,r}} \geq 0.85)$,

$\mathrm{BSSARF_{q,r}} = 1$

Otherwise,

$\mathrm{BSSARF_{q,r}} = \mathrm{Max}(0,1 - \left(0.85 - \mathrm{BSSHREAF_{q,r}}\right) * 2)$

And $\mathrm{BSSHREAF_{q,r}}$ is calculated as:

If $(\mathrm{BSSEH_{q,r}} < 4380)$,

$\mathrm{BSSHREAF_{q,r}} = 1$

Otherwise,

$$BSSHREAF_{q,r} = \frac{\sum_{hr=h-4379}^{h} BSSAFLAG_{q,r,hr}}{4380}$$

The variables used in the calculation of hourly black start service payment are defined in Table 4.2

Table 4.2: Variables Used in Calculation of Black Start Service Amount in ERCOT

Variable	Unit	Definition
$BSSAMT_{q,r}$	\$	Black start service amount per QSE per resource by hour: The standby payment to QSE q for the BSS provided by resource r, for the hour.
$BSSPR_{q,r}$	\$ per hour	Black start service price per QSE per resource: The standby price of BSS resource r represented by QSE q, as specified in the black start agreement.
$BSSARF_{q,r}$	None	Black start service availability reduction factor per QSE per resource by hour: The availability reduction factor of resource r represented by QSE q in the black start agreement, for the hour.
$BSSHREAF_{q,r}$	None	Black start service hourly rolling equivalent availability factor per QSE per resource by hour: The equivalent availability factor of the BSS resource r represented by QSE q over 4,380 hours, for the hour.
$BSSEH_{q,r}$	None	Black start service elapsed number of hours per QSE per resource by hour: The number of the elapsed hours of BSS resource r represented by QSE q since the beginning of the BSS agreement, for the hour.
$BSSAFLAG_{q,r,hr}$	None	Black start service availability flag per QSE per resource by hour: The flag of the availability of BSS resource r represented by QSE q, 1 for available and 0 for unavailable, for the hour.
q	None	A QSE.
r	None	A BSS resource.
hr	None	The index of a given hour and the previous 4,379 hours.
4380	None	The number of hours in a six-month period.

The total hourly payment to each QSE for all BSS resources represented by this QSE is calculated as follows:

$$\boldsymbol{BSSAMTQSETOT_q = \sum_r BSSAMT_{q,r}}$$

The variables used in the calculation of $BSSAMTQSETOT_q$ are defined in Table 4.3.

Table 4.3: Variables Used in Calculation of Black Start Service Amount in ERCOT

Variable	Unit	Definition
$BSSAMTQSETOT_q$	$	BSS amount QSE total per QSE: The total of the payments to QSE q for BSS provided by all the BSS resources represented by this QSE for the hour h.
$BSSAMT_{q,r}$	$	BSS amount per QSE per resource: The standby payment to QSE q for BSS provided by resource r, for the hour.
q	None	A QSE.
r	None	A BSS resource.

Key Features and Assumptions

Some of the key features of this approach are the following:

- Introduces the organization to new BSS providers
- Systematizes a process for selecting service providers
- Provides evidence of a fair selection process
- Encourages existing service providers to enhance operational efficiency and justify their services

It should be noted that the competitive bidding process is premised on the assumption that each bidder will bid only once, and all will submit their bids at the same time.

Modeling Tools

Commercial tools are not required for evaluating the BSS compensation in the electricity market; a scientific calculator or a desktop computer is sufficient for performing the calculations.

Metrics and Units

No relevant metrics are available. The black start compensation consists of various costs expressed in terms of U.S. dollars.

Limitations

Some of the disadvantages of using this approach are the following:

- Higher cost (in terms of selecting a service provider) than signing a favored BSS provider without an RFP
- Creates bureaucracy
- Increased time to finalize a service provider since the process requires a formal screening process, multiple reviews, meetings, presentations and follow-ups
- Difficulty in executing this valuation without significant insight into ERCOT black start market dynamics.

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4.5. Value of Power System Stability Services

Power system stability services maintain reliability and provides resilience as the bulk power system encounters expected and unexpected real-time disruptions and changing conditions. The value of power system stability services is primarily derived from their contribution to maintaining synchronism among generators and maintaining system-wide frequency and acceptable voltage of a synchronous interconnection. PSH plants can potentially contribute stability services at both the machine level and as a service to the larger electricity grid. Thus, stability services provide value by automatically and autonomously controlling deviations of synchronism, frequency, and voltage: 1) before a particular synchronous machine exceeds the 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. Various stability metrics that quantify the effects on system synchronism, frequency and voltage are used to assess the value of stability services provided by PSH units.

The relevant value streams for stability services assessment will be determined by the context, purpose, and perspective chosen for the analysis. For example, like other PSH valuation categories, stability services are highly dependent on location (e.g., topography, proximity to other electricity system assets), technology design (e.g., new or conversion, fixed or adjustable speed), and to whom the analysis is targeted (e.g., PSH plant owner, developer, utility, regulator, grid operator, ratepayers, or society).

The value of automatic and autonomous stability services from a PSH plant or other turbines/generators is not currently directly compensated through mechanisms in regulated or restructured markets. Some stability services are acquired on a cost-of-service basis, notably voltage support and, in a few exceptional cases, primary frequency response. Instead of being incentivized by monetary compensation, conventional generating technologies have generally provided stability services as an inherent feature, and most systems have traditionally had more stability services than needed.

However, in recent years, there has been heightened attention paid to the value of stability services due to the changing resource mix and the increase in inverter-based renewable resources. Although over the past six years frequency response has stabilized or improved (from a long-term downward trend), it remains a concern closely monitored by the NERC (NERC 2019). The metrics used to assess the value of stability services from a PSH project are primarily expressed in physical and numerical units, yet studies are beginning to estimate requirements, costs avoided, or the monetized value of certain stability services, particularly primary frequency response.

Power system stability services are of three categories: inertial frequency response, primary frequency response, and voltage support. *Inertial frequency response* reduces the speed of a frequency decline. *Primary frequency response* is the capacity available for automatic and autonomous local generator response to counter frequency deviations. *Voltage support* protects the system from insufficient voltage quality in both normal operations and in response to disturbances within local areas (e.g., sub-areas within a balancing authority footprint). These services are primarily provided through automatic and autonomous responses at a local distributed level, although voltage support can also be centrally managed.

This section describes the analytical and simulation methodologies available to assess the value of stability services associated with PSH projects involving new units, upgrades, or conversions (e.g., from fixed-speed to adjustable-speed technology). The methodological approaches encompass a progression from lower to higher intensity in terms of cost, data, and time, with a corresponding progression in the complexity and fidelity of the results. This overall approach allows assessment intensity to be matched to the stage of project development or to the desired complexity and fidelity of the analysis. In most cases, even if analytical methodologies are used in initial stages to assess project risk or evaluate different locations, a simulation methodology will be applied before a PSH project is undertaken. The simulation plan would incorporate the interconnection feasibility and system impact study according to FERC Order 2003 for large generator interconnection agreement (FERC 2003) and FERC Order 2006 for small generator interconnection agreement (FERC 2005).

In the U.S., there is a FERC Order that any new generator (including pumped storage) that is to be connected to a bulk power grid must submit a large/small generator interconnection application to the ISO or RTO in which the point of transmission interconnection is located. The process requires that several power system simulation studies be prepared as part of the process. The required system studies include load flow, short circuit and transient stability. Each ISO and RTO has a FERC approved procedure that specifies the studies to be prepared and the dynamic performance levels that the PSH units will be required to meet. In addition to the FERC requirements there are additional dynamic system performance criteria established by the NERC reliability council where the PSH plant will be located.

Power system simulations can be supplemented by cost-avoided estimates (Section 4.5.11), benefits-transfer approaches, or production cost modeling (Section 4.5.10).

4.5.1. Valuation of Stability Services in Regulated and Restructured Markets

The value of stability services is strongly shaped by location within a particular utility service area or balancing authority. Machine synchronization is a unit-level stability attribute, voltage support cannot be transmitted long distances and is important within sub-areas of a larger balancing authority, and frequency response obligations for reliability are allocated at the balancing authority level. Across sub-areas and balancing authorities, the needs for voltage support and frequency reserves vary by the mix of resources in the generation fleet, load characteristics, and geographic distribution of generation.[1]

In traditionally regulated markets, large vertically integrated utilities operate balancing authorities, while in competitive markets, FERC-regulated wholesale market operators (i.e., RTOs or ISOs) operate balancing authorities (FERC 2019). Balancing authorities also are overseen by electricity reliability organizations, which are defined by NERC and approved by FERC. Current compensation mechanisms and reliability requirements for stability services are similar in traditionally regulated markets and wholesale markets (see Table 4.4): Reactive power for voltage support is obtained on a cost-of-service basis in both regulated and wholesale markets, inertia and primary frequency response have not been historically compensated in either market, and recent federal requirements for frequency response apply equally to balancing authorities in regulated and wholesale markets. As of 2017, NERC BAL-003-01 requires each balancing authority to meet a frequency response obligation (NERC 2017).[2] In early 2018, FERC issued Order 842, requiring generating facilities, both synchronous and non-synchronous, that are newly interconnecting to the transmission grid to install, maintain, and operate equipment capable of providing primary frequency response (FERC 2018). Significantly, Order 842 does not require compensation for primary frequency response.

However, attention continues to focus on whether balancing authorities will have sufficient supplies of frequency response and whether to create a market mechanism or use regulatory mandates to incentivize the provision of frequency response. New technologies allow frequency-responsive services to be provided from non-synchronous generators, including battery storage, wind generation, solar generation, and adjustable-speed PSH units. The frequency response rate

[1] Frequency response is an interconnection-wide property. However, the NERC reliability standard for primary frequency response alters the value of this stability service based on the balancing authority in which it is provided. The balancing authority that has the disturbance has an obligation to take action to return frequency to schedule (60Hz). See Eto et al. (2018) for variations in needed primary frequency response characteristics across interconnections.

[2] As a result, some balancing authorities may require new resources to meet their obligations, even when there is sufficient frequency response across the interconnection. For example, the California Independent System Operator, the largest balancing authority in the Western Interconnection, has estimated that it could at times be short of its required frequency response, and to meet its obligation under BAL-003-01 on an interim basis, it is compensating other balancing authorities for transferred frequency response.

from these new technologies is faster than from conventional generation and is prompting exploration of new market products. RTOs including CAISO, MISO, PJM, and ERCOT have ongoing initiatives on primary frequency response (NERC 2012). On the other hand, Hawaiian Electric Companies (HECO) has recently proposed the fast frequency response grid service program with an incentive of $5/kW-month as part of their integrated demand response portfolio (Yuan et al. 2019). As these initiatives move forward, it is possible that in the future, compensation for stability services may differ in important ways across regulated and wholesale markets. In fact, due to the rise of renewable energy resources and synchronous generator retirements, some balancing authorities and ISOs are starting to pay neighboring ISOs for primary frequency response (Balducci 2019). CAISO, for example, has primary frequency response contracts with Seattle City Light (CAISO 2016a) and Bonneville Power Administration (CAISO 2016b).

Within this context of rapidly evolving mechanisms for obtaining stability, a common set of valuation approaches can currently be used across both regulated and wholesale markets, as long as attention is paid to the location-specific value within particular utility service areas or balancing authorities. These approaches are:

- Analytical methods and power system simulations
- Production cost models for primary/fast frequency response
- Avoided cost analysis

Market structure may impact the valuation assessment in multiple ways, including the operational status (e.g., percent generation or reserve capacity), in which specific generation assets may operate. Market signals may also be a part of the control system in an automated or human-in-the-loop manner, complicated by data availability and ease of access to data. In instances where specific data regarding system blueprint or machine-level information are unavailable, substitutions and simplifications by qualified engineers are needed to proceed with the stability valuation assessment.

Table 4.4: Units, Reliability Requirements and Compensation Mechanisms for Stability Attributes

Stability Attribute	Units	Reliability Requirements	Compensation	Proposed or Early Adoption of Market Services
Machine Synchronism	Damping ratio Minimum critical clearing time	>5% (approx.) System dependent	Not compensated Not compensated	
Synchronous Inertia	MW-sec	Few estimates of how much inertia response is needed in particular balancing authorities.	Not compensated in regulated or restructured markets	ERCOT has estimated its inertial requirement and is exploring inertial response market products.

Stability Attribute	Units	Reliability Requirements	Compensation	Proposed or Early Adoption of Market Services
Frequency Governor Response	Frequency response obligation (FRO) = MW/0.1 Hz Primary frequency response = MW	NERC Reliability Standard BAL-003-1.1 obligation for primary frequency response for each BA FERC Order 842 requires newly interconnecting generators to have capability for primary frequency response.	Not generally compensated in regulated or restructured markets	ERCOT, PJM, and HECO are early adopters of a form of fast frequency response market products. Inertial response and primary frequency response can be supplemented or replaced by fast frequency response.
Voltage Support	Reactive power = MW	Location specific FERC Order 827 requires variable generation power plants larger than 20 MW to provide reactive power.	Cost-of-service	

Source: Adapted from Denholm, Sun, and Mai (2019).

4.5.2. System Stability Attributes and Unit Characteristics

Assessing power system grid stability and the potential contribution of a proposed PSH project requires understanding the possible scenarios that may be encountered by the power system with an integrated PSH plant. Implementing this systematically necessitates a test plan based on fault and operation conditions. Typically, these scenarios will correspond to planning scenarios developed at the appropriate level for the defined valuation question that is being addressed in the analysis (e.g.,, utility, balancing authority, or interconnection). The expected conditions in which the PSH will provide stability will vary by where the system is located within the topology of the grid and the largest possible disturbances that may be experienced. This is often explored through definition of the contingencies (e.g., N-1, N-2, or N-1-1) for a particular system.

The *magnitude of disturbance (MOD)* and pre-existing *mitigating attributes (MA)* of the overall system, such as amount of synchronous machine rotational inertia and automatic control responses taken by generation or other flexibility in the system, are considered in the analysis. The MOD and MA are best derived from existing highest impact contingency scenarios for the regional grid (e.g., generation and/or transmission outage, load rejection event, steep ramp in solar/wind generation, etc.) to find the expected boundary condition at the connecting point for the PSH plant.

The *operating state* of the PSH unit in terms of function and available power is also critical to consider because it will impact how the PSH unit responds to a particular event. For example, the governor frequency response is different depending on whether the PSH unit is pumping or generating, which will in turn determine the PSH unit's response time. Depending on the PSH technology, the unit may be capable of mode switching on the order of seconds, where others may switch on the order of minutes. The state may affect other attributes as well, including transient and small signal stability.

The available power flexibility of the PSH plant is another consideration to test against. The *capacity factor* of a plant is defined as the ratio of its actual generation to its maximum potential generation. A similar measure is the generator's *headroom*, i.e., the amount of power by which a generator may increase its power output. Table 4.5 and Table 4.6 illustrate capacity factors for generators across many fuel sources. With this data, it appears that hydro generators generally have a capacity factor near 40% when operated as a generator, while solar is near 25%, indicating that there may be additional capacity available for generation, as required by either source. That is not necessarily the case; hydro can often provide additional output where renewables are typically unable to (unless operating in a curtailed manner).

Table 4.5: Capacity Factors for Non-Fossil Fuel Sources (EIA 2019)

Period	Nuclear	Hydro	Wind	Solar (PV)	Solar (Thermal)	Other Gasses	Biomass	Geothermal
2014	91.7	37.3	34.0	25.9	19.8	68.9	58.9	74.0
2015	92.3	35.8	32.2	25.8	22.1	68.7	55.3	74.3
2016	92.3	38.2	34.5	25.1	22.2	69.7	55.6	73.9
2017	92.2	43.1	34.6	25.7	21.8	68.0	57.8	74.0
2018	92.6	42.8	37.4	26.1	23.6	73.3	49.3	77.3
Mean	92.2	39.4	34.5	25.7	21.9	69.7	55.4	74.7

Table 4.6: Capacity Factors for Fossil Fuel Sources (EIA 2019)

	Coal	**Natural Gas**				**Petroleum**		
Period		Combined Cycle	Combustion Turbine	Steam Turbine	I.C.E.	Steam Turbine	Combustion Turbine	I.C.E.
2014	61.1	48.3	5.2	10.4	8.5	12.5	1.1	1.4
2015	54.7	55.9	6.9	11.5	8.9	13.3	1.1	2.2
2016	53.3	55.5	8.3	12.4	9.6	11.5	1.1	2.6
2017	53.7	51.3	6.7	10.5	9.9	13.5	0.9	2.3
2018	54.0	57.6	11.8	13.7	NA	13.9	2.5	NA
Mean	55.4	53.7	7.8	11.7	7.4	12.9	1.3	1.7

Therefore, if a PSH is operating at maximum power production (i.e., capacity factor of 100% over some duration of time), it cannot provide additional real power support when a disturbance causes frequency droop due to a lack of headroom. A final consideration is the range of *reservoir storage state;* testing should range from nearly full upper reservoir to nearly empty.

The example test matrix in Table 4.7 can be used to evaluate the robustness of the PSH unit's ability to maintain engagement with the greater system and to ensure that the PSH plant trips appropriately to protect the capital investment (e.g., the electromechanical assembly of generator-turbine and motor-pump sets and the civil construction encompassing the assembly and water system).

Table 4.7: Example Test Matrix.
Specific criteria will depend on system attributes (left column) and PSH unit characteristics (top row).

Magnitude of disturbance (MOD) and mitigating attributes (MA)	State of PSH System Characteristics						
	Operating state				Reservoir storage state		
	Generating mode		Pumping mode				
	Max	Min	Max	Min	Full	Partial	Empty
Large loss of generation, loss of some MA							
Large loss of load, MA constant							
Medium loss of generation, small loss of MA							
Medium loss of load, MA constant							

In analyzing these attributes, however, care should be taken to make appropriate choice of PSH operating state, which depends upon the reservoir storage state and the type and location of PSH and is at the discretion of PSH unit developer/operator. For example, a conventional PSH unit may operate at only generating ("Full" or "Partial" upper reservoir state) mode or pumping ("Partial" or "Empty" upper reservoir state) mode while a ternary or quaternary PSH unit may simultaneously operate at both the generating and pumping mode through hydraulic short circuit.

Contingency Selection for PSH Valuation studies

It is very important to select credible contingencies to understand the impact of an interconnected PSH unit on power system stability and to quantify the metrics associated with various stability attributes. Power system stability analysis involves the verification of the following factors after 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
- Sufficient recovery of frequency

When performing dynamic studies, contingencies should be selected in a way such that the above mentioned 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 off 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 (base case), the user should perform power flow 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., a 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 power flows, voltages, and currents for the remaining elements of the model. From these analysis, the user can start to develop an understanding of how each of the contingencies 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, and, when the study is completed, can review the results to rank the contingencies based on the severity of their impact and identify the most severe or critical contingency in the system for which a dynamic simulation can be performed later.

Summary of Analytical and Power System Simulation Approaches

There are three categories of power system analysis tools that can be used to assess the value of stability from a PSH project: (1) analytical approaches based on mathematical linear system stability analysis, (2) digital simulation approaches, and (3) field testing. In practice, theoretical stability should be determined prior to field testing; this is a necessary initial step in valuation. If the valuation analysis warrants moving forward with the project, field testing may follow.

Analytical methods and power system simulations can be used to study the stability performance of different PSH sizes, locations, and technologies. It is also possible to examine performance with different penetrations of inverter-based generation or the stability performance of a PSH plant in comparison to an alternative source (i.e., combined-cycle, steam, battery storage, fast frequency response from solar or wind). These methods express the value of stability in physical or numeric units (see Table 4.4).

Figure 4.4 provides a conceptual overview of recommended stability valuation approaches based on analytical methods and power system simulation. Selection of valuation approaches is based on the scope of the assessment (e.g., the unit type, valuation perspective, context, and purpose). The problem formulation and scenario formulation based on the test matrix criteria described in the preceding section are very similar across the available approaches. Testing should proceed in a logical manner from less expensive (e.g., lower fidelity methods) to more expensive higher fidelity methods to buy down risk and expense as a development moves from concept through to more detailed planning and field testing. While the methodology may vary in terms of cost of analysis, assumptions made, and fidelity of model used, the stability attributes and their assessment metrics remain same.[1]

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[1] Most of the metrics, computed using the analytical technique, can also be deduced through simulation methodologies. At times, the metric used for analytical technique can have a nomenclature different from the simulation methodologies, but a common set of metrics can always be deduced to assess stability attributes. For example, the equal area criterion used in analytical techniques to assess transient stability can always be translated to the critical clearing time (CCT), which can be easily deduced using the simulation methodologies.

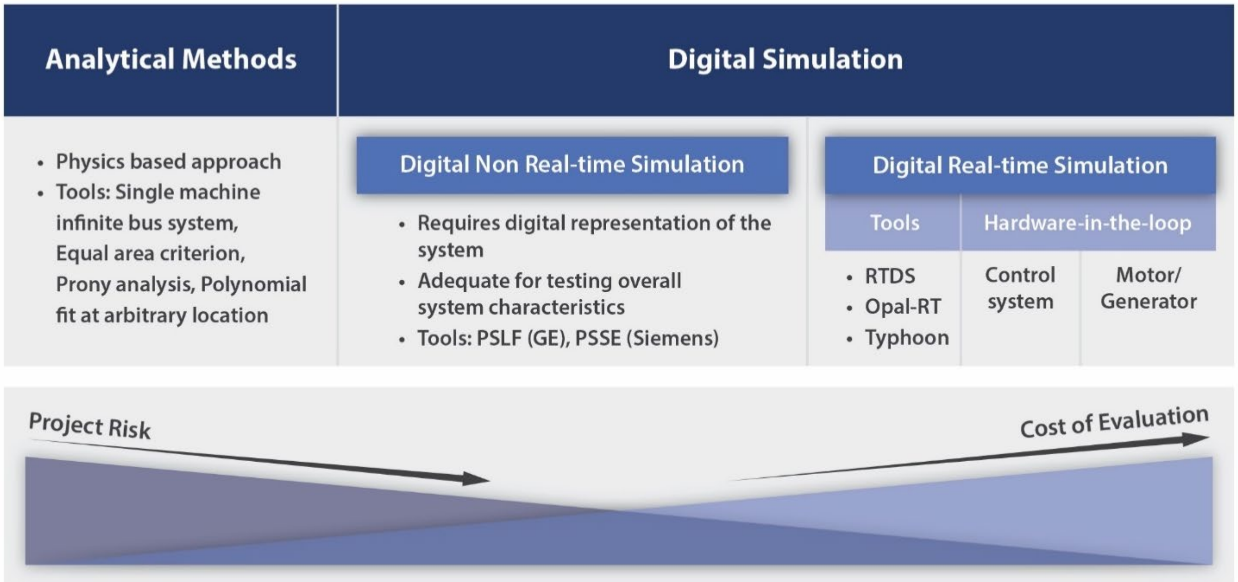

Figure 4.4: Progression of stability valuation approaches from least to most computational and resource exhaustive (also lowest fidelity to highest fidelity).

> *Analytical approaches* are based on mathematical descriptions and used for simplified analysis, while simulation approaches are used to analyze a detailed model without simplification. In applying analytical methods, some assumptions are made, both for the unit under consideration and the grid, to allow the analysis to be tractable. For example, non-linear systems need to be linearized to perform small-signal stability analysis. The extent to which the electric grid is included will also be a constraint. Standard test cases (e.g., IEEE test systems) can be used at the planning stage; however, the interconnection study requirements of the RTO would determine the size of the actual grid to be tested. Analytical methods are a cost-effective way to evaluate the design of the system in an early stage and to make adjustments before continuing to simulation analysis.
>
> *Digital simulation approaches* perform full-scale dynamic analyses of the interactions between a PSH unit and the wider grid and include analyses of events like unstable modes of operation during major disturbances, such as unexpected transmission line or generator trips. Power systems simulation tools are classified as either non-real time or real time.

Non-real-time digital transient analysis simulation, such as the electromagnetic transients (EMT) program type, can be used to analyze real-life power systems, non-linear models, unbalanced distribution networks, and frequency dependent parameters. One consideration in choosing between non-real-time and real-time methodologies is the size of the power system in which the PSH project is located (Strasser 2015). Non-real-time digital simulation environments are easier to implement for very large systems, but they are typically less accurate for assessing certain power system stability attributes than real-time environments. For example, assessing PSH unit response while operating in a wide-area power system with high renewable energy penetration requires a non-real-time environment with the capability to assess dynamic responses.

An inherent advantage of real-time digital simulation is that it enables hardware-in-the-loop (HIL) testing to assess how specific components of the electric grid interact in a high-fidelity environment (Strasser 2015). This serves as both an important assessment of the potential stability value of the project, but can also inform field testing. Real-time digital simulation is especially critical when a new machine technology is being deployed or if an existing machine technology is being deployed in a new system configuration. For example, a real-time digital simulation (with HIL) is needed to conduct a valuation assessment of the power converter controls of a doubly-fed induction machine (DFIM) used for PSH plants to provide frequency and voltage support to the power system. HIL that may be applicable includes attaching prototype control hardware and/or generation components that drive the simulation. Including generation requires large motors controlled by the emulation of the hydraulic and turbine systems to drive the motor/generator, requiring significantly more investment in testing infrastructure.

4.5.3. Power System Stability Overview

Methods and metrics for assessing various power system stability attributes vary depending on many factors, including machine specifications and grid status (e.g., penetration level of solar, wind and other zero inertia resources, net load demand being served, etc.). A matrix of test cases is therefore suggested in order to determine the impact on grid and PSH stability performance. The methods and metrics are largely independent of the testing platform, although each platform has specific advantages and disadvantages, which are outlined below. Since the posed valuation focuses on assessment of the differentiating capabilities and services provided by a new or updated PSH plant, especially with respect to high renewable energy penetration, the test plan accounts for differences in penetration of generation types between hours and seasons as well various levels of disturbances to which the PSH would respond.

They are related in that each is concerned with the impact on the PSH plant, but distinct in the assumed disturbance size. Small disturbances could move a system that verges on instability into one that is unstable. Linear analysis using a mathematical model is sufficient for this determination. Transient analysis provides information about the tolerable magnitude and duration of a large disturbance (e.g., a nearby fault).

Stability Attribute Classification

Dynamic system performance is a general term that encapsulates many interconnected physical processes across multiples scales of power systems. Taxonomies enable tractable stability analysis of specific components of the power system and are thoroughly categorized by Kundur et al. (2004). For practical purposes, the reduced taxonomy in Figure 4.5 is used as the basis for recommending specific power system stability valuation methodologies that should be conducted in the evaluation of a proposed PSH project.

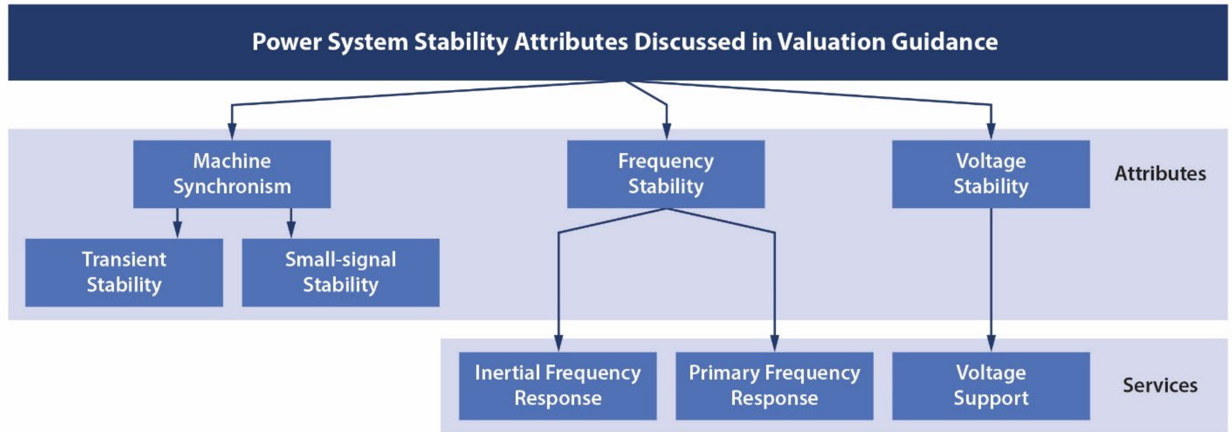

Figure 4.5: Classification of power system stability attributes and services.
Adapted from Kundur et al. 2004.

These stability attributes and services are important to overall stability and are largely related to various components of a PSH plant. *Machine synchronism* refers to the ability of the generator rotor to remain synchronized with other generators in quiescent disturbances, as well as when a larger disturbance event occurs. *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, etc. Conversely, *small-signal stability* is the ability of the grid machines to maintain electromechanical synchronism in the presence of small disturbances. *Inertial frequency response* (or *inertial response*) principally refers to the sub-second response resulting from the synchronous machine transferring mechanical kinetic energy into electrical energy. This short-term response is critical so that non-inertial frequency controls have time to respond. *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. *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 the overall voltage stability of the system.

To understand the overall beneficial impact of PSH, both the services provided by the PSH units and how those services impact stability attributes should be studied. 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 by using various metrics associated with frequency stability, and the amount of services provided by PSH unit can also be quantified to evaluate the cost benefits associated with the service provided.

Time Scales

Response to an imbalance between electric power supply and demand is supported by operating practices across vastly differing time scales. Resources with different technical characteristics are typically deployed in order of response speed, from fast to slow. However, the response time horizon for these resources exhibit some overlap, as illustrated in Figure 4.6.

This section of Chapter 4 addresses valuation of stability that occurs on the shortest time scales to maintain power quality. Operating practices such as regulation, load following, operational reserves, transmission congestion, and scheduling that rely on economic dispatch or manual controls are addressed in other sections of this chapter.

Both inertial frequency response and primary frequency response are also related because inadequate inertial frequency response will cause the frequency to change more rapidly, potentially causing a given unit to trip before governors on the system have a chance to arrest the frequency deviation.

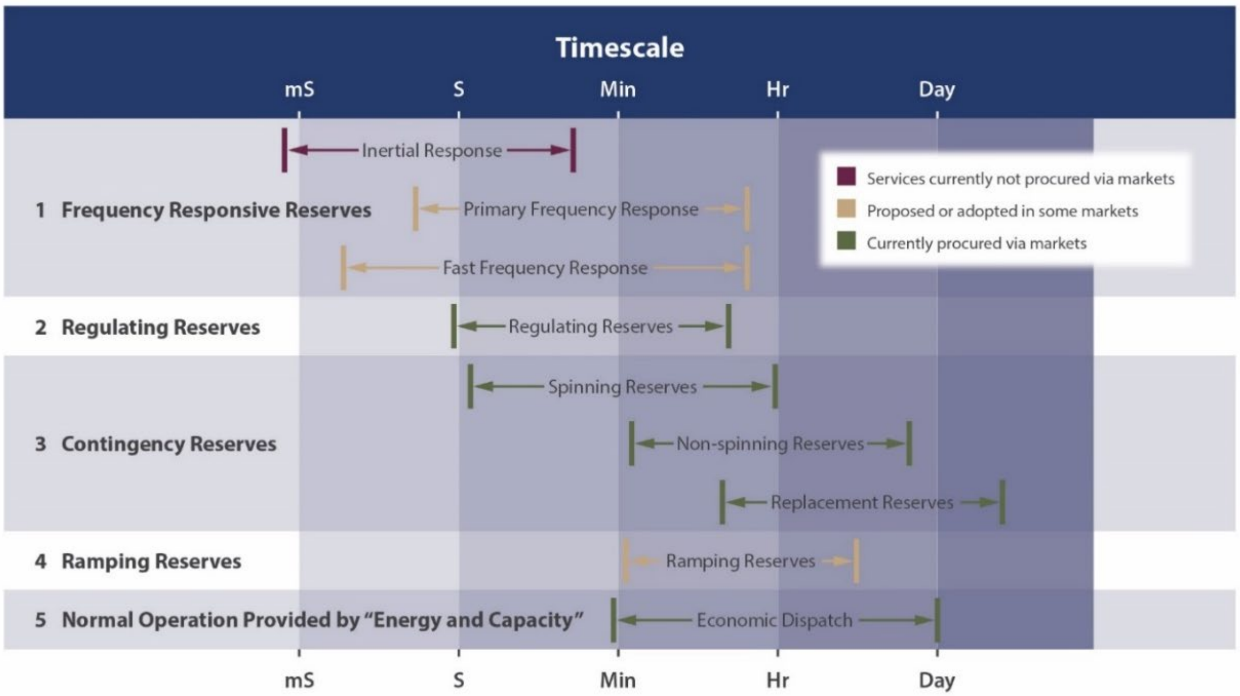

Figure 4.6: Time scales of interest to electric grid operators.
Adapted from Denholm, Sun, and Mai (2019).

A typical frequency excursion and response illustrates the stages of response to a disturbance from synchronous inertial response through fast frequency response, primary frequency response, and the addition of power from regulation (Figure 4.7). Similarly, the machine rotor may be stable up to a certain level of frequency deviation, but will desynchronize and trip after a given threshold is reached (Anderson and Fouad 2002). This section addresses inertial and primary frequency response, along with machine synchronism and voltage support. Valuation of regulation (i.e., secondary frequency) response is addressed in Section 4.3 on ancillary services.

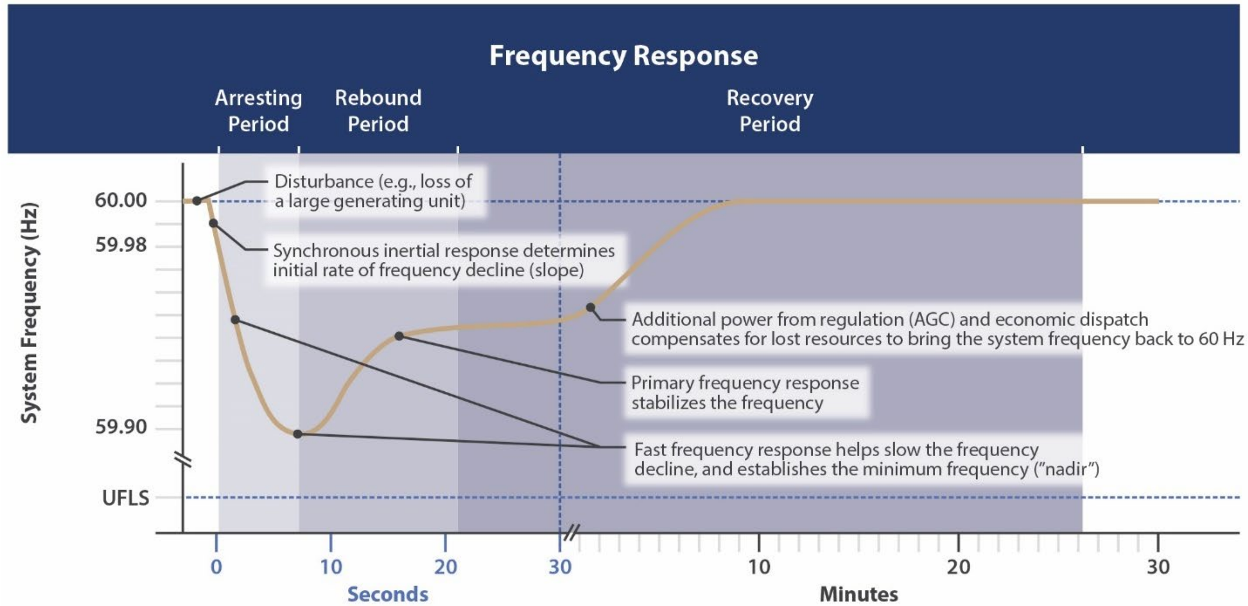

Figure 4.7: Frequency response after a grid frequency event. UFLS stands for under frequency load shedding, which is well below the nadir.
Adapted from Milligan (2018).

It is critical that a given power stability value assessment account for both how the proposed PSH plant will respond and contribute to system events and how the system will respond to possible disturbance scenarios attributable to the proposed PSH plant. For example, if a PSH unit faults and disconnects from the grid, the unit is no longer contributing to stability and it impacts other units on the system. Similarly, the power system stability attributes (e.g., inertial frequency response) impact the stability of a PSH plant, and because the PSH plant will be responding to the magnitude and rate of change of frequency and voltage, it must have limits set to protect itself from damage.

The different attributes and services for power system stability are described in the following sections with a focus on the underlying theory, analytical and simulation methodologies. Simulations for these attributes and services can be carried out using the example methods given in Figure 4.4.

4.5.4. Small-Signal Stability

The two primary scenarios resulting in small-signal instability are a steady divergence of generator rotor angle due to synchronizing torque imbalance or unbounded rotor oscillations due to insufficient damping torque. Most small-signal stability concerns are attributed to the latter, which is the focus of this section; the next section will describe the transient stability phenomena.

Theory

The two main system representations for assessing small-signal stability of a given unit are a single-PSH with infinite bus and small-signal stability of multi-machine systems including a

PSH. For each of these, common metrics include eigenvalues, eigenvectors (or mode shapes), eigenvalue sensitivity, and participation factors.

To obtain a mathematically tractable result, grid connection is simplified to a single electrical line attached to an infinite or "stiff" bus representative of an electric power system (EPS) essentially unaffected by the dynamics of any one generator. The extent and details of the EPS will be determined by the interconnection study requirements from the host RTO. The single machine infinite bus (SMIB) system is widely used in the literature to understand the behavior of a particular generator. In this case, the system including the proposed PSH plant is represented as shown in Figure 4.8.

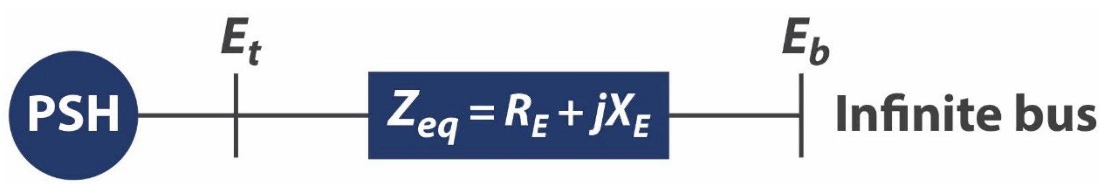

Figure 4.8: Single PSH infinite bus representation used for small signal stability analysis.

Fundamentally, power P_{del} delivered to the infinite bus by the PSH plant is:

$$P_{del} = \frac{E_t E_b}{X_E} sin\delta$$

ignoring line resistance, where δ is termed the *internal rotor angle* of the PSH unit, a mathematical concept useful for understanding the steady-state behavior of the generator in various loading and connective impedance conditions. The rotor angle represents the position of the peak of the magneto-motive force generated by forced rotation of the field circuit (i.e., on the rotor) versus the magneto-motive force in the stator. As the above equation for power delivery indicates, separation of the two peaks increases the amount of power delivered to the EPS until the rotor angle reaches a maximum of 90°, at which point an increase in rotor angle results in a *decrease* in power output, an unstable operating condition.

The SMIB system can be modeled with varying degrees of complexity (as shown in Figure 4.4) to investigate the impact of the individual components of the generator on overall stability. Layers of complexity, from least complex to most, are Newtonian physics (i.e., rotational dynamics of rotor), field effects, damper windings, automatic voltage regulator, and finally the effects of the power system stabilizer (Kundur et al. 1994).

The extension to a multi-machine model is feasible only when sufficient information on the rest of the system, along with other generators, is available to implement in a real-time simulation using a digital blueprint of the system. In this context, the multi-machine system with the PSH unit will include transmission level modeling of the balancing authority area, appropriate levels of renewable energy, and other transmission level components. The multi-machine representation will allow a detailed assessment of the small-signal stability implications of PSH connection to the area EPS.

Analytical Methodologies

Lyapunov's first method of assessing stability is the most frequently used method for small-signal stability analysis. This method is based on the computation of qualities of the characteristic equation of the system (Kundur, Balu, and Lauby 1994; Lyapunov 1967) by considering the linearized state space model. Roots of the characteristic equation are useful to determine the *stability in the small* or "local" stability. If a system has all roots with negative real parts, the system is stable; if not, the system is unstable.

This method focuses on the dominant complex roots, which have the smallest magnitude real part in the characteristic equation. Eigenvalues, eigenvectors, and mode shapes quantify stability and are obtained by deducing the machine dynamic equations in the state-space representation of the general form (Wang, Song, and Irving 2008):

$$\dot{x} = Ax + Bu$$
$$y = Cx + Du$$

where x is the state vector, y is outputs, u is inputs, A is the state matrix, B is the input shaping matrix, C is the output shaping matrix, and D is the feedthrough matrix. The entries in the A, B, C and D matrix are dependent on both the system operating condition and the parameters of the unit under consideration. The dominant roots (i.e., eigenvalues) of this system are frequently complex, given by

$$\lambda_i = \sigma_i \pm j\omega_i$$

where λ_i is the i^{th} eigenvalue of the state matrix such that

$$A\phi_i = \lambda_i \phi_i, \ \forall\, i$$

where ϕ_i is the system's i^{th} right eigenvector. The characteristic response is commonly represented as the weighted combination of the resultant exponential and sinusoidal time responses due to these roots. For complex conjugate roots, oscillation frequency in Hz is given by

$$f_i = \frac{\omega_i}{2\pi}$$

and the damping ratio is given by

$$\zeta_i = \frac{-\sigma_i}{\sqrt{\sigma_i^2 + \omega_i^2}}$$

A larger damping ratio indicates that the system is "relatively more stable" than one with a smaller damping ratio (i.e., oscillation dies out more rapidly). A damping ratio greater than zero is stable. A system with a damping ratio of one will be critically damped and experience no overshoot and no oscillation. Light damping (i.e., small ζ) of a dominant eigenvalue pair, however, is indicative of a system under significant stress, and operations may be constrained in various ways. For example, AC transmission flows will be reduced due to oscillatory behavior.

Thus, for a given unit, at a certain operating condition, analytical methods can be utilized to compute the eigenvalues and damping ratio that quantifies the small-signal stability attribute.

Simulation Methodologies

Digital simulation can be used to assess the stability value of PSH by 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, etc.). Simulation data is compared to measured data to confirm model validity. Small-signal stability can be investigated under the influence of variations like those the PSH unit would experience in its day-to-day operating environment. A test matrix like the one shown Table 4.7 is then used to evaluate the system in various modes of operation with disturbances applied. With the data from the simulation results, numerical techniques like Prony analysis can be used to quantify the small-signal stability attribute.

Prony Analysis

By decomposing the signal into various decaying sinusoids, Prony analysis helps extract the damping information of system frequency from simulation runs made in power system stability simulation tools for small-scale disturbances (Hauer et al., 1990). It is specifically used to compute the damping ratio of system oscillations with the simulation runs that result in ringdown events (e.g., a self-clearing fault). Even though Prony analysis suggests system modes that are lower in order than the actual system, it is an useful tool to help identify individual modes of a system without constructing individual component-based model of the system. Using Prony analysis and PMU data of a post-disturbance ringdown events, PSH operators can estimate the modes of the system and understand how the PSH plant can be strategically used to improve the damping and overall stability of the system. An alternative to Prony analysis could be the use of industry-preferred software like PSSE, which provides add-on tools that can perform small-signal stability analysis of the large-scale power system. Using these tools, power system engineers can obtain the overall damping ratio and eigenvalues and assess the stability of the system under consideration.

4.5.5. Transient Stability

Transient stability is defined as the ability of the power system to return to a steady state after a large disturbance. Large disturbances in this context can be step load changes, faults on transmission lines, transmission line section trips, generator outages, etc. Transient stability assessment is performed most effectively using real-time simulations in large, high-fidelity models of the system being tested. When available, HIL simulations are useful for evaluation of a proposed control system (e.g., with the controller implemented in hardware), stability enhancement devices integrated with the PSH unit, or system protection devices including protective relays.

Conceptually, transient stability is best understood by examining what occurs when a PSH unit's electric power output in generation mode (consumption in pump mode) drops due to some large disturbance. The mechanical input (output) power of the PSH unit will stay constant, thanks to the relatively slow response rate of the hydrogovernor system.. An accelerating (decelerating) torque is applied due to the electric and mechanical power imbalance. Thus, the PSH unit will "spin up" ("spin down") storing (utilizing) kinetic energy in (from) its rotor due to this acceleration (deceleration). At the instance of re-leveling the electric power, the question to be answered then becomes: Has sufficient kinetic energy transferred to (from) the rotor during spin up (spin down) to maintain stable operation of the PSH unit?

Analytical Methodologies

One analytical technique for assessing transient stability of the grid is called the equal area criterion (Anderson and Fouad 2002; Kundur, Balu, and Lauby 1994). The mathematical formulation of this is provided below from the perspective of a proposed PSH unit. The equal area criterion for power system stability studies provides a key metric to assess system stability: the critical clearing time (CCT) (Anderson and Fouad 2002), which is the length of time for which the machine maintains synchronism while experiencing a disturbance. A power system is considered to be stable (unstable) if a fault is cleared before (after) CCT. If the large disturbance or fault is cleared before CCT, the machine will be able to correct the rotor angle error. If the fault is not cleared, then the machine will lose synchronism and must trip, taking the unit offline. In other words, CCT can also be understood as the maximum time for which a fault can be sustained. If the fault is cleared fast enough, the system can remain stable, so it is desirable for the fault to clear as quickly as possible.

The equal area criterion can be explained with the illustration in Figure 4.9. Kinetic energy is gained by the rotor during acceleration when the rotor angle, δ, changes from δ_0 to δ_1, when the mechanical power changes from P_{m0} to P_{m1}. The energy gained is calculated as follows:

$$E_1 = \int_{\delta_0}^{\delta_1} (P_m - P_e) d\delta = A_1$$

Similarly, the energy lost during deceleration when the rotor angle changes from δ_1 to δ_m is calculated as follows:

$$E_2 = \int_{\delta_1}^{\delta_m} (P_e - P_m) d\delta = A_2$$

These energy values, illustrated in Figure 4.9, form the basis for transient stability analysis. Stability is maintained if A_2 can be obtained above the line b-d (see Figure 4.9) and is at least *equal* to A_1. The CCT is the time taken by the rotor angle to result in this energy equality. If, however, A_1 is greater than A_2, stability and synchronism are both lost, since the rotor absorbed more energy than it can return.

It should be noted that a PSH unit's mechanism of transient stability and synchronism depend on the way it is connected to the grid. In an adjustable-speed PSH unit with DFIM, the stator operates at grid frequency while only the rotor is power converter fed. In this case, the power converter should be disconnected from the rotor circuit and a resistance circuit installed, thus making the DFIM a purely asynchronous machine that will not lose synchronism for a long-duration fault (Ledesma and Usaola 2005; Steimer et al. 2014). If the PSH unit is a converter-fed synchronous machine (CFSM), modifications are not required for asynchronous operation. This is because in CFSM design, the cycloconverter directly feeds the stator, with the rotor being DC-field excited. Thus, the CFSM is able to maintain grid synchronism regardless of the asynchronous operational condition of the rotor (Steimer et al. 2014; Valavi and Nysveen 2018).

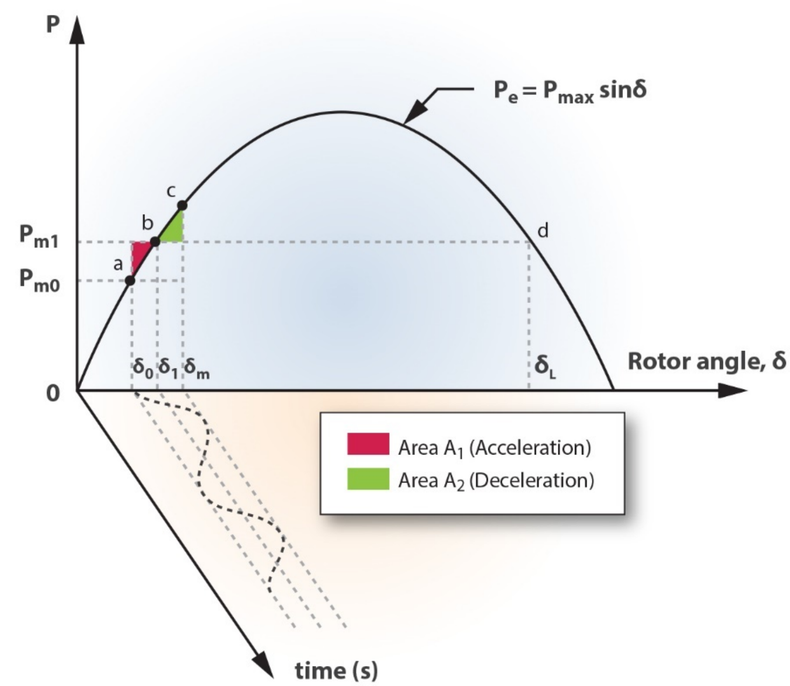

Figure 4.9: Equal area criterion for assessment of transient stability analysis of system with PSH.
Adapted from Kundur, Balu, and Lauby (1994).

Simulation Methodologies

Solving simultaneous nonlinear differential equations is necessary for transient analysis. Therefore, these methods have a high computational burden and often require dedicated computational equipment. Any high-fidelity dynamic power system modeling environment or electromagnetic transient program has the capability to provide a suitable platform to perform transient stability analysis with the PSH unit. The simulation environment can be used to assess faults at various locations and times to determine the magnitude and duration of disturbance events for which the PSH unit maintains synchronism. These disturbance events are applied in various scenarios in the test matrix to assess CCT. The minimum CCT (based on the real power delivered/consumed by the PSH unit) observed across these scenarios is a relevant metric for transient stability and can be computed using dynamic simulation runs on available commercial simulation tools.

Using a multi-machine simulation methodology, the impact of the PSH unit on the stability of the nearby grid can also be evaluated. In this case, multiple faults are executed over a short period of time to represent contingencies for the network attached. The metric for such analysis is the level of contingency in which the PSH unit continued to operate in synchronism, with the greater value being the better solution.

4.5.6. Inertial Frequency Response

Synchronous machines—including generators and loads—have rotational inertia, a property of synchronous machines with large rotating masses that enables them to overcome an immediate imbalance in the system generation and demand. This rotational inertia creates a tendency for the machine to continue rotating at a speed corresponding to the nominal grid frequency immediately after the changes in generation and load. An effect of this rotational inertia is that it affects the rate of change of frequency (ROCOF) immediately after an electrical power imbalance in the grid, and before governors and other controls can respond. High rotational inertia causes the ROCOF to be comparatively lower and vice versa. The system inertial frequency response is represented in terms of ROCOF and frequency nadir/zenith, and these metrics are inversely proportional to the rotational inertia constant. However, as discussed below, ROCOF can also be impacted by inertia emulation and fast frequency controls implemented in the generating units.

Theory

Single-speed PSH units provide inertia directly to the grid, like other synchronous machines. Adjustable-speed PSH units (both DFIM and CFSM) do not directly contribute to overall inertia of the grid due to their asynchronous nature; however, there are some indications that adjustable-speed PSH units do provide some fast frequency response that impacts the ROCOF (Dong et al. 2019; Koritarov et al. 2013; Nagura and Yoshida 2011; Pannatier et al. 2008). The adjustable-speed machines allow the energy exchange between the rotating mass of the machines and the transmission system at variable grid frequency. Thus, it is possible to provide system damping during the transient periods. This is evident from the response of the 400 MW Ohkawachi adjustable-speed PSH plant during the Hanshin earthquake in 1995 (Kuwabara et al. 1996). Assessment of the contributions of inertia from synchronous single-speed machines can be conducted with empirical analysis (Inoue et al. 1997). Inertia contributions from non-synchronous adjustable-speed PSH units and the impacts of synthetic inertia or other fast frequency controls can only be assessed using simulation methods that account for dynamic and transient effects. This is due to the fact that adjustable-speed PSH units are asynchronous in nature and are interfaced to the grid through the use of power converters. Assessing the value of inertial frequency response is important for both synchronous and non-synchronous PSH plants, as it is possible that the presence of the PSH unit may change the relevant planning contingencies and thus valuation of the plant.

Inertial frequency response is critical to grid stability because it slows the ROCOF to the point that controls have the time to stabilize the frequency (corresponding to the "rebound" and "recovery" periods in Figure 4.7). For practical purposes, the ROCOF is proportional to the change in power balance and inversely proportional to the total system inertia. Therefore, more inertia is needed to protect the system against a larger possible power imbalance. In some systems, the ROCOF is relatively homogeneous throughout the system, while in other systems the ROCOF can vary significantly between buses and can largely be a function of connecting impedance (Doheny 2017). In practice, the ROCOF can depend on both operational and fault conditions (Ørum et al. 2015). With PSH units possibly replacing existing synchronous machines in the grid, thus affecting the total system inertia, the response of the system to power imbalances and its ability to maintain frequency stability is of utmost interest to both PSH system developers and grid operators. ROCOF is a metric of inertial frequency response that can be attributed to the frequency stability of the system and can be directly affected by PSH units or their contribution to total system inertia.

Analytical Methodologies

The value of inertia in the grid depends on its impact on system frequency stability. Synchronous machines provide a set level of inertia when they are online, regardless of their current output. Therefore, the significance of inertia in frequency stability will be highest when the largest possible trip of generation and/or load is possible and when there is the least amount of inertia in the system. Typically, the hours when inertia is the lowest are those when there is high solar and wind penetration (ERCOT 2018). The possible fault size depends on the grid system characteristics, such as fault current magnitude for transmission and MW capacity for large baseload generation plants. In some systems, it may be important to consider the propagation of the frequency disturbance through the system, and in other instances this may not be necessary.

An initial basic assessment of whether or not inertia contributions from a proposed PSH project will likely have a measurable impact on inertial frequency response in a given balancing authority area can be performed using analytical methods to assess whether or not system inertia is expected to be close to critical minimal values within a given area.

All of the inertial frequency response methods outlined below require an understanding of the PSH plant's physical properties, because they determine its inertia constant. In particular, the inertia constant H is proportional to the machine's moment of rotational inertia J and its initial frequency ω_0 and inversely proportional to its rated power P_{mva}. The complete theoretical formation for the inertia constant is $H = \frac{J\,{\omega_0}^2}{2\,P_{mva}}$ (Stevenson 1982). Some of the analytical methods outlined below require specific values of the inertia constants of other units in the system while other methods do not.

Three analytical approaches can be used to assess the potential value of inertial frequency response. The purpose of implementing the statistical methods is they are relatively easy to utilize and will provide a first approximation of whether or not a proposed PSH plant (with single or multiple PSH units) will have a measurable impact on inertial frequency response and in which conditions. Therefore, the statistical methods can be implemented for a few of the scenarios involving the lowest anticipated system inertia and largest possible trips (in terms of fault current magnitude for transmission line and MW capacity for large baseload generation plants). Through these statistical methods, an approximate of the total system inertia constant is computed first, then, based on the disturbance scenario considered, the system ROCOF is approximated. It is recommended that more precise simulation methods be pursued for understanding the inertial frequency response contribution if the statistical methods indicate a measurable impact.

Method 1: Polynomial Fit at Arbitrary Location

The polynomial fit at an arbitrary location method involves using empirical data for frequency response corresponding to multiple imbalance events to statistically infer the current system inertia for a given set of online generators (Ashton et al. 2013; Inoue et al. 1997). The inferred inertia can then be manipulated to account for the addition of the PSH unit to assess the impact of the plant on the system. The method's efficacy depends heavily on the assumption of all frequency deviations within the specified dead band for the system being analyzed.

The key steps of the method are the following:

1. Collect frequency response time-series for several imbalance events of interest at a single location.
2. For each imbalance event, estimate a fifth order polynomial of the form
$$\frac{\Delta f(t)}{f_0} = A_5 t^5 + A_4 t^4 + A_3 t^3 + A_2 t^2 + A_1 t$$
where f_0 is the initial frequency, $\Delta f(t)$ is the deviation in frequency at a given time, the A_i terms are empirically derived coefficients, and t is the time following the imbalance event. Implementations can use different orders of polynomials to improve the fit as long as the linear term is retained. Results will vary depending on the accuracy of fit and the order of the polynomial.
3. Estimate system inertia constant H_{sys} as
$$H_{sys} = \frac{-\Delta P}{A_1}$$
where ΔP is the change in generation or load (pu in system load base) causing the power imbalance and A_1 is the coefficient for the linear term obtained in Step 2.
4. Estimate the impact of the addition of the PSH unit on inertia through calculation of its contribution to the system's inertia constant using the relationship
$$H_{sys} = \frac{\sum_i P_{mva,i} H_i}{\sum_i P_{mva,i}}$$
and then back-substituting the modified results through Steps 3 and 2.

This method requires the smallest amount of data and makes the largest number of assumptions. For example, there are differing views about the best polynomial order to use. If this method is implemented, multiple polynomial orders should be tested. The empirical results will also depend on the time window used for fitting the polynomial. Again, there is no strict rule, and multiple time window lengths should be tested. The polynomial order and time window length should be selected based on the best reproduction (with minimum squared fitting error) of the measured time series.

The method also assumes that the electrical system (for example, balancing authority or interconnection) responds uniformly. This is a major assumption that should be assessed prior to implementing this method. Similarly, the method assumes a linear relationship between changes in inertia constant and inertial frequency response, which holds well for a certain duration of frequency transients but is less true once the effects of the disturbance propagate and cause additional units to trip.

Method 2: Frequency at a Neutral Location

The frequency at a neutral location method empirically estimates the inertia frequency response using a slightly different formulation than the polynomial fit at an arbitrary location approach outlined above (Ørum et al. 2015). It requires the identification of a "neutral" location in the system, which can be determined using a number of different approaches.

The key steps of the method are the following:

1. Identify a "neutral" location in the system. In a system where the frequency is close to uniform, the neutral location can be chosen based on its convenience for implementing the following steps. If frequency response to electricity imbalances varies across the system, a location for which PMU frequency measurements are available and where the frequency is the closest to the center of inertia frequency should be chosen (Ørum et al. 2015).
2. Collect frequency response time-series for several imbalance events of interest at the neutral location.
3. For each frequency event, average the frequency for 700 ms beginning 150 ms after the onset of the disturbance. Calculate the change in frequency from before the disturbance to the average obtained from the 700 ms time window.
4. Calculate the ROCOF as the change in frequency from the previous step divided by the time between the onset of the frequency disturbance and the mid-point of the time window (i.e., 500 ms).
5. Estimate the system inertia by solving the equation:

$$\frac{df}{dt} = \frac{-\Delta P}{2\, H_{sys}\, P_{sys}}$$

   where $\frac{df}{dt}$ is the ROCOF and P_{sys} is the sum of rated power from the online generators.
6. Estimate the impact of the proposed PSH plant on inertial frequency response by calculating its contribution to the system's inertia constant using this relationship:

$$H_{sys} = \frac{\sum_i P_{mva,i}\, H_i}{\sum_i P_{mva,i}}$$

   and then back-substituting the modified results through the Steps 5 and 4.

This method assumes that the frequency response at the neutral location is representative of system conditions. For some systems this may be a good approximation and for others not, depending on the uniformity of the frequency throughout the system.

The results also depend on the time window averaging used. The window can be adjusted if total system inertia information is available by comparing the theoretically derived ROCOF and the time-averaged measured system response.

Method 3: Approximated Center of Inertia Frequency

The center of inertia (COI) frequency method starts by formulating a theoretical COI in a given system, which has a frequency labeled f_{COI}, defined as follows (Ørum et al. 2015):

$$f_{COI} = \frac{\sum_i H_i f_i}{\sum_j H_j}$$

Where:
H = the inertia constants of each generator in the system
f = the frequencies of each generator in the system (Akbari et al. 2010).

In practice, if the frequency is not known at each generator, the system can be divided into several zones and the COI frequency can be approximated as follows:

$$f_{COI} = \frac{f_A \sum_i H_{A,i} + f_B \sum_i H_{B,i} + f_C \sum_i H_{C,i} + \cdots}{\sum_j H_{A,j} + \sum_j H_{B,j} + \sum_j H_{C,j} + \cdots}$$

where the zones should be chosen such that frequencies are homogeneous within them. The zones can be comparable in size; however, that depends upon the zoning criteria. The Nordic power system, for example, uses bidding criteria to define the zones (Ørum et al. 2015), while post-fault power flow, voltage and generator stability analysis are used in the British power system (Ashton et al. 2015). It is necessary to have PMU frequency measurements at one location within each zone. Therefore, calculating the COI frequency requires knowing the inertia constants of all the generators (and synchronous loads of comparable size) in the system.

The key steps of the method are:

1. Identify appropriate zones for implementing COI frequency inertia equation. The requirement is that the frequency of generators within a given zone should respond uniformly in varying grid events. The grid events are specified by the interconnection study requirements of the host RTO.

2. Use well-distributed PMU measurements (the minimum is at least one measurement in each zone) to estimate the effective inertia constant *H* of each zone. In this formulation, the *H* values are calculated empirically rather than using existing machine-level information. Note that the empirical *H* values will depend on the mixture of online generators. Therefore, this method must be implemented for each combination of online generators of interest to calculate effective inertia constants for each zone based on generator operations.

3. Calculate the *H* value of the proposed PSH plant on the center of inertia frequency response based on its machine-level characteristics, identify the zone it will be added to, and modify the relevant zonal *H* value for the given zone. The plant may contain a combination of fixed-speed and adjustable-speed PSH units, and the dynamic simulation and modeling for multiple PSH units sharing a common penstock (Koritarov et al. 2013) can be leveraged for *H* value calculation.

4. Use the original and modified center of inertia formulations to estimate the impact of the proposed PSH plant on the center of inertia frequency. For each frequency event, calculate the time-series of COI frequencies corresponding to the event and fit a line to the COI frequencies for the first 400 ms (i.e., 24 cycles in 60 Hz system) after the onset of the disturbance event. The slope of the line is the empirical ROCOF.

Utilizing the various analytical techniques mentioned above, the system operator can become aware of current system inertia conditions and infer ROCOF and other inertial frequency response metrics of the system. This awareness of system inertia and its implications for inertial frequency response is crucial for enabling operators to be prepared for certain operational situations involving low system inertia and its detrimental impact on system frequency stability.

Currently, there is no market mechanism to incentivize either the inertial frequency response from conventional synchronous generators or fast frequency response from asynchronous generators. However, as the penetration of inertia-less, converter interfaced resources continues to increase, it is becoming more evident that inertial frequency response will become a valuable trading commodity in the future ancillary services market. In such a scenario, asynchronous PSH units are expected to receive adequate compensation for their fast frequency response

Simulation Methodologies

A primary value driver of inertia is that it provides more time for frequency response resources to arrest the decline in frequency before measures such as load contracts (i.e., manual load shedding) and under-frequency load shedding (UFLS) must be implemented. The UFLS frequency, f_{UFLS}, may vary by jurisdiction, and the amount of time required for frequency response resources to arrest the frequency change will depend on the system state. As a general rule of thumb, frequency response resources will require approximately 1.5 seconds (i.e., 90 cycles in 60 Hz system) to be implemented and arrest the frequency (NERC 2016). Therefore, the following condition should hold for inertial frequency response to be adequate:

$$ROCOF < \frac{f_0 - f_{UFLS}}{1.5\ s}$$

The above metric provides a good first approximation for synchronous inertia requirements. However, the appropriate time constant will depend on several factors, including the size of the trip and the frequency response assets available. It is the best to assess the inertial frequency response in an environment that enables calculation of the nadir of the frequency deviation. The combined objective of the inertial frequency response and fast frequency response is to limit the frequency deviation to prevent load shedding or additional unit trips. Additional recommendations for determining minimum synchronous inertia requirements can be found in NERC (2016).

To verify the inertial frequency response adequacy in the equation above, first ROCOF is computed based on the frequency data recorded from the simulation. This simulation is carried out for multiple disturbances in a system, and the pre-disturbance and post-disturbance frequency time series are recorded till the frequency nadir or zenith is reached. Once ROCOF is determined, system inertia can be computed based on the mathematical equations discussed above. Using this simulation methodology, the virtual inertia emulation of the PSH unit can be tuned to ensure that the inertial requirements mentioned above are met as well.

4.5.7. Primary Frequency Response

Primary frequency response refers to the governor response provided by conventional (synchronous) PSH units and fast frequency response provided by adjustable-speed (non-synchronous) PSH units. It is the ability to support automatic and autonomous frequency correction, after the frequency excursion has been arrested, through the inertial frequency response. Primary frequency response needs to be assessed to understand the speed and robustness with which it can contribute to grid frequency correction.

Theory

While inertia of individual synchronous generators (as well as other synchronous loads) can slow the initial system ROCOF in response to a frequency disturbance event (Section 4.5.6), active control of the mechanical prime mover (e.g., the rate of water flowing across turbine blades) is needed to fully achieve an acceptable frequency nadir and then restore the system's default frequency. It is a type of proportional control on the frequency. Various mechanisms are in place to perform these functions. Between about 1 and 10 seconds after an event, speed governors of individual generators are a major contributor to overall primary frequency response (Blalock, Cummings, and Bauer 2015). The large difference in reaction time after a frequency disturbance is driven by the fact that hydrogovernors are rate-limited for stability because of the non-minimum phase dynamics caused by the inertia of the water column. This makes hydrogovernors slower than other types of governors. Restoration of frequency to nominal values is typically carried out through AGC, which adjusts the power output of multiple generators to match generation and load within the balancing authority. The primary difference between governor response and AGC is that governor response logic is programmed into each generator (with logic typically hard-coded into individual generators), whereas AGC is centrally coordinated.

Analytical Methodologies

Speed governors have two set point features—dead-band and speed droop—that impact their response to frequency deviations and enable multiple independent generators to respond to frequency disturbance events (NERC 2011), as shown in Figure 4.10 (NERC 2012a). The combined purpose of dead-band and speed droop is to increase system stability for systems with multiple independently operated generators. If these set points are poorly chosen, for example, if there is no dead-band or too large of a droop, then the collective action of individual generators could decrease system stability by causing a net overreaction to an event.

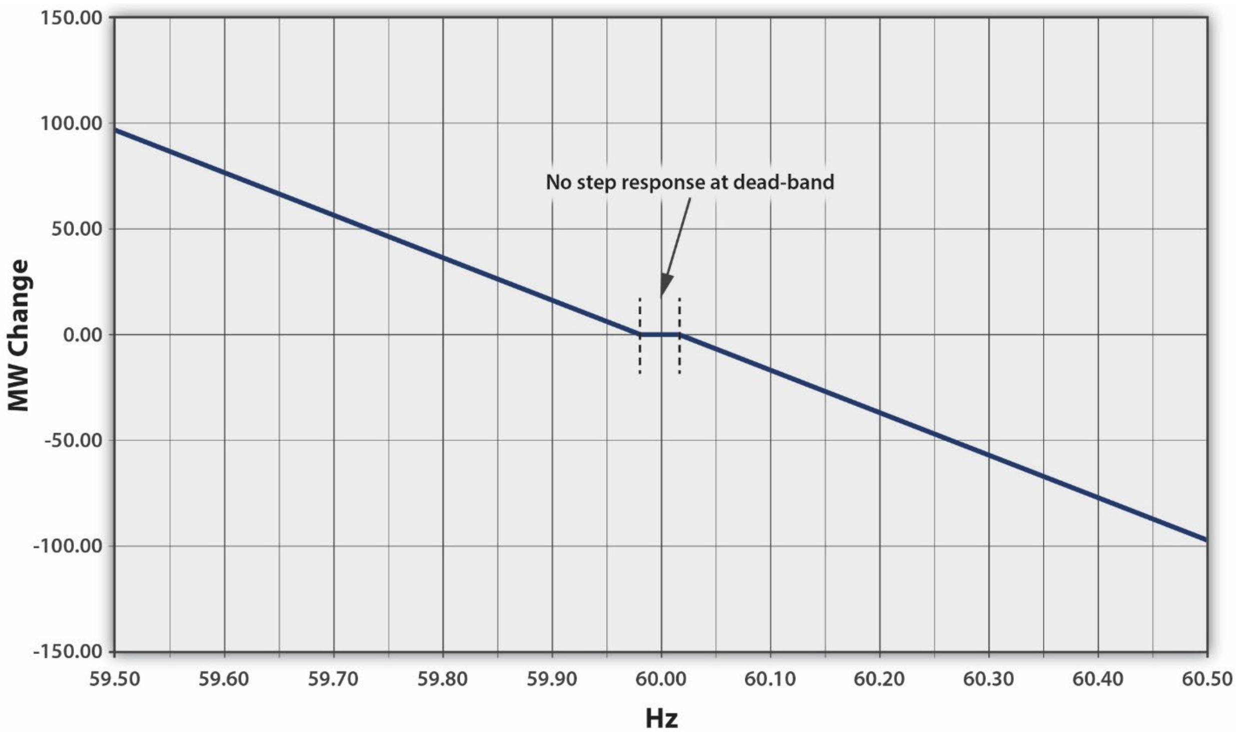

Figure 4.10: Governor response of 600 MW unit. Dead-band is the frequency range for which the power output does not change, and the droop is reflected in the slope of the power output change.
Adapted from NERC (2012a).

Governor set point requirements are typically determined at the transmission interconnection level (NERC 2015). For example, in ERCOT, dead-band requirements range from ±0.017 to ±0.034 Hz, and maximum droop settings range from 4% to 5% (NERC 2015). Overall, the typical effect of the governor frequency response is to modulate power output of a given generator by less than 1% of capacity for about 120 seconds (Blalock, Cummings, and Bauer 2015); however, these parameters depend significantly on the particular event and the overall system characteristics, and in certain settings unit operators may disengage governors because they are not compensated (see NERC 2012 for a discussion of the costs associated with providing frequency response).

The value of governor response to frequency events depends on the size of the event and the interconnection state: which generators are online, their governor attributes, and the percent of capacity at which they are generating prior to the event (NERC 2011). Holding inertia and other factors constant, similarly sized frequency disturbance events will cause a larger frequency deviation when there is less governor response capacity, because speed governors are the primary means of arresting the frequency change. There is also a general trend of decreasing governor response in some interconnections (NERC 2011).

The frequency response analysis tool (FRAT) (Etingov, Kosterev, and Dai 2014) can be used to assess the governor response capacity at the PSH plants. The PNNL-developed frequency response analysis tool automates and systematizes the process of calculating the frequency response based on phasor measurement unit (PMU) observations and supervisory control and data acquisition (SCADA) observations. The FRAT tool provides the measure of primary frequency response based on the frequency nadir and NERC's technique using the pre-fault frequency and an average post-fault frequency over the 20–52 seconds duration. The FRAT tool utilizes analytical methodology to estimate the interconnection frequency response measure for a single event:

$$FRM_{interconnection} = (P_{GenLoss} - P_{LoadLoss})/10(f_B - f_A)$$

Where $P_{GenLoss}$ is an interconnection generation loss
$P_{LoadLoss}$ is an interconnection load loss
f_A is average interconnection frequency before disturbance average out for 16 seconds
f_B is average interconnection frequency after disturbance averaged for 20 to 52 seconds

Simulation Methodologies

The role of governor frequency response is to arrest frequency after an event. Therefore, metrics of governor frequency response adequacy must be based on the extent to which frequency excursions are arrested during the primary frequency response period. Stability metrics for governor frequency response may also include a time component to assess how long the system takes to stabilize. Simulation methodologies help us imitate frequency excursions and their durations for various operational scenarios of PSH units and system operating conditions.

NERC has developed a frequency response characteristic survey (NERC 1989) that provides a methodology for assessing governor response. The survey methodology visually outlines the specific points in the frequency response curve associated with a given event to use in the governor response analysis, but does not define the sampling intervals. NERC Bal-003-1 requires that the frequency should be sampled for 16 seconds prior to the event to determine the nominal frequency and 20 to 52 seconds after the event to determine the arrested frequency corresponding to governor frequency response. System operators and planners can verify these requirements from the simulation results to assess the primary frequency response contribution of PSH units.

4.5.8. Voltage Support

It is important to maintain system-wide voltage profiles within predefined intervals; thus, it is prudent to verify how the voltage support capabilities of the PSH plant perform in static and dynamic conditions. Insufficient availability of reactive power following a disturbance can lead to lower voltage, eventually leading to voltage collapse and system instability. Voltage support from generating units generally have a local impact, but the voltage at various locations in the grid can be controlled by the supply of reactive power from generators or other system devices, such as capacitor banks, throughout the system. Likewise, PSH units can provide voltage support based on their capacity and control topology to enhance the overall voltage stability of the system.

Theory

The attribute associated with voltage support (i.e., voltage stability) is defined as the ability of a system to maintain acceptable voltages at all buses within a given system in both steady state and transient conditions. Insufficient reactive power is the main cause of voltage instability in the same way that torque and active power imbalance is the cause of rotor instability. Voltage support, in turn, is the ability of a unit to provide reactive power to the grid to support voltage magnitude and therefore stability. Voltage support can take the form of either reactive power generation or absorption, depending on the voltage conditions of the grid.

Voltage instability typically occurs in heavily stressed systems and is typically a local phenomenon with the ability to impact large areas. The effects of weak transmission networks and high power transfer are compounded by saturated load-tap changing transformers and other reactive device settings. To illustrate, a radial transmission line connects a generator to a load, as shown in Figure 4.11. The supply voltage E_S drops across line impedance $\bar{Z}_{LN} = Z_{LN}\angle\theta$ and current $\bar{I}$ to the receiving end load with voltage $\bar{V}_R$, load impedance $\bar{Z}_{LD} = Z_{LD}\angle\phi$, and received complex power $\bar{S} = P_R + jQ_R$.

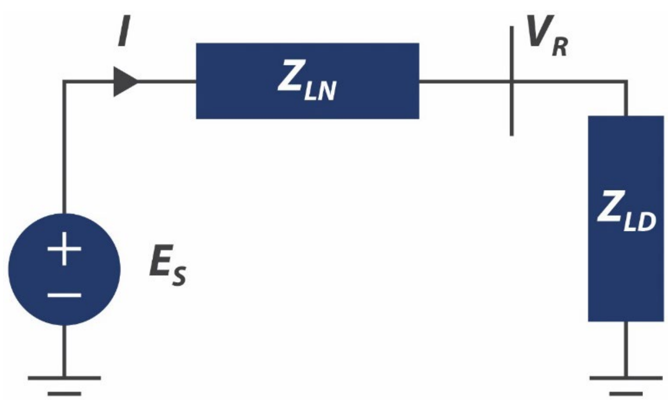

Figure 4.11: Radial transmission line.
Adapted from Kundur, Balu, and Lauby (1994)

Relevant relationships are related through line current and receiving end voltage and are useful in illustrating the influence of generator characteristics, loads, and reactive power devices. These relationships are as follows:

$$I = \frac{1}{\sqrt{F}}\frac{E_S}{Z_{LN}}$$

$$V_R = \frac{1}{\sqrt{F}}\frac{Z_{LD}}{Z_{LN}}\ E_S$$

$$\text{where } F = 1 + \left(\frac{Z_{LD}}{Z_{LN}}\right)^2 + 2\left(\frac{Z_{LD}}{Z_{LN}}\right)\cos(\theta - \phi)$$

$$P_R = \frac{Z_{LD}}{F}\left(\frac{E_S}{Z_{LN}}\right)^2\ cos\phi$$

To illustrate the trends associated with voltage instability, consider Figure 4.12, an adaptation from Kundur, Balu, and Lauby 1994. As the load increases (i.e., Z_{LD} decreases), a corresponding increase in power P_R takes place, eventually maxing out at a "critical value." At this point, maximum power is transferred at the point at which load and line impedance magnitudes are the same (alternatively, their ratio is unity). Beyond this critical impedance ratio, power decreases as loading increases. Simultaneously inspecting voltage and current indicates that while there are two operating points which satisfy the specified power transfer, one requires considerably less current while maintaining an acceptable voltage (see "normal operation" in Figure 4.12) while the second operating point requires significantly more current while at a much lower voltage ("abnormal operation" in Figure 4.12).

The load-voltage characteristic is important to determining how the load responds to a low-voltage event; static loads may stabilize at too low a voltage, for example. Worse, voltage controlled systems (including load-tap changing transformers, for example) can exacerbate the problem and cause voltage reduction by decreasing load impedance Z_{LD} in response to low voltage, further lowering voltage. This phenomenon, known as voltage collapse, shows that voltage stability is also a function of the load (i.e., it is load dependent).

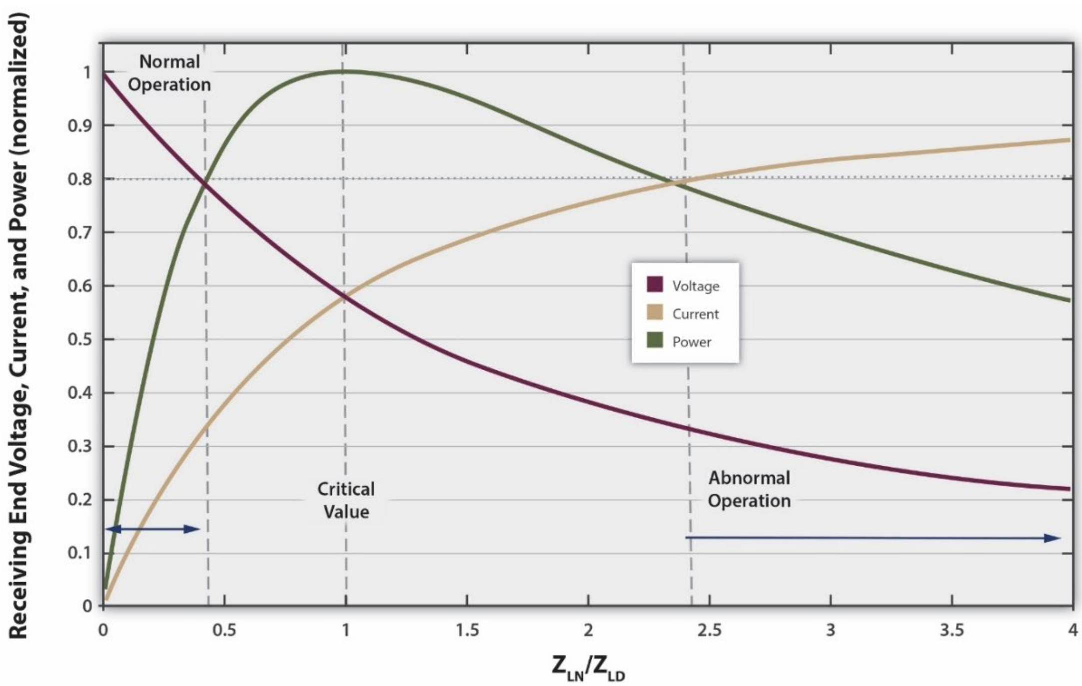

Figure 4.12*: Voltage stability curves.*
Adapted from Kundur, Balu, and Lauby (1994)

Analytical Methodologies

Like the analysis requirements found in machine synchronism studies, the value of small and large-signal voltage support can be assessed with linearized (small-signal) and simulated (large-signal) methods. Recall that the different study methods are useful for decoupling the linear and nonlinear phenomenon and that the information gleaned from one method of analysis complements the other. The two methods attempt to answer three questions: 1) How close is the system to destabilization? 2) Why does a given instability take place? and 3) To what parameters is the destabilization sensitive?

For small-disturbance voltage stability, analysis of voltage and reactive power (V-Q) sensitivity is usually pursued. That is, a system is deemed stable if and only if the sensitivity of voltage with respect to reactive power is positive for every bus in the system. Therefore, an incremental increase in reactive power should result in a positive voltage increase if the system is stable. If the load power factor decreases, and so does the voltage, the system is not small-signal voltage stable. To study this phenomenon analytically, a state-space (linearized) set of equations, based on the network constraints described in their basic form, follows the form below:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_{P\theta} & J_{PV} \\ J_{Q\theta} & J_{QV} \end{bmatrix} \begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix}$$

Where
ΔP = incremental change in bus real power
ΔQ = incremental change in bus reactive power
$\Delta\theta$ = incremental change in bus voltage angle
ΔV = incremental change in bus voltage magnitude

The elements of the Jacobian matrix pre-multiplying the input vector provide information about the sensitivity between the flow of power and changes in bus voltage. Those familiar with power flow (also called load flow) analysis of a static power system recognize this set of equations as equivalent to the "power flow equations" providing a static snapshot of the system conditions at a given time.

With this formulation, modal and eigen-analyses similar to that encountered in small-signal rotor stability are possible. Eigenvalues and their location in the complex plane are used as an indication of stability. Sensitivity of voltage relative to reactive power:

$$\frac{dV_k}{dQ_k} = f(\lambda_k, \lambda_i)\ \forall\ bus\ i$$

is also readily available for each bus k in the system using this analysis. Finally, eigenvalue magnitudes such as $\sqrt{Re\{\lambda_i\}^2 + Im\{\lambda_i\}^2}$ are useful as indications of how close a system is to instability (Kundur, Balu, and Lauby 1994).

A widely used metric for understanding the contribution of a PSH plant to voltage stability is the participation factor (P_{mi}). The participation factor of the PSH plant for voltage support can be computed as follows:

$$P_{mi} = \frac{\Delta Q_m\ for\ machine\ m}{maximum\ \Delta Q\ for\ all\ machines}$$

The participation factor quantifies the voltage support one machine can provide with respect to other assets on the grid. However, reactive power for voltage support is mostly localized to the bus or nearby buses in the connected grid. The relevant measure is the ability of a PSH unit to respond to voltage variation with reactive power and the impact it has on post-disturbance voltage levels. A description of the maximum reactive power Q available in various real power P production scenarios is relevant to the ability to maintain voltage within the required constraints of the grid. The voltage stability performance should be used to assess the minimum and maximum voltage extremes or extreme differences from nominal values at the PSH plant bus.

Simulation Methodologies

Dynamic analysis for large-disturbance voltage stability echoes the approach described in the study of transient machine synchronism. However, due to the load sensitivity mentioned earlier, modeling and simulation accuracy rely heavily on load model accuracy and often require significantly longer simulation times in order to capture the longer-term dynamics of voltage-controlled devices (e.g., load tap changer transformers).

From a PSH plant perspective, voltage stability service requires being able to provide reactive power on demand while maintaining the real-power supply during normal and abnormal conditions. The systems level approach and simulation conditions for interpreting the PSH plant's contribution to voltage support can be derived directly from the simulations used for assessing small-signal stability and transient stability.

In steady state conditions of operation, PSH reactive power vs. voltage (i.e. $Q - V$) curves are provided with machine-level characterization and information. Usually this information is provided by the manufacturers; however, detailed verification of these characteristics can be conducted. Special emphasis on the accurate modeling of the automatic voltage regulators (AVRs) is key to understanding the voltage support capabilities of a PSH plant.

To quantify a PSH unit's impact on system voltage stability, a post-disturbance metric can be used on the disturbance simulation data. This refers to the number of buses exhibiting post-disturbance voltage above a certain threshold. The threshold can be selected based on the under-voltage load shedding (UVLS) criteria. Due to reactive power exchange from the PSH unit, the post-disturbance voltage across the critical loads can settle above the UVLS threshold, thus ensuring stable system operation.

Simulation techniques can help compare various PSH technologies and their respective voltage supports. It should be noted that voltage support from generating units is typically obtained through the interconnection requirements.

4.5.9. Stability Modeling of Pumped Storage Hydropower

Digital representations of the PSH unit are required for each of the digital simulation methods. The digital representation is a mathematical formulation of individual components and their interactions that is suitable for digital modeling platforms. Therefore, the precise formulation of the digital representation may vary with the modeling platform choice.

The overall PSH system to assess is composed of subsystems including the hydraulic components, electrical components, and the relevant electrical grid. Figure 4.13 provides a basic overview of these sub-systems for the case of a DFIM design. The power converter is an AC-DC-AC cycloconverter that feeds the variable frequency AC field excitation. The components will vary depending on design. For example, in a CFSM, the cycloconverter feeds the armature while the rotor has DC field excitation (Valavi and Nysveen 2018). Such a power converter would not be required for a synchronous turbine/pump design.

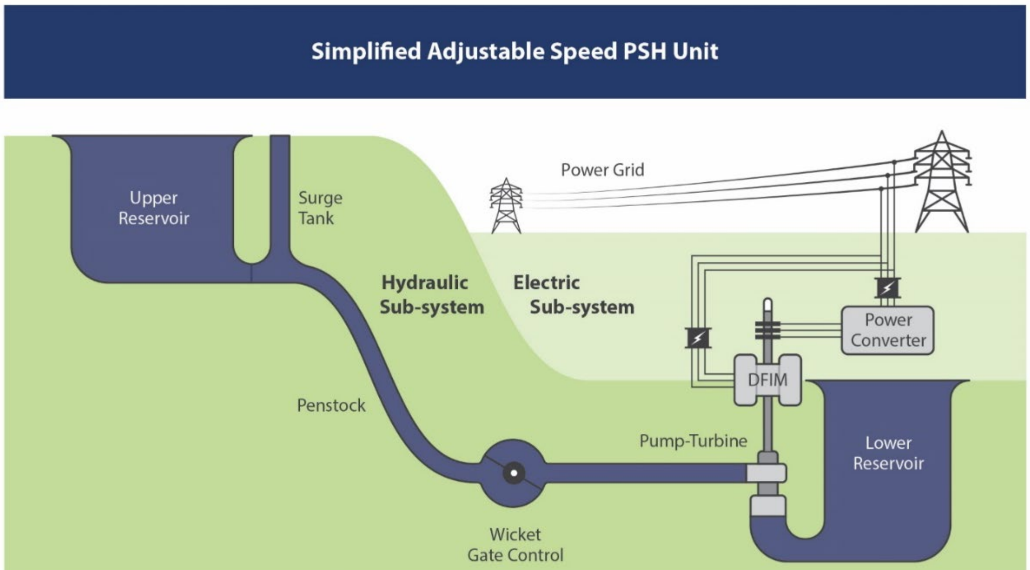

Figure 4.13: Representation of an adjustable-speed closed-loop PSH unit. The power converter is an AC-DC-AC cycloconverter feeding the variable frequency AC field excitation.
Adapted from Mohanpurkar et al. (2018).

Model Development

Digital representations of other units in the power grid can often be obtained from libraries or entities that regularly do planning analysis, such as utilities or balancing authorities. If available, a digital blueprint of the actual power grid that the PSH plant will be connected to should be used. In instances where the digital blueprint is not available, it is appropriate to use an IEEE test system. If using an IEEE test system, it is critical that the test system reflects the attributes of the actual grid. Some of the attributes to match between systems are the amount of generation from specific energy sources (e.g., thermal, hydro, solar, wind), interconnection loads, circuit breaker logic, and temporal differences in grid conditions. Additionally, multiple versions of the digital test grid should be developed to reflect current conditions and projected future states relevant to the design-life of the project.

Digital Representation of PSH Unit

The highest fidelity means of assessing how a proposed PSH unit will integrate into the power system and impact system stability without conducting field testing is to implement a digital model. PSH plant operation and power system stability analysis involve multiple time-scales that must be represented in the digital representation. Ensuring this fidelity in a digital environment requires either characterizing the system using HIL testing or implementing partial differential equation representations of the PSH sub-systems. The two main subsystems that must be considered are the hydraulics and the electronics (Figure 4.13).

Critical components of the hydraulic subsystem include the upper and lower reservoirs, surge tank, penstock, wicket gates, shut-off valves, governor, and turbine/pump. Several sources explain the equations necessary to adequately represent the hydrodynamics, including Mohanpurkar et al. (2018). Thorough descriptions of how to model the turbine/pump and governor systems are provided by IEEE (2013). It is notable, though, that if new technology is going to be deployed, the personnel developing the digital representation should work closely with the device manufacturer to ensure the components are appropriately characterized.

Digital Representation of PSH Electric Subsystem

The electric subsystem is dependent on the type of system chosen for the project. The model will be based on the power motors and generators and control inputs necessary. This will be different for synchronous machine type generation/pumps and DFIM systems.

The components of the electric sub-system include the electric motor(s)/generator(s), power converters (machine side and line side) for AC field excitation of rotor, auxiliary power supply, and main power transformer. The models for the electric components will depend on the components used in the PSH system. The equations used to model the interface between the electric components will depend on the PSH unit configuration. In particular, there are fundamental differences in how to represent different pump/turbine equipment based on whether it is single-speed, adjustable-speed, or ternary. Mohanpurkar et al. (2018) provides the relevant electric system equations for an adjustable-speed PSH unit; Muljadi et al. (2015) presents equations for a generator/power converter dynamic model; Argonne also produced a series of reports detailing how to represent adjustable-speed and ternary PSH units (Donalek et al. 2013, Feltes et al. 2013, Koritarov et al. 2013). Modeling and simulation of quaternary PSH units are recently available from NREL (Dong et al. 2020).

Digital Representation of the Electric Grid

As noted, a digital blueprint of the actual power grid that the PSH plant will be connected to should be used if it is available. The blueprint should provide electric network information as well as dynamic parameters of the connected electric machines. The extent to which the actual power grid model will be used is determined by the interconnection study requirements from the host RTO. Trade-offs between the level of complexity in modeling and cost of evaluation (Figure 4.4) should also be considered. In instances where the digital blueprint is not available, it is appropriate to use an IEEE test system, but it is critical that the test system reflect the attributes of the actual grid where the PSH resource will be located. Some of the attributes to match between systems are the amount of generation from specific energy sources (e.g., thermal, hydro, solar, wind), interconnection loads, circuit breaker logic, and temporal differences in grid conditions. Additionally, multiple versions of the digital test grid should be developed to reflect current conditions and anticipated future states during the life of the project. The extent of the grid that needs to be included may depend on the intended siting of the PSH plant. If there are expectations that dynamics of the topology of the connected grid will be important, a greater portion of the grid may need to be simulated. If there is a strong tie into a substation where the PSH plant is a small element of the overall system, a simpler model may be sufficient. The specific testing of the PSH system may be performed by setting a nearby boundary condition at the connection point of the PSH plant, the substation where it ties into the grid, or the entire system blueprint. Parameters set at the boundary condition include frequency, phase, and voltage profiles established by a set of disturbances, including expected contingency conditions.

Control System Representation

The overall performance of the generator is impacted by the control applied to the system. The control system has a set of inputs provided by sensors and set point inputs and filtered by the control law transfer function to compute actuator command signals. PSH plant and unit sensors are design-dependent, but may include measurements of voltage and frequency at the electric grid, level of reservoirs, position of wicket gate, flow through the penstock, and speed of turbine pumps. The implemented control system combines these inputs to determine the necessary signals to the wicket gate control, commands to power electronics or excitation control, etc. Control system implementation is a prime candidate for HIL testing in real-time simulation and has been shown to solve potential unforeseen issues prior to field testing or commissioning of the unit (Mohanpurkar et al. 2018).

4.5.10. Production Cost Analysis of Primary/Fast Frequency Response

Production cost models evaluate metrics related to system reliability and can be used to estimate the impact of a primary/fast frequency response constraint in an operating cost minimization study of a balancing area or interconnection (Denholm and Jorgenson 2018). Open source, academic and commercial production cost models are available (for example, PLEXOS is a common commercial production cost model).

Production cost models with primary/fast frequency response constraints can be used to estimate whether or not each balancing authority can supply sufficient frequency response in accordance with NERC standard BAL-003-01. They can also be used to assess the costs avoided, or if market products become available, the potential revenue associated with different assumptions for primary/fast frequency response provision. For example, in a case study using this approach, adding a requirement for primary frequency response increased total operational costs in CAISO by about $4/MWh of primary frequency response. This is similar in size to the costs of spinning reserve products in many wholesale markets (Denholm and Jorgenson 2018).

By modeling different constraints and assumptions about available generation resources, this valuation approach can be used to compare the costs of primary/fast frequency response in systems with and without PSH or between a PSH unit and an alternative source of primary/fast frequency response.

Overall, this valuation approach is sensitive to many underlying assumptions. The modeling approach depends on the chosen scenarios of the future generation resource mix (including storage), estimates of how many and which types of generators have the equipment needed to provide primary/fast frequency response, and the actual provision of real energy. The approach is also limited by the addition of considerable computation time.

Prior Studies

Ela, E., V. Gevorgian, A. Tuohy, B. Kirby, M. Milligan, and M. O'Malley. 2013. "Market designs for the primary frequency response ancillary service—Part I: Motivation and design." *IEEE Transactions on Power Systems* 29 (1): 421–431. https://doi.org/10.1109/TPWRS.2013.2264942.

Garcia, M., and R. Baldick. 2019. "Real-Time Co-Optimization: Interdependent Reserve Types for Primary Frequency Response." *Proceedings of the Tenth ACM International Conference on Future Energy Systems*: 550–555. https://doi.org/10.1145/3307772.3335319.

Trovato, V., A. Bialecki, and A. Dallagi. 2018. "Unit Commitment with Inertia-Dependent and Multispeed Allocation of Frequency Response Services." *IEEE Transactions on Power Systems* 34.(2): 1537–1548. https://doi.org/10.1109/TPWRS.2018.2870493.

Zhang, G., E. Ela, and Q. Wang. 2019. "Market Scheduling and Pricing for Primary and Secondary Frequency Reserve." *IEEE Transactions on Power Systems* 34 (4): 2914-2924. https://doi.org/10.1109/TPWRS.2018.2889067.

4.5.11. Avoided Cost Analysis

Avoided costs analysis can be conducted to supplement physical and numeric performance estimates from analytical and digital simulations. This approach is used when potential revenue or costs avoided can be estimated by transferring estimated values from one or more study sites (e.g., a comparable location, time, and application) to a proposed action at another place or time (Boyle and Parmeter 2017; Smith 2018).

For example, in a recent study on the operational benefits of new PSH facilities, a simulation model was used to perform look-ahead optimization in a 24-hour time window with an hour time step across a one-year time horizon in several specific locations. This analysis estimated the potential frequency response in kW per year based on the number of frequency response events at a similarly situated storage asset. The next step in the analysis was then to estimate costs avoided (uncompensated benefits to the system) by multiplying the modeled kW-year of primary frequency response by an appropriate estimate of the value of primary frequency response from a comparable location and application. This study estimated the value of frequency response from an additional small PSH facility in the Pacific Northwest and in CAISO using $52 kW-year, which is the average of two recent primary frequency response contracts between CAISO and adjacent balancing authorities. The transfer of this value was deemed appropriate given the nature of the contracts and the proximity of the actual contracted frequency response values to the location of interest in the analysis.

Avoided cost analysis is sensitive to assumptions about the comparability between the primary benefits value and the study site. Sensitivity testing and switch point analysis can be used to address some of the uncertainties, biases, and omissions associated with this approach. The primary limitation of this approach is the lack of historical price data for stability services;

however, emerging market products and locally negotiated cost-of-service values for stability provide an opportunity to apply this approach.

Prior Studies

Balducci, P. J., et al. 2019. *Shell Energy North America's Hydro Battery System: Final Market Assessment Report*. http://doi.org/10.2172/1526319.

Balducci, P., P. Leslie, C. Jin, C. Daitch, D. Wu, A. Marshall, and M. Kintner-Meyer. 2013. *Assessment of Energy Storage Alternatives in the Puget Sound Energy System.* http://doi.org/10.2172/1114900.

Greenwood, D.M., K.Y. Lim, C. Patsios, P.F. Lyons, P.C. Taylor, and Y.S. Lim. 2017. "Frequency Response Services Designed for Energy Storage." *Applied Energy* 203: 115-127. https://doi.org/10.1016/j.apenergy.2017.06.046.

4.5.12. Summary of Valuation Metrics

Table 4.8 provides a summary of valuation metrics for power system stability services.

Table 4.8: Summary of Power System Stability Metrics

Stability Attribute	Metrics and Units	Application	Value Driver
Machine Synchronism	Eigenvalues, eigenvectors (or mode shapes), eigenvalue sensitivity, and participation factors Fewer components that may resonate (i.e., amplify disturbances) during switching	Synchronous PSH design	• Higher quality power than non-synchronous design • Fewer instances of generation tripping off line due to expected or unexpected disturbances
Small-Signal Stability	Damping ratio 0% to 100% Pole location in complex plane	Synchronous PSH design	• Increase in real energy delivered over greater distances (inter-area steady-state AC line power flow) • Higher generator active output • Improved power quality • Fewer instances of generation tripping off line due expected or unexpected disturbances

Stability Attribute	Metrics and Units	Application	Value Driver
Transient Stability	Equal area criterion Critical fault clearing time (CFT) Rise time, overshoot, oscillating frequency, settling time Additional stability margin	Synchronous PSH design	• Fewer instances of generation tripping off line due expected or unexpected disturbances (generator loading, ride through, etc.)
Inertial Frequency Response	Rate of change of frequency (ROCOF) Critical minimum value Inertia constant ROCOF margin compared to under-frequency load shedding (UFLS) = Hz Measured in energy—how much energy can be injected rapidly into the system—GW-seconds Few estimates of inertial response requirements	Interconnection-wide Single-speed and adjustable-speed PSH design Function of connecting impedance	• Improved power quality • Fewer instances of generation tripping off line due expected or unexpected disturbances
Governor Response	Seconds Interconnection frequency response performance measure = MW/0.1 Hz Under-frequency load shed margin = Hz Cost of maintaining headroom	Interconnection wide (allocated to balancing authorities)	• Fewer instances of generation tripping off line due expected or unexpected disturbances
Voltage Support	Number of buses with voltage violation Participation factor Increased short circuit capacity Low-voltage ride-through for AC-DC converters is improved to prevent cascading voltage	Sub-area within a balancing authority footprint	• Increase in real energy import/export capability • Fewer instances of generation tripping off line due to expected or unexpected disturbances

To identify value in the individual criteria for overall grid stability, value drivers and PSH plant sensitivities must be linked to those criteria. Therefore, influential factors that are key to machine synchronism, frequency regulation, and voltage support are used to identify value driver(s) and relate them to the test matrix.

Principal high-level value drivers for PSH are centered on improving the energy export capability, reliability, and quality of delivered power. By breaking down the benefits from a PSH installation into the physical attributes inherent in a PSH system, the origin of the value drivers can be shown. General system improvements provided by a PSH include the following:

- Improved grid frequency support by quickly sourcing or sinking large quantities of power through the pumped hydro system. Method of study: dynamic simulation, PCM.

- Improved dynamic (i.e., transient) stability, which allows for longer critical clearing times before dispatchable generation goes out of synchronism and non-dispatchable, renewable resources detach from the grid during large disturbance events. Method of study: dynamic simulation.

- Improved voltage stability through automatic VAR control, which leads to a larger energy import/export capability. Method of study: dynamic simulation.

- Minimal or no filtering components required by large installations of passive and active elements such as capacitor, reactor, or static VAR compensator (SVC) banks. This leads to a less noisy power supply that will not resonate with other grid passive components and could prevent excessive voltage spikes due to resonance during element switching. Method of study: analytical, dynamic simulation.

- Improved power quality by utilizing the inertia in the rotating machine to reduce immediate area voltage and frequency fluctuations. This helps non-dispatchable, renewable generation retain connection during grid disturbances and reduces passive element resonance. Is also increases the short circuit capacity of the grid, ultimately reducing the effect of abnormal transients and harmonics. Method of study: analytical, dynamic simulation.

- A dispatchable PSH resource available to grid operators that is considered clean renewable generation and can be used during peaking energy consumption hours (contrary to other clean sources). Method of study: PCM.

Each of the enhancements above is related to the operational characteristics of the PSH unit, but their ultimate impact is directly influenced by the PSH size and point of common coupling location. Static power flow analysis followed by dynamic simulation should be performed at potential POI locations to determine if the system operating limits have been improved, or if other concerns must be addressed (e.g., peak shaving is necessary). For example, if the change in inertia or power transfer capabilities in the surrounding region is not significantly improved, the value of the PSH at that location will be minimal.

Details of the operational characteristics described in the previous sections are summarized in the remainder of this section.

1. **Steady-state synchronism** using the small-signal stability criteria previously presented focuses on a reduced ability of the system to consistently transfer (and consequently, sell) power freely on the market. Power system characteristics related to the small-signal stability of a particular system (as illustrated in Figure 4.8 and associated equations) include the following:
   - Inter-area steady-state AC line power flow
     - Systems with lightly damped dominant modes (i.e., eigenvalues) oscillate with high amplitude for an extended time, reducing the maximum and steady state power transferable along a transmission corridor to the EPS.
     - Method of study: analytical.
   - Generator active power output (loading)
     - Generators operating with large internal rotor angles (that is, those straining to "keep up" with electric load demand) must reduce power output, reducing revenue, to retain synchronism and a sufficient safety margin.
     - Method of study: analytical.
   - Influential generator location within the grid
     - Contributions of a PSH unit to steady-state synchronism of an electric grid depends in part on the impedance by which it is connected. High impedance connections (i.e., X_e in Figure 4.8 is "large") because of long transmission lines due to the remote location of the PSH unit force the unit to operate at a higher internal rotor angle than if connected via low impedance.
     - Method of study: analytical.
   - Excitation system configuration
     - High-gain automatic voltage regulators (AVRs) used in the exciter circuit tend to reduce damping torque while increasing synchronizing torque in normal-to-high steady-state PSH generator output. This can result in generator separation from the system if a power system stabilizer (PSS) is unused or poorly tuned. As a result, PSSs are required for all units of significant output.
     - Method of study: analytical.
   - Power system stabilizer configuration
     - PSSs are used to counteract the negative effects of a high-gain exciter and add necessary damping to generator rotor oscillations. Initialization and tuning of this system is critical to PSH functionality to ensure that it contributes positively to overall system stability.
     - Method of study: analytical.
   - Static and dynamic reactive power devices
     - In addition to modifying the power factor for improved power transfer, passive devices create resonant characteristics which may interact negatively with lightly damped system dynamics (e.g., local oscillations).
     - Method of study: analytical, dynamic simulation.

2. **Transient stability** is infrequently performed by the operator in real-time, as much of the dynamic analysis is done *a priori* during contingency analysis, i.e., assessing the impact of

generator trips and transmission line faults under simulated operating conditions. Planners, forecasters, asset owners, and individuals within a market responsible for unit commitment, however, are concerned with the following factors, which greatly influence transient stability:

- Generator loading
    - The amount of accelerating torque borne stably by the rotor decreases drastically in a faulted condition during heavy loading.
    - Method of study: dynamic simulation.
- Fault location, clearing time, and type
    - The ability for a PSH unit to ride through a transient event and add positively to the transient stability of a network is dependent on the fault type and location, as well as the amount of time the fault takes to clear.
    - Method of study: dynamic simulation.
- Post-fault transmission system reactance
    - Reactance after the fault will greatly influence the transient stability characteristics of the unit, which is tightly coupled to the steady-state consideration of the PSH unit location within the grid.
    - Method of study: dynamic simulation.
- Generator internal reactance (i.e., low reactance increases peak power and reduces initial rotor angle)
    - Modern PSH units typically have low internal reactance, allowing them to operate at a lower initial rotor angle to deliver the required power. This, in turn, reduces the effective generator loading, as mentioned above.
    - Method of study: analytical.
- Generator inertia
    - Accelerating torque acting on the rotor forces an increase in rotor angle as a function of generator inertia; high inertia resists rapid changes in rotor angle, aiding in transient stability.
    - Method of study: analytical, dynamic simulation.

3. **Inertial frequency response** focuses primarily on the ability of the PSH to aid in a reduction in the ROCOF. As described previously, the following characteristics impact primary inertial frequency response:
    - Generator inertia
        - Primary frequency response is improved when large PSH generators are producing appreciable amounts of power. Also see discussion regarding dynamic stability, above.
        - Method of study: analytical.
    - Governor characteristics
        - Primary frequency response is also improved when governor responses are appropriately applied. These responses, associated with the prime mover, change the rate at which the rotor is subject to changes in mechanical torque and hence the ability to adjust rotational velocity to mitigate high ROCOF. Dead-band settings (i.e., the range of rotor velocities for which the governor "does nothing," as in Figure 4.10), also impact the value of a PSH unit's primary frequency response.
        - Method of study: analytical, dynamic simulation.

4. Voltage stability concerns, both small and large-signal, are similar to those associated with machine synchronization. Additional factors are tied to the PSH's AVR, including the following:
   - Voltage control limits
     - To provide reactive power/voltage support, an increase in exciter current is necessary. However, practical limitations (frequently thermal in nature) bound the amount of voltage support a given PSH unit can contribute.
     - Method of study: dynamic simulation.
   - Loading
     - Similar to the concerns relating to synchronism, the ability to increase power output on the fly is limited by practical limitations within the armature and field windings of the generator.
     - Method of study: analytical, dynamic simulation.

5. Power system issues that play a significant role in voltage stability and should be considered in the analysis of a PSH's ability to contribute to stability include the following:
   - Load-tap changing transformers and other reactive power devices
     - Active devices used for voltage tuning and reactive power support (shunt or series) may inadvertently exacerbate sustained low voltage depending upon their location within the system and the device settings.
     - Method of Study: analytical, production cost model (PCM).
   - Load characteristics
     - Voltage sources too far from load centers
     - Method of study: PCM
     - Insufficient load reactive compensation
     - Method of study: PCM.
   - Poorly coordinated voltage control devices
     - Method of study: dynamic simulation.

4.5.13. References

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4.6. System-Wide Impacts of PSH Operations

In addition to estimates of energy and ancillary service value streams, operational modeling can be used to estimate system-wide effects, such as overall production costs, emissions, cycling increases or decreases, and a number of other attributes.

4.6.1. Methodological Approaches for the Assessment of System-Wide Impacts

The most common approach to estimating the system-wide impacts of the addition of a new pumped storage plant is production cost modeling. The production cost modeling approach provides the most information about how a new storage unit would affect system operation; however, it is more complex to implement compared to many other methods. At times, something as simple as a price-taker model is all that is needed (e.g., it can provide a quick estimate of curtailment reduction for a given region). Both methodologies are discussed below.

Types of System-Wide Impacts

The types of impacts that are calculated tend to vary with system and location. Typical classes of impacts include the following:

- Emissions changes
- Curtailment impact
- Capacity value by generator class
- Cycling (starting, stopping, and ramping) of the fossil fleet

Note that the types of metrics that can be calculated for each class of impacts vary with modeling approach and are described in the respective modeling approach section.

Production Cost Approach

Overview

The methodology and models used to assess system-wide impacts are identical to those used for calculating the value of energy arbitrage and ancillary services (the impacts are calculated concurrently with the energy and ancillary services co-optimization). Please see those sections for additional information about the production cost modeling approach.

Metrics and Units

Numerous metrics can be calculated as part of production cost operations modeling or derived from its results. A few of the more common are listed below:

- Overall production cost ($)
- Capacity factor—provides a measure of how much the storage is utilized
- Capacity value (MW)—how much power the storage device provides during times of peak load-related stress
- Curtailment (MWh)—helps quantify how adding storage impacts curtailment
- Pumping load (MWh)—a measure of how much energy was used in charging storage devices (e.g., refilling reservoirs)

- System-wide emissions
    - NO_x (lbs or kg)
    - SO_x (lbs or kg)
    - CO_2 (lbs or kg)
    - Carbon (lbs or kg)—useful in markets that have carbon limits or prices
- Pumping-related emissions
    - NO_x (lbs or kg)
    - SO_x (lbs or kg)
    - CO_2 (lbs or kg)
    - Carbon (lbs or kg)—useful in markets that have carbon limits or prices
- Cycling of the fossil fleet—helps gage the impact on other generators
    - Generator starts/stops
    - Generator start/stop cost ($)
    - Generator ramping amount (MW)
    - Generator ramping cost ($)
- Fuel use (Btu or kJ)

Most of the above metrics are directly available as model output; that is, it is as simple as adding a reporting variable for the parameter of interest. Where a metric is not directly available from the model, it can usually be easily calculated as a part of the post-processing work. For example, generator ramps are typically calculated *ex post* from the time-series results.

Modeling Approach

The key features, assumptions, tools, limitations and prior studies for estimating system-wide effects are very similar to those used for calculating energy arbitrage and ancillary services. Please see those sections for general information about the production cost modeling approach and prior studies.

As mentioned above, much of the system-wide impact-related information is available directly from the production cost modeling results (e.g., curtailment and kilograms of system emissions). Other parameters can be easily calculated from the model's time-series results; for example, emission abatement costs can be derived from the emission results.

Price-Taker Approach

Description

A price-taker approach can be convenient for estimating very limited system-wide impacts for small storage plants in areas where energy and ancillary service prices are known. A discussion of some of the metrics that can be estimated as well as the modeling approach is provided below.

Metrics and Units

As mentioned above, the metrics that can be calculated via a price-taker approach are much more limited. Common examples are listed below:

- Capacity factor—how much the storage is utilized
- Capacity value (MW)—how much power the storage device provides during times of peak load-related stress

- Pumping load (MWh)—how much energy was used in charging storage devices (e.g., refilling reservoirs)

Note that the above metrics will either have to be programmed into the price-taker model or derived from the model's output.

Modeling Approach

The key features, assumptions, tools, limitations and prior studies for estimating system-wide effects are very similar to those used for calculating energy arbitrage and ancillary services via the price-taker model. Please see those sections for general information on the price-taker modeling approach.

While the metrics of interest can sometimes be added to the model, an easier approach may be to derive the metrics from the price-taker model output. For example, generation, pump load, and price streams (commonly available price-taker output) can be imported into a spreadsheet and then used to calculate metrics such as capacity factor, capacity value, pump load, and curtailment impact.

Operational Impacts on PSH Plants

Most of the existing PSH plants in the world, and practically all of the existing PSH plants in the United States, have been designed for a typical diurnal operation cycle, with pumping during the night and generating during the peaking hours of the day and evening. If needed, the PSH plants could perform multiple pumping and generation cycles during the day, but that was rarely necessary. Typically, that kind of operation was needed only in case of special events, such as the forced outages of large coal and nuclear units, when PSH plants were called on to provide backup reserve for capacity on outage.

Since most of the time PSH plants were following their regular diurnal operation cycle, the design characteristics were typically optimized for highest efficiency in full generating and pumping mode of operation. While PSH plants could generate in a wider operating range, operation at lower power outputs was less efficient, especially in the so-called rough zones of pump-turbine operation, which for conventional fixed-speed PSH plants were relatively wide (typically between 40% and 60% of the nominal power output). In addition to lower efficiency, operation in the rough zone was to be avoided because of increased cavitation, shaft vibrations, and other effects that could contribute to premature aging and damage to pump-turbine and other hydraulic and electro-mechanical equipment. As most of the existing PSH plants were using conventional fixed-speed technology, rough zone operation was not an issue in the pumping mode, because they could only pump at full unit capacity. However, that did not allow for much operational flexibility to be provided to the power system during the pumping mode of operation.

With the advance of variable renewables, such as wind and solar, there was a need to provide additional storage and flexibility to power system operations, to be able to integrate larger quantities of variable generation into the power system. As an energy storage technology, PSH plants were called upon not only to provide more ramping up and down to compensate for the fluctuations of variable resources, but to perform multiple daily starts and stops. A good example of this kind of change in daily operations is the Helms PSH plant in California, which used to have a typical diurnal cycle of operation, but in recent years has changed its mode of operation and now is mostly pumping during the day, thus accommodating rapidly increasing solar PV generation in California. The intermittency of solar generation often requires frequent ramping up and down to compensate for the variability. Frequent ramping, starts and stops, and changes in PSH plant mode of operation are likely to cause additional wear and tear on PSH units and equipment, because most of the traditional PSH plants were not designed for this type of operation.

As the need for more operational flexibility has been recognized by power system operators and PSH equipment manufacturers, new and advanced PSH technologies have been developed in recent years. These more flexible PSH technologies include adjustable-speed PSH technologies (doubly fed induction machines and converter-fed synchronous machines), ternary units, and the latest quaternary technology. The conventional fixed-speed PSH technology has also been improved to provide better efficiency, faster ramping rates, and a wider operating range in the generating mode of operation. All of these advanced PSH technologies can provide multiple start and stop cycles per day and can change the mode of operation (e.g., from full pumping to full generation) very quickly, in a few minutes.

In a PSH valuation analysis, it is important to recognize and try to estimate both the benefits and costs of flexible PSH operation. The benefits primarily benefit the power system, while the costs mainly affect the PSH plant. System benefits typically include reduced cycling and ramping of other (e.g., thermal) units in the system, flattening of the net load curve for thermal and nuclear power plants, reduced curtailments of variable generation, and others. On the other hand, increased cycling and ramping of PSH plants may cause increased wear and tear and accelerated aging of their hydraulic and electro-mechanical equipment, require more frequent maintenance, and reduce the time before the major overhaul is needed. These costs may be significant, especially if the PSH plant was not designed for this type of operation.

Both the benefits and the costs of more flexible operation of PSH plants are difficult to estimate. In principle, simulations of power system operations using a detailed production cost model can be used to estimate the benefits by comparing the results of cases with and without the PSH plant. However, the analyst has to separate the portfolio benefits resulting from flexible PSH operations from other benefits and contributions provided by the PSH to the system. For example, some of the portfolio effects of flexible PSH operation may already be included in the value of PSH energy arbitrage.

The main difficulty in estimating operational impacts on PSH plants is that currently there is very limited information available on the cost of increased cycling and ramping of PSH units. The hydropower industry and the U.S. Department of Energy have been funding research in this area in recent years, so more information and data that could be used to estimate these costs should be available in the future.

4.7. PSH Transmission Benefits

Energy storage systems, including PSH, can be used to enhance the operational flexibility of, and remove constraints in, the transmission system. As those constraints are removed, value is obtained and can be monetized. The two transmission services evaluated in this section include transmission congestion relief and transmission deferral.

> *Transmission system congestion* refers to the situation in which the demand for transmission capacity in certain areas of the grid exceeds transmission grid capabilities, as detected by violations of system thermal limits, voltage stability, or angular stability. Transmission system congestion has a wide range of impacts, from the use of power grid infrastructure to the behavior of each market participant. From the market side, the presence of transmission system congestion may prevent the use of relatively inexpensive resources to meet load requirements and may, in addition, facilitate the attempt of a particular seller to exercise market power. From the grid side, attempting to operate a transmission system beyond its rated grid capabilities may trigger unexpected line faults or generator outages. PSH may help with the transmission congestion relief by pumping in an export-constrained zone (a zone with surplus electricity generation that cannot be transferred to other zones due to transmission congestion), or by generating in an import-constrained zone, as instructed by the RTO or utility system operator.

> *Transmission deferral benefits* are tied to the planning of future investments as opposed to real-time congestion relief, and are realized by either (a) PSH operations enhancing the capabilities of the existing transmission system, thus deferring the need for new transmission capacity expansion, or (b) by extending the economic life of existing transmission assets by reducing transmission line and substation loads. Energy storage systems, including PSH, can play an important role by reducing loading on a specific portion of the transmission system. This allows investments that would ordinarily be made to accommodate load growth or regulate voltage to be postponed, extending the life of the current system. The value from this use case can also be defined by reducing the need for market participants to purchase transmission rights at financial transmission rights (FTR) auctions. This benefit is often analyzed on a location-specific level, as it helps defer or postpone specific projects and transmission system upgrades that otherwise would be needed earlier in order to meet the growing transmission demands.

The remainder of this section defines the value proposition associated with using PSH to provide the these two transmission services, reviews existing literature on the topic, and outlines multiple approaches to modeling potential benefits. Modeling approaches for both small and large-scale PSH investments are detailed, and limitations inherent in each approach are evaluated.

4.7.1. Transmission Congestion Relief

Transmission congestion occurs during the periods in which the load on transmission lines exceeds the load-carrying capabilities of the network. This overloading of the system can lead to a variety of costly effects, such as violations of network security limits during both normal and contingency operations. These violations could include thermal limits, angular stability, voltage stability, or margins of reliability. A variety of factors contribute to the overcapacity of the system. These include fuel availability across interconnected portions of the grid, the organization of nearby markets, or a system of transmission lines that are fundamentally undersized to handle growing demand.

Congestion occurs whenever the system state of the grid is characterized by violations of the physical, operational, or security constraints under which the grid operates. Traditionally, the solution to the issue of transmission congestion is to incorporate additional transmission lines or enhance the capability of current lines through thermal or voltage-support upgrades. Energy storage poses a valuable solution to this issue both through its ability to store energy during off-peak periods and provide relief when the transmission lines become congested by alleviating instabilities and overloading. Batteries, flywheels, and other fast energy storage devices have the ability to provide corrective actions. Larger energy storage systems, like PSH, on the other hand, have the capability to provide active power support over longer durations while relieving load constraints (Del Rosso and Eckroad 2014).

The traditional solution to congestion is investment in transmission lines. An alternative approach to relieving transmission system congestion is to improve the utilization of existing infrastructure by permitting more flexibility and controllability (Grünbaum et al. 2012). In a competitive electricity market, market participants will submit their market bids and offers as the basis for the determination of the generation and demand profiles for the market horizon. If the market dispatch fails to provide a feasible operating state (i.e., provides a state with power flow constraint violations), the RTO has to undertake congestion relief actions with controllable devices as well as with generator redispatch. In this process, the RTO aims to move the power flow solution from an infeasible state to a feasible state with the least cost. Congestion relief can be realized by installing controllable devices in the transmission system, such as FACTS devices, energy storage or PSH plants, possibly supplemented with communication and information gathering systems. Among all these devices, PSH plants represent a good candidate for congestion relief service since they are very flexible and can be quickly dispatched with a high ramp rate to alleviate system congestion during peak hours. The rest of this subsection will mainly focus on the outline and modeling of PSH for transmission system congestion relief. For this analysis, we present an approach that can be used in a price-taker model and for the system analysis or production cost focused approach. For the production cost modeling approach, we use PLEXOS for illustrative purposes. These model types are described in more detail in the next section.

Methodology

When modeling the benefits of transmission congestion relief, a price-taker model can be used if the PSH plant is of a sufficiently small power capacity (around 10 MW or less). The price-taker model measures impacts on the margin, typically but not necessarily with perfect foresight, while not attempting to address system dynamics. Effectively, the price-taker model is predicated on the assumption that if the PSH unit has a small power capacity, it will not shift the supply curve or change system-level operations or prices. With the price-taker model, shadow prices are typically established for various services, which are matched to hourly power and energy requirements and used to co-optimize the operation of the PSH unit to maximize avoided costs or revenue, subject to the technical limitations of the PSH plant. System analysis models are more complete, modeling system impacts, but require a significant time investment and lack flexibility in terms of layering use cases. This section outlines approaches for valuing congestion relief using both price-taker and system analysis (price-influencer) modeling approaches.

Valuing Transmission Congestion Using a Price-Taker Model

The price-taker modeling approach can rely either on market data or on transmission contract rates.

Price-Taker Model Using Locational Marginal Price

Regional Transmission Operators (RTOs) around the country publish locational marginal price (LMP) data from historical market clearing processes. In addition, the LMPs are broken down, and the constituent cost elements—energy, loss, and congestion—are also published by the RTOs. (CAISO now also publishes the greenhouse gas component of LMP.) Based on this information, a price-taker resource can calculate the marginal impact on congestion using the LMP differentials between a pair of pricing nodes. While we refer to the price-taker model within this section, this characterization is a bit of a misnomer. LMP breakdown, as outlined in this section, is by definition reliant on assigning value based on changes in prices. Therefore, this section does not rely faithfully on a price-taker model but does rely on small marginal impacts without evaluating system or market effects. As such, it can be used within the framework of a price-taker model even if it is not reliant on the assumption that prices are fixed. With that noted, the shift in prices estimated here would need to be factored into the arbitrage calculations when using a price-taker modeling approach.

Congestion costs arise when a high-cost unit is dispatched instead of the inexpensive generation that would be used if there were no transmission congestion. When locational marginal pricing is used, system dispatch payments reflect the difference in payments to generators (and the production cost, which may not be the same as generators' revenues from market clearing) from an ideal uncongested power grid. Customers that import energy may incur additional congestion charges in proportion to the difference between energy prices at the generation source and the load. The sum of these congestion charges is called congestion rent (Lesieutre and Eto 2003). The nodal price or LMP represents the cost of a unit change in load at the bus. If the system has no binding constraints, all LMPs will be equal. In regions without RTO markets, an analogous hourly marginal cost is referred to as the system lambda (λ), which represents the marginal system cost of serving additional load at a given location:

$$\lambda = \frac{\delta C}{\delta D}$$

Where:
δC = the change in system cost
δD = the change in load
λ = the lowest cost to support the given demand at an ideal uncongested power grid

At any bus *i*, the LMP λ_i is made up of these three components:

$$\lambda_i = \lambda + \alpha_i + \beta_i \lambda_z$$

Where:
α_i = the marginal loss cost
β_i = the congestion cost

The marginal loss cost α_i reflects the impact that a unit increment in load at bus *i* would have on overall system losses, assuming these losses are absorbed at the slack bus. From the optimal solution, α_i can be computed as follows:

$$\alpha_i = \sum_{j \in K_i} 2R_{i,j} P_{i,j} S_{i,j}$$

Where:
K_i = the lines connected to bus *i*
$R_{i,j}$ = the resistance on line between bus *i, j*
$P_{i,j}$ = the power flow on the line between bus *i, j*.
$S_{i,j}$ = the shift-factor between bus *i* and line *j*, which represents the change in flow on the branch between bus *i* and line *j* for a one megawatt increment in injection at bus *i* and simultaneous withdrawal at the slack bus.

Once the LMP λ_i and the marginal loss cost α_i are computed, the marginal congestion cost β_i is the balance of the LMP equation below:

$$\beta_i = \lambda_i - \lambda - \alpha_i$$

One method used to estimate the impact of injection/withdrawal at a node on the power flows through the network is based on the estimation of shift factors. A shift factor (SF) shows how the flow in the branch will change if the injection at the bus changes by 1 MW. All SFs are computed relative to the reference bus (the reference or slack bus is assumed to be the sink bus in this instance), with the SF being dependent on the location of the reference bus. The SF at the reference bus is set to zero. SFs are solely dependent on the network topology and impedance.

SFs are also known by other names:

- Power transfer distribution factors
- Power distribution coefficients
- Effectiveness factors
- Impedance factors

The following simplified economic dispatch formulation illustrates the relationship between SFs and power flows in the transmission network. The first equation below is the objective function to be minimized, representing system production cost. The second and third equations are the system power balance equation and power flow and transmission capacity constraints respectively. The fourth represents the generation capacity constraints.

$$Min\,(\sum_{i=1}^{N} C_i * P_{gi} - \sum_{i=1}^{N} B_i * D_i)$$

$$\sum_{i=1}^{N} P_{gi} - \sum_{j=1}^{L} P_{lj} = 0$$

$$\sum_{i=1}^{N} S_{ki} * \ P_{gi} \leq T_k^{Max}, k = 1,2, \dots, K$$

$$P_{gi}^{min} \leq P_{gi} \leq P_{gi}^{max}, i = 1,2, \dots, N$$

Where:
C_i = generator *i*'s production cost
P_{gi} = the decision variable representing generator *i*'s production
B_i = the bidding of *i*th demand
D_i = the power of *i*th demand
P_{lj} = the load at bus l
T_k^{Max} = transmission capacity constraints
I = power injected by generator
k = transmission line
S_{ki}. = the generation shift factor

Hence, the LMP difference between any two congested lines between buses *i, j* can be calculated as follows:

$$\Delta_{i,j} = \lambda_i - \lambda_j$$

The value of congestion relief from generator *i* may be calculated as follows:

Value = $\sum \Delta_{i,,j} * P_{gi} * S_{g \rightarrow AB,}$ for ALL combinations of price nodes {A,B}

Where $S_{g \rightarrow AB}$ = the vector of generation shift factors, representing the impact of injection by generator *g* on the transmission path between bus A and bus B.

This method may overestimate the benefit associated with congestion relief, because it measures changes in power even on uncongested transmission lines and attributes the benefits based on the LMP differences between the associated set of nodes. To correct the problem, an alternate approach is to use the shadow prices associated with only the congested transmission lines. The calculation changes slightly:

Value = $\sum \Delta_{i,,j} * P_{gi} * S_{g \rightarrow K}$, for ALL congested transmission lines K

The following steps can be used for assessing the value of congestion relief using market data:

1. Identify the set of congested power lines using the day-ahead/real-time dispatch results

2. Identify the generation SFs, as reported by the RTOs (e.g., CAISO effectiveness factors[1])
3. Identify the shadow prices for binding constraints as reported by RTOs for day-ahead/real-time
4. Compute the value of congestion relief based on incremental amounts of generation/withdrawal.

Price-Taker Model Using Contract Data and Administratively Set Rates

One of the main constituents of LMPs is the cost of transmission congestion, along with energy costs and costs for the marginal losses. In the event that market participants are able to alleviate the congestion by providing energy in real time, the LMP drop provides value to consumers and transmission authorities. However, these benefits are typically not monetized directly or completely. The remainder of this section discusses mechanisms for receiving direct compensation for the provision of transmission services.

Financial transmission rights, or FTRs as they are commonly known, allow holders to pay ahead for congestion costs so that the market participant is able to hedge against uncertainty for the transmission congestion cost part of the LMP (Flores-Espino et al. 2016). A market participant with or without an energy obligation can buy these FTRs to hedge or to engage in arbitrage.

FTRs are commonly used by RTOs and have different names depending on the RTO. This form of instrument includes congestion revenue rights (CRR) for CAISO and ERCOT, transmission congestion contracts for NYISO, and FTR for ISO-NE, PJM, and MISO (Flores-Espino et al. 2016). In ISO-NE, FTRs are used as a financial tool to share congestion *rent*, i.e., the difference between customer costs and generators' production cost, collected by the RTO. ISO-NE offers monthly and annual FTRs that holders can sell or market participants bid to buy. The source point is the point of entry of a megawatt of energy into the transmission system, and the sink point is the point of exit for the same. The difference between the expected prices at these two locations is the price of the FTR, which is defined in terms of megawatts flowing in the direction of the sink point from the source point in the auction market (Ma, Xingwang 2002). The true price of an FTR is determined in the monthly/annual auctions. The point is that a market participant's maximum willingness to pay for an FTR should be no greater than the expected differences in day-ahead LMPs between the two locations. The market participants enter their bids (desired quantity, maximum willingness to pay), which are then used by the RTO to clear the auction.

The auction market works in much the same way for all other financial transmission rights overseen by different RTOs. For example, if a pumped storage hydro unit wanted to bid into the FTR market in PJM, it has to be a PJM member or a customer to be eligible.[2] If the unit fulfills the minimum requirements to participate in the auction market, it may register with PJM. In return, PJM is required to make sure basic credit requirements are met in order to let the unit bid into the market. For CAISO and ERCOT, the CRR can be bid into through the auction market or allocated by the RTO. The procedure remains the same overall, and the purpose is to provide for hedging against congestion costs in the day-ahead market.

[1] https://www.caiso.com/Documents/2210Z.pdf
[2] https://learn.pjm.com/three-priorities/buying-and-selling-energy/ftr-faqs/what-are-ftrs.aspx#faq-box-text2

FTRs can be used to bypass the LMP congestion charges. They give market participants the ability to obtain a better price certainty when delivering energy across the grid.

Transmission system operators (including RTOs) can also enter into bilateral contracts with utilities and independent power producers to provide relief for transmission constraints. The contracts are exercised by calling on participating entities to provide relief from constraints that may adversely impact the reliability of the system.
Bonneville Power Administration's (BPA's) Open Access Transmission Tariff states the following in Attachment M—Procedures for Redispatch:

> …parameters and procedures for redispatch by BPA's Power Services at the request of BPA's Transmission Services (TS). TS may request redispatch during any period when TS determines that a transmission constraint exists on the Transmission System and such constraint may impair the reliability of the system. TS may not request redispatch under this Attachment M to make additional firm or non-firm transmission sales.

Steps associated with provision of congestion relief using a bilateral agreement with BPA:

1. A customer must have an executed bilateral agreement with BPA to supply bilateral redispatch for congestion management.
2. Requests to deploy bilateral redispatch for congestion management will be issued by BPA Transmission Services.
3. Schedules associated with bilateral redispatch for congestion management are to be submitted in accordance with Section J of the Scheduling Transmission Service Business Practice.

Valuing Congestion Relief Using a Price-Influencer Model

In organized wholesale markets, the challenge of congestion management for the transmission system operator is to create a set of rules that ensure sufficient control over producers and consumers (generators and loads) to maintain an acceptable level of power system security and reliability in both the short term (real-time operations) and the long term, while maximizing market efficiency.

The operation of congestion relief in a wholesale electricity market takes place, typically, in two stages. First, the market participants will submit their market bids and offers as the basis for the determination of the generation and demand profiles for the market horizon. If the market dispatch fails to provide a feasible operating state (i.e., provides a state with constraint violations in power flow), the RTO has to start congestion relief with remedial actions, such as generator redispatch and load shedding. In this process, the RTO aims to move the power flow solution from an infeasible state to a feasible state with the least cost. Different RTOs have different procedures in this congestion relieving stage.

CAISO portions the grid into a number of preferred zones (Bompard et al. 2003). The auction-based results provide preferred schedules established by the several scheduling coordinators in the bilateral markets. If the market dispatch still results in congestion even after readjustment bids, it is eliminated using redispatch with zonal partitioning. Congestion redispatch provides zonal prices and transmission usage prices with the interface flows. Typically, there is either no congestion or easily relievable congestion within the zones, so when zone partitioning is used, the goal is to remove interzonal interface congestion. On the other hand, new markets for FTRs have been introduced as a way to negotiate the ownership of congested paths and to provide market mechanisms to improve economic efficiency in the use of the transmission network.

In PJM, the RTO conducts a centralized market dispatch for each time period in the scheduling interval. In the market dispatch, nodal prices are computed according to specific constraints during congestion.

ERCOT's balancing energy market includes two submarkets: (1) zonal portfolio congestion management market, and (2) local unit specific congestion management market. The function of the first market is to purchase portfolio balancing energy bids to maintain a power balance between qualified scheduling entities' generation schedule and ERCOT's short-term load forecast and to manage any zonal congestion. The function of the second market is to deploy unit specific balancing energy up and down bids to manage local congestion.

The key steps in modeling the use of PSH to alleviate transmission congestion are as follows:

1. Prepare grid data and load data for contingency relief analysis.
2. Model the selected PSH system in selected locations in PLEXOS. PSH is modeled in PLEXOS by defining the input parameters for the maximum capacity, pumping efficiency, pumping capacity, energy storage, and other parameters.

Using the output of the production cost model, the RTO will run a power flow analysis to check power flow feasibility and violations such as thermal limits, angular stability, voltage stability, or margins of reliability. If the production cost model generator dispatch fails to provide a feasible operating state, congestion relieving procedures should be conducted. A PSH located at a congestion bus can provide a back-up energy source during a contingency event to relieve thermal overload, thereby alleviating the transmission congestion. This solution requires a series of power grid unit commitments as well as power flow solutions to be solved and tested for contingency cases to prove the concept.

Key Features of Price-Taker and Price-Influencer Approaches

- The price-taker approach benefits from fewer data requirements and the flexibility to easily integrate this use case with others for co-optimization.
- The price-influencer approach is preferred, but it requires the use of complex production cost simulation models with the capability to simulate and optimize the scheduling of the entire power system.
- Transmission congestion relief analysis is closely related to other potential economic benefits of the PSH plant, such as energy arbitrage. For the valuation of PSH projects, the value of energy arbitrage is typically analyzed separately, so accounting for it also in the transmission congestion relief analysis could lead to double counting of this value.
- The transmission deferral analysis approach can support the investment decision-making process for new transmission system upgrades.

Modeling Tools
Price-taker models include Battery Storage Evaluation Tool (Pacific Northwest National Laboratory), StorageVET (EPRI), DER-CAM (Lawrence Berkeley National Laboratory), Energy Storage Computational Tool (Navigant, now Guidehouse), Permanent Load-Shifting Cost-Effectiveness Tool (E3), Qwest (Sandia National Laboratories), and ES-GRID (DNV).

Production cost models, such as GridView (ABB), GTMax (Argonne National Laboratory), PLEXOS (Energy Exemplar), PROMOD (ABB), or Aurora (Energy Exemplar) can be used to study the transmission benefits of PSH projects.

Metrics/Units
- Shift factor quantifies how the flow in the branch will change if the injection at the bus changes by 1 MW.
- Congestion charge component of LMPs ($/MWh).
- $/MW value of congestion relief in FTR market transactions (U.S. dollars).

Limitations
- When the price-taker model is used, the full system effects are not fully captured.
- Any reduction in the congestion component of an LMP would also affect energy arbitrage opportunities. The price-taker model would fail to address the effects of congestion relief on market competition and will not capture the changes in LMPs.
- Given the previous limitation, a production cost model should ideally be used in order to simultaneously evaluate the impact of changing LMPs on arbitrage benefits.

Prior Studies
- In Del Rosso and Eckroad (2014) and Khani, Zadeh, and Hajimiragha (2016), using energy storage systems for congestion relief in transmission systems as an ancillary service is investigated. The simulation results show energy storage systems can be effectively used for congestion relief.
- EPRI (2011) and Zhu and Momoh (1998) present different methods for calculating transfer capability to identify the best location and sizing for installing energy storage to relieve transmission congestion.
- Grünbaum et al. (2012) summarizes different methods of utilizing FACTS to relieve transmission system congestion. The article presents STATCOM with energy storage, thyristor-controlled series compensation, and Dynaflow as three main options for system congestion relief.
- In Lesieutre and Eto (2003), the definition and calculation of transmission congestion costs are summarized. Based on the calculation methods, the report reviewed published estimates of transmission congestion costs at different ISOs.
- An analysis by DNV GL (2017) discusses the breakdown of LMPs in their relation to congestion: the market energy component, which is the market clearing price for each incremental MW of load, the marginal congestion component, which is the incremental congestion cost at any given pricing point, and the marginal loss component, which factors in the cost of losses at a given pricing point. When transmission congestion is evident, higher-cost resources are in demand on a single side of the congestion constraint,

as the less expensive units face transmission limit constraints. This causes a price imbalance, with higher prices following where the generation assets are most needed (Ela et al. 2013). The cost of congestion at a particular site on the system represents the value of placing an additional unit of capacity at that location. There is a criticism of this approach, however, in that it is believed the congestion costs do not adequately capture the whole capital cost of transmission and that it is difficult to arrive at accurate results given that charges are often highly specific to location (Denholm et al. 2014; Eyer and Corey 2010).

- Denholm et al. (2014) use a "scenario-based modeling" approach when evaluating significant penetration of distributed generation photovoltaics on a grid system using a production cost model. This approach places a value on the transmission capacity value of distributed generation photovoltaics by simulating system operations using different combinations of planned transmission investments and quantities of distributed generation photovoltaics. Through this methodology they are able to simulate entire systems and capture congestion costs by running scenarios with and without different combinations of assets. The authors were able to compare the results of a variety of iterations in a static topology, including scenarios in which installation quantities have surpassed marginal impacts on power flow patterns. Other researchers have evaluated the benefits of congestion relief using power market simulation programs. Programs such as GridView work to establish a platform for the utilization assessment of transmission assets as well as an analysis of benefits for system expansions (Feng et al. 2003).
- Mohsenian-Rad (2016) uses an optimization framework to coordinate the operation of price-maker energy storage assets in energy markets with transmission constraints. The research finds that, in the price-maker model, the congested lines were often desirable when profitability increases are the objective, as this leads to imperfect competition and the creation of price differentials across time slots. This congestion relief in all cases leads to arbitrage as the optimal use case for the coordinated energy storage systems. In determining profits, the researcher found that locational diversity of these systems is a key point in a transmission constrained network. He also found that even the storage systems with lower energy efficiency could maintain a profit margin despite the profits being sensitive (and positively related) to round trip energy efficiency.
- Congestion risk can also be evaluated through the impact of individual transmission constraints on a new storage investment project. Congestion results are sensitive to changes in market and to any new generation that may be entering the system or any transmission upgrades that are expected to occur. Significant influences can specifically be found from expansions of distributed energy resources entering the grid such as wind and solar which could provide an increase in congestion risk (DNV GL 2017).
- The $/kW value of congestion relief has a wide range in the literature when considered from a price-taker perspective. In their transmission congestion charge (TCC) methodology, NYISO places the value at $10/kW-year, while in California, which is experiencing rapid growth in renewables that contribute to high congestion, it is estimated in a range of $4.48-$19.71/kW-year. However, Del Rosso and Eckroad (2014) derived the benefit for a 50 MW/25 MWh battery storage system at $258/kW-year, placing it far beyond other estimates. Overall, Balducci et al. (2018a) found the mean value for congestion relief to be $72/kW-year when looking across numerous available studies.

4.7.2. Transmission Deferral

Storage plays a role in transmission upgrade deferral by reducing loading on a specific portion of the transmission system. This allows deferral/avoidance of investments that would ordinarily be made to accommodate load growth or regulate voltage by extending the life of the current system. The value from this use case can also alleviate the need to purchase transmission rights from third-party transmission providers (Balducci et al. 2018a). This benefit is often analyzed on a location-specific level, as it helps to defer specific projects that planners may forecast as necessary to meet growing load demand. Transmission deferral benefits are realized through either enhancing the capacity of the existing transmission system, thus deferring the need for capacity expansion, or extending the economic life of existing transmission assets by reducing load.

It is important to note that PSH cannot be used to defer all forms of investments. Projects that are required to accommodate future load growth are good candidates for deferral. Other common characteristics of significant transmission deferral opportunities include uncertainty with respect to the timing of block load additions, the potential for environmental permitting or other barriers that could result in delays, high transmission project costs, locations with high peak to average-demand ratios, and transmission paths with modest projected load growth rates (ESA 2018).

Valuing Multiple Year Transmission Deferral Benefit

The price-taker modeling approach for a transmission investment relies on measuring the difference in present value costs realized through deferring the investment into the future.

Price-Taker Model Based on Evaluation of Planned Transmission Investments

For the PSH to be of value for this use case, it would either be co-located with large-scale generation, such as a wind farm, or must be located electrically downstream of the constrained asset and be able to reduce load below load-constrained levels. The benefit flows through the change in the revenue requirements in present value terms by deferring investment in the asset. In most cases, PSH would need only be made available for this use case for a limited number of hours each year. The relatively low number of hours required to defer investments is advantageous when co-optimizing this with other use cases.

To evaluate the present value benefits of deferring new transmission investment, the following steps are required:

Step 1: Define the asset and constraint. An initial step typically involves evaluating regional or utility-driven transmission and distribution capital expenditure plans. These plans will identify the presence and location of transmission investments with the potential for deferral through the deployment of PSH. If a transmission investment deferral opportunity exists, local constraints must next be determined. In Figure 4.14, the transmission system's current load carrying capacity at the location of the planned investment is defined as 55 MW. With the enhanced capacity realized through a small modular 10 MW/60 MWh PSH unit, the load carrying capacity would expand to 65 MW.

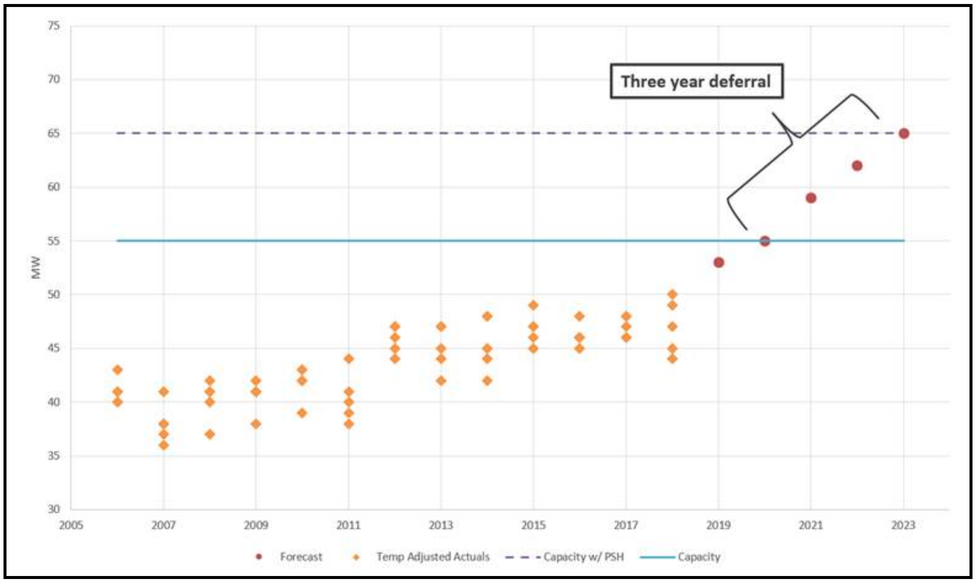

Figure 4.14: Temperature-adjusted peak load (2006–2018) and forecast peak load (2019–2023).

Step 2: Define current load and future load growth in order to determine the deferral period. Historic load data should be acquired during historic peak conditions, which are typically in the winter or summer depending on the nature of load and weather patterns in the specified region. Assuming a winter peak, Figure 4.14 presents temperature-adjusted loads during the 2008-2018 time period.

Because the peak day for 2018 was warmer than peak days in previous years, the peak was lower. Given that the peak load for the most recent year is lower than those in the past, it may be appropriate to scale that peak day for a colder period. In Figure 4.14, all loads were scaled for a 23°F design day. The revised 2018 peak is then used as the basis for future load growth. Local load growth forecasts are used to project future peaks. Figure 4.14 shows how the peak load is forecast to reach the adjusted load carrying capacity, including PSH, of 65 MW in 2023. This means that the deferral period is between 2020 and 2023, or three years. Transmission deferral periods can be extended when load growth forecasts are low, thus leading to significant transmission deferral benefits.

PSH is energy limited, so the shape of the peak load also matters. Needle peaks require relatively small increments of energy and therefore pose few challenges due to energy constraints. In our example, 60 MWh must cover the entirety of the period when load exceeds the load carrying capacity of the existing transmission system. In Figure 4.15, load is presented for the annual peak period in the winter of 2017/2018. In 2017, annual peak load reaches approximately 45 MW when not temperature-adjusted.

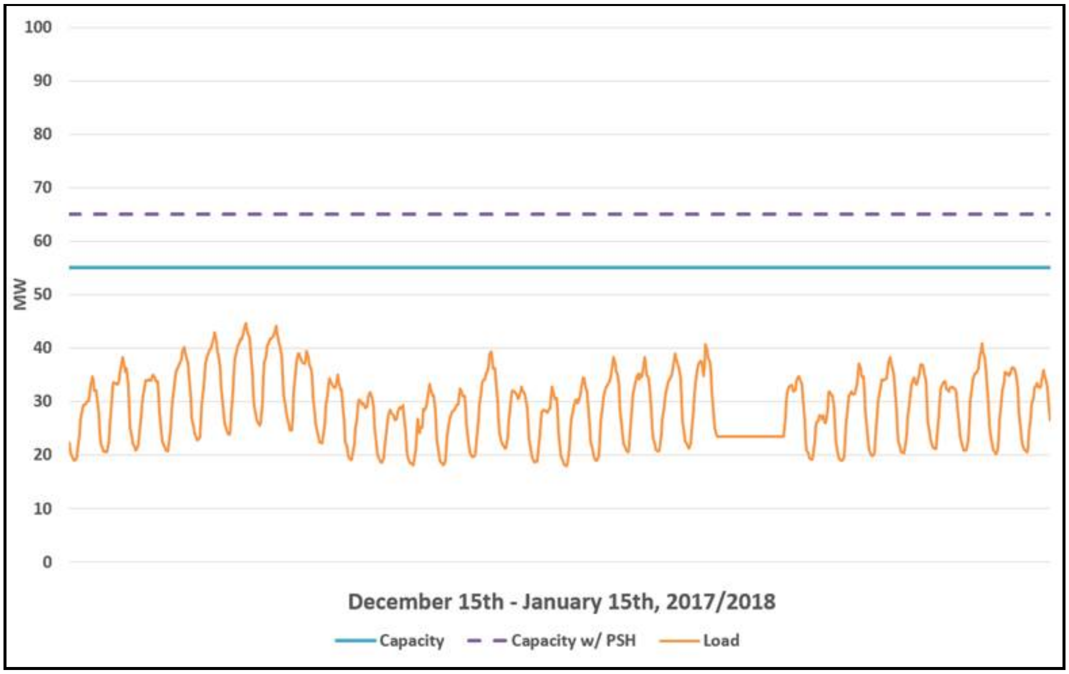

Figure 4.15: Peak load during peak month in 2017.

Figure 4.16 presents the forecast peak load for the peak month in 2023. While the load is projected to fall short of the load carrying capacity of the transmission system plus PSH, this only accounts for the power component of the equation. The PSH must hold sufficient energy to cover the load that falls above the initial 55 MW constraint and below the new 65 MW constraint. The four-day period during which load reaches its peak is highlighted in Figure 4.17. Energy in the PSH must be sufficient to cover this entire period. If it fails to meet the higher load requirements, the deferral period must be reduced to reflect the period during which it can meet all requirements. For the purposes of this calculation, we will assume it can meet the requirements and the deferral period is set at three years.

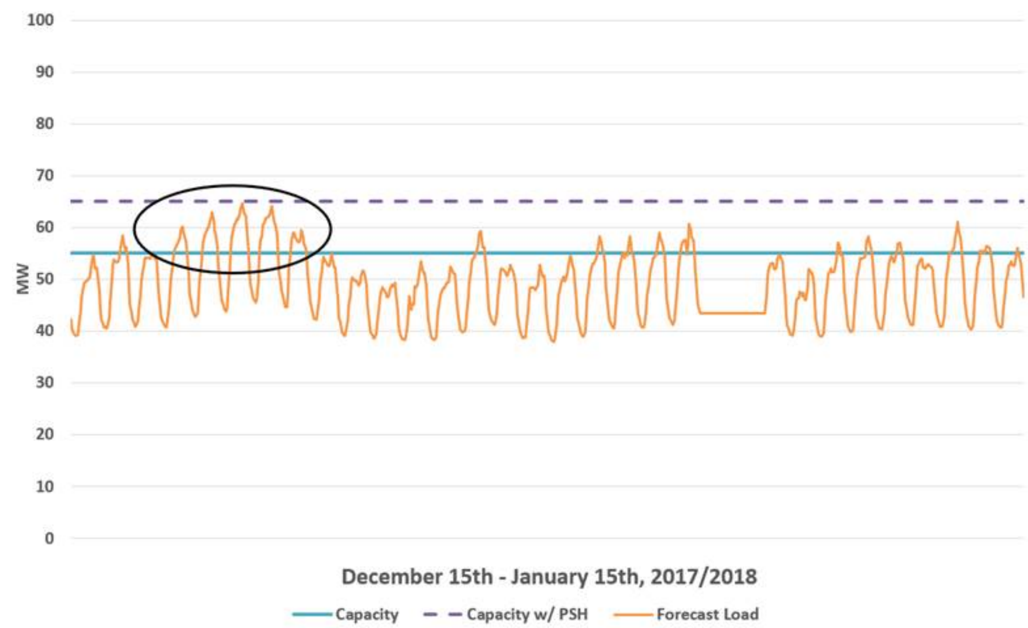

Figure 4.16: Forecast peak load during peak month in 2023.

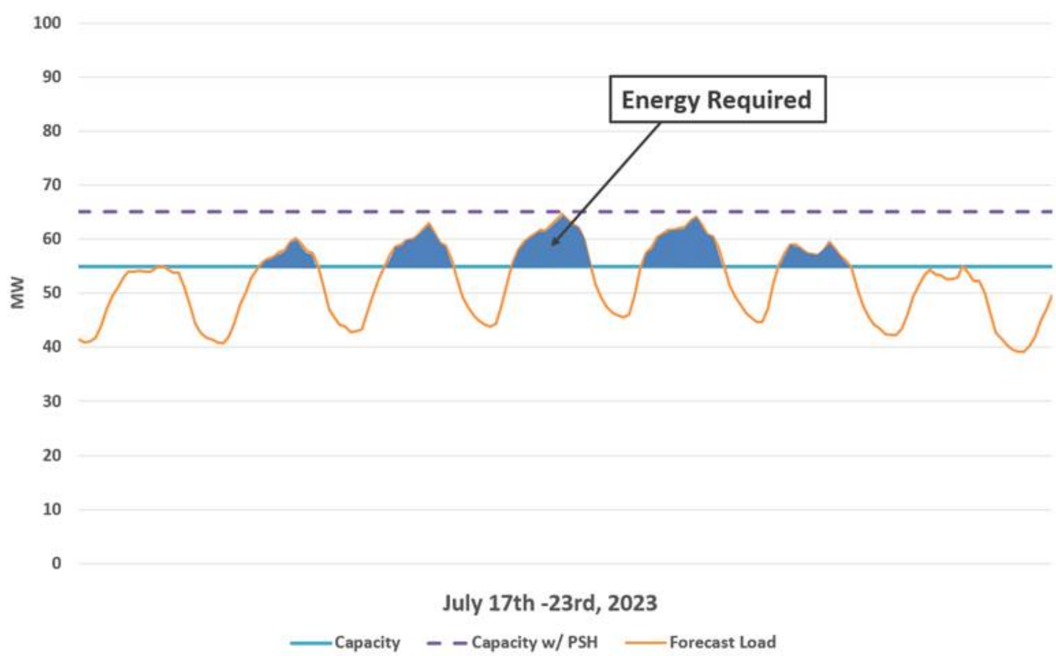

Figure 4.17: Forecast peak load during select period in 2023

Step 3: Calculate the deferral value. In its most simple form, the value of deferral can be estimated by taking the change in present value costs of the system. The change in present value costs would be estimated using the equation below. Let's assume the cost of the transmission upgrade is $50 million, the inflation rate is 2%, and the discount rate, which is based in this case on the weighted cost of capital for a utility, is 6%.

$$\text{Present Value} = \text{Future Value}/(1+i)^n$$

Where:
i = discount rate
n = number of deferral years

If the deferral period in this case is three years, the present value cost of the investment would be reduced from $50 million to $44.55 million, resulting in transmission deferral benefits of $5.45 million.

While this equation outlines the basic premise, it would be insufficient for most transactions. The optimal approach would be to prepare a detailed pro-forma for the asset in two scenarios: with and without PSH. The pro-forma should be used to identify the full costs of the deferrable transmission upgrade over its useful economic life, including any tax, depreciation, debt, insurance, and maintenance costs. These annual costs should then be compressed into present value amounts for both scenarios (investment in 2020 and 2023), with the cost difference serving as the value of transmission deferral in the form of avoided costs. Doane et al. (1976) presents a comprehensive set of equations for calculating the present value of all capital and recurrent costs over the economic life of a grid asset.

Step 4: Characterize PSH requirements and build constraints into model. The area falling under the load curve but above the load carrying capacity of the existing transmission system in Figure 4.17 must be characterized in terms of hourly power output requirements for the PSH unit. Whenever forecast load exceeds the load carrying capacity of the existing transmission system, that value must be identified and built in as a constraint in the modeling framework, be it a price-taker model, like EPRI's StorageVET or PNNL's BSET or a production cost model like PLEXOS. During those hours, PSH must be discharging at an amount to reduce load below the load carrying capacity of the existing system. That constraint must be built into the co-optimization process in a manner that limits the availability of the PSH unit for other uses during those peak hours.

Transmission deferral can also be achieved by reducing the wear and tear on existing transmission assets and thus extending their useful life. By reducing the load served by existing transmission assets below load carrying capacity, the existing transmission equipment can operate at lower temperatures and reduce operational wear and the occurrence of ground faults, which accelerate degradation of existing transmission assets. Balducci et al. (2018b) provides an example of transmission deferral through reducing loads on a submarine transmission cable serving the San Juan Islands in Washington.

Valuing Single Year Transmission Upgrade Deferral Benefits

PSH can be flexibly used to defer expensive improvements or capacity additions to transmission and distribution equipment by providing flexibility to the grid. The framework for valuing an annual benefit of transmission upgrade deferral has two steps:

Step 1: Estimate the transmission upgrade cost and annual revenue requirement for the transmission upgrade. For a utility, the annual revenue requirement represents the amount of annual revenue required to pay carrying charges for capital equipment and to cover expenses, including fuel and maintenance.

Step 2: Estimate T&D deferral benefit. The second step is to estimate the single-year benefit for deferring a transmission upgrade when its cost is known, based on the congestion relief calculated through power flow analysis in Section 4.7.1.

Key Features

- A detailed step-by-step price-taker modeling approach has been used widely in the estimation of transmission and distribution deferral benefits, particularly for investments in small-scale electrochemical battery storage. The approach outlined in this section relies on assessments of specific investments with the potential to be deferred through the deployment of energy storage to meet future load growth and other demands placed on the transmission grid.
- In addition to the economic benefits, the power flow analysis can estimate system resilience or system vulnerability by running the contingency analysis, especially on extreme events. This would be similar to but simpler than identifying system congestion, described earlier.

Modeling Tools

Modeling tools include BSET (PNNL), StorageVET (EPRI), DER-CAM (LBNL), Energy Storage Computational Tool (Navigant, now Guidehouse), Permanent Load-Shifting Cost-Effectiveness Tool (E3), Qwest (Sandia National Laboratories), and ES-GRID (DNV).

Production cost models, such as GridView (ABB), GTMax (Argonne), PLEXOS (Energy Exemplar), PROMOD (ABB), or Aurora (Energy Exemplar) can be used in the study.

Metrics/Units

- Number of transmission investment deferral years
- Avoided transmission investment cost ($)
- Change in forecasted load carrying capacity (MW)

Limitations

- Boosting transmission capacity can affect system prices. The price-taker approach fails to account for the effects of these shifting prices.
- A production cost model is required to formulate and quantify the maximum benefits or cost reduction that can possibly be obtained from the system.

Prior Studies

- Chang et al. (2014) estimated the value of transmission deferral at $36/kW-year, which is in line with ERCOT's average transmission cost per kW during their summer peaks. The authors used this average cost to sidestep the need to conduct a detailed transmission planning analysis, which would look at the deferral value of each potential opportunity on the system.

- Eyer (2009) defines a single-year transmission and distribution upgrade deferral benefit as the annual revenue requirement for an upgraded transmission or distribution facility with the assumption that any payment towards what is avoided is considered to be avoided indefinitely. The report estimates that if the output of a storage system is 3%–5% percent of the load carrying capacity, it could defer a transmission upgrade by one or two years. Given a set of assumptions where the transmission equipment is upgraded from 12 MW to 16 MW capacity, and a storage system with 3% of load carrying capacity is specified, Eyer (2009) estimates that if it costs $100/kW for the transmission equipment upgrade, there is an associated $500/kW of storage benefit for one year of deferral, measured in terms of the power capacity of the battery.

- Balducci et al. (2018b) evaluated transmission deferral through reducing loads on a submarine transmission cable serving the San Juan Islands in Washington. This study developed an electro-thermal life model that evaluated the reduced wear and tear on a currently installed cable resulting from deployment of a battery energy storage system at a substation on Decatur Island. The model demonstrated that once the energy storage system was installed at the Decatur Island substation, it could be used to serve loads which will reduce power flow and thus stress on the submarine cable, resulting in the potential extension of the cable's life. The energy storage system was found to extend the life of the $40 million cable that has an expected life of approximately 40 years by an additional 3.4 years, leading to a $2 million benefit in PV terms.

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4.8. PSH Non-Energy Services

Reservoirs that impound water are often considered multipurpose reservoirs since they can simultaneously or sequentially provide consistent and reliable services to both competing and complementary stakeholders. Typically, PSH reservoirs (see example in Figure 4.18 offer a significant water resource which may have many uses, although they are most often associated with energy storage for hydropower production and electric grid services. However, as with conventional hydropower reservoirs, PSH reservoirs may be able, in some cases, to provide some potential valuable non-power benefits, such as flood control, recreation, water supply, and irrigation.

An overall valuation of a multipurpose reservoir requires explicit quantifications of the benefits. This is most readily achieved for energy-related services. Power is generated and sold in a regulated market, where monetization is achieved through a market-driven pricing mechanism. Ancillary service benefits are also clearly identified, as their economic contributions to electric power markets have been isolated and quantified since the Energy Policy Act of 1992. Most non-energy-related benefits, on the other hand, are overlooked in the context of hydropower multipurpose reservoir benefits. When these benefits are monetized, their economic value often surpasses that of power generation (Institute for Water Resources 2013), contributing substantially to local economies and affecting millions of people.

Figure 4.18: Upper reservoir of Muddy Run PSH (1,070 MW) in Pennsylvania.

These competing uses within an integrated system must be balanced to meet operating rules, management practices, consumer demands, and environmental constraints in support of the project's multipurpose objectives.

While multipurpose reservoirs provide significant contributions to national economic development every year, very little research has been done to evaluate their benefits (Bonnet et al. 2015). A landmark study by Bonnet et al. (2015) found that power generation does not contribute the largest national economic development benefit in most cases. Rather, recreation and irrigation provided the largest economic benefit for federal multipurpose reservoirs. According to Bonnet et al. (2015), of the 157 hydropower dams owned by the U.S. Bureau of Reclamation (USBR), U.S. Army Corps of Engineers (USACE), and Tennessee Valley Authority (TVA), 76% are authorized for recreational use, 58% help prevent flood damage, and only 6.4% are authorized solely for hydropower generation. A similar analysis has not been conducted for the U.S. PSH fleet.

This study is an on-going work conducted by national laboratories for the DOE to estimate the economic benefits and energy and non-energy services of PSH reservoirs. Given the important role that PSH plays in the provision of energy storage services in the U.S., there are other non-energy functions that PSH can provide that are very seldom quantified. The focus of this section is to attempt to quantify the non-power services that are provided by PSH.

The following is an attempt at defining a methodology for quantifying non-energy economic benefits for PSH reservoirs. The goal of this task is to inform stakeholders and the public about the socio-economic benefits of PSH reservoirs, as well as provide PSH developers and operators worldwide with an awareness of how the benefits of PSH reservoirs could potentially be distributed across multiple uses.

4.8.2. Methodology

This study leverages the analytical methodology presented in Bonnet et al. (2015), which assessed multipurpose benefits of hydropower reservoirs. Unlike conventional hydropower reservoirs, which often serve multiple purposes, many pumped storage reservoirs in the U.S. were developed for the primary purpose of providing energy storage for hydropower. While PSH reservoirs typically offer smaller storage capacity than conventional hydroelectric dams, the water stored in a PSH reservoir offers a valuable commodity which may be used for various other purposes besides just power production. The following benefit categories defined in Bonnet et al. (2015) and visualized in Figure 4.19 are used here to establish a framework for assessing *potential* PSH reservoir benefits:

- **Hydropower generation:** Operation and use of generating facilities and/or equipment for producing power using water as the sole source.
- **Flood control:** Water storage reservoirs that facilitate the prevention and/or lessen the severity of flood damage to valuable resources within a flood basin.
- **Recreation:** The use of water bodies (reservoirs or rivers) for physical recreational activities (boating, fishing, swimming, etc.).
- **Water supply:** Public and private withdrawals of water used for consumption and for municipal and industrial needs.
- **Environmental benefits:** Upper reservoir might store and provide significant benefit for downstream aquatic communities during drought seasons.
- **Irrigation:** The withdrawal and use of water from reservoirs to meet the need for crop and plant irrigation to sustain growth and production.

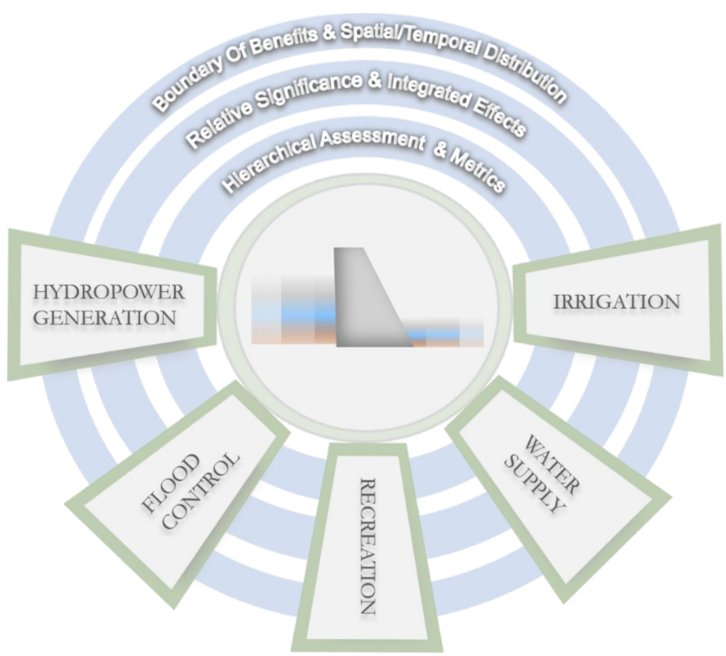

Figure 4.19*:* PSH multipurpose benefit categories.

When considering these various benefits of a traditional PSH reservoir in an evaluation framework, it is important to avoid double counting by following the conservation of mass. For example, if a reservoir with 10 million gallons per day (MGD) of water use assigns 8 MGD to hydropower generation, only 2 MGD can be used for other purposes, such as water supply or irrigation. However, for a PSH project, there are cases of interest that may challenge this approach in which the same parcel of water volume may be declared valuable to more than one purpose. For example, in the event of a flood, the same water used to produce hydropower can also have a value for flood control, as the withdrawal and release of the same water is effectively acting as a storage and release flood control measure to some degree. In addition, for PSH facilities that operate in an intra-basin transfer capacity, the water that is withdrawn from one basin and released in another can provide both hydropower service and water supply to a separate basin.

While some uses can be complementary, with valuable inter-dependent economic benefits, each category is identified and valued independently within a PSH multipurpose benefits valuation framework. As noted in Bonnet et al. (2015), several challenges arise when considering how to value and compare benefits for hydropower. Compared with conventional hydropower, PSH water use can be more easily monitored since the system is of limited size. Still, valuation metrics may not be easily comparable across the different benefit categories. As was found in Bonnet et al. (2015), it is expected that a reservoir's quantified benefit will depend on the reservoir volume, geography, allocated storage, and installed capacity, among many other factors.

The sections which follow describe the methodology used to evaluate non-power benefits of PSH reservoirs. Due to data limitations, the data collection and analysis methodologies described require significant engineering judgment and interpretation, and the results may contain a high level of uncertainty.

This methodology is developed to standardize and quantify a base case of the primary economic benefits of reservoirs.

Flood Control

Benefits from flood control may be quantified in terms of the damages avoided (potential or realized) to structures, contents of structures, and land use in locations that would have otherwise been inundated had the reservoir not been in place. From a modeling perspective, the reservoir storage can be applied to the floodplain during a flooding event to assess the effect the additional storage volume has on inundation. The cost of damage avoided to land, buildings, goods, and activities with the flood plain is used as a measure of benefit. In some cases, a flood-stage-damage relationship can be developed for a particular region.

As mentioned previously, PSH reservoirs are typically smaller than conventional hydropower reservoirs; thus, the flood control capacity and area shielded from inundation are proportionately smaller. However, with a majority of PSH reservoirs located in or near the headwaters of the watershed, the volume of water stored in a PSH reservoir that could be attributed to flood avoidance may not be not trivial in some cases. Rivers and reservoirs in these areas are more sensitive to changes in volume (elevation and flooding) than a main river, and the water stored in a PSH can be effective as a flood control measure.

Flood Control Metrics

- Multipurpose use: Flood control
- Benefit: Flood damages avoided
- $ Metric: Dollar value of property damage prevented

Recreation

Both conventional hydropower and PSH reservoirs can offer recreation opportunities like fishing, boating, camping, swimming, water sports, and wildlife observation. Since many PSH storage reservoirs empty and fill on a regular basis to provide hydropower generation, recreational safety at PSH facilities can be quite different from that at conventional hydropower facilities. When a PSH facility discharges flow into a downstream stream or river, the additional flows can serve various recreational purposes.

Recreation benefits are quantified in terms of visitor spending. Common procedures for estimating recreation spending include the travel cost method, the contingent valuation method, and unit day values, with the unit day value approach the most often used (USACE 2000). The travel cost method approach assumes that visitor spending (in terms of travel and time) increases with distance, with a demand curve developed using travel and time as price surrogates. The contingent valuation method approach uses location-specific surveys asking respondents to indicate how much they are willing to pay for recreation activities for which they are currently not paying. The commonly used unit day value approach assumes that benefit can be estimated by multiplying the number of visitors by the average spending per visit. Visitor count estimates are typically obtained through direct surveys, state and national park service data, or regional economic and population models. Spending estimates are typically obtained through direct survey (Black et al. 1998, Cardno Entrix 2011; Chang et al. 2012; Stynes 2005; Chang et al. 2008; USACE 2000; White et al. 2013).

Since recreation data are often difficult to obtain, it is common for some locations to estimate features and trends based on those of other recreation areas across the nation with similar characteristics. Given this difficulty, and the diversity of local recreational activities and preferences across the country, estimates of visitor counts and spending can be highly uncertain.

Recreation Value Metrics

- Multipurpose use: Recreation
- Benefit: Visitor spending
- $ Metric**:** Number of visits × average spending per visit × capture rate × regional economic multiplier

4.8.2.3 Water Supply

Approximately 17% of all surface and groundwater withdrawals in the U.S. are used for public, municipal, and industrial uses (Maupin et al. 2014). Multipurpose reservoirs often assign a percentage of their total storage to water supply and are capable of releasing or withdrawing stored water. PSH reservoirs are also able to restore water storage using pumps, thus enabling supply for when water is most needed.

The benefits of water supply from a reservoir for public, municipal, and industrial uses (not including irrigation) can be computed by multiplying the supply volume by the average price of water, thus producing a value per acre-ft of water (U.S. Department of the Interior 2014; Institute for Water Resources 2013; TVA 2012). In some cases, annual water prices are not available; instead, historical prices may be escalated to present-day value, or generalized estimates may be used. The price of water assumes the cost of procuring an alternative water supply and the cost of constructing and maintaining the associated infrastructure for delivery to end users (Pizzimenti, Olsen, and Wilson 2010).

Water Supply Value Metrics

- Multipurpose use: Water supply
- Benefit: MGD of withdrawals
- $ Metric: Average price of water x MGD withdrawn

Irrigation

The majority of irrigated farmland in the U.S. is located west of the Mississippi River and is supplied by water procured and distributed largely by the USBR. Irrigation benefits are most prevalent in arid regions where rainfall is lower and infrastructure (e.g., pumping stations, diversion dams, canals) is needed to supply water to locations both near and far.

The benefits of water supply for irrigation can be computed by multiplying the total irrigation area by the value of crops grown over that area. Geographic information system (GIS) imagery can be used to discern land use, including crop type, and estimate the acreage of crop coverage. Crop yield data can then be used to estimate the crop production and multiplied by national crop prices from the U.S. Department of Agriculture to estimate the gross value of crops.

Irrigation Value Metrics

- Multipurpose use: Irrigation
- Benefit: Crop production
- $ Metric: Gross value of crops produced using irrigation

GHG Emissions Impacts

GHG reduction assessment has been increasingly encouraged to promote environmentally sustainable business development. The hydropower industry has a vested interest in promoting hydropower sustainability and efficiency at existing hydropower assets to reduce electric sector's reliance on high GHG emitting generation resources.

Hydropower generation represents a tangible amount of electricity generation that, in ideal circumstances, could be used in place of an expensive and high CO_2 emitting power plant. To quantify the achievable reduction in CO_2 emissions through hydropower optimization, the average emissions of the system or power plant whose energy will be replaced must be known or calculated (UNFCCC 2014). While a full electricity system scale emission analysis is outside the scope of this study, a high-level analysis of the electricity system can instruct the development of appropriate coefficients, methodologies, and emissions estimates.

In case of PSH plants, the impact on GHG emissions depends on the type of generation capacity that is used for pumping and the type of capacity that is displaced when the PSH plant is generating. Typically, PSH plants are used as peaking capacity, and their generation would most likely result in a reduction of output at high-cost fossil fuel plants. If most of the energy provided for pumping comes from clean (e.g., nuclear) or renewable energy resources (e.g., hydro, wind, solar, and others), the overall GHG impact of PSH operation is likely to be positive, i.e., no increase in total GHG emissions from the power system. On the other hand, if most of the pumping energy comes from thermal power plants utilizing fossil fuels, the operation of the PSH plant may actually increase the overall GHG emissions from the power system.

Computing Emissions Impacts

The impact of the PSH on GHG emissions from the power system can be assessed by utilizing production cost models to simulate the system operation with and without the PSH plant. Alternatively, if production cost simulations are not available, an appropriate methodology for determining the emissions impact generated through hydropower and PSH optimization is the UNFCCC Clean Development Mechanism AM0052, "Increased electricity generation from existing hydropower stations through Decision System optimization." This methodology outlines the CO_2 emissions offsets that result when existing, grid-connected hydroplants implement optimization techniques to improve hydropower efficiency. It can be applied to existing hydro plants that are not currently optimized using a decision support system, where no significant equipment upgrades have occurred during the data collection period, and when no major changes to reservoir size or other key physical parameters are expected. Additional restrictions and restraints are outlined in the full methodology description (UNFCCC 2019).

The overall emissions reduction is computed as:

$$ER_y = (EG_{Bl,y} \times EF_y) - PE_y$$

Where:
ER_y= Emissions reduction in metric tons CO_2 (tCO_2)
$EG_{Bl,y}$= Baseline electricity generation during project year y (MWh)
EF_y= CO_2 emissions factor of the local electricity system (tCO_2/MWh)
PE_y= Project emissions during project year y (tCO_2)

The project emissions during the year are assumed to be zero (PEy = 0). The emissions factor, EFy, represents the emissions rate (tCO_2/MWh) of the displaced electricity from local fossil fuel plants. A comprehensive determination of EFy requires knowledge of the exact generation mix of displaced electricity, the amount of each fossil fuel consumed, the net calorific value of each fossil fuel consumed, the net electricity generated and delivered by each fossil fuel plant for at least the past three years, and the fuel consumption and net electricity generation for the five most recent fossil fuel units, or the set of most recent capacity additions that provide 20% of system generation (from the UNFCCC "Tool to calculate the emission factor for an electricity system"). By providing an upper and lower limit to potential emissions factors, a high degree of confidence could be obtained. Values used to compute CO_2 emission factors are presented in Table 4.9

Table 4.9: Values Used to Compute CO_2 Emissions Factor

Source	IPCC Default *EF*	Heat rate	Average *EF*
Unit	(kg CO_2/GJ)	(BTU/kWh)	(kg CO_2/MWh)
Coal	96.1	10,089	943.8
Natural Gas	56.1	10,354	544.1
Lignite	101.0	10,089	965.8

The upper and lower values of EF_y could be input into the equation above to estimate the total emissions reductions in metric tonnes of CO_2.

Example: Table 4.10 assumes a 1,000 MW, 10 hr/day PSH and estimates the CO_2 reduction to offset the mix of generation described above.

Table 4.10: Estimated Yearly Fossil Fuel CO_2 Reductions Due to PSH Generation

	Yearly PSH generation (MWh) *(Example: 1,000 MW for 10hr/day for 365days)*		**CO_2 emissions factor** (kg CO_2/MWh) EF_y	**Total avoided emissions** (tCO_2) ER_y
PSH	3,650,000	**Low** (natural gas offset)	544.1	1,985,965
		High (coal offset)	943.8	3,444,870

The estimated total of avoided fossil fuel CO_2 emissions ranges from about 2 million metric tonnes (natural gas offset) to about 3.5 million metric tonnes (coal offset). The projected fifty-year CO_2 emission reduction estimate, assuming similar conditions persist into the future, would range between 100 and 175 million metric tons. A comprehensive spatial distribution of the electricity system would provide the most appropriate emission factor.

Note: U.S. EPA's AVERT tool provides a national marginal emissions factor for the Equivalencies Calculator (EPA 2020).

Estimation of Job Creation and Economic Impact from PSH Development

The methodology used to estimate job creation and economic impacts of developing any new production facility is based on input-output (IO) modeling. IO tables are stylized representations of inter-industry relationships across the economy. For a given increase in spending in one sector, the ripple effects throughout the economy described by the IO tables are summarized through multipliers that can be computed for a local, regional, or national economy (Clouse 2020).

IO analysis allows estimation of three types of effects on employment, output, income, or value added:

- **Direct effects**: Jobs, output, income, and value added resulting from permitting, engineering design, construction, operation and maintenance of the facility. It also includes turbine-generator unit manufacturing.
- **Indirect effects**: Jobs, output, income, and value added impacts on other industries resulting from business-to-business purchases from the hydropower industry. Examples of indirect effects of a new PSH facility include activity and jobs related to plant components produced at manufacturing facilities that service a wide range of industries beyond hydropower and transactions related to project financing and insurance.
- **Induced effects**: Jobs, output, income, and value added supported by the wages generated from project construction and operation. These are household purchases in other sectors of the economy (e.g., housing, restaurants, shopping).

Estimates for the three types of effects are computed separately for the construction and operation phases of the project. For jobs, estimates are typically presented in full time equivalents to roll up full-time and part-time jobs into a single measure. Job creation estimates generated through this methodology are typically gross figures that do not consider jobs lost or foregone in other sectors as a result of the particular investment being considered.

Project-specific details matter most for estimating the size of direct effects. Once the direct effects are estimated, indirect and induced effects are driven by the IO-based multipliers that typically involve the use of IMPLAN software and databases. For PSH, important project details would include size, number of turbine-generator units, configuration (e.g., whether both reservoirs need to be constructed or at least one is already in place), and development cost estimates. Regional direct and indirect effects can change significantly depending on the concentration of hydropower-related manufacturing in the project region.

Recent examples of employment and economic impact estimates associated with PSH development include a 2009 study by Navigant Consulting (now Guidehouse Consulting) on potential U.S. job creation by 2025 in several hydropower deployment scenarios and a 2017 case study of employment and economic impacts commissioned by Dominion Energy as part of its evaluation of a 1,000 MW PSH facility in southwest Virginia (Chmura 2017). NREL's hydropower jobs and economic development impact (JEDI) model offers an interactive tool to estimate employment and economic impacts of new PSH construction. The JEDI tool allows the user to specify a long list of inputs regarding hydropower project characteristics and cost, to which it then applies multipliers to determine state-level direct, indirect, and induced effects on employment, output, and value added.

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5. Integration of Results for Valuation of PSH Services

Energy storage systems face a unique challenge when attempting to assign value to the services they can provide. An energy storage system could act as a generator, a load, or a transmission/distribution resource. These devices, including PSH, have operational limitations and behaviors that are not entirely captured with nameplate ratings or single value specifications. Unlike traditional generation technologies, an energy storage system'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.

Models used to determine least-cost approaches to meeting the needs of the electric system consider how and in what ways energy storage could be used. In order to perform this action, PSH must be represented and modeled in a manner that accurately captures its operational characteristics. This characterization is essential when comparing PSH to alternative competing technologies. Bulk power system planners, market operators, and PSH designers all need ways of understanding how PSH can be used to address grid needs.

This Guidebook addresses grid services that can be provided by PSH systems and defines approaches for assigning value to each of these services. However, like 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 one hour, there is less of it available in the next. There is also competition 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 a complex question. Each value stream or use case has a set of requirements and limitations that must be addressed in order 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 so as to avoid double counting.

An ideal integration process, as facilitated through a valuation tool or production cost model, would comprise the following:

> **Estimation of electrical system effects due to the operation of the PSH unit.** A thorough understanding of how the charging and discharging of the PSH unit is affecting the electrical system is important in estimating the value it can provide to that system. The electrical grid is a highly complex system. Thus, the PSH unit will not operate in a vacuum. If a schedule defined within the model to maximize value has a destabilizing effect on grid operations, the outcome could result in reliability declines and lost value. In turn, an ideal model would predict the destabilizing effect and alter the operational pattern to avoid generating the problem or to devise an approach for mitigating it.

PSH performance characterization. Changes in the SOC of the PSH unit must be characterized in the model, and charging and discharging profiles optimized in order to maximize value to the grid. An ideal model would capture any non-linearity in terms of changes in SOC varied by power output levels, SOC ranges, ramping capabilities, or any other relevant parameters. Change in performance characteristics over the life of the unit should be related back to specific types of operations and accounted for both in the lifecycle costs of the unit and the economic optimization.

Accounting for forecast uncertainties. All models estimate value based somewhat on a series of predictions tied to PSH performance, market responses, price fluctuations, and electrical system conditions. No set of assumptions can reflect perfect foresight. Therefore, any given set of forecasts has a certain amount of uncertainty inherent in it, and planning PSH operation around these forecasts would ideally account for that. The best models used to predict PSH value would not simply estimate an absolute value but rather would estimate a forecast-risk-adjusted value. Further, the best analyses also include a series of sensitivity analyses that demonstrate the sensitivity of results to adjustments in certain parameters (e.g., fluctuations in price growth, discount rate adjustments). These sensitivity analyses are instrumental in gauging the importance of each assumption or parameter on the outcome of the valuation assessment.

Mathematical optimization considering all possible services simultaneously. As we will explain later in this section, the ideal model would account for all the complexities mentioned earlier (e.g., PSH state, electric system effects, market effects, forecast-error effects) while computing the mathematically optimal dispatch schedule for the PSH. This estimation procedure should not require the user to specify a hierarchy *a priori* but rather should allow the algorithm itself to determine the optimal schedule, subject to the landscape of economic opportunities and to technical limitations.

Ability to define the optimal ratings and location within the power system. As part of finding the mathematically optimal dispatch of the use cases considered, an even more robust model would have the capacity to site and size the PSH asset so as to maximize value within an existing electrical grid.

Freely available and easy to use. The ideal model would be one readily available for all to use and would not require extensive training to understand or apply.

While the characteristics outlined above would be ideal, reality intervenes in this case and demonstrates that most models optimize across a limited number of use cases, and price-taker models ignore electrical system and market effects, tend to use simplistic representations of internal states, and fail to capture the complexity of market dynamics.

Figure 5.1 provides brief summaries of some of the existing energy storage valuation tools evaluated in the literature. While each of these models contain advanced features, none of them entirely embodies all of the characteristics just outlined. As a result, different models are often used to meet different valuation needs. Because price-taker models focus on marginal changes in value obtained by PSH operation in the electrical grid, holding all other parameters constant, they could theoretically be used to evaluate a broad set of use cases, including bulk power, transmission, grid ancillary services, distribution, and even customer energy management-focused services (e.g., in case of small distributed PSH). The primary limitation of these models is that they fail to model the system and market effects of the PSH and are, therefore, of limited use when assessing the value of large-scale (>10 MW) investments (Balducci et al. 2018).

To better understand the integration process, this section uses an example to walk through the co-optimization process. In this simplified example, the benefit streams include only balancing, which covers both frequency regulation and load following for a vertically integrated investor-owned utility, spin/non-spin reserves, arbitrage, and primary frequency response. For the day highlighted in Figure 5.2, there are only three benefit streams under consideration. The first panel presents the hourly energy and balancing prices. The second panel presents the optimal discharge for the day, which includes peak shaving required to provide capacity as needed at 7:00 p.m. The third, and final, panel demonstrates the change in SOC resulting from the optimal discharging of the PSH unit.

To define this optimal operation in price-taker models, the user must define the relevant prices and the operations required of the PSH unit to obtain each value. For capacity, that means the rules around participation (e.g., the PSH unit must demonstrate the capacity to provide four hours of generation at full rated capacity when called on during certain time periods) and the probability that such a call will be made, and the value of the service must be defined and input into the model. Arbitrage requires only price inputs, while regulation also requires definition of an AGC signal. System analysis models effectively define the system effects and perform the co-optimization process automatically. However, care should be taken when there are effects that spill over between use cases. For example, PSH provides congestion relief, which reduces the congestion component of LMPs. As a result, LMPs change, as does arbitrage revenue.

Results obtained through modeling of the PSH unit must be processed in order to accurately determine the NPV, BCR, the return on investment (ROI), payback period, or other factors that define the estimated economic and financial viability of the project. BCR refers to the ratio of benefits to costs in which a ratio greater than 1.0 indicates a project with a positive return, while a payback period refers to the length of time it takes the project to recover its initial investment. While models may simulate operation of the PSH unit for a limited time (e.g., one year), the benefits must be evaluated over the economic life of the unit.

Multiple accounting frameworks are available that can offer a variety of perspectives and metrics. Changing the analytical viewpoint (e.g., from PSH operator to grid operator) can substantially alter the ROI of the project as different stakeholders are responsible for different components of the total project cost and may not necessarily obtain all the benefits the PSH plant is capable of providing. The accounting basis of the financial assessment must be well defined.

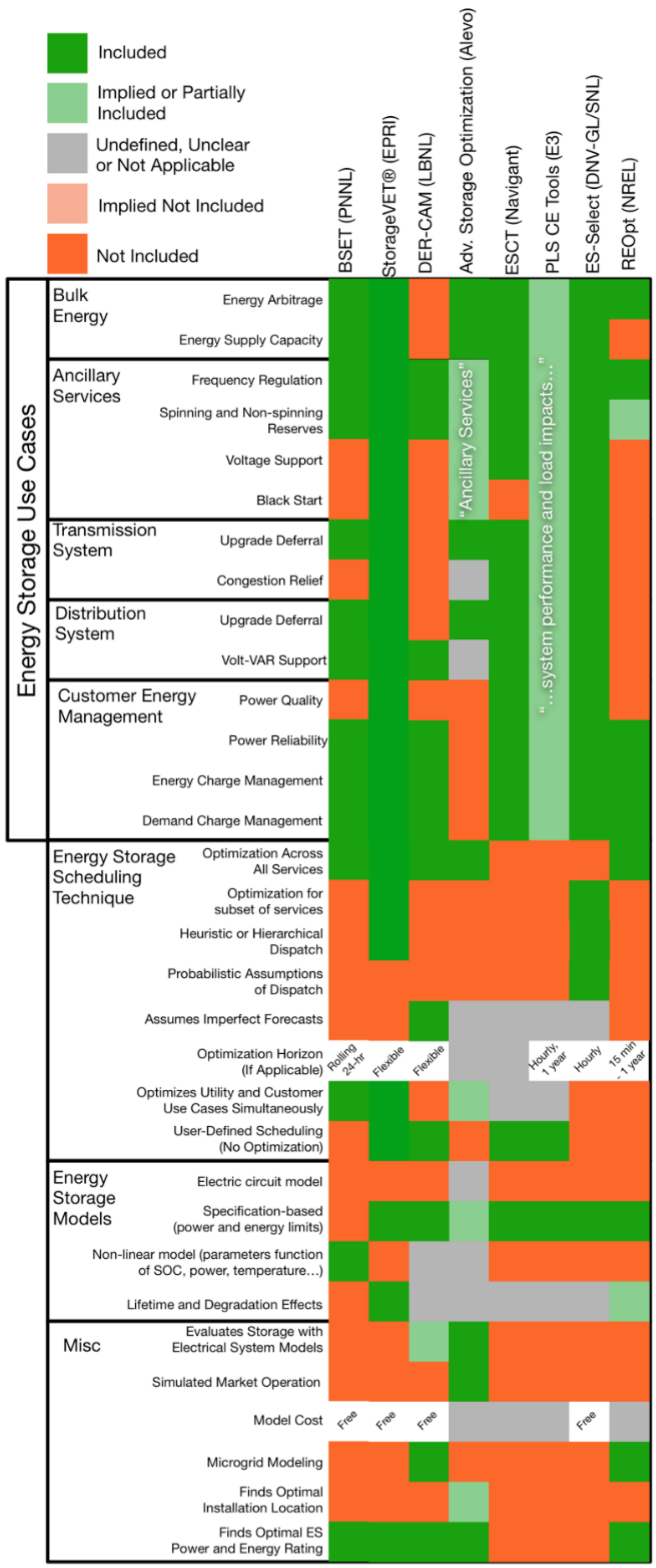

Figure 5.1: Review of energy storage price-taker models.

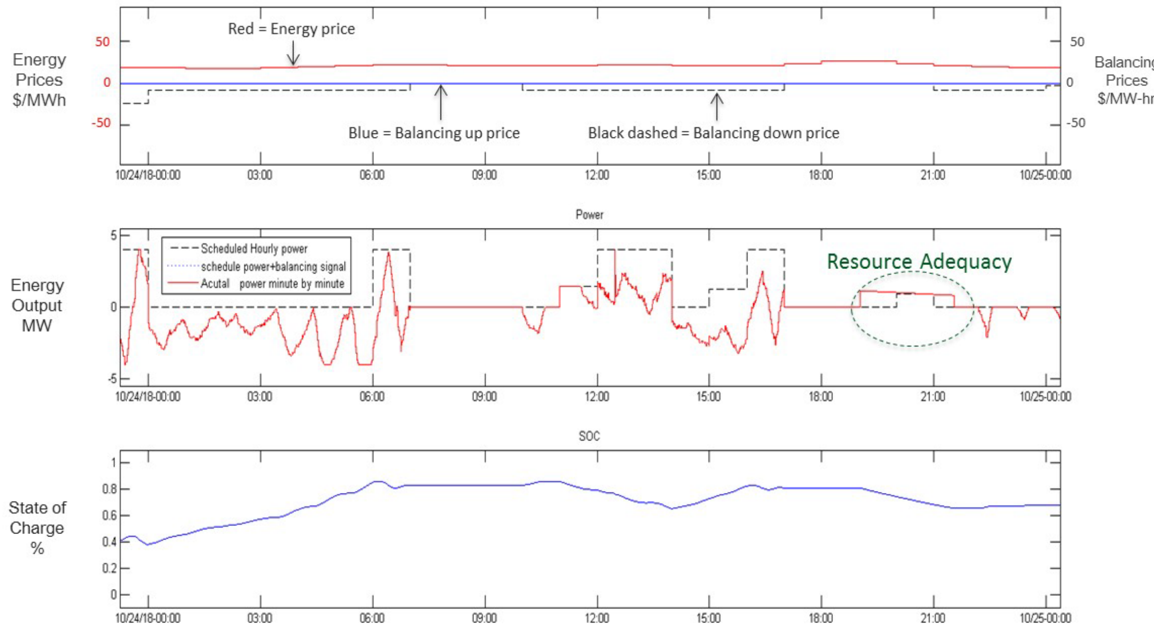

Figure 5.2: Optimal PSH operation for one day.

In addition to the above considerations, accounting for parameters that may vary over the life of the project is necessary in order to accurately reflect the ROI, and these should be factored into the accounting framework. Elements to consider could include: price growth, variability in system load, assumptions regarding alternative technology prices and fuels, and the effects of carbon taxes. Assuming that the system will remain static and these components unchanged could overstate or undervalue benefits over the life of the asset.

Following the application of the appropriate accounting framework to achieve an ROI, it is also important to perform sensitivity analysis around the results. Sensitivity analysis consists of varying a number of key assumptions within the analysis, holding all else constant, and evaluating any results that may have shifted as a consequence. Doing so can illustrate the positive and negative effects of making small changes to the analysis as well as show which aspects of the analysis are robust to changes.

5.1. References

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6. Summary and Conclusions

The valuation of PSH projects is a complex analysis, as it involves estimating the value of many services and contributions that these projects provide to the power system, which typically requires the use of detailed modeling and simulation tools. In addition, the analyst needs a comprehensive knowledge of the power system in which the PSH plant is located, as well as the operational performance characteristics and capabilities of PSH project that enable it to provide various services and contributions to the grid. The type of electricity market and its market rules, technical and operational characteristics and limits, and the environmental and regulatory constraints may all impact the value of a PSH project and its services.

This Guidebook describes a cost-benefit and decision analysis valuation framework and provides detailed step-by-step guidance on how to perform the valuation of PSH projects. The Guidebook also describes various methodological approaches that can be used for the valuation of services and contributions provided by PSH plants. It also describes the modeling tools that can be used to analyze the value of different PSH services and contributions, as well as the metrics that can be used to measure their impacts.

The valuation framework and the fifteen-step valuation process have been designed to be applicable to PSH projects of different sizes and in various locations in the electrical grid, from small PSH projects at the distribution level to large system storage projects at the transmission level. The valuation framework is also applicable to PSH projects characterized by different ownership types, from public and investor-owned utilities to independent power producers and other PSH developers. Finally, the valuation framework was designed to be applicable to any market environment, from vertically integrated utilities to fully restructured electricity markets. The Guidebook also describes various methodological approaches that can be used for the valuation of PSH services and contributions and provides guidance on which approaches are applicable to which market environments.

The specific goals for the development of the PSH valuation guidance were defined as follows:

1. Develop a 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
3. Transfer and disseminate the PSH valuation guidance to the hydropower industry, PSH developers, and other stakeholders

The valuation guidance and the valuation process presented in this Guidebook were applied to two proposed PSH projects in the U.S. (Banner Mountain PSH, being developed by Absaroka Energy, and Goldendale Energy Storage Project, a joint development by Copenhagen Infrastructure Partners and Rye Development). These two test case studies are summarized in two separate technical reports to illustrate how the valuation process presented in this Guidebook can be applied to actual PSH projects. Note that these two case studies were performed to test the valuation guidance and the underlying methodology and were not meant to perform an actual valuation of these two PSH projects. In this context, all results and findings of these two case studies should be considered for illustration purposes only, as they serve to illustrate the valuation process to Guidebook users.

The users of this Guidebook should also be aware of and recognize numerous limitations and challenges associated with the PSH valuation process. The key challenges are the analytical complexities and uncertainties. Because PSH plants provide many different types of services and contributions, their evaluation requires the use of sophisticated modeling tools and detailed modeling and simulation of power system operations. The valuation of different PSH services may require different methodological approaches for their evaluation and estimation, and the analyst may need to apply different valuation approaches to different market environments, which also contributes to the complexity of analyses.

In addition to significant analytical complexities, analysts also face numerous uncertainties when performing the valuation analysis. PSH projects have a very long lifetime (50 years or more) and will be operating in the power system for many years. At present, power systems are rapidly evolving, and their generation mix is changing from year to year, so estimating the value of any grid service, especially in the long term, is a challenge. With changes in the generation mix, the role and value of PSH projects in the system may also change over time. Other long-term uncertainties, such as the future prices of natural gas and other fuels for thermal power plants, new generation and demand-side technologies, and evolving electricity market structures and market rules, are all difficult to predict but will certainly affect the value of a PSH project over its lifetime.

Nevertheless, although subject to numerous uncertainties that cannot be avoided, the valuation analysis is still very useful as it provides information to decision-makers about the estimated value of the PSH project and supports the decision-making related to the project (e.g., whether to go ahead with the project or not). If there are several potential alternatives being analyzed, the valuation analysis may allow for the comparison of alternatives and choosing the one with the highest estimated value.

Another benefit of the valuation methodology and guidance presented in this Guidebook is that its application will provide for a comprehensive, transparent, and repeatable valuation of PSH projects. The application of PSH valuation guidance will also allow for better understanding of the valuation process among different stakeholders and how the valuation was performed for the project being evaluated.

To help the analyst navigate through the valuation process presented in this Guidebook, the project team is currently developing a companion PSH valuation tool. The tool will be publicly available and will have a decision tree structure to help the user navigate through the valuation process. The goal is to help the user perform the valuation of PSH projects in a systematic, transparent, and consistent manner.

APPENDICES

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Appendix A: Metrics

No.	Name	Description	Unit	Reference
Reliability				
1	System average interruption frequency index (SAIFI)	SAIFI indicates how often the average customer experiences a sustained interruption over a predefined period of time. SAIFI = (Σ Number of customers interrupted)/(Total number of customers served)	Interruptions/ customer-year	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices.* https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
2	System average interruption duration index (SAIDI)	SAIDI indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in minutes or hours of interruption. SAIDI = (Σ Customer minutes of interruption)/(Total number of customers served)	Minutes/ customer-year or hours/ customer-year	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
3	Customer average interruption duration index (CAIDI)	CAIDI represents the average time required to restore service. CAIDI = (Σ Customer minutes of interruption)/(Total number of customers interrupted) = SAIDI/SAIFI	Minutes or hours	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
4	Customer total average interruption duration index (CTAIDI)	CTAIDI represents the total time in the reporting period that average customers who actually experienced an interruption were without power. This index is a hybrid of CAIDI and is similarly calculated, except that those customers with multiple interruptions are counted only once. CTAIDI = (Σ Customer interruption durations)/(Total number of distinct customers interrupted)	Minutes or hours	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices.* https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
5	Customer average interruption frequency index (CAIFI)	CAIFI gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once, regardless of the number of times interrupted for this calculation. CAIFI = (Σ Number of customer interruptions)/(Total number of distinct customers interrupted)	Interruptions/ customer-year	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices.* https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
6	Average service availability index (ASAI)	ASAI represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period. ASAI = (Customer hours service availability)/(Customer hours service demand)	No dimension	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381

No.	Name	Description	Unit	Reference
7	Customers experiencing multiple interruptions index ($CEMI_n$)	$CEMI_n$ indicates the ratio of individual customers experiencing *n* or more sustained interruptions to the total number of customers served. $CEMI_n$ = (Total number of customers that experienced *n* or more sustained interruptions)/(Total number of customers served)	No dimension	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
8	Customers experiencing long interruption durations index (CELID)	CELID indicates the ratio of individual customers that experience interruptions with durations longer than or equal to a given time. That time is either the duration of a single interruption (s) or the total amount of time (t) that a customer has been interrupted during the reporting period.	No dimension	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
9	Average system interruption frequency index (ASIFI)	The calculation of the ASIFI is based on load rather than customers affected. ASIFI is sometimes used to measure distribution performance in areas that serve relatively few customers that have relatively large concentrations of load, predominantly industrial/commercial customers. Theoretically, in a system with homogeneous load distribution, ASIFI would be the same as SAIFI. ASIFI = (Σ Connected kVA of load interrupted)/(Total connected kVA served)	Interruption/ load-year	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
10	Average system interruption duration index (ASIDI)	The calculation of the ASIDI is based on load rather than customers affected. ASIDI = (Σ Connected kVA duration of load interrupted)/(Total connected kVA served)	Minutes/ load-year or hours/ load-year	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
11	Momentary average interruption frequency index (MAIFI)	MAIFI indicates the average frequency of momentary interruptions. MAIFI = (Σ Number of customer momentary interruptions)/(Total number of customers served)	Interruptions/ customer-year	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
12	Momentary average interruption event frequency index ($MAIFI_E$)	$MAIFI_E$ indicates the average frequency of momentary interruption events. This index does not include the events immediately preceding a sustained interruption. $MAIFI_E$ = (Σ Number of customer momentary interruption events)/(Total number of customers served)	Events/ customer-year	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381

No.	Name	Description	Unit	Reference
13	Customers experiencing multiple sustained and momentary interruption events index ($CEMSMI_n$)	$CEMSMI_n$ is the ratio of individual customers experiencing *n* or more of both sustained interruptions and momentary interruption events to the total customers served. Its purpose is to help identify customer issues that cannot be observed by using averages. $CEMSMI_n$ = (Total number of customers experiencing *n* or more interruptions)/(Total number of customers served)	No dimension	IEEE Std 1366-2012. *IEEE Guide for Electric Power Distribution Reliability Indices*. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=6209381
14	Loss-of-load probability (LOLP)	LOLP is defined as the probability of system daily peak or hourly demand exceeding the available generating capacity during a given period. The probability can be calculated either using only the daily peak loads (or daily peak variation curve) or all the hourly loads (or the load duration curve) in a given study period.	No dimension	NERC. *Probabilistic Assessment Technical Guideline Document, August 2016*. https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf.
15	Expected unserved energy (EUE)	EUE is defined as a measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. EUE is energy-centric and analyzes all hours of a particular year. Results are calculated in megawatt hours (MWh). EUE is the summation of the expected number of megawatt hours of load that will not be served in a given year as a result of demand exceeding the available capacity across all hours. This measure can be normalized based on various components of an assessment area (i.e., total of peak demand, net energy for load, etc.). Normalizing the EUE provides a measure relative to the size of a given assessment area.	MWh	NERC. *Probabilistic Assessment Technical Guideline Document, August 2016*. https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf.
16	Loss-of-load hours (LOLH)	LOLH is generally defined as the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the classic LOLE calculation. To distinguish this expected value from the classic calculation, the hourly LOLE is often called LOLH. It must be noted that the classic LOLE in days per year is not interchangeable with the LOLH in hours per year (i.e., LOLE of 0.1 days per year is not equivalent to a LOLH of 2.4 hours per year.) Unlike the classic LOLE metric, there is currently no generally acceptable LOLH criterion.	Hour/year	NERC. *Probabilistic Assessment Technical Guideline Document, August 2016*. https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf.
17	Loss-of-load expectation (LOLE)	LOLE is generally defined as the expected number of days per year for which the available generation capacity is insufficient to serve the daily peak demand.	Days/year	NERC. *Probabilistic Assessment Technical Guideline Document, August 2016*. https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf.

No.	Name	Description	Unit	Reference
18	Loss-of-load events (LOLEV)	LOLEV is defined as the number of events in which some system load is not served in a given year. A LOLEV can last for one hour or for several continuous hours and can involve the loss of one or several hundred megawatts of load. Note that this is not a probability index, but a frequency of occurrence index.	Events/year	NERC. *Probabilistic Assessment Technical Guideline Document, August 2016.* https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf.
19	Customer interruption cost (CIC)	CICs are normalized by dividing the costs by either the annual energy consumed or the peak demand. These normalized costs are weighted either by annual energy consumed or by peak demand to give the customer sector values.	$/kW or $/kWh	Allan, R., and R. Billinton. 2000. "Probabilistic assessment of power systems." *Proceedings of the IEEE* 88 (2): 140-162. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=823995
20	Value of lost load (VoLL)	VoLL is the estimated amount that customers receiving electricity with firm contracts would be willing to pay to avoid a disruption in their electricity service. It is expressed in $/kWh and forms a valuable index for comparing alternatives at the global HLI and HLII levels.	$/kWh	Allan, R., and R. Billinton. 2000. "Probabilistic assessment of power systems." *Proceedings of the IEEE* 88 (2): 140-162. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=823995
21	Interrupted energy assessment rate (IEAR)	IEAR can be used with the available adequacy indices in order to assess the severity associated with unsupplied energy due to supply interruptions. IEAR can be used as a customer-related index in making decisions regarding load curtailment philosophies and reliability related rate setting. It is expressed in $/kWh and forms a valuable index for comparing alternatives at the global HLI and HLII levels.	$/kWh	Allan, R., and R. Billinton. 2000. "Probabilistic assessment of power systems." *Proceedings of the IEEE* 88 (2): 140-162. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=823995
22	Area control error (ACE)	ACE is the instantaneous difference between scheduled and actual net generation and demand within a given balancing authority area tracked by system operators. Imbalances in customer demand and generation result in unintended inflows or outflows from neighboring systems to a balancing authority that can affect system reliability within the balancing authority and in neighboring systems.	MW	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
23	Control performance standard 1 (CPS1)	CPS1 calculates how a balancing authority's ACE contributes to frequency imbalances in the system on a 12-month rolling basis. Minimizing deviations in frequency over time is critical to maintaining system reliability.	No dimension	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
24	Frequency and severity of emergency events	All systems can call emergency events when supply becomes tight. For example, PJM has several types of emergency events, including primary reserve alerts, which are declared when estimated primary reserve is less than the forecast requirement. Emergency events indicate when the system is at risk of not meeting load, and reliability may be threatened.	Event/year	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf

No.	Name	Description	Unit	Reference
25	Availability of supply with dual fuel or firm fuel contracts	Concerns about natural gas supply during winter months have recently led system planners to track the gas generators that can either be fueled with alternative fuel, such as oil, or have firm gas contracts. Systems such as PJM have begun to provide performance incentives to encourage gas plants to install dual-fuel capabilities or procure firm fuel contracts.	%	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
26	Flexible capacity	CPUC now requires utilities to procure sufficient flexible capacity such that they can reliably meet the largest three-hour ramp in system load, net of wind and solar generation. Large ramps in net load occur in late afternoon as load is increasing and solar generation is decreasing simultaneously. This requirement is in addition to California's traditional resource adequacy requirement.	MW	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
27	Availability of transmission	NERC collects information to develop transmission metrics that analyze outage frequency, duration, causes, and many other factors related to transmission outages. NERC will also issue an annual public report showing aggregate metrics for each NERC region, and each transmission owner reporting TADS data will be provided a confidential copy of the same metrics for its facilities.	Multiple	NERC. 2010. *Transmission Availability Data System.* https://www.nerc.com/pa/RAPA/tads/Pages/default.aspx
28	System average RMS frequency index (SARFI)	SARFI represents the average number of specified RMS variation measurement events that occurred over the assessment period per customer served, where the specified disturbances are those with a magnitude less than x for sags or a magnitude greater than x for swells. In the evaluation, x is the RMS voltage threshold with possible values of 10, 50, 70, 80, 90, 110, 120 and 140.	Average events per customer	Brooks, D. L., et al. "Indices for assessing utility distribution system RMS variation performance." *IEEE Transactions on Power Delivery* 13 (1): 254-259. http://doe.org/10.1109/61.660886.
29	System instantaneous average RMS frequency index (SIARFI)	SIARFI represents the average number of specified instantaneous RMS variation measurement events that occurred over the assessment period per customer served. The specified disturbances are those with a magnitude less than x for sags or a magnitude greater than x for swells and a duration in the range of 0.5–30 cycles. In the evaluation, x is the RMS voltage threshold with possible values of 10, 50, 70, 80, 90, 110, 120 and 140.	Events per customer	Brooks, D. L., et al. "Indices for assessing utility distribution system RMS variation performance." *IEEE Transactions on Power Delivery* 13 (1): 254-259. http://doe.org/10.1109/61.660886.
30	System momentary average RMS frequency index (SMARFI)	In the same way that SIARFI is defined for instantaneous variations, SMARFI is defined for variations having durations in the range of 30 cycles to 3 seconds for sags and swells and in the range of 0.5 cycles to 3 seconds for interruptions.	Average events per customer	Brooks, D. L., et al. "Indices for assessing utility distribution system RMS variation performance." *IEEE Transactions on Power Delivery* 13 (1): 254-259. http://doe.org/10.1109/61.660886.

No.	Name	Description	Unit	Reference
31	System temporary average RMS frequency index (STARFI)	STARFI is very similar to SMARFI but is defined for temporary variations having durations in the range of 3–60 seconds.	Average events per customer	Brooks, D. L., et al. "Indices for assessing utility distribution system RMS variation performance." *IEEE Transactions on Power Delivery* 13 (1): 254-259. http://doe.org/10.1109/61.660886.
32	System average restoration index (SARI)	SARI quantifies the average duration of each interruption experienced during the period. It is calculated by dividing the period SAIDI value by the period SAIFI value. The SARI index measures the average number of hours per service interruption.	Average hours per service interruption	*Board of Commissioners of Public Utilities Report on Regulatory Performance Measures for Newfoundland and Labrador Hydro.* http://www.pub.nf.ca/hydro2003gra/correspondence/GTreportPerformanceMeasures.pdf
Resilience				
1	Share of assets (e.g., transformers) that have been storm-hardened	Assets built to higher construction standards for the purposes of maintaining operation in extreme conditions, such as severe weather events, will allow the system to maintain operation in a diverse set of conditions.	%	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
2	Share of distribution lines that have been undergrounded	Reduced exposure that distribution lines have to external factors will allow the system to maintain operation during extreme conditions that may otherwise cause outages but may expose wires to flooding.	%	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
3	Number and type of backup systems	The availability of redundant capacity that can operate in the case of outages due to extreme conditions will allow the system to maintain operation.	Count and type	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
4	Capacity and/or load with islanding capability	The ability of system operators to maintain sections of a larger system in the case that other sections are unavailable increases the ability to maintain operations during extreme conditions.	MW	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
5	Black start capacity	The amount of capacity that can start without an operational system.	MW	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
6	Available backup generation and equipment	Available backup generation and equipment is the amount of available backup generation and equipment including backup transformers.	MW	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
7	The presence or extent of advanced metering infrastructure (AMI)	AMI is the presence or extent of advanced metering infrastructure (AMI), which can provide information that helps utilities optimize their response.	Count	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf

No.	Name	Description	Unit	Reference
8	Time until restoration of critical services	Restoring power to critical social services such as hospitals, police, and fire is most important in the event of an emergency. Systems that can restore these critical services quickly provide value to customers.	Minutes or hours	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
9	Time until full system restoration	Systems that can restore service to all customers, not just a subset of critical services, in a timely manner provide greater value to customers than systems with long restoration times.	Minutes or hours	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
10	Average (or percentage) customers experiencing an outage during a specified time-period	Self-explanatory. Data required for the computation is the total kVA of load served.	Count	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
11	Critical customer energy demand not served	Expected amount of energy not being served to critical consumers by the system during the period considered due to system capacity shortages or unexpected severe power outages. Required information is total kVA of load interrupted for critical customers.	kW	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
12	Average (or %) of critical loads that experience an outage	Self-explanatory. Can be evaluated once total kVA served to critical customers is determined.	kW	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
13	Cost of grid damages	Refers to the total costs incurred to repair or replace lines, transformers, etc.	S	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
14	Loss of utility revenue	Refers to the total outage cost for the utility.	$	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
15	Avoided outage cost	Requires the determination of total kVA of interrupted load avoided, and subsequent determination of the cost if the loads had suffered outages.	$	GMLC. 2017. Grid Modernization: Metrics Analysis. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf

Flexibility				
1	Periods of flexibility deficit (PFD)	The PFD is a measure of the number of periods when the available flexible resources were less than the required flexibility for a given time horizon and direction.	Periods	EPRI. 2014. *Metrics for Quantifying Flexibility in Power Systems.* https://www.epri.com/#/pages/product/3002004243/?lang=en
2	Expected unserved ramping (EUR)	The expected unserved ramping is the total magnitude of the deficit of net flexibility. The EUR is similar to but not identical to the expected unserved energy metric in capacity adequacy planning.	MWh	EPRI. 2014. *Metrics for Quantifying Flexibility in Power Systems.* https://www.epri.com/#/pages/product/3002004243/?lang=en
3	Insufficient ramp resource expectation (IRRE)	IRRE is a second measure of the frequency of flexibility shortfalls over a variety of time horizons. The key difference between the PFD and IRRE is that the IRRE uses a probabilistic approach to determine the likelihood of meeting each net load ramp drawn from a distribution at each time period.	%	EPRI. 2014. *Metrics for Quantifying Flexibility in Power Systems.* https://www.epri.com/#/pages/product/3002004243/?lang=en
4	Flexibility well-being assessment	A well-being analysis combines the information in the PFD and EUR metrics to determine whether a system is in a user-defined safe, warning, or dangerous state.	Safe, warning or dangerous	EPRI. 2014. *Metrics for Quantifying Flexibility in Power Systems.* https://www.epri.com/#/pages/product/3002004243/?lang=en
5	Cost and/or price volatility	Cost and/or price volatility reflects the range of outcomes and the potential for undesirable high cost outcomes due to the ability of the system to adapt to changing market conditions over the long term.	$/MWh	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
6	Fuel diversity of generating capacity	Fuel diversity of generating capacity (% reliance on a resource), which bridges operational and planning flexibility, is a commonly used metric that provides an indication of the extent to which a system can respond to short and long-term developments in fuel prices and environmental regulations without requiring large capital investments.	%	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
7	System regulating capability	The system regulating capability measures the ability of the portfolio to respond to load swings. The ratio of the regulating reserve to the demand response, which can quick start capacity to the system peak load, it is used to score portfolios of generating resources developed using various strategies and across various portfolios.	Normalized	TVA. 2015. *Integrated Resource Plan 2015 Final Report.* https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf

8	Flexibility turndown factor	Ratio of the must-run and non-dispatchable energy (wind, solar, and nuclear) to the annual sales. Measures the ability of the system to serve low load periods.	Normalized	TVA. 2015. *Integrated Resource Plan 2015 Final Report.* https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf
9	Flexibility resource indicator	Ratio of natural gas-fired combustion turbine nameplate capacity and 15% of hydropower capacity to the nameplate capacity of wind. Provides a general ratio of the amount of flexible resources typically used for balancing variable generation to the amount of resource-based variability in the system. Identifies circumstances or scenarios where sufficiency of flexibility might be a concern and require more in-depth examination.	Normalized	WECC. 2013. *2013 Interconnection-wide Plan: Plan Summary.* https://www.wecc.biz/Reliability/2013Plan_PlanSummary.pdf
10	Net demand ramping variability	Historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps (actual load less production from VERs) using one-minute data. Measures the maximum net demand variability faced by a balancing authority. Ultimately, the BA needs to have adequate resources available to meet the expected demand variability. Tracking this metric allows for early identification of potential areas for further analysis.	MW of net demand variability	NERC. 2015. *Essential Reliability Services Task Force Measures Framework Report.* http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf
11	LOLE flex (LOLE multi-hour and LOLE intra-hour)	Attributes loss of load events during times when generation capacity was not limited (i.e., there was excess capacity available, but it could not be accessed due to flexibility constraints) to either multi-hour or intra-hour flexibility deficits. Expands the traditional definition of LOLE to account for operating flexibility in order to answer the question: How much capacity and operating flexibility is needed for a power system to meet the one day in 10 years LOLE reliability standard?	Days with loss of load in 10 years	*Flexibility Metrics and Standards Project—a California Energy Systems for the 21st Century (CES-21)*. 2016. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=9282
12	Binding flexibility ratio	Measures the ratio of the flexibility demand to the flexibility supply in the operational time interval where flexibility is most binding. Helps to better gauge the flexibility of planned resource portfolios.	Normalized	LBNL. 2015. *Flexibility Inventory for Western Resource Planners*. https://emp.lbl.gov/sites/all/files/lbnl-1003750.pdf
13	Flexible capacity need	A monthly measure of the maximum 3-hour contiguous ramp in the net load plus the larger of the most severe single contingency or 3.5% of the monthly peak load. Part of an annual flexible capacity technical study to determine the flexible capacity needed to help ensure system reliability. The flexible capacity need is then allocated to LSEs.	MW of flexible capacity	CAISO. 2017. *Final Flexible Capacity Needs Assessment for 2017.* https://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf
14	Renewable curtailment	Percentage of the available renewable energy that must be curtailed due to flexibility limitations. It can highlight the consequence of insufficient flexibility.	Normalized	Energy and Environmental Economics, Inc. 2015. *Western Interconnection Flexibility Assessment*. https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/WECC_Flexibility_Assessment_ExecSumm_2016-01-11.pdf

15	Percent of unit-hours mitigated	This metric provides an indication of the magnitude of mitigation occurring in RTO and ISO markets, as measured by the percentage of unit hours that prices were set at the mitigated price on an annual basis. High values of this metric may be due to a lack of flexibility in the system. CAISO reported the highest percentage of mitigated hours in this report. CAISO has large intermittent renewable fleet requiring flexibility operations.	Normalized	FERC. 2017. *Staff Report – Common Metrics Report*. https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf
16	Demand response (DR)	DR as a % of total installed capacity. Provides an indication of the contribution of DR to maintaining the short and long-term reliability.	Normalized	FERC. 2017. *Staff Report – Common Metrics Report*. https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf
17	Control performance standards (CPS1, CPS2, BAAL)	CPSs measure a Balancing Authority's (BA's) area control error (ACE), which indicates how well system operators maintain a balance between supply and demand. BAs need to meet NERC-mandated performance standards to show that they are maintaining an adequate balance. Decreases in control performance indicate that the system operator is not maintaining a balance between supply and demand. This can be due, in part, to insufficient flexibility.	Normalized	NERC. 2013. *BAL-001-2—Real Power Balancing Control Performance Standard Background Document.* https://www.nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/BAL-001-2_Background_Document_Clean-20130301.pdf
18	Wind generation fraction	Leading metrics using weather and production cost models can be used to characterize demand for flexibility. Lagging metrics can be used to identify trends and correlations (e.g., high wind generation and load shedding may indicate that insufficient intra -hour ramping capability was available at that time). Large fractions of generation coming from wind can lead to a range of challenges.	Ratio	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
19	Solar generation fraction	Leading metrics using weather and production cost models can be used to characterize demand for flexibility. Lagging metrics can be used to identify trends and correlations (e.g., high solar generation and load shedding may indicate insufficient multi-hour ramping capability).	Ratio	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
20	Wind/solar generation volatility	Standard deviation, autocorrelation, or other statistical measures may provide a valuable metric for estimating the demand for flexibility.	MW	GMLC. 2017. *Grid Modernization: Metrics Analysis*. https://gridmod.labworks.org/sites/default/files/resources/GMLC1%201_Reference_Manual_2%201_final_2017_06_01_v4_wPNNLNo_1.pdf
Sustainability				
1	Material intensity	Material intensity is expressed as pounds of material wasted (not converted to desirable product) per unit output. This metric is calculated by subtracting the mass of product and saleable co-products from the mass of raw materials input to the process.	lb/kWh	Schwarz, J., et al. 2002. "Use sustainability metrics to guide decision-making." *Chemical Engineering Progress* 98(7): 58-63. https://pdfs.semanticscholar.org/b29a/e01b85d8ef7c72150a7e938823c02a4ee685.pdf

2	Energy intensity	Energy intensity is expressed in terms of BTUs per unit output. It is a measure of the net fuel-energy consumed to provide the heat and power required for the process. Energy inputs to the process include natural gas, fuel oil, steam and electricity.	Btu/kWh	Schwarz, J., et al. 2002. "Use sustainability metrics to guide decision-making." *Chemical Engineering Progress* 98(7): 58-63. https://pdfs.semanticscholar.org/b29a/e01b85d8ef7c72150a7e938823c02a4ee685.pdf
3	Water consumption	Water consumption is expressed as gallons of fresh water, excluding rainwater, consumed per unit output.	Gallons/kWh	Schwarz, J., et al. 2002. "Use sustainability metrics to guide decision-making." *Chemical Engineering Progress* 98(7): 58-63. https://pdfs.semanticscholar.org/b29a/e01b85d8ef7c72150a7e938823c02a4ee685.pdf
4	Toxic emissions	Toxic emissions are expressed as pounds of toxic material emitted by the process per unit output.	lb/kWh	Schwarz, J., et al. 2002. "Use sustainability metrics to guide decision-making." *Chemical Engineering Progress* 98(7): 58-63. https://pdfs.semanticscholar.org/b29a/e01b85d8ef7c72150a7e938823c02a4ee685.pdf
5	Pollutant emissions	Pollutant emissions are expressed as pounds of pollutants emitted by the process per unit output.	lb/kWh	Schwarz, J., et al. 2002. "Use sustainability metrics to guide decision-making." *Chemical Engineering Progress* 98(7): 58-63. https://pdfs.semanticscholar.org/b29a/e01b85d8ef7c72150a7e938823c02a4ee685.pdf
6	Greenhouse gas emissions	The discharge of greenhouse gases, such as carbon dioxide, methane, nitrous oxide and various halogenated hydrocarbons, into the atmosphere. Combustion of fossil fuels, agricultural activities and industrial processes contribute to greenhouse gas emissions.	Tons/MWh	USDA. "NAL Agricultural Thesaurus and Glossary." https://agclass.nal.usda.gov/mtwdk.exe?k=glossary&l=60&w=6273&n=1&s=5&t=2
7	Water temperature impacts	Power plants that use once-through cooling may not consume significant quantities of water, but through water usage they generate water temperature impacts that can affect temperature-sensitive plants and animals in the body of water where the effluent is discharged.	N/A (qualitative metric)	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
8	Tons of ash	Tons of ash generated by a coal power plant is an indicator of landfill needs and the associated environmental impacts from landfill activities.	Tons	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
9	Land use	Land use measures the land requirements and the potential environmental impacts (such as land cleared and loss of habitat) for the generating facility itself but also potentially for supply lines or waste storage and disposal.	Acres	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
10	Lifecycle impacts	Lifecycle impacts from the materials and production processes necessary for new equipment will vary significantly across resource types, sources of materials, and locations of production.	Years	PNNL. 2016. *Valuation of Electric Power System Services and Technologies*.

				https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-25633.pdf
11	Electric sector CO_2 emissions from GHGRP	Absolute CO_2 emissions as reported to the EPA's Greenhouse Gas Reporting Program in mandatory facility reporting in GHGRP (CFR 40 Part 98). Facilities that emit 25,000 metric tons or more per year of GHGs are required to submit annual reports to EPA under the GHGRP.	Metric tons of CO_2 equivalent	EPA, 2016. GHG Reporting Program Data Sets. https://www.epa.gov/ghgreporting/ghg-reporting-program-data-sets
12	Electric sector CO_2 emissions from CAMD	Absolute CO_2 emissions as reported to the EPA Clean Air Markets Division (CAMD) for mandatory reporting of CO_2 emissions data from continuous emission monitoring systems. Mandatory reporting under EPA's Acid Rain Program (CFR 40 Part 75).	Metric tons of CO_2	EPA. 2018. Air Markets Program Data. https://ampd.epa.gov/ampd/
13	GHG emissions covered under emissions-limiting regulations	Percentage of emissions covered under emissions-limiting regulations. Helps to develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors.	Percentage	SASB. 2016. *Sustainability Accounting Standard - Infrastructure Sector. Electric Utilities Sustainability Accounting Standard.* http://www.sasb.org/
14	GHG emissions covered under emissions-reporting regulations	Percentage of emissions covered under emissions-reporting regulations. Helps to develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors.	Percentage	SASB. 2016. *Sustainability Accounting Standard - Infrastructure Sector. Electric Utilities Sustainability Accounting Standard.* http://www.sasb.org/
15	Corporate fulfillment of RPS target by market	Percentage fulfillment of RPS target by market. Aims to develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors.	Percentage	SASB. 2016. *Sustainability Accounting Standard – Infrastructure Sector. Electric Utilities Sustainability Accounting Standard.* http://www.sasb.org/
16	Customers served in RPS markets	Number of customers served in markets subject to renewable portfolio standards. Aims to develop and disseminate sustainability accounting standards that help public corporations disclose material, decision-useful information to investors.	Number of customers	SASB. 2016. *Sustainability Accounting Standard – Infrastructure Sector. Electric Utilities Sustainability Accounting Standard.* http://www.sasb.org/
17	Electric sector SO_2 and NOx emissions from eGRID	Absolute NOx and SO_2 emissions as compiled by the EPA in its eGRID data product; data sources include Clean Air Markets program (CAMD) and the EIA's Monthly Energy Review (MER). Can be used by consumers, researchers and other stakeholders to develop criteria pollutant emission inventories, air quality analysis, consumer information disclosure, avoided emission estimates, etc.	Tons of NOx and SO_2	EPA. 2016. Emissions & Generation Resource Integrated Database (eGRID). https://www.epa.gov/energy/egrid
18	Electric sector SO_2 and NOx emissions from CAMD	Absolute SO_2 and NOx emissions as reported to the EPA Clean Air Markets Division (CAMD) for mandatory reporting from continuous emission monitoring systems. Mandatory reporting under EPA's Acid Rain Program (CFR 40 Part 75).	Tons of SO_2 and NOx	EPA. 2018. Air Markets Program Data. https://ampd.epa.gov/ampd/
19	Electric sector SO_2 and NOx	Absolute NOx and SO_2 emissions as compiled by the EIA in its Electric Power	Tons of SO_2 and NOx	EIA. 2017. *Electricity–Electric Power Annual.*

	emissions from EIA's EPA	Annual. Aims to provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding.		https://www.eia.gov/electricity/annual/
20	Electric sector SO_2, NOx, mercury emissions from EIA's AEO	Absolute SO_2, NOx, and mercury emissions as compiled by the EIA in its Annual Energy Outlook. Aims to provide independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding.	Short Tons SO_2, NOx, Mercury	EIA. 2018. *Annual Energy Outlook 2018.* https://www.eia.gov/outlooks/aeo/
Affordability				
1	Levelized cost of energy (LCOE)	LCOE represents the average revenue per unit of energy production that would be required by a project owner to recover all investment and operating costs. It includes a specified return on investment over a specified project financial life, as well as an assumed project utilization rate. The computation for LCOE takes the following general form: $\left(\frac{\text{fixed charge factor} * \text{capital costs} + \text{fixed O\&M}}{\text{annual expected generation hours}}\right) + \text{variable O\&M} + \text{fuel}$	\$/MWh	EIA. 2013. *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement.* https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf
2	Levelized avoided cost of electricity (LACE)	LACE represents the potential revenue available to the project owner from the sale of energy and generating capacity. This cost is a weighted average of the marginal cost of electricity dispatch during the periods in which the project is assumed to operate, weighted by the number of hours of assumed operation in each time-period. The marginal cost of meeting system planning reserves is weighted by the estimated capacity credit for each technology. $[\sum_{t=1}^{Y}(\text{marginal generation price}_t * \text{dispatched hours}_t) + (\text{capacity payment} * \text{capacity credit})] / (\text{annual expected generation hours})$	\$/MWh	EIA. 2013. *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement.* https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf
3	Marginal generation price	Marginal generation price is the cost of serving load to meet the demand in the specified time period. This price is typically determined by the variable cost (fuel cost plus variable O&M) of the most expensive generating unit that needs to be dispatched to meet energy demand. This price may also be impacted by the cost of meeting any environmental or portfolio policy requirements by the marginal generators (that is, the cost of purchasing renewable energy credits for a non-qualifying generator).	\$/MWh	EIA. 2013. *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement.* https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf

4	Capital Costs	Capital cost is the initial investment per unit of capacity in the project, expressed in $/MW. For any given technology, this cost may vary over time based on a number of factors, including declining technology costs due to learning and cost adjustments from broader economic factors, such as the cost of construction commodities and availability of resources for geographically constrained energy sources like wind, geothermal, or hydro.	$/MW	EIA. 2013. *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement*. https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf
5	Variable O&M cost	Variable O&M is the expenditure per unit of generation for operations and maintenance, expressed in $/MWh. This expenditure includes costs that are closely tied to the actual operating hours of the equipment, such as consumable maintenance items and refurbishment costs that are scheduled based on operating hours (rather than on a calendar basis).	$/MWh	EIA. 2013. *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement*. https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf
6	Fixed O&M cost	Fixed O&M is the annual expenditure per unit of project capacity for operations and maintenance, expressed in $/MW/year. This includes costs that remain relatively constant, regardless of plant utilization levels, such as worker salaries and maintenance or refurbishment costs that are scheduled on a calendar basis rather than an operating-hours basis.	$/MW/ year	EIA. 2013. *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement*. https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf
7	Capacity payment	Capacity payment is the value to the system of meeting the reliability reserve margin. It is determined as the payment that would be required to incentivize the last unit of capacity needed to satisfy a regional reliability reserve requirement.	$	EIA. 2013. *Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement*. https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf
8	Locational marginal price (LMP)	LMP is defined as the marginal price for energy at the location where the energy is delivered or received. For accounting purposes, LMP is expressed in dollars per megawatt-hour ($/MWh). LMP is a pricing approach that addresses transmission system congestion and loss costs as well as energy costs.	$/MWh	PJM. "PJM Glossary." http://www.pjm.com/Glossary.aspx#index_L
9	Market-clearing price (MCP)	The price that is paid by all load and paid to all suppliers for the service received or provided.	$/MWh	PJM. "PJM Glossary." http://www.pjm.com/Glossary.aspx#index_L
10	Locational reliability charge	Fee applied to each LSE that serves load in PJM during the delivery year. Equal to the LSE's daily unforced capacity obligation multiplied by the applicable final zonal capacity price.	$	PJM. "PJM Glossary." http://www.pjm.com/Glossary.aspx#index_L
11	Net present value (NPV)	NPV represents the net profit generated by an investment, calculated from the discounted sum of future costs and revenues.	$	NREL. 2011. *Impact of Different Economic Performance Metrics on the Perceived Value of Solar Photovoltaics*. https://www.nrel.gov/docs/fy12osti/52197.pdf

12	Profitability index (PI)	PI represents the project NPV divided by the initial investment cost. PIs represent the discounted percent return on an investment, and PIs greater than zero represent profitable investments.	%	NREL. 2011. *Impact of Different Economic Performance Metrics on the Perceived Value of Solar Photovoltaics*. https://www.nrel.gov/docs/fy12osti/52197.pdf
13	Benefit-to-cost (B/C) ratio	The B/C ratio represents the discounted system revenues divided by the discounted system costs. A B/C ratio greater than one represents a profitable investment. The main difference between the PI and B/C ratio is that all costs in the B/C ratio are discounted, whereas PI is calculated by normalizing the difference between discounted revenues minus costs (NPV) by the undiscounted initial investment cost.	%	NREL. 2011. *Impact of Different Economic Performance Metrics on the Perceived Value of Solar Photovoltaics*. https://www.nrel.gov/docs/fy12osti/52197.pdf
14	Internal rate of return (IRR)	The IRR represents the discount rate at which the project NPV equals zero and is frequently interpreted as the annualized return on investment.	%	NREL. 2011. *Impact of Different Economic Performance Metrics on the Perceived Value of Solar Photovoltaics*. https://www.nrel.gov/docs/fy12osti/52197.pdf
15	Modified IRR (MIRR)	MIRRs are similar to IRRs, but positive net revenues are explicitly reinvested at the company's or individual's opportunity cost of capital rather than implicitly reinvested at a rate equal to the system IRR.	%	NREL. 2011. *Impact of Different Economic Performance Metrics on the Perceived Value of Solar Photovoltaics*. https://www.nrel.gov/docs/fy12osti/52197.pdf
16	Simple payback period (SPP)	The length of time after the first investment that the undiscounted sum of costs and revenues equals zero. Provides an easy to understand representation of cost effectiveness.	Years or months	PNNL. 2015. *Methodology for Evaluating Cost-effectiveness of Commercial Energy Code Changes*. https://www.energycodes.gov/sites/default/files/documents/commercial_methodology.pdf
17	Customer cost burden	Proportion of customer income devoted to purchasing desired level of electricity service. Foundational to estimating customer affordability.	Fraction	NYSERDA. 2011. *Home Energy Affordability in New York: The Affordability Gap (2008-2010)*. http://www.nyserda.ny.gov/-/media/Files/EDPPP/LIFE/Resources/2008-2010-affordability-gap.pdf
18	Affordability gap factor	Indication of the difference between affordable customer costs and observed customer costs. Provides scale to the affordability question: How unaffordable are electricity costs on average?	Fraction	NYSERDA. 2011. *Home Energy Affordability in New York: The Affordability Gap (2008-2010)*. http://www.nyserda.ny.gov/-/media/Files/EDPPP/LIFE/Resources/2008-2010-affordability-gap.pdf
19	Affordability gap index	Temporal index of affordability gap factor compared to a base year. Answers the question: is electricity becoming more or less affordable?	Index	NYSERDA. 2011. *Home Energy Affordability in New York: The Affordability Gap (2008-2010)*. http://www.nyserda.ny.gov/-/media/Files/EDPPP/LIFE/Resources/2008-2010-affordability-gap.pdf
20	Net revenue requirements—utility	Annual stream of revenue necessary to recover the total costs of a project including capital (in the form of depreciation), operating costs including fuel, financing costs including interest and required return on rate on equity, and taxes including both costs and incentives.	$/year	ORNL. 1993. *Report on the Study of Tax and Rate Treatment of Renewable Energy Projects.* https://www.osti.gov/servlets/purl/10117412

21	Avoided cost—utility	Net change in the costs of the overall system with the development of the specified project. Used by utilities and regulators for establishing the value of a project compared to its alternatives and for setting the value of distributed generation technologies.	$	NREL. 1995. *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies*. https://www.nrel.gov/docs/legosti/old/5173.pdf
Security				
1	Reportable cybersecurity incidents	Reports the total number of reportable cybersecurity incidents that occur over time and identifies how many of these incidents have resulted in a loss of load. It is important to note that any loss of load will be counted, regardless of direct cause. For example, if load was shed as a result of a loss of situation awareness caused by a cybersecurity incident affecting an entity's energy management system, the incident would be counted even though the cybersecurity incident did not directly cause the loss of load. This metric provides the number of reportable cybersecurity incidents and an indication of the resilience of the BES to operate reliably and continue to serve load.	Count	NERC. 2017. *Security Performance Metrics (Draft)*. https://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/DRAFT%20SOR%20Chapter%20X%20Security%20Metrics%2020170305_v4_redline.pdf
2	Reportable physical security events	Reports the total number of physical security reportable events that occur over time and identifies how many of these events have resulted in a loss of load. It is important to note that any loss of load is counted, regardless of direct cause. For example, if load was shed as a result of safety concerns due to a break-in at a substation, the event is counted even though no equipment that directly caused the loss of load was damaged. The metric provides the number of physical security reportable events and an indication of the resilience of the BES to operate reliably and continue to serve load.	Count	NERC. 2017. *Security Performance Metrics (Draft)*. https://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/DRAFT%20SOR%20Chapter%20X%20Security%20Metrics%2020170305_v4_redline.pdf
3	Electricity Information Sharing and Analysis Center (E-ISAC) membership	This metric reports the total number of electricity sector organizations and individuals registered as members of E-ISAC. E-ISAC members include NERC registered entities and others in the electricity sector including distribution utilities (i.e., membership is not limited to BPS organizations). Given today's rapidly changing threat environment, it is important that entities be able to quickly receive and share security-related information. This metric identifies the number of organizations registered, as well as the number of individuals. Increasing E-ISAC membership should serve to collectively increase awareness of security threats and enhance the sector's ability to respond quickly and effectively.	Count	NERC. 2017. *Security Performance Metrics (Draft)*. https://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/DRAFT%20SOR%20Chapter%20X%20Security%20Metrics%2020170305_v4_redline.pdf

4	Industry-sourced information sharing	This metric reports the total number of Incident Bulletins (Cyber Bulletins and Physical Bulletins) published by E-ISAC based on information voluntarily submitted by E-ISAC member organizations. Incident Bulletins describe physical and cybersecurity incidents and provide timely, relevant, and actionable information of broad interest to the electricity sector. This metric provides an indication of the extent to which E-ISAC member organizations are willing and able to share information related to cybersecurity and physical security incidents they experience.	Count	NERC. 2017. *Security Performance Metrics (Draft)*. https://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/DRAFT%20SOR%20Chapter%20X%20Security%20Metrics%2020170305_v4_redline.pdf
5	Global cyber vulnerabilities	This metric reports the number of global cybersecurity vulnerabilities considered to be high severity based on data published by the National Institute of Standards and Technology (NIST). NIST defines high severity vulnerabilities as those with a common vulnerability scoring system (CVSS) of seven or higher. The term "global" is an important distinction as this metric is not limited to information technology typically used by electricity sector entities.	Count	NERC. 2017. *Security Performance Metrics (Draft)*. https://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/DRAFT%20SOR%20Chapter%20X%20Security%20Metrics%2020170305_v4_redline.pdf
6	Global cyber vulnerabilities and incidents	This metric compares the number of annual global cybersecurity vulnerabilities and incidents in order to identify a possible correlation between vulnerabilities and incidents.	Count	NERC. 2017. *Security Performance Metrics (Draft)*. https://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/DRAFT%20SOR%20Chapter%20X%20Security%20Metrics%2020170305_v4_redline.pdf
7	GridEx exercise participation	This metric compares the number of organizations participating in each of the GridEx security and crisis response exercises conducted by NERC every two years. NERC's large-scale GridEx exercises provide electricity organizations the opportunity to respond to simulated cybersecurity and physical security attacks affecting the reliable operation of the North American grid.	Count	NERC. 2017. *Security Performance Metrics (Draft)*. https://www.nerc.com/comm/CIPC/Agendas%20Highlights%20and%20Minutes%202013/DRAFT%20SOR%20Chapter%20X%20Security%20Metrics%2020170305_v4_redline.pdf
8	Protective Masures Indes (PMI)	Physical security refers to measures and features that protect a facility and its buildings, perimeter, and occupants from intrusion. The PMI captures the protective measures in place in a given facility and serves as key indicator characterizing the protective posture of a facility.	No dimension	ANL. 2013. *Protective Measures Index and Vulnerability Index: Indicators of Critical Infrastructure Protection and Vulnerability.* https://www.researchgate.net/publication/299526826_Protective_Measures_Index_and_Vulnerability_Index_Indicators_of_Critical_Infrastructure_Protection_and_Vulnerability
9	Vulnerability Index (VI)	This index indicates the vulnerability of a given facility to physical attack and intrusion. It is the opposite of PMI.	No dimension	ANL. 2013. *Protective Measures Index and Vulnerability Index: Indicators of Critical Infrastructure Protection and Vulnerability.* https://www.researchgate.net/publication/299526826_Protective_Measures_Index_and_Vulnerability_Index_Indicators_of_Critical_Infrastructure_Protection_and_Vulnerability

10	Resilience Measurement Index (RMI)	RMI characterizes the resilience of critical infrastructure. It captures the elements in place that contribute to the resilience of a given facility, such as preparedness, mitigation measures, response capabilities, and recovery mechanisms.	No dimension	ANL. 2013. *Resilience Measurement Index Index: An Indicator of Critical Infrastructure Resilience.* https://publications.anl.gov/anlpubs/2013/07/76797.pdf
11	Consequences Measurement Index (CMI)	CMI characterizes the maximum consequences potentially generated by an adverse event at a facility. This index includes information on public health and safety, economic, psychological, and governance and mission impacts from the loss of the facility.	No dimension	ANL. 2013. *Resilience Measurement Index Index: An Indicator of Critical Infrastructure Resilience.* https://publications.anl.gov/anlpubs/2013/07/76797.pdf
12	Number of successful or unsuccessful intrusion or attack	This metric captures the total number of attacks against a given utility's facilities. Describes how prepared the electric sector is for a physical attack.	No dimension	CPUC. 2015. *Regulation of Physical Security for the Electric Distribution System.* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454097
13	Number of false or nuisance alarms	Collection of the number of non-attack-related incidents for a given utility. Describes how prepared the electric sector is to a physical attack.	No dimension	CPUC. 2015. *Regulation of Physical Security for the Electric Distribution System.* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454097
14	Cybersecurity workforce management	Describes how prepared the electric sector is for a cyberattack.	N/A	EPRI. 2015. *Creating Security Metrics for the Electric Sector.* http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002005947
Power Quality				
1	Telephone influence factor (TIF)	For a voltage or current wave in an electric supply circuit, the ratio of the square root of the sum of the squares of the weighted root-mean-square values of all the sine-wave components (including alternating current waves both fundamental and harmonic) to the root-mean-square value (unweighted) of the entire wave.	%	IEEE Std 519-2014. *IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.* https://ieeexplore.ieee.org/document/6826459/
2	Total demand distortion (TDD)	The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the maximum demand current. Harmonic components of orders over 50 may be included when necessary.	%	IEEE Std 519-2014. *IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.* https://ieeexplore.ieee.org/document/6826459/
3	Total harmonic distortion (THD)	The ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order and specifically excluding interharmonics, expressed as a percent of the fundamental. Harmonic components of orders over 50 may be included when necessary.	%	IEEE Std 519-2014. *IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.* https://ieeexplore.ieee.org/document/6826459/
Stability				
1	System operating limit (SOL)	The value (such as MW, MVAR, amperes, frequency or volts) that satisfies the most	MW, MVAR, amperes,	NERC. "Glossary of Terms Used in NERC Reliability Standards."

		limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System operating limits are based on certain operating criteria. These include but are not limited to: • Facility Ratings (applicable pre- and post-contingency equipment ratings or facility ratings) • Transient stability ratings (applicable pre- and post contingency stability limits) • Voltage stability ratings (applicable pre and post-contingency voltage stability) • System voltage limits (applicable pre- and post-contingency voltage limits)	frequency or volts	https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
2	Stability limit	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.	MW	NERC. "Glossary of Terms Used in NERC Reliability Standards." https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
3	Total flowgate capability (TFC)	The maximum flow capability on a flowgate is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit) is not to exceed the associated system operating limit.	MW	NERC. "Glossary of Terms Used in NERC Reliability Standards." https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
4	Total transfer capability (TTC)	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas in specified system conditions.	MW	NERC. "Glossary of Terms Used in NERC Reliability Standards." https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
5	Available flowgate capability	A measure of the flow capability remaining on a flowgate for further commercial activity over and above already committed uses. It is defined as TFC less existing transmission commitments (ETC), less a capacity benefit margin, less a transmission reliability margin, plus postbacks, plus counterflows.	MW	NERC. "Glossary of Terms Used in NERC Reliability Standards." https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
6	Capacity benefit margin (CBM)	The amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission service provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.	MW	NERC. "Glossary of Terms Used in NERC Reliability Standards." https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
7	Interconnection reliability operating limit	A system operating limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk electric system.	MW, MVAR, amperes, frequency or volts	NERC. "Glossary of Terms Used in NERC Reliability Standards." https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

8	Available transfer capability (ATC)	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as total transfer capability less existing transmission commitments (including retail customer service), less a capacity benefit margin, less a transmission reliability margin.	MW	NERC. "Glossary of Terms Used in NERC Reliability Standards." https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
Economy				
1	Direct jobs	Jobs generated from a change in spending patterns resulting from an expenditure or effort. (e.g., construction jobs for a retrofit project).	Count	ACEEE. *How Does Energy Efficiency Create Jobs?* https://aceee.org/files/pdf/fact-sheet/ee-job-creation.pdf
2	Indirect jobs	Jobs generated in the supply chain and supporting industries of an industry that are directly impacted by an expenditure or effort.	Count	ACEEE. *How Does Energy Efficiency Create Jobs?* https://aceee.org/files/pdf/fact-sheet/ee-job-creation.pdf
3	Induced jobs	Jobs generated by the re-spending of received income resulting from direct and indirect job creation in the affected region.	Count	ACEEE. *How Does Energy Efficiency Create Jobs?* https://aceee.org/files/pdf/fact-sheet/ee-job-creation.pdf
4	Gross jobs	The total number of jobs supported by an industry and its supply chain.	Count	ACEEE. *How Does Energy Efficiency Create Jobs?* https://aceee.org/files/pdf/fact-sheet/ee-job-creation.pdf
5	Labor intensity	The number of jobs necessary to support the spending required to produce goods and services.	Count	ACEEE. *How Does Energy Efficiency Create Jobs?* https://aceee.org/files/pdf/fact-sheet/ee-job-creation.pdf
6	20-year expected value PVRR	The total plan cost (capital and operating) expressed as the present value of revenue requirements (PVRR) over the 20-year study period, generated from stochastic analysis or the expected value of the probability distribution of plan costs.	$	TVA. 2015. *Integrated Resource Plan 2015 Final Report.* https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf
7	Average system cost years 1–10	Average system cost for the first 10 years of the study, computed as the levelized annual average system cost (revenue requirements in each year divided by sales in that year).	$/MWh	TVA. 2015. *Integrated Resource Plan 2015 Final Report.* https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf
8	Risk/benefit ratio	Area under the plan cost distribution curve between P(95) and expected value divided by the area between expected value and P(5).	Ratio	TVA. 2015. *Integrated Resource Plan 2015 Final Report.* https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf
9	Risk exposure	The point on the plan cost distribution below which the likely plan costs will fall 95% of the time based on stochastic analysis.	$	TVA. 2015. *Integrated Resource Plan 2015 Final Report.* https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf

Appendix B: Representative Analytical Modeling Tools

Disclaimer: Information in this section was drawn from multiple readily available sources, including promotional materials. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof.

Table B.1: Energy Storage Valuation Tools

Features	BSET (PNNL)	Battery XT (DNV GL)	DER-CAM[1] (LBNL)	GEMS (Greensmith Energy)	GridStore (Integral Analytics)	StorageVET (EPRI)
Simulation of storage characteristics (e.g., degradation)	Can accurately characterize battery performance, round trip efficiency rates across varying states of charge (SOC) and battery degradation caused by cycling.	Battery life depends on factors such as temperature, sizing, use profile, control system, chemistry and manufacturing of the battery. Experimental and analytical efforts have been undertaken to understand the above aspects.	Capabilities similar to BSET.	Capabilities similar to ES-Select.	Round trip efficiency, complex battery ramp rates and depth-of-discharge degradation constraints can be modeled.	Battery storage complex battery ramp rates and depth-of-discharge degradation constraints can be modeled. Pumped storage hydro minimum operating charge and discharge can be modeled.
Manufacturer protocol testing	Can be carried out. DOE test protocol results for vanadium flow battery at Avista are available in public reports.	Offers end users a platform to assess the ability of different energy storage systems to perform application duty cycle. Capability is built out of DNV GL's battery testing protocol to evaluate capabilities of any given energy storage system for any use profile.	Not possible.	Delivers core value of energy storage technology. Allows for testing of batteries and power conversion systems. When performing ramp rate control, closely monitors irradiance and responds in milliseconds with charging/ discharging protocol.	Not possible.	Not possible.

[1] DER-CAM can be used for optimizing investments considering different types of DERs, not just energy storage systems.

Features	BSET (PNNL)	Battery XT (DNV GL)	DER-CAM[1] (LBNL)	GEMS (Greensmith Energy)	GridStore (Integral Analytics)	StorageVET (EPRI)
Co-optimization of services/revenue stacking	Co-optimization of services such as arbitrage, capacity value, and distribution deferral can be carried out.	Information not available.	Capabilities similar to BSET.	Capabilities similar to BSET and DER-CAM.	Co-optimization of services such as arbitrage, firming of renewable capacity, frequency regulation, renewable curtailment reduction, and peak-load shifting.	Capabilities similar to GridStore.
Optimal sizing/siting	Can perform optimal sizing of storage devices for benefit maximization. Aids in the siting of energy storage systems by capturing/measuring location-specific benefits.	Information not available.	Can find the optimal portfolio, sizing placement, and dispatch of a wide range of devices, while co-optimizing value streams such as load shifting, peak shaving, power export agreements, or participation in ancillary service markets.	Optimizes performance scoring against battery optimization/sizing and charge/discharge profiles to maximize the economic return to the system owner/operator.	Can perform optimal sizing of storage devices in large power networks. No information regarding ability to optimally site storage.	To perform siting/sizing, user should run sensitivity analysis over varying parameters by evaluating a set of alternatives and providing information on their value.
Comparison between various storage technologies	Comparative analysis between different battery storage technologies (lead-acid, Li-ion) can be done. Cannot model pumped storage hydro units.	Comparative analysis between different battery technologies can be done. Cannot model pumped storage hydro units.	Capabilities similar to BSET.	Comparative analysis between different battery storage technologies can be done. Cannot model pumped storage hydro units.	Comparative analysis between different battery storage technologies can be done. User-defined models for pumped storage units can be built.	Comparative analysis between most battery storage technologies (flywheel, battery, CAES, pumped storage) can be done. Can model pumped storage units including (e.g., minimum operating charge and discharge parameters).

Features	BSET (PNNL)	Battery XT (DNV GL)	DER-CAM[1] (LBNL)	GEMS (Greensmith Energy)	GridStore (Integral Analytics)	StorageVET (EPRI)
Market participation	Can differentiate between storage benefits by region and market structures/rules. Defines benefits for various types of utilities (e.g., large utilities operating in organized markets and vertically integrated investor-owned utilities operating in regulated markets).	Not available.	Capabilities similar to BSET**.**	Ensures maximum ROI for frequency regulation while enabling optimal storage system design and operation. ROI maximization achieved via the ability to participate in the market 24/7 with no need to exit for battery re-balancing. If an owner is a price taker, system can operate in every hour of each day, subject to routine maintenance.	Simulates the operation of a battery in day-to-day energy markets to evaluate the potential of technological and price constraints associated with operation. For valuation, considers the impact of market and the market conditions, including the behavior of ISOs. Considers the rules associated with how energy can be entered into and traded within markets during valuation.	Can calculate optimal market revenues or avoided costs associated with alternative infrastructure or resources. Can model various grid services such as spinning reserves, non-spinning reserves, frequency regulation, resource adequacy, voltage support and black start (with the storage solutions).

Table B.2: Energy Storage Valuation Tools

Battery Storage Evaluation Tool (BSET)	
Developer	Pacific Northwest National Laboratory
Availability	The tool is available under a royalty-free, non-exclusive license agreement.
Description	BSET is a computer model that simulates the use of an energy storage system to meet multiple objectives. An energy storage device can be charged and discharged in different ways over time. BSET can determine how to control the battery in an optimal manner such that total benefits are maximized. The tool simulates one year of battery storage operations to evaluate the benefits to the power grid, including energy arbitrage, balancing service, capacity value, distribution system equipment deferral, and outage mitigation. The evaluation tool automatically uses input data to repeatedly formulate and solve the optimization problem at each hour of the evaluation period, and to simulate the actual power exchange on a minute-by-minute basis.
Major Studies	https://availabletechnologies.pnnl.gov/technology.asp?id=413
Developer URL	https://availabletechnologies.pnnl.gov/technology.asp?id=413
Documentation URL	http://www.sandia.gov/ess/docs/pr_conferences/2015/EESAT%202%20Wednesday/Balducci.pdf
Battery XT	
Developer	DNV GL
Availability	Commercial proprietary software can be purchased from the developer.
Description	Battery XT is a software tool that compiles battery life cycle data and predicts battery degradation in different conditions and duty cycles. This service provides manufacturers with third party test results validated to a standard protocol and provides end users the ability to evaluate battery service life for any given application. Through lifetime assessment services, Battery XT helps match the best energy storage technology to the best application, and vice versa. In this way, DNV GL is working to bring together manufacturers and end users to facilitate the technology adoption process and provide technical due diligence to streamline project financing.
Major Studies	Industry project reports are not publicly available.
Developer URL	https://www.dnvgl.com/services/battery-xt-35181
Documentation URL	https://www.dnvgl.com/publications/battery-xt-98083
Distributed Energy Resources Customer Adoption Model (DER-CAM)	
Developer	Lawrence Berkeley National Laboratory
Availability	Open-source software can be downloaded by contacting the developer.
Description	DER-CAM is a powerful and comprehensive decision support tool that primarily serves the purpose of finding optimal DER investments in the context of either buildings or multi-energy microgrids. This widely accepted, and extensively peer-reviewed model has been developed by LBNL since 2000 and can be used to find the optimal portfolio, sizing, placement, and dispatch of a wide range of DERs, while co-optimizing multiple stacked value streams that include load shifting, peak shaving, power export agreements, and participation in ancillary service markets.

	While the objective function of DER-CAM can be easily modified or even replaced by a multi-objective analysis, it is most commonly defined by a site's total annual cost of energy supply**.** This includes costs associated with both new and existing DER, operation and maintenance costs, and fuel costs, and also all costs related to utility imports, whether fixed, time-dependent, energy-based, or power-based.
Major Studies	• *Regional Analysis of Building Distributed Energy Costs and CO_2 Abatement: A U.S.–China Comparison.* 2014. http://eta-publications.lbl.gov/sites/default/files/lbnl_6678e_final.pdf. • *Electric Storage in California's Commercial Buildings*. 2013. http://eta-publications.lbl.gov/sites/default/files/lbnl-6071e.pdf.
Developer URL	https://building-microgrid.lbl.gov/projects/der-cam.
Documentation URL	https://building-microgrid.lbl.gov/sites/default/files/DER-CAM_User_Manual.pdf.
GEMS	
Developer	Greensmith Energy Management Systems
Availability	Commercial proprietary software can be purchased from the developer.
Description	Greensmith Energy designs and deploys advanced energy storage systems. From grid-scale to behind-the-meter and microgrid solutions, GEMS enables effective and efficient delivery of stable power. The traditional approach for managing storage assets is to deploy a plant controller that interacts with the batteries and a power control system layered on top of the battery management system. The GEMS software-based plant controller that interacts directly with the battery, the power control system, and the battery management system. The software includes battery optimization algorithms to increase the life of the system, revenue-stacking features, future proofing features and fleet management features.
Major Studies	This tool has been used by California ISO to conduct different energy storage valuation studies, though no reports were found online.
Developer URL	http://www.greensmithenergy.com/software.
Documentation URL	http://www.greensmithenergy.com/sites/default/files/greensmith-energy-brochure.pdf.
GridStore	
Developer	Integral Analytics, Inc.
Availability	Commercial proprietary software can be purchased from the developer.
Description	GridStore simulates the operation of a battery in day-to-day energy markets to calculate the potential of technological and price constraints associated with operating in that market and the total potential revenue from having that resource. It helps build an accurate business case that considers the intrinsic and extrinsic value of storage and the full spectrum of risks and opportunities associated with the storage asset. It is designed not only to value batteries. Its basic underlying algorithms are good for valuing all kinds of energy assets. It is a powerful tool for understanding how much the time arbitrage is worth from any type of storage asset. It can be used to precisely and accurately determine the revenue potential, risks and value associated with purchasing, operating, or hedging any grid-scale asset. Initially developed on the same highly detailed financial engineering methods used to value complex energy assets and traded commodity

	contracts, GridStore grid-scale battery valuation software can deliver some of the most accurate financial pro-forma estimates available in the industry today. Without these detailed financial valuations, other methods risk under-valuing, or incorrectly valuing, many types of storage applications. The GridStore methodology uses many of the same ideas deployed in the natural gas industry to value gas storage assets, but with additional emphases on weather related value-at-risk over the life of the battery asset.
Major Studies	No reports were found online.
Developer URL	http://www.integralanalytics.com/products-and-services/storage-and-renewable-evaluation/gridstore.aspx.
Documentation URL	http://www.integralanalytics.com/files/documents/related-documents/IA_Gridstore_Brochure.pdf.
StorageVET	
Developer	Electric Power Research Institute
Availability	It can be accessed by sending a request to the developer.
Description	StorageVET can assist in the estimation of benefits and costs of energy storage in diverse use cases. The tool performs optimization and simulation of energy storage project dispatch for user-configured cases. The user can flexibly customize cases for different locations, project specifications, value objectives, and constraints. It is a price taker model that incorporates time-series loads, prices, and other information to run project simulations. The tool may utilize pre-configured data for reference scenarios or technologies, or the user may fully customize the case. It currently contains data customized for the California power market. Key benefits of using the tool are: ▪ It may be used by stakeholders to more clearly communicate the benefits and costs of energy storage in different instances. ▪ It enables the customization of energy storage projects for optimization, simulation, and financial analysis. ▪ It may help users benchmark of multiple project options. ▪ It can support the choice of energy storage project sizing and technology specifications, choose optimal locations, and maximize the operational value of existing storage.
Major Studies	• *Economic Sizing of Batteries for the Smart Home.* 2017. https://www.nrel.gov/docs/fy18osti/70684.pdf. • *2017 Integrated Resource Plan*. 2017. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM03_8-25-2016_to_8-26-2016.pdf. • *Policies for Storing Renewable Energy, International Energy Agency: Renewable Energy Technology Deployment*. 2016. http://iea-retd.org/wp-content/uploads/2016/08/20160305-RE-STORAGE.pdf.
Developer URL	https://www.epri.com/#/pages/product/000000003002009357/?lang=en.
Documentation URL	https://publicdownload.epri.com/PublicDownload.svc/product=000000003002009357/type=Product.

Table B.3: Capacity Expansion Planning Tools (A–N)

Features	Aurora (Energy Exemplar)	E4ST (RFF)	EGEAS (EPRI)	Haiku (RFF)	MARKAL (ETSAP)	NEMS (EIA)
Zonal representation of demand/load projections	Nodal and zonal database including Canada and the U.S.	Documentation does not explicitly discuss data availability. This tool stems from Power Systems Engineering Research Center and is now maintained by two universities and RFF.	Nodal and zonal database including Canada and the U.S. Nodal/zonal representations are also available for countries such as China, Saudi Arabia, Israel and South Korea.	Lower 48 U.S. states divided into 21 zones.	Nine U.S. regions representing demand regions (EPA model). Supplies of other fuels are divided into their respective coal and oil supply regions.	Zonal representation only for the U.S. (22 zones). Canada and Mexico are modeled by firm export of power using a supply curve.
Baseline of generation/ transmission	Benchmarked by vendor (generation and transmission).	No information currently available on benchmarking.	Benchmarked to the EIA dataset.	Benchmarked by vendor to EIA dataset (generation and transmission).	Benchmarked for generation database. Not baselined for transmission.	Benchmarked by vendor to EIA dataset (generation and transmission).
Cost of technology and fuels for future years	Yes, it is considered. Further details regarding method of forecasting costs not provided.	Yes, it is considered	Users input load forecast, costs and characteristics of existing and potential resources, purchase power contracts, and all future potential planning options.	Yes, it is considered. Further details regarding method of forecasting costs not provided.	Yes, as adopted by EPA.	Yes, it is considered. Further details regarding method of forecasting costs not provided.
Data to represent constraints on foreign systems or trade (e.g., between two nations)	Yes, it is considered. User-defined constraints can be formulated.	Appropriate constraints can be easily modeled by the user.	Such constraints have to be modeled separately by the user.	The developer is currently working on including such data.	No constraints are currently modeled for transmission lines between U.S. and Mexico or U.S. and Canada.	Yes, it is considered. Further modeling details are not provided.
Geographic scope	Regional to interconnect.	Regional to national.	Interconnect to national.	Interconnect to national.	Regional to national.	Regional to national.

Features	Aurora (Energy Exemplar)	E4ST (RFF)	EGEAS (EPRI)	Haiku (RFF)	MARKAL (ETSAP)	NEMS (EIA)
Demand and supply curves for electricity market representation	No information available regarding the modeling of demand/supply curves.	They are not modeled.	Supply curve not represented directly but via the cost curve of each generator in the database.	Source of primary energy can be represented by a supply curve.	Source of primary energy can be represented by a supply curve. Primary energy is converted to secondary forms (e.g., electricity). Model finds the optimal supply chain to meet all demands.	Models only exist for the U.S. and not for Canada or Mexico. Modeling is similar to that of MARKAL.
Quality of data (uniformity across different regions/ countries)	No information available regarding control of data quality.	No information is provided.	As grid evolves, actual quality control needs to be performed routinely via experiments. Greatly depends on the source of the dataset.	It is assumed that quality of data is uniform across countries Data from Canada is unavailable.	EPA data is used for analyses based in the U.S. Most of the analyses are performed in an international context. Assessment of data quality is difficult if there are multiple sources.	No information available regarding control of data quality.
Relevant time steps (important for modeling demand and renewable resources)	Hourly.	Solves DCOPF and expansion planning by years.	Hourly.	Load duration curve with 12 time slices (3 seasons × 4 time blocks.	Annual.	Load duration curve with 9 time slices (3 seasons × 3 time blocks).
Generation represented?	Generation optimally dispatched. Investment and dispatch decisions are at individual GU level.	Yes, optimally determines the supply stack.	Generation optimally dispatched. Investment and dispatch decisions are at individual GU level.	Aggregated capacity buildout by technologies. Generally does not incorporate individual GU granularity. Optimally determines the supply stack.	All fuels and power generation resources are modeled. Also represents oil, natural gas and nuclear markets.	All fuels and power generation resources are modeled. Optimally determines the supply stack.

Features	Aurora (Energy Exemplar)	E4ST (RFF)	EGEAS (EPRI)	Haiku (RFF)	MARKAL (ETSAP)	NEMS (EIA)
Transmission represented?	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines. Nodal model characterizes transmission constraints between generating units.	Representation of DC transmission capacity limits across several zones in the U.S.	Transmission (thermal) constraints are modelled on a course zonal interface basis only for the U.S. No information regarding modeling of similar constraints for other countries.	Representation of transmission capacity limits (thermal constraints) between major zones.	Transmission (thermal) constraints are modelled on a coarse zonal interface basis only for the U.S.	No information available regarding modeling of transmission constraints.
Energy storage modeling	No information provided by the developer or any online resource.	Can model flywheels, CAES, thermal devices, and pumped storage technology among others.	Modeled as a generating unit with pumping and generating capacity with a full cycle efficiency factor. User can specify the maximum amount of energy that can be generated based on capacity of the storage reservoir. Amount of pumping and generation is based on system dispatch economics. System dispatch economics primarily driven by the spread of on-peak and off-peak energy prices.	Generation by hydroelectric pumped storage capacity not permitted during base time blocks. For pumped storage, it is assumed that any generation by pumped storage results from electricity consumption in base time block to prepare water for generation in higher value time blocks. Amount of generation determined by efficiency of pumps and time-block-specific electricity prices relative to the electricity price for industrial customers in base time block.	No information regarding storage modeling is provided in official documentation.	Capable of modeling pumped storage for applications such as load shifting, decreasing demand in peak time slices, etc. Can also model storage efficiency when producing energy. Energy storage can be optimally dispatched to both maximize economic value and assess reliability needs.

Table B.4: Capacity Expansion Planning Tools (M-Z)

Features	PLEXOS (Energy Exemplar)	ReEDS (NREL)	Strategist (ABB)	US-REGEN (EPRI)	WASP (IAEA)
Zonal representation of demand/load projections	No zonal representation. Load model is built for a specific time period of interest. PLEXOS in the U.S. is working on including parts of Canada as part of EI database.	Zonal representations for U.S. and Canada (divided into 138 zones). Net imports from Canada are modeled. Mexican regions are not modeled.	Zonal representations for U.S. and Canada. Net imports from Canada are modeled. Mexican regions are not modeled.	Nodal and zonal database including Canada and the U.S. Nodal/zonal representations are also available for countries such as China and Saudi Arabia	Nodal and zonal database available for the U.S. No information regarding availability for Canada or other parts of the world.
Baseline of generation/ transmission	Benchmarked by vendor (generation and transmission).	Benchmarked by vendor to EIA dataset (generation and transmission).	Benchmarked by vendor to EIA dataset (generation and transmission).	Benchmarked to the EIA dataset.	Official documentation does not provide relevant information
Cost of technology and fuels for future years	Yes, it is considered in the expansion planning models.	Yes, it is considered. Further details regarding method of forecasting costs not provided.	Yes, it is considered within the dynamic programming optimization algorithm.	Yes, it is considered, though the model does not consider uncertainty in prices.	User can provide information as input.
Data to represent constraints on foreign systems or trade (e.g., between two nations)	All paths for power flows across the border have their limits.	Appropriate constraints can be easily modeled by the user.	The user can model appropriate constraints within the dynamic programming framework.	The developer is currently working on including such data.	All paths for power flows across the border have their limits.
Geographic scope	Utility, state, regional or interconnect.	Interconnect to national.	Utility, state or discrete region.	Interconnect to national.	National or sectoral.
Demand and supply curves for electricity market representations	Supply curve not represented directly but via the cost curve of each generator in the database.	Model does not determine the demand/supply equilibrium. Assumes the equilibrium in supply/demand and then selects the optimal technology mix.	No information regarding modeling is publicly available.	Supply curve not represented directly but via the cost curve of each generator in the database. Demand curve is also modeled and interpreted as total value to consumers.	They are not modeled within the software.
Quality of data (uniformity across different regions/ countries)	Assumes that quality of data is uniform across countries. NERC checks for data quality regardless of the associated country.	Current version cannot perform studies using data from non-U.S. regions.	Depends on the source of the dataset. Difficult to evaluate data quality if multiple sources are involved.	Highly dependent on the source of the dataset.	Assumes that quality of data is uniform across countries Data quality may substantially degrade if multiple sources are involved.

Features	PLEXOS (Energy Exemplar)	ReEDS (NREL)	Strategist (ABB)	US-REGEN (EPRI)	WASP (IAEA)
Relevant time steps (important for modeling demand and renewable resources)	Sub-hourly.	Load duration curve with 9 time slices (3 seasons × 3 time blocks).	Hourly.	Hourly.	Hourly.
Generation represented?	Generation optimally dispatched. Investment and dispatch decisions are at individual GU level.	Aggregated capacity buildout by technologies. Generally does not incorporate individual generating unit granularity. Optimally determines the supply stack.	Generation optimally dispatched. Investment and dispatch decisions are at individual GU level.	Aggregated capacity buildout by technology. Generally does not incorporate individual generating unit granularity. Optimally determines the supply stack.	Aggregated capacity buildout by technology. Does not incorporate individual GU granularity. Optimally determines the supply stack.
Transmission represented?	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines. Nodal model characterizes transmission constraints between generating units. Simplifies power flow through transmission network as DC flow.	Representation of DC transmission capacity limits across 138 zones in the U.S.	Very limited transmission system representation. Discrete/selected transmission lines are represented.	Models transmission capacity between regions and requires that generation and load plus net exports and line losses balance in each time segment and for each region. No constraints related to transmission or distribution within a region.	Representation of transmission capacity limits (thermal constraints) between main zones.

Features	PLEXOS (Energy Exemplar)	ReEDS (NREL)	Strategist (ABB)	US-REGEN (EPRI)	WASP (IAEA)
Energy storage modeling	Can model flywheels, CAES, thermal devices, and pumped storage technology among others. For storage modeling, factors in charging or pumping modes, efficiency, generating (minimum and maximum generation), ramp rate (MW/min), ancillary service provisions, reservoir or storage device (minimum and maximum storage, storage natural inflow and losses modeled). According to sources reviewed, PLEXOS has not yet modeled a battery.	Includes three utility-scale energy storage options: PHS, batteries, and CAES, which are capable of load shifting (arbitrage), providing planning and operating reserves, and reducing renewable curtailment. Allows modeling the efficiency of the unit in storing and generating energy. Scheduling may be based on the region or the LMP at the unit Energy storage is optimally dispatched to maximize economic value.	Different storage technologies can be modeled. Generation and fuel cost module performs marginal cost dispatch of storage (pumped storage, battery).	UC model only represents pumped hydro storage at existing capacities. In part, this omission is due to the lack of endogenous storage investments in the dynamic version of US-REGEN. Other technologies will be modeled in future versions.	Pumped storage plants can be modeled by specifying installed capacity, cycle efficiency, pumping capacity, generation capacity, etc. Pumped storage plants are limited both in capacity and energy. Composite pumped storage plants or other types of storage technologies can also be modeled.

Table B.5: Capacity Expansion Planning Tools

Aurora	
Developer	Energy Exemplar
Availability	Commercial proprietary software can be purchased from the developer.
Description	Aurora uses market fundamentals and advanced dispatch logic to give energy executives, developers and resource planners an accurate view of a portfolio's value. Its speed lets analysts perform multiple long-term model runs to evaluate completely when and in what conditions resources will perform economically. The software calculates net power costs and system costs for individual resources. Marketers, developers and utilities can use this capability to easily determine how to position a contract or value a new resource in the market. Fast and easy to use, this software is also able to produce both short-term and long-term price forecasts for all major market zones and trading hubs. It simulates supply and demand on an hourly basis to provide electric price forecasts. This model is suitable for harmonization analysis. The integrated feature of expansion planning and hourly production cost modeling will allow the analyst to explore optimal investment paths and optimal operational strategies to minimize cost. This tool and the appropriate scenario analysis would provide deep insight into benefits and cost savings from both energy services as well as balancing services of a cross-border electricity coordination.
Major Studies	• *The Biannual Northwest Power Plan Uses the AURORA Model*. 2016. https://www.nwcouncil.org/reports/seventh-power-plan. • *2015 Integrated Resource Plan at Avista Corporation*. 2015. https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/appendix-b-final.pdf?la=en. • *Electricity Resource Analysis at Puget Sound Energy*. 2013. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppK.pdf.
Developer URL	http://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/ /.
Documentation URL	A license must be obtained from Energy Exemplar to access the software and official documentation.
E4 Simulation Tool (E4ST)	
Developer	Resources for the Future
Availability	The software is available openly without charge.
Description	E4ST is policy analysis and planning software built to simulate in detail how the power sector will operate and evolve in response to environmental and non-environmental policies and regulations, renewable and non-renewable generation investments, transmission investments, input prices, pricing structures, demand changes, and so on. The user specifies the policies, investments, and other inputs of each simulation. E4ST predicts operation, generator investment and retirement, DC transmission investment, prices, consumer effects, producer profits, emissions, emission health effects, and the other elements of societal net benefits (social surplus), among other outcomes. It

	is therefore well suited for uniquely comprehensive benefit-cost analysis, as well as for projecting various other outcomes. E4ST simulates successive multi-year periods, predicting hourly system operation along with generator construction and retirement. It can be used with a model of any power system from anywhere in the world. Its developers have developed detailed E4ST-compatible models of the three major U.S. and Canadian grids for simulations using E4ST, and they are working to add Mexico. E4ST has been used for projects for FERC, DOE, DOI, NYISO, and the city of New York, as well as for peer-reviewed studies published in research journals.
Major Studies	• *Co-Emission and Welfare Effects of Electricity Policy and Market Changes: Results from the EMF 32 Model Intercomparison Project*. 2018. https://www.sciencedirect.com/science/article/pii/S0140988318301154?via%3Dihub. • *Systems Analysis in Electric Power Sector Modeling: Evaluating Model Complexity for Long-Range Planning*. 2017. http://www.rff.org/research/publications/systems-analysis-electric-power-sector-modeling-evaluating-model-complexity. • *Costs and Benefits of Saving Unprofitable Generators: A Simulation Case Study for US Coal and Nuclear Power Plants.* 2017. http://www.rff.org/research/publications/costs-and-benefits-saving-unprofitable-generators-simulation-case-study-us.
Developer URL	http://e4st.com/.
Documentation URL	http://e4st.com/wp-content/uploads/2016/02/E4ST-manual-1.0b2.pdf.
Electric Generation Expansion Analysis System (EGEAS)	
Developer	Electric Power Research Institute (EPRI)
Availability	Proprietary software; license can be obtained from the developer.
Description	EGEAS was developed by EPRI for use by utility planners to evaluate integrated resource plans, independent power producers, avoided costs and plant life management programs. It also has some modules added to specifically accommodate demand-side management options and to facilitate the development of environmental compliance plans. It contains four capacity analysis options that range from preliminary analysis tools based on screening curves to sophisticated non-linear analysis tools that utilize a generalized benders decomposition algorithm and dynamic programming algorithm. A stand-alone, detailed probabilistic production costing algorithm is also available for production cost and reliability analysis. EGEAS was the forerunner of current generation expansion planning models and continues to be used by major utility companies and ISOs.
Major Studies	• *MISO/PJM Joint Modeling Case Study: Clean Power Analysis*. 2017. http://www.pjm.com/~/media/library/reports-notices/clean-power-plan/20170310-pjm-miso-cpp-case-study.ashx.

	• *Southwest Power Pool Economic Studies Working Group Report*. 2017. https://www.spp.org/documents/48685/eswg%20minutes%20&%20attachments%2020170215.pdf. • *MISO Energy Storage Study Phase 1 Report*. 2011. http://www.uwig.org/miso_energy_storage_study_phase_1_report.pdf.
Developer URL	http://eea.epri.com/models.html#tab.=3&tab=3.
Documentation URL	http://membercenter.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=3002011877.
Haiku	
Developer	Resources For the Future
Availability	Proprietary software; license can be obtained from the developer.
Description	RFF's Haiku model is a simulation of regional electricity markets and interregional electricity trade in the continental U.S. The model accounts for capacity planning, investment, and retirement over a multi-year horizon and for system operation over seasons of the year and times of day. Electricity demand is represented by price-sensitive demand schedules by customer class, and changes in demand can be implemented through investments in energy efficiency, time of day pricing, and other regulatory changes. The model identifies least-cost compliance strategies for compliance with various types of regulations of sulfur dioxide, nitrogen oxide, carbon dioxide, and mercury emissions. Market structure is represented by cost-of-service (average cost) pricing and market-based (marginal cost) pricing in various regions. Electricity demand is characterized by price responsive functions for each region and time-period for three sectors of the economy: residential, commercial, and industrial. Electricity supply is characterized for each region and time-period by a set of fully integrated modules that determine generation capacity investment and retirement, system operation including interregional power trading, prices and production in fuel markets, and compliance strategies for emissions regulations including investment in pollution abatement technologies. Generation capacity is classified in model plants that are distinguished by geographic region and a set of salient technology characteristics including fuel type, vintage, and generator technology.
Major Studies	• *Electric Power in the U.S. and Canada: Opportunities for Transboundary Regulatory and Planning Harmonization*. 2015. http://www.rff.org/events/event/2015-10/electric-power-united-states-canada-and-mexico-opportunities-transboundary. • *Modeling the Electricity Sector: A Summary of Recent Analyses of New EPA Regulations*. 2012. *RFF Working Paper*. http://www.rff.org/research/publications/modeling-electricity-sector-summary-recent-analyses-new-epa-regulations.
Developer URL	http://www.rff.org/research/publications/haiku-documentation-rff-s-electricity-market-model-version-20.
Documentation URL	http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-Rpt-Haiku.v2.0.pdf.

Market Allocation (MARKAL)	
Developer	National Risk Management Research Laboratory, U.S. Environmental Protection Agency
Availability	Proprietary software; license can be obtained from the developer.
Description	MARKAL is an expansion planning model. The model chooses an optimal energy flow path starting from primary energy to meet future energy demands. It is based on linear optimization techniques that search for least cost pathways among the various energy conversion processes to meet future demands. The model generally represents all energy supply and demand sectors, and not just electricity. For the U.S. representation, EPA developed a MARKAL model with nine regions. The model optimally (cost-minimal approach) selects technologies to meet demand on a yearly basis. As such, it does not represent delivery and other operational complexity that would provide insights into reliability or resiliency issues. It is designed to answer questions about likely policy implications with respect to technology choices. MARKAL was developed in a cooperative multinational project over a period of almost two decades by the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency. It is a generic model tailored by the input data to represent the evolution over a period, usually 40 to 50 years, of a specific energy system at the national, regional, state or province level. The uses of MARKAL include: • Identification of least-cost energy systems • Identification of cost-effective responses to restrictions on emissions • Prospective analysis of long-term energy balances in different scenarios • Evaluation of new technologies and priorities for R&D • Evaluation of effects of regulations, taxes, and subsidies
Major Studies	• *Electricity Capacity Expansion Modeling, Analysis, and Visualization: A Summary of Selected High Renewable Modeling Experiences.* 2015. https://www.nrel.gov/docs/fy16osti/64831.pdf. • *Irish TIMES: Power Sector*. 2013. https://www.ucc.ie/en/media/research/energypolicymodeling/IrishTIMES-PowerFinal.pdf. • *Capacity Expansion Planning for the New Zealand Electricity Market*. 2008. https://www.ea.govt.nz/dmsdocument/4454.
Developer URL	https://www.epa.gov/.
Documentation URL	https://nepis.epa.gov/Exe/ZyPDF.cgi/P100I4RX.PDF?Dockey=P100I4RX.PDF.
National Energy Modeling System (NEMS)	
Developer	U.S. Energy Information Administration
Availability	Proprietary software; license can be obtained from the developer.
Description	NEMS was developed to provide 20- to 25-year forecasts and analyses of energy-related activities. It uses a central database to store and pass inputs and outputs between the various components. The NEMS electricity market module (EMM) provides a major link in the NEMS framework. In each model year,

	EMM receives electricity demand from the NEMS demand modules, fuel prices from the NEMS fuel supply modules, expectations from the NEMS system module, and macroeconomic parameters from the NEMS macroeconomic module. EMM estimates the actions taken by electricity producers to meet demand in the most economical manner and then outputs electricity prices to the demand modules, fuel consumption to the fuel supply modules, emissions to the integrating module, and capital requirements to the macroeconomic module. The model iterates until a solution is reached for each forecast year. EMM represents the capacity planning, generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biomass; the cost of centralized generation facilities; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The submodules consist of capacity planning, fuel dispatching, finance and pricing, and electricity load and demand.
Major Studies	• *Annual Energy Outlook 2018*. 2018. https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf. • *Assessing the Economic Value of New Utility-Scale Generation Projects*. 2013. https://www.eia.gov/renewable/workshop/gencosts/pdf/1_Namovicz.pdf.
Developer URL	https://www.eia.gov/outlooks/aeo/info_nems_archive.php.
Documentation URL	https://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/m068(2016).pdf.
PLEXOS	
Developer	Energy Exemplar Pty. Ltd.
Availability	Commercial proprietary software can be purchased from the developer.
Description	PLEXOS uses state-of-the-art mathematical optimization and distributed computing methods to meet the demands of energy market participants, system planners, investors, regulators, consultants and analysts. It provides a comprehensive range of features integrating electric, water, gas and heat production, transportation and demand over simulated timeframes from minutes to several years, delivered through a common simulation engine with easy-to-use interface and integrated data platform. Additional features of the tool are: • Optimal power flow (OPF) with losses fully integrated with dispatch and unit commitment • Security and N-x contingency constraints, DC lines and phase shifters • Generic constraints and interface limits, transmission aggregation, Monte Carlo simulation, multiple AC networks (10,000s of buses and lines), nodal pricing and price decomposition • Long, medium and short-term analysis with one integrated simulation engine • Perform comprehensive modeling of the economics and technical limits of fossil-fired and renewable generation • Model ancillary service provision co-optimized with generation dispatch and unit commitment to sub-hourly level, with detailed treatment of start-up and shutdown

Major Studies	*PLEXOS Publications*. 2010–2017. https://energyexemplar.com/publications/research-publications/
Developer URL	https://energyexemplar.com/.
Documentation URL	A license must be obtained from Energy Exemplar to access the software and official documentation.
Regional Energy Deployment System (ReEDS)	
Developer	National Renewable Energy Laboratory
Availability	Software can be accessed with authorization from NREL.
Description	ReEDS is a long-term capacity-expansion model for the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous U.S. It is designed to analyze critical issues in the electric sector, especially potential energy policies, such as clean energy and renewable energy standards or carbon restrictions. ReEDS provides a detailed representation of electricity generation and transmission systems and specifically addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal load and generation profiles, variability and uncertainty of wind and solar power, and the influence of variability on the reliability of electric power provision. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary service requirements and costs.
Major Studies	• *Modeling the Value of Integrated U.S. and Canadian Power Sector* Expansion. 2017. https://www.sciencedirect.com/science/article/pii/S1040619016302822. • *Impact of Clean Energy R&D on the U.S. Power Sector.* 2017. https://www.nrel.gov/docs/fy17osti/67691.pdf.
Developer URL	https://www.nrel.gov/analysis/reeds/.
Documentation URL	https://www.nrel.gov/docs/fy17osti/67067.pdf.
Strategist	
Developer	ABB, Inc.
Availability	Commercial proprietary software can be purchased from the developer.
Description	Strategist has been the industry standard for integrated resource planning for nearly 30 years. Users include municipalities, electric cooperatives, state commissions, consulting firms, and investor-owned utilities. Strategist's multiple application modules include forecasted load modeling, energy efficiency programs, production cost calculations including the dispatch of energy resources, optimization of future decisions, and nonproduction-related cost recovery, such as construction expenditures, allowance for funds used during construction (AFUDC), insurance, and property taxes. Strategist's PROVIEW module utilizes a proprietary dynamic programming algorithm to optimally select and rank alternative resource plans based on different objective functions including minimizing utility cost and average rates. Resource

	alternatives are evaluated while also considering purchases from and sales to a spot energy market. PROVIEW can evaluate all types of supply and demand side alternatives. Key Strategist benefits include: • Generates and evaluates all appropriate resource plans via dynamic programming algorithm • Evaluates the economics of resource alternatives that require capital outlay • Analyzes long-range rate strategy and its implications • Provides multi-area resource optimization.
Major Studies	The tool is frequently used by major utilities in North America for capacity expansion planning studies. Public online reports are unavailable.
Developer URL	https://new.abb.com/enterprise-software/energy-portfolio-management/commercial-energy-operations/capacity-expansion.
Documentation URL	https://www.pnm.com/documents/396023/3306887/Strategist+Presentation+Nov+10+2016_Post.pdf/9e0c91f9-a78b-4d5e-8fd1-bd13be018241.
U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN)	
Developer	Electric Power Research Institute
Availability	Proprietary software; license can be obtained from the developer.
Description	US-REGEN is an energy economy model developed and maintained by EPRI. It combines a detailed dispatch and capacity expansion model of the United States electric sector with a high-level dynamic computable general equilibrium model of the U.S. economy. The two models are solved iteratively to convergence, allowing analysis of policy impacts on the electric sector taking into account economy level responses. The electric sector model can also be run separately with higher regional and temporal resolution or for a single year with unit commitment constraints. This makes US-REGEN capable of modeling a wide range of environmental and energy policies in both the electric and non-electric sectors. US-REGEN is a regional model of the U.S. It can consider multiple sub-regions of the continental U.S., to account for differences in resource endowments, energy demand, costs, policies, and policy impacts. By default, the model uses 15 sub-regions, each an aggregation of states, but can be configured to consider any arbitrary aggregation of the lower 48 states. US-REGEN is an inter-temporal optimization model. It solves in three-year time steps from 2015 through 2030, and five-year time steps thereafter to 2050.
Major Studies	• *The costs and value of renewable portfolio standards in meeting decarbonization goals*. 2018. https://www.sciencedirect.com/science/article/pii/S0140988318301427. • *Systems Analysis in Electric Power Sector Modeling: Evaluating Model Complexity for Long-Range Planning*. 2017. http://www.rff.org/research/publications/systems-analysis-electric-power-sector-modeling-evaluating-model-complexity. • *Simulating annual variation in load, wind and solar by representative hour selection.* 2018. https://www.iaee.org/en/Publications/ejarticle.aspx?id=3083.
Developer URL	http://eea.epri.com/models.html#tab.=3&tab=0.
Documentation URL	http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002010956.

	http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004748.
Wien Automatic System Planning (WASP)	
Developer	International Atomic Energy Agency
Availability	Proprietary software; free license can be obtained from the developer.
Description	The WASP was originally developed by TVA and Oak Ridge National Laboratory to meet the needs of the IAEA's market survey for nuclear power in developing countries conducted in 1972. WASP is designed to find the economically optimal generation expansion policy for an electric utility system within user-specified constraints. It utilizes probabilistic estimation of system production costs, unserved energy cost, and reliability; linear programming techniques for determining optimal dispatch policy satisfying exogenous constraints on environmental emissions, fuel availability and electricity generation by some plants; and the dynamic method of optimization for comparing the costs of alternative system expansion policies. The modular structure of WASP permits the user to monitor intermediate results, avoiding wasted computer time due to input data errors. The new features and enhancements incorporated in the latest WASP version are: • Option for introducing constraints on environmental emissions, fuel usage and energy generation • Representation of pumped storage plants • Fixed maintenance schedule • Environmental emission calculations • Expanded dimensions which can handle up to 90 plant types with various configurations
Major Studies	• *Modeling and assessment of long-term development scenarios of Ukraine's nuclear energy*. 2016. https://ideas.repec.org/a/eip/journl/y2016i3p94-106.html. • *Optimization Model using WASP-IV for Pakistan's Power Plants Generation Expansion Plan*. 2012. http://www.iosrjournals.org/iosr-jeee/Papers/Vol3-issue2/H0323949.pdf. • *Generation expansion planning for Iran power grid.* 2010. http://ijste.shirazu.ac.ir/article_826_a78da5685241e133233f421f65d48135.pdf.
Developer URL	https://www.iaea.org/topics/energy-planning/energy-modeling-tools http://ledsgp.org/resource/wien-automatic-system-planning-package/?loclang=en_gb.
Documentation URL	http://ledsgp.org/wp-content/uploads/2015/10/WASP-manual.pdf.

Table B.6: Production Cost Simulation Tools

Features	Aurora (Energy Exemplar)	FESTIV (NREL)	GE MAPS (GE)	GridView (ABB)	PLEXOS (Energy Exemplar)	PROMOD (ABB)	RIM (PNNL)	UPLAN (LCG)
Zonal representation of demand/ load projections	Nodal and zonal database including Canada and the U.S.	Highly temporally resolved model to explore imbalance implications from renewables and the cost implication. It is used for very detailed analyses of more spatially confined problems (smaller spatial scale than whole interconnection).	Can provide nodal and zonal representations.	Has nodal WECC, EI and ERCOT as standard database. No information regarding Canada and Mexico in the database.	No zonal representation. Load model is built for a specific time-period of interest. PLEXOS in the U.S. is working on including parts of Canada as part of EI database.	Yes, for EI, WECC and ERCOT. WECC database also includes data from BC Hydro and AESO in Canada, and from Baja California in Mexico. EI database also includes data from Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick and Nova Scotia.	PNNL has a dataset from WECC that has full representation of U.S., Canada and northern Baja California (Mexico) transmission transfers. A dataset of the Eastern interconnection also exists.	Usually performed for RTOs within ISO footprints. Number of zones vary for different footprints. Highly resolved model for very detailed transmission analyses.
Baseline of generation/ transmission	Benchmarked by vendor (generation and transmission).	EIA and other sources.	Benchmarked by vendor (generation and transmission).	Benchmarked by vendor (generation and transmission).	Benchmarked by vendor (generation and transmission).	EI and ERCOT databases benchmarked by vendor. For WECC, the appropriate committee will publish highly calibrated datasets.	Usually based on EIA data for a particular year.	Benchmarked by vendor (generation and transmission).
Cost of technology and fuels for future years	Yes, it is considered. Further details regarding method of forecasting costs not provided.	No, not relevant as model only dispatches existing technologies.	No, not relevant as model only dispatches existing technologies.	No, not relevant as model only dispatches existing technologies .	It can be considered if running PLEXOS in long-term mode.	Yes, it is considered. Further details regarding method of forecasting costs not provided.	No cost of technology considered. Only cost of future fuels for electricity production.	No, not relevant as model only dispatches existing technologies.

Data to represent constraints on foreign systems trade (e.g., between two nations)	Yes, it is considered. User-defined constraints can be formulated.	Such constraints can be freely defined by the user.	Constraints for flowgates or transmission lines can be set by the user. The line flow constraints are represented in terms of power limits and not energy trade limits over a time specific duration	Constraints for flowgates or transmission lines can be set by the user. The line flow constraints are represented in terms of power limits and not energy trade limits over a time specific duration	All paths for power flows across the border have their limits.	All paths for power flows across the border have their limits.	Yes, model has constraints with respect to transfer capabilities as well as generation constraints. Model can incorporate any kind of constraint.	Highly resolved and detailed modeling options. Analyst can explore and model both transmission and generation constraints
Geographic scope	Regional to interconnect.	State, regional or interconnect.	Regional to interconnect.	Regional to interconnect.	Utility, state, regional or interconnect.	Regional to interconnect.	State, regional or interconnect.	Regional to interconnect.
Demand and supply curves for electricity market re-presentations (Production cost models may estimate the cost for demand response for implicit supply curve representa-tion)	No information available regarding the modeling of demand/supply curves.	Demand response can be modeled as a resource that has cost characteristics similar to that of a generator.	Demand response can be modeled as a resource that has cost characteristics similar to that of a generator.	Demand response can be modeled as a resource that has cost characteristics similar to that of a generator.	Supply curve not represented directly but via the cost curve of each generator in the database.	Supply curve not represented directly but via the cost curve of each generator in the database and demand curves for individual customer groups.	Demands are given as input. Demand response is currently not represented but could be as a negative generation. Supply curves do not exist.	Not directly modeled. Demand and supply curves can be generated as an outcome of several runs. The curves are not modeled as inputs.
Quality of data (uniformity across different regions/ countries)	No information available regarding control of data quality.	Depends on which data set is being used. Uses secondary data from other vendors.	It is assumed that quality of data is uniform across countries. NERC checks for data quality regardless of the associated country. As grid evolves, actual quality control needs to be performed routinely via experiments.	It is assumed that quality of data is uniform across countries. NERC checks for data quality regardless of the associated country. As grid evolves, actual quality control needs to be performed routinely via experiments.	It is assumed that quality of data is uniform across countries. NERC checks for data quality regardless of the associated country. As grid evolves, actual quality control needs to be performed routinely via experiments.	It is assumed that quality of data is uniform across countries. NERC checks for data quality regardless of the associated country.	Depends on what data set is being used. Uses secondary data from other vendors.	It is assumed that quality of data is uniform across countries. NERC checks for data quality regardless of the associated country.

Relevant time steps (important for modeling demand and renewable resources)	Hourly.	Seconds to hours.	Hourly.	Sub-hourly.	Sub-hourly.	Hourly.	Sub-hourly.	Hourly.
Generation represented?	Generation optimally dispatched. Output decisions are at individual GU level.	Generation optimally dispatched at hourly and sub-minute time-steps. Output decisions are at individual GU level.	Generation optimally dispatched. Output decisions are at individual GU level.	Generation optimally dispatched. Output decisions are at individual GU level.	Generation optimally dispatched. Output decisions are at individual GU level.	Generation optimally dispatched. Output decisions are at individual GU level.	Like FESTIV.	Generation optimally dispatched. Output decisions are at individual GU level.
Transmission represented?	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines. Nodal model characterizes transmission constraints between generating units.	Major transmission lines and nodes represented. Uses a DC model of transmission network.	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines. Nodal model characterizes transmission constraints between generating units . Simplifies power flow through transmission network as DC flow.	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines.	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines. Nodal model characterizes transmission constraints between generating units. Simplifies power flow through transmission network as DC flow.	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines. Nodal model characterizes transmission constraints between generating units . Simplifies power flow through transmission network as DC flow.	Like PLEXOS.	Major transmission lines and nodes represented. Nodal models represent potential congestion on individual transmission lines. Power flow through transmission network can be modeled as AC or DC flow.

Energy storage modeling?	Detailed modeling of most storage technologies (pumped storage, battery, CAES, etc.). No further modeling details provided.	Can show how energy storage can reduce costs and improve reliability. Recent focus is on how the ISO can best include energy storage in its energy and ancillary service market designs. So far, the model has focused on pumped storage hydro. Developers are in discussion with other experts within NREL to look at concentrated solar thermal power with thermal energy storage.	MAPS optimally dispatches energy storage to maximize economic value. Energy storage efficiency rates can be input into MAPS. Has been used by ISOs and utilities to model pumped storage (no further modeling details provided).	Can model each energy storage type and has the ability to model the storage efficiency when producing energy. Energy storage can be optimally dispatched both to maximize economic value and assess reliability needs.	Can model flywheels, compressed air, thermal devices, and pumped storage technology among others. For storage modeling, it factors in the charging or pumping modes; efficiency; generating (minimum and maximum .generation); ramp rate (MW/min); ancillary service provisions; reservoir or storage device (minimum and maximum storage, storage natural inflow and losses modeled) PLEXOS has not modeled a battery yet	Can model the efficiency of the unit (PSH, CAES, flywheel-based) in storing and generating energy. The scheduling may be based on the region or the LMP at the unit. Energy storage is optimally dispatched to maximize economic value.	Modeling capabilities similar to FESTIV. Can create detailed models of both battery storage and pumped storage hydro.	Storage can be optimally dispatched to both maximize economic value and assess reliability needs. Energy storage efficiency rates can be put into the program. UPLAN can handle numerous energy efficiency variables including energy loss, probability of regulation call, ramp rate, ancillary service product and MW capability. For pumped hydro storage, comprehensive infrastructure inputs can be utilized including river system

Table B.7: Production Cost Simulation Tools

Aurora	
Developer	Energy Exemplar
Availability	Commercial proprietary software can be purchased from Energy Exemplar.
Description	Aurora uses market fundamentals and advanced dispatch logic to give energy executives, developers and resource planners an accurate view of a portfolio's value. Its speed lets analysts perform multiple long-term model runs to evaluate completely when—and in what conditions—resources will perform economically. The software calculates net power costs and system costs for individual resources. Marketers, developers and utilities can use this capability to easily determine how to position a contract or value a new resource in the market. Fast and easy to use, this software is also able to produce both short-term and long-term price forecasts for all major market zones and trading hubs. It simulates supply and demand on an hourly basis to provide electric price forecasts. This model is suitable for harmonization analysis. The integrated feature of expansion planning and hourly production cost modeling will allow the analyst to explore optimal investment paths and optimal operational strategies to minimize cost. This tool and the appropriate scenario analysis would provide deep insight into benefits and cost savings from both energy services as well as balancing services of a cross-border electricity coordination.
Major Studies	• *The Biannual Northwest Power Plan*. 2016. https://www.nwcouncil.org/reports/seventh-power-plan. • *2015 Integrated Resource Plan at Avista Corporation*. 2015. https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/appendix-b-final.pdf?la=en. • *Electricity Resource Analysis at Puget Sound Energy*. 2013. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppK.pdf.
Developer URL	https://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/.
Documentation URL	A license must be obtained from Energy Exemplar to access the software and official documentation.
Flexible Energy Scheduling Tool for Integrating Variable Generation (FESTIV)	
Developer	National Renewable Energy Laboratory
Availability	Proprietary software can be purchased from NREL.
Description	NREL's FESTIV simulates the behavior of the electric power system to help researchers understand the impacts of variability and uncertainty on power system operations. Electric power system operators use a variety of scheduling techniques to match electricity generation and demand. When

	the total supply of energy is different from the total demand, system operators must deploy operating reserves (including regulating, following, contingency, and ramping reserves) to correct the energy imbalance. The way they do this, and especially the way they plan for this, can affect the reliability and efficiency of the power system—particularly if it includes large amounts of variable generation. FESTIV allows researchers to explore different operating reserves strategies on system operations. FESTIV is a multiple-timescale, interconnected simulation tool that includes security-constrained unit commitment, security-constrained economic dispatch, and automatic generation control sub-models. Each sub-model is connected to subsequent sub-models such that the output of one sub-model serves as the input to the next. FESTIV is completely configurable so that the effects of different operating temporal resolutions and operating strategies can be explored. FESTIV produces not only economic metrics but also reliability metrics. This enables FESTIV to fully investigate the trade-offs in economic benefits, reliability benefits, and incentive structures.
Major Studies	Related publications can be found at https://www.nrel.gov/grid/festiv-model.html.
Developer URL	https://www.nrel.gov/grid/festiv-model.html.
Documentation URL	https://www.nrel.gov/docs/fy11osti/50641.pdf.
GE MAPS	
Developer	General Electric Company
Availability	Commercial proprietary software can be purchased from GE Energy.
Description	GE Energy offers the MAPS software, which provides the detailed modeling of various business needs. The main components of the tool are: • Based on an optimization approach that searches for a least-cost SCUC and SCED of generators within a transmission system • Can provide nodal or zonal representations of demands/load projections • Runs for one full year with hourly time increments • Simplifies the power flow calculation by linearized DC flow equations. This software is capable of assessing resource adequacy and other aspects of reliability of a system, analyzing the impact of changes in the system on system operation, assessing transmission congestion and locational marginal prices, describing the daily pattern of emissions, etc.
Major Studies	• *Eastern Renewable Generation Integration Study*. 2016. https://www.nrel.gov/docs/fy16osti/64472.pdf. • *The Impact of High Wind Penetrations on Hydroelectric Unit Operations*. 2011. https://www.nrel.gov/docs/fy11osti/52251.pdf. • *Western Wind and Solar Integration Study*. 2010. https://www.nrel.gov/docs/fy10osti/47434.pdf.

Developer URL	https://www.geenergyconsulting.com/practice-area/software-products/maps.
Documentation URL	http://www.uwig.org/shortcourse2014/Session-28-29-Hinkle.pdf https://www.ferc.gov/CalendarFiles/20100608145127-Van%20Zandt,%20GE%206-9-10.pdf.
GridView	
Developer	ABB, Inc.
Availability	Commercial proprietary software can be purchased from ABB.
Description	GridView simulates the market operation of an electric power system under constrained transmission. It can be used to study the operational and planning issues facing regulated utilities, as well as competitive electric markets. The simulation program mimics the operation of electricity markets by performing SCUC and SCED. It simulates the economic operation of power systems in sub-hourly intervals for periods ranging from one day to many years depending on the application. A fundamental requirement for such a program is the modeling capability of SCUC and SCED as they are done in GridView. At the SCUC stage, GridView determines the startup, shutdown schedules, and dispatches generators to minimize the total system cost while satisfying the various generation and transmission constraints. It is typically used for determining the utilization of generators and transmission lines in a regulated or deregulated environment, calculating the production cost of generation in a deregulated environment, calculating the LMP in a deregulated environment, evaluating the operational and economic impacts of renewable energy resources, such as wind, solar PV systems, etc.
Major Studies	• *Transmission Expansion Planning Department Study*. 2015. https://www.wecc.biz/Reliability/TEPPC-Value-Proposition.docx. • *Renewable Electricity Futures Study*. 2012. https://www.nrel.gov/docs/fy13osti/52409-ES.pdf. • *SunShot Vision Study*. 2012. https://www.nrel.gov/docs/fy12osti/53310.pdf.
Developer URL	https://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis/gridview.
Documentation URL	https://library.e.abb.com/public/d25b0020b72d94eac1256fda00488560/GridView%20Presentation.pdf. https://new.abb.com/docs/librariesprovider139/default-document-library/gridview_brochure.pdf?sfvrsn=4.

PLEXOS	
Developer	Energy Exemplar Pty. Ltd.
Availability	Commercial proprietary software can be purchased from Energy Exemplar.
Description	PLEXOS uses state-of-the-art mathematical optimization and distributed computing methods to meet the demands of energy market participants, system planners, investors, regulators, consultants and analysts alike. It provides a comprehensive range of features seamlessly integrating electric, water, gas and heat production, transportation and demand over simulated timeframes from minutes to several years, delivered through a common simulation engine with easy-to-use interface and integrated data platform. Additional features of the tool are: • OPF with losses fully integrated with dispatch and unit commitment • Security and N-x contingency constraints, DC lines and phase shifters • Generic constraints and interface limits, transmission aggregation, Monte Carlo simulation, multiple AC networks (10,000s of buses and lines), nodal pricing and price decomposition • Long, medium and short-term analysis with one integrated simulation engine • Perform comprehensive modeling of the economics and technical limits of fossil-fired and renewable generation • Model ancillary service provision co-optimized with generation dispatch and unit commitment to sub-hourly level, with detailed treatment of start-up and shutdown.
Major Studies	*PLEXOS Publications*. 2010–2017. https://energyexemplar.com/publications/research-publications/
Developer URL	https://energyexemplar.com/.
Documentation URL	A license must be obtained from Energy Exemplar to access the software and official documentation.
PROMOD	
Developer	ABB, Inc.
Availability	Commercial proprietary software can be purchased from ABB.
Description	PROMOD is recognized in the industry for its flexibility and breadth of technical capability, incorporating extensive details in generating unit operating characteristics and constraints, transmission grid topology and constraints, generation analysis, unit commitment/operating conditions, and market system operations. It uses an hourly chronological dispatch algorithm that minimizes costs (or bids) while simultaneously adhering to a wide variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, transactions, and customer demand. Key features include: • LMP forecasting for selected nodes, user-defined hubs, or load-weighted or generator-weighted zones • Economic transmission analysis in presence of renewables to quickly evaluate the economic benefit/cost, the increase/decrease in

	hourly/monthly congestion, and the increase/decrease in reliability metrics associated with transmission expansion • Zonal power market analysis for quantifying operating risks associated with each facility and developing a detailed forecast of market prices and system operation in various conditions
Major Studies	• *Transmission Planning using Production Cost Simulation and Power Flow Analysis*. 2018. https://www.wecc.biz/Administrative/Round-Trip%20Panel%20-%20Zhu.pdf. • *MTEP Model Update: Battery Storage Modeling*. 2017. https://old.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2017/20170714/20170714%20EPUG%20Item%2006%20MTEP18%20Model%20Update%20Battery%20Storage%20Modeling.pdf. • *National Assessment of Energy Storage for Grid Balancing and Arbitrage*. 2013. https://energyenvironment.pnnl.gov/pdf/National_Assessment_Storage_PHASE_II_vol_1_final.pdf.
Developer URL	https://new.abb.com/enterprise-software/energy-portfolio-management/market-analysis/promod.
Documentation URL	http://search.abb.com/library/Download.aspx?DocumentID=9AKK106930A8226&LanguageCode=en&DocumentPartId=&Action=Launch.
Renewables Integration Model (RIM)	
Developer	Pacific Northwest National Laboratory
Availability	License to access the software can be purchased from PNNL.
Description	PNNL's RIM features two functions: (a) modeling the security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED). It has been used for research purposes to explore electric grid stress case scenarios in extreme weather conditions such as drought and concurrent heat wave conditions. The model is calibrated to the PROMOD results for both the WECC and the Eastern Interconnection. The model uses the full WECC data set that includes all of the Canadian and Mexican that are part of the WECC. For the eastern interconnection, the data set includes all U.S. generators and a reduced set of Canadian generators. Mexican generators east of the Mississippi are not represented. The model simulates the unit commitment problem in hourly time steps. It uses a linearized DC power flow representation. While the model is technically suitable to perform a North American harmonization analysis, the specific feature sets of climate change of RIM are not likely to be utilized. As with all of the other production cost models, the biggest challenge would be to develop the data set for cross-border trades.
Major Studies	*A Modified Priority List-Based MILP Method for Solving Large-Scale Unit Commitment Problems*. 2015. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=7286561.
Developer URL	https://energyenvironment.pnnl.gov/ei/capabilities.asp.
Documentation URL	Not currently available online.

UPLAN	
Developer	LCG Consulting
Availability	Commercial proprietary software can be purchased from LCG.
Description	UPLAN Network Power Model incorporates a rich, integrated representation of physical features of the electric generators, loads and transmission, financial characteristics and system operation. It performs coordinated marginal cost (or bid) based energy and ancillary service procurement, congestion management, N-x contingency analysis with SCUC and SCED like those used by ISOs. It performs SCUD and SCED computations both in a zonal and nodal transmission representation. It realistically characterizes generators' market participation based on opportunity or marginal cost-based bidding, with arbitrage (simulated via an enhanced Nash equilibrium algorithm). The tool is used for short and long-term analysis for: • Day-ahead SCUC and SCED • Co-optimization of energy and ancillary services • Hourly energy capacity and ancillary services prices and revenues • Generation expansion and retirements and maintenance • Intermittent energy and storage (pumped storage, CAES, BESS) modeling
Major Studies	As per the official website, UPLAN has been used to perform various studies for U.S. utility and ISO/RTO clients but the reports are generally not publicly available.
Developer URL	http://www.energyonline.com/Products/UPlane.aspx.
Documentation URL	A license must be obtained from LCG to access the software and official documentation.

Table B.8: Hydropower Simulation and Hydro-Thermal Coordination Tools

Features	CHEERS (Argonne)	GTMax (Argonne)	SDDP (PSR)	Valoragua (EDP Portugal)
Model inputs	Meteorological inputs, inflows, inflow temperatures, outflows. Physical characteristics of dam/reservoir, operating characteristics/constraints, initial conditions. Reservoir storage and elevation history, initial conditions, daily water releases. Firm customer loads, long-term firm contracts, power interchanges, station service loads.	Electric requirements including losses. Cogeneration thermal demand. Irrigation requirements. RiverWare forebay and stream inlet flows for alternate hydro conditions. Fuel prices, O&M, spot and forward prices for power market purchases and sales. Thermal start-up and minimum generation costs. Generating unit characteristics (e.g., heat rates, capabilities).	Hydro configuration (choice of plant, plant parameters, maximum/minimum turbining inflow, minimum total outflow, O&M cost.) Plant parameters—reservoir (maximum/minimum storage, initial condition, area, etc.). Various plant topology parameters. Hydroelectric loss factor. Alert and minimum volume. Flood control storage. Maximum/minimum total outflow.	Electric (power system) nodes. Demands at the nodes. Secondary power demand and exports. Maintenance crews. Thermal power plants and imports Hydraulic nodes information (storage capacity, average water level, inflows). Spillway information. Pumping plant information (power consumed, average static head, maximum pumped water flow, etc.). Definition of transmission subsystem.
Model outputs	Near-term schedules for power generation, ancillary services (regulation up and down, spinning and non-spinning reserves), and water release. Optimized hydropower water release and dispatch operation schedules.	Units that will be dispatched in the new market and those that will be stranded. Power that will be generated and sold during each hour of a period. Appropriate times to buy/sell power in spot market. Projected available transmission capacity for each hour in a region. Marginal value of water in reservoirs.	Similar to Valoragua's.	Electric nodes (fixed power demands, hydro turbine power output, net power flow, marginal energy cost, etc.). Secondary demand and exports (power/energy supplied, utilization factor, cost of supplied energy, etc.). Reservoirs (initial storage, final storage, marginal value of water). Hydro-plant outputs.
Programming language	LINGO and AMPL	AMPL	Julia	FORTRAN
Computational approach	MINLPs piece-wise linearized to MILPs.	MILP approach to simultaneously solve the objective.	Problem formulated as a stochastic dynamic program.	Problem formulated as MILP.
Computational time step	User-defined and can range from one second to one year.	Hour.	Month, week.	Hour, month.

Features	CHEERS (Argonne)	GTMax (Argonne)	SDDP (PSR)	Valoragua (EDP Portugal)
Modeling environment	Performs daily runs to optimize day-ahead planning and real-time operations. Using WUOT-generated daily release volumes and measures of environmental performance, develops optimized hydropower water release and dispatch operation schedules.	Objective is to maximize the net revenues of power systems by finding a solution that increases income while keeping expenses to a minimum. Model computes and tracks hourly energy transactions, market prices, and production costs.	Detailed modeling environment considers operational details of hydro/thermoelectric plants, spot and energy markets, hydrological uncertainty, load duration curve representation.	Various power and hydro-electric system components are modeled using inputs shown in Model Inputs.
Zonal representation of demand/load projections	Can implement a zonal load.	Zonal representation for all regions across the world.	Zonal load implementation is possible.	It is possible.
Demand and supply curves for electricity market representations[1]	Demand response can be modeled as a resource that has cost characteristics similar to that of a generator.	Demand response can be modeled as a resource that has cost characteristics similar to that of a generator.	Each demand can be defined as a curve that indicates its willingness to purchase energy for different price levels of the system.	No information on modeling of the supply curve. Can be provided as inputs from tool such as EMCAS.
Generation representation	Generation optimally dispatched to maximize revenues due to sale of energy and ancillary services. Output decisions are at individual GU level.	Generation optimally dispatched to maximize net revenues. Output decisions are at individual GU level.	Very detailed hydro-thermal power system optimal dispatch mechanism. Output decisions are made at individual GU level.	Similar to SDDP's.
Transmission representation	Major transmission lines and nodes are represented. Nodal models represent potential congestion on individual transmission lines.	Represented only as flow interface (with capacity limits included) between multiple zones.	Detailed transmission network: Kirchhoff laws, power flow limit in each circuit, losses, security constraints, export and import limits for electrical areas, etc.	Transmission subsystem is modeled as an oriented network where the nodes represent geographical areas of gen/consumption and the links represent transmission or interconnection lines.
Geographic scope	Very flexible and can model at any level from broad to detailed.	Regional to interconnect.	Generalized for applications across the world.	Has been used in studies of large and small systems throughout the U.S. and Europe. Generalized for global applications.

[1] Production cost models may estimate the cost for demand response for implicit representation of the supply curve.

Features	CHEERS (Argonne)	GTMax (Argonne)	SDDP (PSR)	Valoragua (EDP Portugal)
Types of applications	Can create of day-ahead and real-time schedules. Provides solutions that suggest when, where, and how much water to release from reservoirs, power to generate from individual units, and capacity to reserve for ancillary services to fulfill reliability criteria and for sales to the market.	Determines hourly, weekly, and seasonal power and energy offers to customers and fine tune hourly resource generation patterns, spot market transactions, energy interchanges, and power wheeling. Computes economic and financial costs associated with environmental restrictions on hydropower operations. Identifies operational strategies that optimize the value of company's resources while taking advantage of market opportunities.	Model has been used in valuation studies for new hydro and thermal power plants, assessment of regional markets and international interconnections in several countries on five continents.	Determination of the hydro plants' operational characteristics in order to reach minimum annual operating costs. With WASP, model can determine the interaction between the two models will lead to determining the optimal expansion plan and operating strategy for the power system. Impacts of operational rules for a given reservoir on downstream levels.

Table B.9: Hydropower Simulation and Hydro-Thermal Coordination Tools

Conventional Hydropower Energy and Environmental Systems (CHEERS)	
Developer	Argonne National Laboratory
Availability	Proprietary software; license can be obtained from the developer.
Description	The CHEERS model focuses on day-ahead scheduling and real-time operations. Building on the Argonne team's experience developing other modeling tools and performing power systems analyses around the globe, CHEERS is a next-generation model that incorporates many "wish-list" features that have been expressed by model users over the years. CHEERS was designed not simply as an academic research tool, but as a practical daily-use tool to help actual hydropower schedulers make decisions that increase hydropower efficiency and the value of power generation and ancillary services. Its development was guided by and continues to be refined by feedback from a hydropower industry technical review committee as well as the schedulers who use it on a daily basis.
Major Studies	• *Modeling and Analysis of Advanced Pumped Storage Hydropower in the United States.* 2014. http://www.ipd.anl.gov/anlpubs/2014/07/105786.pdf. • *Optimizing Hydropower Day-Ahead scheduling for the Oroville-Thermalito Project*. 2012. http://adsabs.harvard.edu/abs/2012AGUFM.H43J..02V.
Developer URL	https://www.anl.gov/es/water-use-optimization-toolsetconventional-hydropower-energy-and-environmental-systems.
Documentation URL	https://anl.app.box.com/s/xswjuj3g4tyc6v63q5p2ld1keyvexrbz.
Generation and Transmission Maximization Model (GTMax)	
Developer	Argonne National Laboratory
Availability	Proprietary software; license can be obtained from the developer.
Description	The GTMax model helps researchers study complex marketing and system operational issues. With the aid of this comprehensive model, utility operators and managers can maximize the value of the electric system, considering not only its limited energy and transmission resources, but also firm contracts, IPP agreements, and bulk power transaction opportunities on the spot market. GTMax maximizes net revenues of power systems by finding a solution that increases income while keeping expenses at a minimum. At the same time, the model ensures that market transactions and system operations remain within the physical and institutional limitations of the power system. When multiple systems are simulated, GTMax identifies utilities that can successfully compete in the market by tracking hourly energy transactions, costs, and revenues. An added benefit of GTMax is that it simulates some limitations, including power plant seasonal capabilities, limited energy constraints, transmission capabilities, and terms specified in firm and IPP contracts. GTMax also considers detailed operational limitations, such as power

	plant ramp rates and hydropower reservoir constraints. Currently, power companies are using GTMax to determine hourly, weekly, and seasonal power and energy offers to customers and to compute the costs of environmental legislation. GTMax can also be used to fine-tune hourly resource generation patterns, spot market transactions, energy interchanges, and power wheeling on the transmission system.
Major Studies	• *Financial Analysis of Experimental Releases Conducted at Glen Canyon Dam during Water Year 2014*. 2015. https://www.osti.gov/biblio/1223204. • *Ex Post Power Economic Analysis of Record of Decision Operational Restrictions at Glen Canyon Dam*. 2010. https://www.wapa.gov/regions/CRSP/environment/Documents/PostRODFinal.pdf. • *Simulation Analysis on the Power Grid in Northeast Asia with GTMax.* 2008. https://www.tandfonline.com/doi/abs/10.1080/12269328.2008.10541284.
Developer URL	https://ceeesa.es.anl.gov/projects/Gtmax.html.
Documentation URL	https://ceeesa.es.anl.gov/pubs/60360.pdf. https://ceeesa.es.anl.gov/pubs/61079.pdf.
Stochastic Dual Dynamic Programming (SDDP)	
Developer	PSR, Inc.
Availability	A license must be obtained to install the latest software version.
Description	SDDP is a hydrothermal dispatch model with representation of the transmission network, used for short, medium and long-term operation studies. The model calculates the least-cost stochastic operating policy of a hydrothermal system, taking into account various aspects such as: • Operational details of hydro plants (water balance, limits on storage and turbined outflow, spillage, filtration etc.) • Detailed thermal plant modeling (unit commitment, generation constraints due to "take or pay" fuel contracts, concave and convex efficiency curves, fuel consumption constraints, bi-fuel plants etc.) • Representation of spot markets and supply contracts • Hydrological uncertainty It is possible to use stochastic inflow models that represent the system hydrological characteristics (seasonality, time and space dependence, severe droughts etc.) and the effect of specific climatic phenomena such as the El Niño.
Major Studies	• *Application of SDDP in Electricity Markets with Hydroelectricity*. 2017. http://cermics.enpc.fr/~delara/SESO/SESO2017/SESO2017_Thursday_Philpott.pdf. • *An Optimal Hydro-Thermal Planning Model for the New Zealand Power System*. 2004. https://www.tandfonline.com/doi/abs/10.1080/1448837X.2004.11464107.
Developer URL	https://www.psr-inc.com/softwares-en/?current=p4028.
Documentation URL	https://www.psr-inc.com/wp-content/uploads/softwares/SddpUsrEng.pdf

Valoragua	
Developer	Electricidade de Portugal, Portugal (original developer)
Availability	A license must be obtained to install the latest software version.
Description	The economic assessment of the role that nuclear power may play in satisfying the future electricity requirements of a country or a region necessitates carrying out integrated power system expansion analysis in order to ensure that nuclear energy is objectively and adequately compared against other available options for electricity generation. To help its developing member states in carrying out integrated power system expansion analysis, IAEA has developed the computer model called WASP. This model has been made available to interested member states for use in long term expansion planning of their power system, including the assessment of the role of nuclear power. The WASP model has proven to be very useful for this purpose and is accepted worldwide as a sound tool for electricity planning. Notwithstanding its many advantages, certain shortcomings of the methodology have been noticed, with regards to representation of hydroelectric power plants. In order to overcome these shortcomings, IAEA decided to acquire the computer model called Valoragua, originally developed by Electricidade de Portugal, for optimizing the operating strategy of a mixed hydro-thermal power system. This program, when used together with WASP, would allow economic optimization of hydro-thermal power systems with a large hydro component.
Major Studies	▪ *Expansion Planning of the Electricity Generating System Using the Valoragua and WASP-IV Models in Nepal*. 2016. https://www.nepjol.info/index.php/HN/article/view/15352. ▪ *Modeling hydro plants in deregulated electricity markets: Integration and application of EMCAS and Valoragua*. 2008. https://ieeexplore.ieee.org/document/4579096/.
Developer URL	https://www.iaea.org/
Documentation URL	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/19/024/19024151.pdf?r=1

Table B.10: Water Allocation Decision Support Systems

Features	CalSim (Department of Water Resources, California)	MODSIM-DSS (Colorado State University)	HEC-ResSim (HEC)	RiverWare (University of Colorado)	Vista DSS (Hatch)	WRAP (Texas A&M)
Model inputs	Physical capacities and specific regulatory and contractual requirements. System configuration consisting of facilities, operations, and regulations along with limits or preferences on operation. State of the system at the beginning of a period is defined by state variables that are input directly (e.g., reservoir inflows, target demands). Hydrologic data.	River/reservoir system topology data. Imported river basin maps. Data regarding river gages, diversion dams, instream flow requirements, and reservoirs. Sequences of stream inflows, reservoir evaporation rates. Demands for water and energy.	Watershed setup module provides a common framework for watershed creation and definition among different modeling applications. Reservoir network module is used to construct a river schematic, describe the physical and operational elements of the reservoir system, and develop alternatives to be analyzed. Time series of stream flows and reservoir evaporation rates are entered in HEC-DSS format.	Hydrologic inflows into the rivers and reservoirs at certain points, or river gage data and reservoir storages that can be used to calculate the hydrologic inflows. Volume-elevation-area tables for level reservoirs, or headwater-storage-flow tables for sloped reservoirs. River reach and canal data. Thermal power system data. Water routing, water quality, power generation, hydraulics and operating rules.	Reservoir data inducing storage curves and water level constraints. Power plant data including unit efficiencies, turbine discharge curves, operating ranges. Watershed data including drainage areas, elevations, and calibrated parameters describing runoff characteristics. Historic and real time water levels. Historic, real time and forecast temperature and precipitation. Historic and real time snowpack data. Historic inflow sequences.	HYD program assists in developing monthly naturalized stream flow and reservoir net evaporation-precipitation depth data for the SIM hydrology input files. SIM program simulates the river/reservoir water allocation/management/use system for input sequences of monthly naturalized flows and net evaporation rates. SALT reads a SIM output file and a salinity input file. Input on water rights: control point location, annual diversion amount, instream flow requirements, etc.
Model outputs	Outputs such as river flows and diversions, reservoir storage, delta flows and exports, water quality, delta salinity and OMR can be obtained.	Water availability at nodes (non-storage, demand and reservoir) and potential system optimization.	Generation parameters (turbine flows, efficiency, head). Total reservoir outflow. Outflows at turbine, valve and spillway. Reservoir elevation.	Reservoir and reach outflows and/or reservoir storages, elevations, and energy. Can also include water quality and water accounting information.	Target water levels at storage reservoirs. Implied value-of-water in storage in each storage reservoir. Probabilistic definition of variables over the planning period: revenues, costs, water levels, flows at all points in the network, generation for system/ plants/units, reserves, energy surpluses/deficits, etc.	Stream flows, channel losses, reservoir storage, evaporation volume, energy shortage, firm energy produced, available stream flow, hydropower shortage, electric energy generated, and reservoir storage capacity.

Features	CalSim (Department of Water Resources, California)	MODSIM-DSS (Colorado State University)	HEC-ResSim (HEC)	RiverWare (University of Colorado)	Vista DSS (Hatch)	WRAP (Texas A&M)
Programming language	Water Resources Engineering Simulation Language	C++.NET, Basic.NET	Java	C++	C++	FORTRAN
Computational approach	A modeling language, Water Resources Engineering Simulation Language, is used to serve as an interface between the user and the LP/MILP solver, time-series database, and relational database.	Network linear programming. Simulation computations are governed by user-specified priorities in considering water management requirements.	Ad hoc (strategies developed specifically for a particular model). Follows an upstream-to-downstream progression in considering requirements for reservoir storage and releases, diversions, and hydropower generation.	Characteristics similar to ResSim's with an additional LP-based option.	Hourly LP formulation to define the system configuration and the environmental, political, and biological requirements for that system.	Ad hoc (strategies developed specifically for a particular model).
Computational time step	Month, day.	Month, week, day.	15 minutes to day.	Hour to year.	Hour, week, month.	Month, day, other.
Modeling environment	Physical description of the system is expressed through a user interface with tables outlining the system characteristics. Priority weights and basic constraints are also entered in the system tables.	Based on network flow programming with a reservoir/river system represented by a network of nodes and links with information compiled through an object-oriented interface.	Various elements provided by watershed setup, reservoir network, and simulation modules are used to construct and execute a model.	Has an object/slot-based environment for building models within the context of object-oriented programming and provides three optional solution options.	No information available.	WRAP is about managing programs, files, input records, and results tables, with water management and use practices being described in the terminology of water rights.
Interface features	WRIMS graphical user interface version WRIMS 2.0 is available to run various scenarios while simulating system operation. Recent graphical user interface (GUI) improvements are added functionality to include new water management scenarios and better error handling ability.	Provide sophisticated GUIs with menu-driven editors for entering and revising input data and displaying simulation results in tables and graphs. Has features allowing a river/reservoir system schematic to be created by selecting and connecting icons.	Like MODSIM or RiverWare. Connects with and relies upon graphics capabilities of the HEC-DSS.	Provide sophisticated GUIs with menu-driven editors for entering and revising input data and displaying simulation results in tables and graphs. Has its own simulation rule language to allow users to express reservoir/river system operating requirements as a series of statements with if-then-else constructs.	Provide sophisticated GUIs with menu-driven editors for entering and revising input data and displaying simulation results as tables and charts.	Has a simple user interface for managing programs and files, which relies upon standard MS Office programs for entering, editing, and displaying data. Connects with and relies upon graphics capabilities of the HEC-DSS.

Features	CalSim (Department of Water Resources, California)	MODSIM-DSS (Colorado State University)	HEC-ResSim (HEC)	RiverWare (University of Colorado)	Vista DSS (Hatch)	WRAP (Texas A&M)
Types of applications	Generalized water resources modeling system for evaluating operational alternatives of large, complex river basins. Used for climate change, sea-level rise, hydrology and system operations related applications	Can simulate flood control, hydropower, water supply, environmental flows, and other reservoir management purposes. Relative priorities represented by objective functions coefficients may optionally be economic costs or benefits. Has water salinity and water quality modeling feature.	Flood control, water supply and hydropower simulation. Representation of complex prioritized reservoir operating rules. Real-time or planning analysis. Monte-Carlo, ensemble and firm yield analysis.	Can simulate flood control, hydropower, water supply, environmental flows, and other reservoir management purposes. Has recently been expanded to increase flexibility to model flood control. Relative priorities represented by objective functions coefficients may optionally be economic costs or benefits.	Determination of best timing of reservoir storage drawdown and recovery, and associate best timing of market purchases and sales. Minimization of spill. Clear forecast of the probabilistic system operation, including revenues, costs, water levels, flows at all points in the network, generation for the system/plants/units, reserves, etc. Direction for the short-term scheduling, in the form of value-of-water in storage.	Can simulate flood control, hydropower, water supply, environmental flows, and other reservoir management purposes. Has particularly comprehensive options for reliability and frequency analyses. Can simulate water salinity.
Geographic scope	Developed for California (covers 35 out of 58 counties). Generalized for applications around the globe.	Applicable throughout the western U.S. or in regions with comparable water allocation systems .	Has been used in studies of large and small systems throughout the United States and around the world.	Tennessee Valley, Colorado River, Upper Rio Grande, San Juan Basin.	Applicable throughout the U.S. and Canada (or in regions with comparable water allocation systems).	Routinely applied in Texas in regional and statewide planning studies. Generalized for applications around the world.

Table B.11: Water Allocation Decision Support Systems

CalSim	
Developer	Department of Water Resources and Bureau of Reclamation, California
Availability	It can be copied, distributed, and modified freely, but one may not restrict others in their ability to copy, distribute, and modify it.
Description	CalSim is a generalized water resources modeling system for evaluating operational alternatives of large, complex river basins. It integrates a simulation language for flexible operational criteria specification, a linear programming solver for efficient water allocation decisions, and graphics capabilities for ease of use. These combined capabilities provide a comprehensive and powerful modeling tool for water resource systems simulation. CalSim is the model used to simulate California State Water Project/Central Valley Project operations. CalSim 2 is the latest version of CalSim available for use. The entire system and related operational criteria in CalSim are specified as input to Water Resource Integrated Modeling System (WRIMS) and may be modified or replaced without requiring changes in WRIMS.
Major Studies	• CalSim II Modeling and Results. 2016. http://www.californiawaterfix.com/wp-content/uploads/2017/10/App_5.A_CALSIM.pdf. • CalSim II Modeling and Results. 2016. http://www.westcoast.fisheries.noaa.gov/publications/Central_Valley/CAWaterFix/app_5.a_calsim.pdf. • CALSIM II Modeling Studies of the Delta-Mendota Canal/California Aqueduct Intertie. 2009. https://www.usbr.gov/mp/nepa/includes/documentShow.php?Doc_ID=4110.
Developer URL	http://baydeltaoffice.water.ca.gov/modeling/hydrology/CalSim/index.cfm.
Documentation URL	http://baydeltaoffice.water.ca.gov/modeling/hydrology/CalSim/Documentation/CalsimManual.pdf. http://baydeltaoffice.water.ca.gov/modeling/hydrology/CalSim/Documentation/CalsimUsersGuide.pdf.
MODSIM Decision Support System (MODSIM-DSS)	
Developer	Colorado State University
Availability	It can be accessed by obtaining a license from the developer.
Description	MODSIM is a generic river basin management decision support system for analysis of long-term planning, medium-term management, and short-term operations. MODSIM is free from expensive licenses for proprietary software since all components are developed from native code or shareware in the Microsoft.NET framework. MODSIM includes a powerful, interactive graphical user interface for creating, locating and connecting river basin network components, as well as spreadsheet-style data editing in an object-oriented spatial data base management system. Flexible data import and export tools are included for interaction with external data base management systems. One of the advantages of the MS.NET framework is the ability to customize MODSIM for any specialized operating rules, input data, output

	reports, and access to external modules such as water quality models running concurrently with MODSIM, all without having to modify the original source code. The basic solver in MODSIM is a state-of-the-art network flow optimization algorithm up to two orders of magnitude faster than solvers in other river basin modeling packages and capable of simulating complex, large-scale networks. An iterative solution procedure allows consideration of non-network and conditional constraints. GEO-MODSIM, a full implementation of MODSIM operating as a custom extension in ArcGIS (ESRI, Inc.), allows automatic generation of MODSIM networks from geometric networks and processing of spatial database information in a GIS.
Major Studies	• *Assessing drought threats to agricultural water supplies in climate change by combining the SWAT and MODSIM models for Geum River basin*. 2016. https://www.tandfonline.com/doi/abs/10.1080/02626667.2015.1112905?src=recsys&journalCode=thsj20. • *MODSIM modeling of Henrys Fork basin alternatives*. 2013. https://www.usbr.gov/pn/studies/henrysfork/techrept/modsim.pdf. • *MODSIM-based water allocation modeling of Awash River Basin*. 2012. https://www.sciencedirect.com/science/article/pii/S0341816213000970
Developer URL	http://modsim.engr.colostate.edu/modsim.php.
Documentation URL	https://www.engr.colostate.edu/ens/tools/ajax.
Hydrologic Engineering Center's Reservoir System Simulation (HEC-ResSim)	
Developer	Hydrologic Engineering Center, U.S. Army Corps of Engineers
Availability	HEC-ResSim was developed for the U.S. Army Corps of Engineers and is made available to the public whenever appropriate. Use is not restricted, and individuals outside of the Corps of Engineers may use the program without charge. HEC will not provide user assistance or support for this software to non-Corps users.
Description	HEC-ResSim is used to model reservoir operations at one or more reservoirs for a variety of operational goals and constraints. The software simulates reservoir operations for flood management, low flow augmentation and water supply for planning studies, detailed reservoir regulation plan investigations, and real-time decision support. HEC-ResSim can represent both large and small-scale reservoirs and reservoir systems through a network of elements (junctions, routing reaches, diversion, reservoirs) that the user builds. The software can simulate single events or a full period-or-record using available time-steps. HEC-ResSim is a decision support tool that meets the needs of modelers performing reservoir project studies as well as meeting the needs of reservoir regulators during real-time events.
Major Studies	• *Modeling Interconnected Reservoirs with HEC-ResSim*. 2018. https://ascelibrary.org/doi/10.1061/9780784481424.024. • *Application of HEC-ResSim in the study of new water resources in the Panama Canal*. 2017. https://www.tandfonline.com/doi/abs/10.1080/23249676.2017.1355759. • *Using HEC-ResSim for Columbia River Treaty Flood Control*. 2010. https://acwi.gov/sos/pubs/2ndJFIC/Contents/9F_Modini_3_01_10.pdf.

Developer URL	http://www.hec.usace.army.mil/software/hec-ressim/.
Documentation URL	http://www.hec.usace.army.mil/software/hec-ressim/documentation/HEC-ResSim_31_UsersManual.pdf.
RiverWare	
Developer	University of Colorado
Availability	Proprietary software; license can be purchased from the developer.
Description	RiverWare is a reservoir and river basin modeling tool that allows the user to model and analyze a variety of basin operations in both simulation and forecast modes for more effective decision-making. RiverWare's modeling kit represents various physical and structural basin features (e.g., dams, power generators, reservoirs, rivers, tunnels, water consumers) using RiverWare objects, and the objects' built-in algorithms mimic the physical processes of corresponding basin features. The RiverWare Policy Language allows the user to formulate basin operational policies into a ruleset, which approximates real-time decisions by water managers. RiverWare's wide variety of applications range from short-term operations to long-term planning and analysis in a river basin, for example, hydropower optimization, optimized daily scheduling operations of reservoirs, multi-objective decision-making, water accounting, water quality, environmental flows, and climate change assessments. RiverWare allows the user to select various generic basin features and link them together to create a basin topology. The software's features and utilities allow a wide variety of functions ranging from data-related operations, application of different solution approaches, management of model runs, and integration of user-defined policies. In addition, the software has a list of supplementary tools, e.g., RiverWare Study Manager and Research Tool, RDFtoExcel, and Graphical Policy Analysis Tool, which assist in the creation, running, and analysis of the RiverWare model.
Major Studies	• *Hydropower Modeling Challenges*. 2017. https://www.nrel.gov/docs/fy17osti/68231.pdf. • *Multi-objective Modeling in RiverWare for USACE-SWD*. 2015. https://www.colorado.edu/cadswes/sites/default/files/attached-files/10f_avance_03_01_10.pdf. • *Integration of Water Supply and Demand: RiverWare Upper Missouri Basin System Model.* http://dnrc.mt.gov/divisions/water/management/docs/training-and-education/miabs-11_umbia-riverware-modeling-lanini.pdf.
Developer URL	http://www.riverware.org/.
Documentation URL	http://www.riverware.org/PDF/RiverWare/documentation/index.html.
Vista DSS	
Developer	Hatch Ltd.
Availability	Proprietary software; license can be purchased from the developer.
Description	Water-resource and power-system operators need to consider and improve how they manage this valuable resource, always bearing in mind and balancing the constraints imposed by power generation, flood control,

	management of drought risks, recreation, maintaining water quality, irrigation, domestic and industrial users, the fishing industry, and more. In addition, waterpower-systems operators and hydroelectric utilities need to identify the best scenarios for maximizing revenues in the electricity market, using long-term contracts and spot-energy market transactions. Ancillary service requirements must be considered, too. Finding the best ways to manage operations is particularly challenging for utilities that must coordinate multiple generation sources in addition to hydro, such as wind, solar, and thermal generation. Vista DSS is a toolbox used by system operators, dispatchers, and engineering-operations staff to help determine long-term storage planning and management, short-term (hourly time resolution) scheduling, and real-time dispatch.
Major Studies	https://www.hatch.com/en/About-Us/Publications/Technical-Papers?itemId={66DB809D-F252-4015-B302-758919E270B3}.
Developer URL	https://www.hatch.com/en/Expertise/Services-and-Technologies/Vista-Decision-Support-System
Documentation URL	Not publicly available.
Water Rights Analysis Package (WRAP)	
Developer	Department of Civil Engineering, Texas A&M University
Availability	Can be accessed by sending a request to the developer.
Description	Water resources development, water allocation, and river/reservoir system operations are simulated with WRAP using sequences of historical naturalized stream flows and reservoir surface net evaporation less precipitation rates to represent river basin hydrology. The generalized simulation modeling system is used to assess hydrologic and institutional water availability and reliability in satisfying requirements for environmental instream flows, water supply diversions, hydroelectric energy generation, and reservoir storage. Flood control reservoir operations may also be modeled. Salinity simulation capabilities are provided. Basin-wide impacts of water resources development projects and changes in water use and management practices are evaluated. The model is generalized for application to any river/reservoir/water-use system, with input datasets being developed for the specific river basin or region of concern. The statewide Water Availability Modeling System implemented and maintained by the Texas Commission on Environmental Quality consists of the generalized WRAP modeling system and input datasets for all river basins of Texas. WRAP may be applied either in conjunction with the Water Availability Modeling System or independently. In applying the Water Availability Modeling System, model users modify the already-created WRAP input data files available from the Texas Commission on Environmental Quality to model the alternative water resources development plans, water management strategies, and water use scenarios being investigated in their studies. For river basins outside of Texas, model users must develop the input datasets required for their specific applications.
Major Studies	*Texas Water Resources Institute Publications.* https://ceprofs.civil.tamu.edu/rwurbs/OtherReports.zip.

	Daily Water Availability Modeling Reports. https://ceprofs.civil.tamu.edu/rwurbs/DailyReports.zip.
Developer URL	https://ceprofs.civil.tamu.edu/rwurbs/wrap.htm.
Documentation URL	https://ceprofs.civil.tamu.edu/rwurbs/WRAPmanuals.zip.

Table B.12: Agent-Based Electricity Market Simulation Tools

Features	AMES (Iowa State University)	EMCAS (Argonne)	MASCEM (IPP)	NEMSIM (CSIRO)	PowerACE (Germany)	STEMS-RT (EPRI)
System participants	Trader, market, transmission grid, ISO.	ISO, regulator, customer, demand companies, generator, generation companies, transmission operator, distribution companies.	Generator, consumer, trader, market facilitator, market operator, network operator.	NEMMCO (Australian ISOs), customers, generation companies, network service provider, retail companies.	Consumer, load serving entities, generator, electricity trader, market operator.	Customers, generation companies.
Functions of ISO	System reliability assessment, day-ahead unit commitment, dispatch, settlement.	Projection function, market function, scheduling function, dispatching function, settlement function.	Market function, scheduling function.	Market dispatch, scheduling.	Only market functions.	None.
Electricity market capabilities (consists of generation, marketing, transmission, distribution and central administration)	Relatively complete (no distribution).	Complete.	Relatively complete (no distribution).	Relatively complete (no transmission and distribution).	Relatively complete (no distribution).	Marketing function only (bidding in pool markets).
Market models	Two settlement.	Pool market and bilateral contract.	Two settlement.	Pool market and bilateral contract.	Two settlement and CO_2 emission.	Pool market.
Transmission model	DC.	AC and DC.	Information unavailable.	None.	None.	None.
Decision-making for agents	Makes basic decisions related to specific roles.	Decision-making at six temporal levels (hourly/half-hourly, daily, weekly, monthly, yearly, multi-yearly).	Makes basic decisions related to specific roles.	Decision-making at six temporal levels (hourly/half-hourly, daily, weekly, monthly, yearly, multi-yearly).	Makes basic decisions related to specific roles.	Bidding strategies in the bidding process.
Adaptation (method for mimicking real-world decision-making)	JReLM (Java-based reinforcement learning).	Observation-based and exploration-based learning.	Dynamic strategy, scenario analysis.	Look-ahead decision process.	Not explicitly defined.	Information unavailable.

Table B.13: Agent-Based Electricity Market Simulation Tools

AMES	
Developer	Department of Economics, Iowa State University
Availability	The free open-source tool can be downloaded from the official website.
Description	AMES has four main components: traders, transmission grids, markets, and an ISO. AMES is programmed in Java and developed using Repast for Java. The trader agent contains two types of entities: buyers (load serving entities) and sellers (generators). The market component has a two-settlement system, which consists of a day-ahead market and a real-time market. The ISO has four functions: system reliability assessment, day-ahead unit commitment, dispatch, and settlement. A reinforcement learning module, called JReLM, is integrated into the simulation framework for adaptive decision-making of traders. The physical transmission system is modeled as a five-node transmission grid. In summary, AMES is composed of several separate modules, each of which can be extended, and new modules can also be added. AMES is open source, which facilitates the future extension of the software.
Major Studies	• *An 8-Zone ISO-NE Test System with Physically-Based Wind Power.* (2017). http://www2.econ.iastate.edu/tesfatsi/EightZoneISONETestSystemWithWind.LiTesfatsion.pdf. • Testing Institutional Arrangements via Agent-Based Modeling: A U.S. Electricity Market Application. (2011). *Computational Methods in Economic Dynamics*. http://www2.econ.iastate.edu/tesfatsi/LMPCorrelationStudy.LST.pdf.
Developer URL	http://www2.econ.iastate.edu/tesfatsi/AMESMarketHome.htm
Documentation URL	http://www2.econ.iastate.edu/tesfatsi/AMESStateSpaceModel.pdf http://www2.econ.iastate.edu/tesfatsi/AMESTestBed.2009IEEEPESGM.pdf
Electricity Market Complex Adaptive System (EMCAS)	
Developer	Argonne National Laboratory
Availability	Proprietary software; license can be obtained from the developer.
Description	EMCAS was developed by the Center for Energy, Environmental and Economic Systems Analysis at the Argonne National Lab. As one of the most popular agent-base simulation (ABS) systems for electricity markets, EMCAS has been used in several states by local ISOs and has hosted successful applications. EMCAS is essentially an ABS system with the capabilities of decentralized decision-making along with learning and adaptation for agents. Each agent contains a wide range of strategies. User-specified market rules can be added and their impact on individual agents and the whole system can be examined. EMCAS assigns the local customers and generators to each bus. Customers are covered by demand companies and each physical generator must belong to a specific generation company. It consists of two basic assumptions for the inner-zonal and inter-zonal transmission system. There is no agent

	model of generator of last resort or real-time transmission database in EMCAS. Nevertheless, transmission and other information is available to all agents in EMCAS through its ISO agent. The market information system maintained and updated by the ISO stores system level information such as system load projection, scheduled outages, historical market clearing prices, and transmission capacity.
Major Studies	• *Impact of Plug-In Hybrid Electric Vehicles on the Electric Power System in Illinois*. 2010. https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5619781. • *Influence of Cross-border Energy Trading on Prices of Electricity in Croatia*. 2009. https://ieeexplore.ieee.org/abstract/document/5207202/.
Developer URL	https://ceeesa.es.anl.gov/projects/emcas.html.
Documentation URL	https://ceeesa.es.anl.gov/pubs/61084.pdf.
Multi-Agent Simulator for Competitive Electricity Markets (MASCEM)	
Developer	Polytechnic Institute of Porto and University of Trás-os-Montes e Alto Douro
Availability	Proprietary software; license can be obtained from the developer.
Description	MASCEM is developed to study competitive electricity markets. The agents in MASCEM include a market facilitator, generators, consumers, market operators, traders, and a network operator. The markets considered in MASCEM are a pool market and a bilateral contract market. The trader agents are similar to the demand companies in EMCAS. Consumers in MASCEM are not necessarily assigned to a trader. Instead, individual consumers could directly submit their buy bids to the market operator in the pool market. The market facilitator, mainly acting as a regulatory agent, is employed to coordinate and monitor the simulated market. The market operator assumes some ISO administration functions such as calling for bidding, receiving sell and buy bids from generators and consumers (or traders), respectively, determining market clearing prices, and finally deciding to accept or reject the received bids. In the bilateral market, generators and traders directly negotiate with each other to make bilateral contracts. However, both the accepted bids in the pool market and bilateral contracts must be sent to the network operator to check the transmission capacity. Adaptation in the form of dynamic strategies and scenario analysis is utilized by the supply and demand agents to help their bidding decisions.
Major Studies	▪ *Nord Pool Ontology to Enhance Electricity Market Simulation in MASCEM.* 2017. https://link.springer.com/chapter/10.1007/978-3-319-65340-2_24. ▪ *Pan-European Electricity Market Simulation Considering European Power Network Capacities*. 2015. https://ieeexplore.ieee.org/abstract/document/7406275/. ▪ *Analysis of Strategic Wind Power Participation in Energy Market using MASCEM Simulator*. 2015. https://ieeexplore.ieee.org/abstract/document/7325552/.
Developer URL	http://www.mascem.gecad.isep.ipp.pt/overview.php.

Documentation URL	https://ieeexplore.ieee.org/abstract/document/1249170/. https://ieeexplore.ieee.org/abstract/document/5696716/.
National Electricity Market Simulator (NEMSIM)	
Developer	CSIRO Manufacturing and Infrastructure Technology and CSIRO Atmospheric Research, Australia
Availability	Proprietary software is developed specifically for the Australian electricity market.
Description	NEMSIM is a special ABS system developed for the Australian national electricity market. The agents defined in NEMSIM include generator companies, network service providers, retail companies, and the National Electricity Market Management Company. The roles of the network service providers and the retail companies resemble that of the transmission operator and the demand companies in EMCAS, respectively. NEMSIM also makes several assumptions similar to those in EMCAS. First, bidding and bilateral contracts are two marketing options. The pool market of NEMSIM is also at the day-ahead level, and for any long-term transactions, bilateral contracts will be used instead. Its transmission system has transmission capacity for transactions between two different regions. One role of the National Electricity Market Management Company is to dispatch power from generator companies to meet the load demand at half-hour intervals. Because NEMSIM is designed particularly for the Australian national electricity market, its extensions to other energy markets may be difficult and could require significant modifications. Moreover, it lacks the function for transmission analysis. Future development of NEMSIM might add learning algorithms such as genetic algorithms, genetic programming, Q-learning, or classifier systems into the adaptive decision process.
Major Studies	• *Solar Power Supply to Mitigate the Diurnal and Seasonal Electricity Demand in Victoria*. 2010. https://publications.csiro.au/rpr/download?pid=csiro:EP106701&dsid=DS2. • *Modeling Australia's National Electricity Market Using NEMSIM*. 2008. http://www.simulationaustralasia.com/files/upload/pdf/research/142_Paper_E.pdf.
Developer URL	http://citeseerx.ist.psu.edu/viewdoc/summary?doi=10.1.1.111.7128
Documentation URL	http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.111.7128&rep=rep1&type=pdf http://www.simulationaustralasia.com/files/upload/pdf/research/142_Paper_E.pdf

PowerACE	
Developer	University of Karlsruhe and Fraunhofer Institute for Systems and Innovation Research, Germany
Availability	Proprietary software; license can be obtained from the developer.
Description	An agent-based computational economics (ACE) tool, PowerACE is designed to study the CO_2 emissions trading market. Agents defined in PowerACE are generators, load serving entities, electricity traders, long term planners, market operators, certificate traders, and consumers. The ABS model is based on Java. Besides the usual trading in both the pool and bilateral markets, one distinct feature in PowerACE is the proposal of a market for CO_2 emissions allowance. CO_2 allowance trading agents are the main participants in this market. A typical bid for CO_2 emissions allowance consists of the type of bidding (buy/sell), bidding price, bidding quantity, and valid period. The ABS model investigates the effects of CO_2 emission trading on the bidding prices in regular power markets as well as the long-term investment decision. The capability of investigating environmental issues (such as CO_2 emission) is a good optional feature to be included in the development of new energy market ABSs because these issues, besides receiving increasing popular attention, could change the power production structure and long-term investment decisions of generation companies.
Major Studies	• *Incentivizing Smart Charging: Modeling Charging Tariffs for Electric Vehicles in German and French Electricity Markets*. 2018. https://www.sciencedirect.com/science/article/pii/S2214629618301865. • *Meeting the Modeling Needs of Future Energy Systems*. 2017. https://onlinelibrary.wiley.com/doi/full/10.1002/ente.201600607. • *Market Power in the German Wholesale Electricity Market*. 2009. http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.457.6226&rep=rep1&type=pdf.
Developer URL	https://www.wiwi.uni-augsburg.de/en/bwl/veit/research/research_projects/powerace/
Documentation URL	http://www.gsdp.eu/uploads/tx_conturttnews/Philipp_Ringler_-_PowerACE_-_Agent-Based_Simulation_of_Electricity_Markets.pdf http://www.me.unm.edu/~mammoli/CPS09/Sensfuss_German-electricity-markets.pdf
Short-Term Electricity Market Simulator Real Time (STEMS-RT)	
Developer	Electric Power Research Institute
Availability	Proprietary software; license can be obtained from the developer.
Description	The major entities in STEMS-RT are the market, human participants, and computer agents. Each human agent or computer agent represents either a buyer (consumer or demand company) or a seller (generation company). Both human participants and computer agents interact with the market by submitting their bids. Human participants in the market use their own strategies, while computer agents employ their built-in bidding strategies. Some benefits and values offered by the STEMS-RT software include: • Stress-test market designs: Test new market design rules in controlled laboratory conditions prior to implementation.

	• Design and test bidding strategies: Devise, test, and better understand the strategic views of market participants. Investigate how market behavior is affected by the incentives produced by various market rules. • Ensure resource adequacy: Investigate how reserve margins and forward contracts can best be utilized to ensure that markets will have sufficient resources and reliability. • Manage market power: Illuminate the conditions in which markets do not behave competitively. Investigate measures for ensuring that these conditions are avoided or mitigated. • Measure market performance: Devise and investigate new metrics for market performance. Study how various performance measures are related in different market and system conditions.
Major Studies	Relevant project reports and publications are not publicly available.
Developer URL	https://www.epri.com/#/pages/product/000000000001008532/?lang=en
Documentation URL	A license must be obtained from EPRI to access the software and official documentation.

Table B.14: Transmission System Planning Tools

Features	DSA Tools (Powertech)	EPfast (Argonne)	ETAP (Operation Technology)	GE PSLF (GE)	PowerWorld Simulator (PowerWorld)	PSS/E (Siemens)
Power flow analysis	AC or DC power flow analysis can be performed. Fast decoupled and Newton-Raphson algorithms are available.	DC power flow analysis can be performed using LINGO.	AC or DC power flow analysis can be performed. Newton-Raphson power flow algorithm is available.	AC or DC power flow analysis can be performed. Fast decoupled, Newton-Raphson and Gauss-Siedel algorithms are available.	AC or DC power flow analysis can be performed. Fast decoupled or Newton-Raphson algorithms are available.	AC or DC power flow analysis can be performed. Fast decoupled, Newton-Raphson and Gauss-Siedel algorithms are available.
Voltage stability analysis (VSAT)	VSAT can be used to perform contingency screening, scenario analysis, security and transfer limit assessment and modal analysis.	Heuristics can be employed to analyze voltage collapse scenarios .	Key features of the software include sensitivity analysis, modal analysis, PV/QV analysis, reactive power reserve calculation, etc.	Capabilities similar to VSAT from DSA Tools.	PV/QV is a simulator add-on available for analyzing a power system's static voltage stability margins. Can help the analyst/transmission planner determine ways to strengthen the system against the risk of voltage collapse	Capabilities similar to VSAT from DSA Tools
Transient stability analysis (TSAT)	TSAT can be used for system security assessment, contingency analysis, stability limit determination, frequency stability analysis, etc.	Heuristics can be used to account for transient instabilities such as power swings or frequency decays.	Software can be used to simulate generator start-up, set and adjust exciter/AVR parameters, set speed governor parameters, simulate loss of excitation, etc.	Can be used for system security assessment, contingency analysis, stability limit determination, and frequency stability analysis.	Capabilities similar to DSA Tools, PSLF and PSS/E.	Allows complex PSCAD models to communicate with a PSS/E transient stability simulation. This hybrid simulation allows dynamic system equivalents in PSCAD and more accurate model behavior in PSS/E.
Small signal stability analysis (SSAT)	SSAT can be used in a broad range of applications, including validation and calibration of dynamic models, verification of system oscillations, identification of characteristics for critical modes, etc.	Not possible.	Information unavailable.	Capabilities similar to SSAT from DSA Tools.	Capabilities similar to SSAT from DSA Tools.	Provides an extension of analytical methods to examine wide-area system oscillations Includes methods to investigate long-term stability. Allows a deeper view into eigen vectors, determines the best damping locations, and allows evaluation of damping strategies.

Features	DSA Tools (Powertech)	EPfast (Argonne)	ETAP (Operation Technology)	GE PSLF (GE)	PowerWorld Simulator (PowerWorld)	PSS/E (Siemens)
Process automation	Python scripts can be used to extract and export computation results.	Information unavailable.	It is possible to automate using a button in the ETAP GUI.	EPCL scripts can be used to extract and export computation results.	SimAuto add-on can be used to automate processes using Visual Basic, Visual C++ or Python scripts.	Python scripts can be used to extract and export computation results. Full FORTRAN, batch command, and Python API for all program functions and features.
Maximum system size handled	Up to 100,000 buses and 15,000 generators.	Up to 200,000 nodes and 300,000 lines.	Up to 100,000 buses and 10,000 generators.	Up to 80,000 buses.	Up to 250,000 buses.	Up to 200,000 buses and 20,000 generators.
Data import/export	Data (for PSS/E and PSLF) and graphics importing/exporting facilities are available.	No information available in documentation.	MS Excel and Access worksheets can be mapped to ETAP elements. Data files can be imported from/exported to tools such as PSS/E and PowerFactory.	Difficult to import data from/export data to other comparable packages.	MS Excel worksheets can be mapped to PowerWorld elements. Data files can be imported from/exported to tools such as PSS/E and PSLF.	High-level Python Excel and Word interface. Reading/writing to/ from Excel and Word. Interactive spreadsheet reports supporting filtering and sorting with export to Excel and CSV formats.
Power system modeling	Rich library of models including network, load, generator, renewables, HVDC, FACTS, relays and user-defined models.	Dynamic modeling of various power system components such as generators is not carried out.	Rich library of models including network, load, generator, renewables, HVDC, FACTS, relays and user-defined models.	Library of models include network, load, generator, renewables (different types of wind and solar PV models), HVDC, FACTS, relays and user-defined models.	Capabilities similar to PSLF and PSS/E.	Advanced modeling of FACTS, induction machines, ZIP loads, motors, generator controls, and wind and PV resources.

Features	DSA Tools (Powertech)	EPfast (Argonne)	ETAP (Operation Technology)	GE PSLF (GE)	PowerWorld Simulator (PowerWorld)	PSS/E (Siemens)
Energy storage modeling	PSAT supports models for pumped storage, battery, SMES, and other energy storage devices. Power flow with such devices can be imported in VSAT/TSAT/SSAT for advanced stability analysis. Detailed dynamic characteristic and operational features of such devices can be included.	Information unavailable.	ETAP supports models for battery energy storage devices including dynamic characteristic and operational features of such devices. No information provided about modeling of pumped storage hydropower.	Modeling capabilities similar to PSS/E.	Supports dynamic simulation models for, battery, flywheel, and other energy storage technologies. User-defined models can be created for pumped storage hydropower.	Includes dynamic simulation models that can be used to simulate the system response of the energy storage facilities to a variety of system disturbances. Some battery energy storage system models in the dynamics simulation model catalog will require specific vendor defined characteristics to be filled out. User-written models for advanced pumped storage technologies (adjustable-speed PSH, ternary PSH) can be built.
Transmission network optimization	ACOPF module is available.	DCOPF can be used.	Can be effectively used for OPF, optimal capacitor placement, volt/VAR optimization, switching optimization and transformer tap optimization.	Not possible.	Simulator can be used to carry out AC/DC OPF, SCOPF and analyze OPF reserves.	Capabilities similar to ETAP. Cannot perform optimal capacitor placement.
Hybrid simulation (co-simulation of positive-sequence load flow and electromagnetic transient simulation tools)	Can be performed with electromagnetic transient simulation tools (PSCAD, RTDS/RSCAD).	Not possible.	Not possible.	Not possible.	Not possible.	Hybrid simulation interface between PSCAD and PSS/E transient stability tool. Allows complex PSCAD models to communicate with a PSS/E transient stability simulation. This hybrid simulation allows dynamic system equivalents in PSCAD and more accurate model behavior in PSS/E.

Table B.15: Transmission System Planning Tools

DSA Tools	
Developer	Powertech Labs, Inc.
Availability	Commercial proprietary software can be purchased from Powertech Labs.
Description	DSA Tools is a suite of leading-edge power system analysis tools that provides the capabilities for a complete assessment of system security, including all forms of stability. It offers a complete toolset for power system planning and operational studies. In addition to rich modeling capabilities and advanced computational methods, the software has useful study tools that enable significant productivity improvements. The key components in the suite—VSAT, TSAT, and SSAT—have also been designed to be used for on-line DSA.
Major Studies	• *MISO Online Dynamic Security Assessment*. 2016. https://www.ieee-pes.org/presentations/gm2015/PESGM2015P-002360.pdf. • *Small-Signal Stability Study for ERCOT*. 2014. http://www.ercot.com/content/news/presentations/2014/SSS%20Study%20for%20ERCOT%20Final%20Report%20(Public)_R2.pdf. • *Security Assessment of the Planned Western Interconnection for the years 2020 and 2022.* 2013. https://www.wecc.biz/Reliability/ASU_ReliabilityAnalysis.pdf.
Developer URL	https://www.powertechlabs.com/dsatools-services/
Documentation URL	https://static1.squarespace.com/static/5670ab04c647ad9f554e4d9f/t/5abacbc4758d462671a3dd69/1522191314248/Power+Systems+sector.pdf https://static1.squarespace.com/static/5670ab04c647ad9f554e4d9f/t/59690120e3df28c37006e31b/1500053793492/DSATools.pdf
EPfast	
Developer	Argonne National Laboratory
Availability	Proprietary software; a license can be obtained from Argonne to access it.
Description	EPfast is an electric power infrastructure modeling tool used to examine the impacts of power outages on large electric grid systems. The tool models the tendency of power systems to "island" after either man-made or natural disturbances, which, in turn, can lead to regional power network deficiencies (i.e., blackouts) due to an imbalance between power supply and demand. Example applications include: analysis results that enable utility operators to identify system vulnerabilities and implement preventative measures; critical power infrastructure, resiliency and vulnerability analyses; and system dependency/interdependency analyses with non-power infrastructure systems. EPfast produces data that enable local utility operators to spot system vulnerabilities and implement preventative measures, as well as contributes to critical power infrastructure, resiliency, and vulnerability analyses.
Major Studies	• *Simulation of the January 2014 Polar Vortex and Its Impacts on Interdependent Electric-Natural Gas Infrastructure.* 2017. https://ieeexplore.ieee.org/abstract/document/8248120/.

	• *Simulation of the September 8, 2011, San Diego Blackout*. 2014. https://ieeexplore.ieee.org/abstract/document/7020005/.
Developer URL	http://www.anl.gov/grid/project/electrical-power-network-modeling-epfast
Documentation URL	https://ieeexplore.ieee.org/document/6147891/
Electrical Transient Analyzer Program (ETAP)	
Developer	Operation Technology, Inc.
Availability	Commercial proprietary software can be purchased from Operation Technology, Inc.
Description	ETAP is the industry leader used worldwide in all types and sizes of power systems, including generation, transmission, distribution, and industrial systems such as oil and gas, manufacturing, steel, cement, mining, data centers, nuclear facilities, transportation, smart grid solutions, renewable energy, and more. ETAP provides transmission planning and operations engineers with comprehensive tools for the design, simulation and operation of reliable utility networks all in one tool. ETAP integrated transmission applications were developed for simultaneous offline and real-time use. ETAP can combine load flow, short circuit, dynamic stability, protection and SCADA models into one common and integrated database. This is the next generation approach as opposed to the current industry practice of trying to couple offline system planning tools with real-time data via external files.
Major Studies	Utility and power system consulting companies across North America use ETAP for different types of power system studies, but final reports are not published online.
Developer URL	https://etap.com/solutions/network-planning-optimization
Documentation URL	Brochures can be obtained by contacting the developer.
GE Positive Sequence Load Flow (PSLF)	
Developer	General Electric Company
Availability	Commercial proprietary software can be purchased from GE Energy.
Description	GE's proprietary transmission system planning and power flow software: • Simulates physical behavior of the power grid and connected equipment • Provides voltages and line flows, system dynamic behavior • Is extensively used to study major power system events such as the 2003 Northeast U.S. blackout • Provides a mechanism for ensuring that power system equipment is properly modeled (e.g., as per appropriate IEEE standards) • Can perform power system studies similar to those performed by Siemens PSS/. The algorithms in PSLF have been developed to handle large utility-scale systems of up to 80,000 buses. A complete set of tools allows the user to switch smoothly between data visualization, system simulation, and results analysis. The dynamic analysis tools package allows users to perform transient stability analysis for multiple events on cases containing up to

	80,000 buses. This tool can be run in batch mode, allowing the execution of multiple dynamic simulations without requiring user interaction. The steady state analysis tools package allows users to perform traditional thermal and voltage analysis, static voltage stability analysis and transfer limit analysis.
Major Studies	• *Joint Transmission Planning Base Case Preparation Process.* 2017. https://www.caiso.com/Documents/ISO-SCEMOD-032-1Requirements.pdf. • *Small Signal Stability of the Western North American Power Grid with High Penetrations of Renewable Generation*. (2016). https://www.osti.gov/servlets/purl/1368990. • *Western Wind and Solar Integration Study Phase 3: Frequency Response and Transient Stability*. 2014. https://www.nrel.gov/docs/fy15osti/62906.pdf.
Developer URL	https://www.geenergyconsulting.com/practice-area/software-products/pslf
Documentation URL	https://www.geenergyconsulting.com/sites/gecs/files/PSLF-HPC-Brochurer1.pdf
PowerWorld Simulator	
Developer	PowerWorld Corporation
Availability	Commercial proprietary software can be purchased from PowerWorld Corp.
Description	PowerWorld Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems of up to 250,000 buses. The capabilities of this software are very similar to GE's PSLF and Siemens PTI's PSS/E software. The tool is used by: • Leading ISOs and utilities of all sizes to analyze and visualize transmission operations and expansion planning • Leading ISOs, IPPs, economists, power traders, and power marketers to analyze and visualize wholesale electric power markets • Several renewable energy developers and their consultants to assess transmission effects of renewable resources
Major Studies	• *Avista System Planning Assessment, Avista Corporation*. 2017. http://www.oasis.oati.com/AVAT/AVATdocs/2017_Avista_System_Planning_Assessment_-_Study_Plan.pdf. • *Resilient Grid Operational Strategies Report*. 2016. https://www.energy.gov/sites/prod/files/2017/01/f34/Resilient%20Grid%20Operational%20Strategies%20Report--Phase%202.pdf.
Developer URL	https://www.powerworld.com/products/simulator/overview
Documentation URL	Brochures/manuals can be obtained by contacting the developer.
Power System Simulator for Engineering (PSS/E)	
Developer	Siemens PTI
Availability	Commercial proprietary software can be purchased from Siemens PTI.

Description	PSS/E is a power system simulation and analysis tool for power transmission operations and planning. It is used in over 145 countries around the world, by utility transmission planning and operations engineers, consultants, universities, and research labs. PSS/E allows users to perform a wide variety of analysis functions, including: power flow, dynamics, contingency analysis, optimal power flow, voltage stability, transient stability simulation, and much more. Since its inception in 1972 as the first commercially available software for transmission system simulation, PSS/E has achieved "industry standard" status and offers the distinct advantage of being one of the leading power transmission system simulation and analysis tools in the world. PSS/E is widely used in the industry for generation interconnection studies, transmission planning and operation, renewables and integrated T&D planning and grid data management.
Major Studies	• *Summary of Stability Base Cases for TPL 001-4 Studies*. 2016. *Independent System Operator — New England*. https://www.iso-ne.com/static-assets/documents/2016/06/2016_final_summary_of_stability_basecases_for_tpl_001_4_studies.pdf. • *System Strength Assessment of the ERCOT Panhandle System*. 2016. http://www.ercot.com/content/news/presentations/2016/Panhandle%20System%20Strength%20Study%20Feb%2023%202016%20(Public).pdf. • *Institute of Electrical and Electronics Engineers Power and Energy Society Task Force on Benchmark Systems for Stability Controls: Report on the 14-Generator System (Australian Reduced Model)*. 2013. http://www.sel.eesc.usp.br/ieee/australian_test_system/Australian_Reduced_Model%20_14_generator_system_PSSE_study_report.pdf. • *Dynamic Simulation Studies of the Frequency Response of the Three U.S. Interconnections with Increased Wind Generation*. 2010. https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Dynamic_Simulation_Studies.pdf.
Developer URL	https://www.siemens.com/global/en/home/products/energy/services/transmission-distribution-smart-grid/consulting-and-planning/pss-software/pss-e.html
Documentation URL	https://www.siemens.com/content/dam/webassetpool/mam/tag-siemens-com/smdb/energy-management/services-power-transmission-power-distribution-smart-grid/consulting-and-planning/power-systems-simulation-software/siemenspti-software-psse-brochure-2017.pdf

Table B.16: Distribution System Planning Tools

Features	ETAP (Operation Technology)	GridLAB-D (PNNL)	LoadSEER (Integral Analytics)	OpenDSS (EPRI)	Synergi Electric (DNV GL)	WindMil (Milsoft)
Power flow analysis	Can perform unbalanced power flow studies. Can perform time-series unified power flow studies considering varying load and generation.	Can perform unbalanced and time-series power flow studies.	Can perform unbalanced AC power flow studies.	The software offers several power flow options such as snapshot power flow, daily power flow, yearly power flow and harmonics power flow.	Can perform unbalanced AC power flow studies. Harmonic load-flow analysis of loads and capacitors can be performed.	Can perform unbalanced AC power flow studies.
Reliability assessment	Can assess the availability and quality of power supply throughout the distribution network using indices such as SAIFI, SAIDI and CAIDI.	Reliability module provides the ability to induce events on a system and evaluate their impacts. The module collects and outputs module-appropriate metrics to a log file for user evaluation. Module is only an event-inducing and metrics-recording module and requires specific interfaces to other modules of interest.	Has been used for reliability assessment studies by distribution utilities. Can compute metrics such as SAIFI, SAIDI and CAIFI to assist in the analysis.	Has been used for reliability evaluation studies on distribution feeders with high solar PV penetration. Can compute metrics such as AENS, SAIFI, SAIDI and CAIFI to assist in analysis.	Outage events are brought into Synergi where they are correlated and used to calculate the performance indices of the base system. User can see root causes of reliability problems, impact of new or relocated reclosers and switches and evaluate mitigation strategies like tree trimming.	Reliability analysis includes calculation of predicted reliability indices (SAIFI, SAIDI, CAIDI, ASAI, ALIFI, ALIDI) for existing and proposed distribution system configurations. Analysis is based upon the number and distribution of customers and the predicted failure rates of lines and equipment.
Load allocation method	Load allocation software considers automatic meter readings of kW and kVAR demand combined with a number of methods to allocate the load for each load point.	Information not available.	Allocates distribution system peak load growth to customer class based on energy use. Allocates load to distribution feeders by customer class.	Allocated based on load allocation factors. Allocation factors for loads are defined using the XFKVA property.	Information not available.	Loading data may be entered for each load element or may be calculated using powerful load allocation functions.
Network optimization	Can perform different types of optimization such as OPF, switching optimization, optimal capacitor placement and volt/VAR optimization.	Can perform different types of optimization such as ACOPF, switching optimization, and volt/VAR optimization.	Can perform switching optimization, optimal power flow and DER allocation	Capabilities similar to GridLAB-D from PNNL	Optimal switching and N-x contingency studies can be performed. Volt/VAR optimization studies can also be performed.	Optimal switching and contingency analysis can be performed. Volt/VAR optimization studies can also be performed.

Features	ETAP (Operation Technology)	GridLAB-D (PNNL)	LoadSEER (Integral Analytics)	OpenDSS (EPRI)	Synergi Electric (DNV GL)	WindMil (Milsoft)
Renewable integration studies	Enables engineers to conceptualize the collector systems, determine wind & PV solar penetration and perform grid interconnection studies.	Can perform different studies involving utility-scale solar PV integration.	LoadSEER can be used to perform detailed modeling of rooftop solar PV. Can directly integrate solar forecasts or other microgrid impacts down to the customer level.	Capabilities similar to GridLAB-D from PNNL	Capabilities similar to GridLAB-D and OpenDSS.	Capabilities similar to GridLAB-D and OpenDSS.
Energy storage modeling	Battery discharging analysis module can model, size and analyze the performance of batteries. The module calculates the battery capacity, voltage, current, and output power as the battery discharges through a duty cycle. Duty cycle can be calculated from either load current summation or load flow calculations. User-defined dynamic models program can build or customize complex storage devices (e.g., pumped storage)	Generic energy storage models are not available. Users can create their own custom storage modules and control algorithms (e.g., pumped storage, flywheel, etc.).	Detailed battery energy storage modeling can be carried out. No information on modeling pumped storage units.	The storage element is essentially a basic generator element that can be dispatched to either produce power or consume power within its power rating and stored energy capacity. With proper controls, the storage model can operate in several different modes (peak shave, load follow) or can be operated through the implementation of a special control algorithm externally. Detailed user-defined models representing pumped storage can be built.	Can model large battery energy storage systems and a variety of control models. Pumped storage hydro models not available.	Information not available.
Load forecasting method	ETAP load forecasting is a tool for industrial users as well as utilities to adaptively, reliably and accurately forecast future short-term loading in the system.	Currently not implemented. Will be considered for a future version of the software.	Employs three types of load forecasting including regression of peak circuit loads on weather and economic variables, econometric forecast of energy using these same or similar independent variables, and spatial load forecast using GIS land use and geographic information.	Present allocation algorithm is designed to adjust load elements to match measured currents Does not adjust generator objects. Purpose is to distribute load kW in a reasonable fashion given only minimal measurements.	Synergi Forecaster is available as an add-on to manage load agents in a multi-year environment for long range planning studies.	Capable of performing such forecasting studies. Further details regarding methods not available in public reports or brochures.

Features	ETAP (Operation Technology)	GridLAB-D (PNNL)	LoadSEER (Integral Analytics)	OpenDSS (EPRI)	Synergi Electric (DNV GL)	WindMil (Milsoft)
Process automation	It is possible to automate processes using a button in the ETAP GUI.	The Python editor files allow for a .glm file to be parsed into a system of Python objects, making it easy to change property values and create automated programs to continually run the software.	No information available.	The COM interface can be used to automate processes using MATLAB, Python, C# or R.	Python scripting builds script routines to automate analysis. COM solver provides a programming platform to support client-specific analysis applications and automate planning and operations analysis functions.	Specific buttons are available in the GUI to automate processes such as contingency analysis.

Table B.17: Distribution System Planning Tools

ETAP	
Developer	Operation Technology, Inc.
Availability	Commercial proprietary software can be purchased from Operation Technology, Inc.
Description	See Table B.14.
Major Studies	Utility and power system consulting companies across North America use ETAP for different types of power system studies, but final reports are not published online.
Developer URL	https://etap.com/sectors/distribution
Documentation URL	Brochures can be obtained by contacting the developer.
GridLAB-D	
Developer	Pacific Northwest National Laboratory
Availability	Open-source software can be downloaded from the official website.
Description	GridLAB-D was developed by PNNL in collaboration with industry and academia through funding from the DOE Office of Electricity Delivery and Energy Reliability. GridLAB-D is designed as an open-source tool, freely available to any user, to encourage collaboration with industry and academia. The BSD-style license allows vendors to add or extract their own modules without exposing internal intellectual property. GridLAB-D is a flexible, agent-based simulation environment designed to model not only the power system, but the overlying systems that affect the power system. At its simplest, GridLAB-D examines the detailed interplay between all elements of a distribution system from the substation to end-use load. GridLAB-D provides a valuable test bed for evaluating control strategies and cost-to-benefits ratios. It provides a sand box for studying the effects of smart grid technologies without the cost and complexity of field demonstrations.
Major Studies	• *WECC MVWG Report to MS on using GridLAB-D for T&D Co-simulation.* 2018. https://www.wecc.biz/Administrative/MVWG%20Report%20-%202018%20February.pdf. • *Economic Impacts of Distributed PV Generation on California's Distribution System.* 2014. https://ei.haas.berkeley.edu/research/papers/WP260.pdf. • *Distributed Generation and Distributed Storage by Ausgrid*. 2014. https://www.ausgrid.com.au/-/media/Files/Customer-Services/Homes/Solar/SGSC_Distributed_Generation_and_Distributed_Storage_Technical_Compendium.pdf.
Developer URL	https://www.gridlabd.org/
Documentation URL	https://www.gridlabd.org/brochures/20180212_gridlabd_brochure.pdf

LoadSEER	
Developer	Integral Analytics, LLC
Availability	Commercial proprietary software can be purchased from the developer.
Description	LoadSEER, developed by Integral Analytics, is a spatial load forecasting tool used by electric distribution system planners to predict load and power changes, where on the grid the loads will occur, how DG changes the load shape, and when it must be supplied. LoadSEER spatial load forecasts address both short-term circuit trends and long-term grid expansion, while remaining consistent with the overall corporate load forecast for energy and peak demand. The resulting forecast provides system planners with substation, circuit and small-area resolution time series load growth and load shape changes. The tool accommodates risk analysis, integrates resource planning with demand side management measures, and values electric related decisions that have significant locational influences. LoadSEER can assess the capital budgeting implications of storage, including capacity at risk, reliability, cost-effectiveness and revenue requirements, years into the future.
Major Studies	• Seattle City Light Load Forecasting Review. 2017. https://www.seattle.gov/Documents/Departments/CityLightReviewPanel/Documents/FinalReport_CityLightForecastingReview_24_Mar_2017.pdf. • *PG&E's Distribution Resources Plan Webinar*. 2015. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5140. • *Spatial Electric Load Forecasting Methods for Electric Utilities*. 2007. http://quanta-technology.com/sites/default/files/doc-files/Spatial%20Forecasting%20Report%20-%202007.pdf.
Developer URL	http://www.integralanalytics.com/products-and-services/spatial-growth-planning/loadseer.aspx
Documentation URL	http://www.integralanalytics.com/files/documents/related-documents/LoadSEER.pdf

Open Distribution System Simulator (OpenDSS)	
Developer	Electric Power Research Institute
Availability	Open-source software can be downloaded from the official website.
Description	OpenDSS is a comprehensive electrical system simulation tool for electric utility distribution systems. OpenDSS technically refers to the open-source implementation of the DSS. It is implemented as both a stand-alone executable program and a COM DLL designed to be driven from a variety of existing software platforms. The executable version adds a basic user interface on to the solution engine to assist users in developing scripts and viewing solutions. The program basically supports all rms steady-state (i.e., frequency domain) analyses commonly performed for utility distribution systems. In addition, it supports many new types of analyses that are designed to meet future needs, many of which are being dictated by the deregulation of U.S. utilities and the formation of distribution companies worldwide. Many of the features found in the program were originally intended to support distributed generation

	analysis needs. Other features support energy efficiency analysis of power delivery and harmonics analysis. The DSS is designed to be indefinitely expandable so that it can be easily modified to meet future needs. OpenDSS has been widely used for studies such as distribution planning and analysis, general multi-phase AC circuit analysis and analysis of distributed generation interconnections.
Major Studies	• *Distributed Energy Resources: Technical Considerations for the Bulk Power System*. 2018. https://www.ferc.gov/legal/staff-reports/2018/der-report.pdf. • *Modeling, Analysis and Deployment of High PV Penetration in a Distribution System, PSERC Project Webinar*. 2012. https://pserc.wisc.edu/documents/general_information/presentations/pserc_seminars/psercwebinars2012/Ayyanar_PV_slides_PSERC_webinar_Oct2_2012.pdf. • *Modeling Smart Grid Applications with Co-Simulation*. 2010. https://ws680.nist.gov/publication/get_pdf.cfm?pub_id=905684.
Developer URL	http://smartgrid.epri.com/SimulationTool.aspx
Documentation URL	http://svn.code.sf.net/p/electricdss/code/trunk/Distrib/Doc/OpenDSSManual.pdf
Synergi Electric	
Developer	DNV GL
Availability	Commercial proprietary software can be purchased from DNV GL.
Description	Synergi Electric is engineering simulation and analysis software for power distribution systems. It helps a team of utility power distribution engineers plan, investigate, and operate their system. It is an intuitive engineering environment for working with feeders, networks, and substations and is built around detailed models of real-world facilities, customer loads, protective devices and reliability information. Key benefits include: • A complete framework of power analysis tools in a single model and user interface • Multi-year analysis reporting provides engineers an efficient view for short range and long-range planning • Time series analysis has been added to address the variabilities in load and generation on high penetration PV circuits • Python scripting builds script routines to automate analysis • Data handling in Synergi Electric is efficient and open, leveraging structured query language for importing external data sources • COM Solver provides a programming platform to support client-specific analysis applications and automate planning and operations analysis functions
Major Studies	Electric utility and consulting companies across the U.S. and Europe use the tool for a variety distribution system studies, but study reports are not published online for public viewing.
Developer URL	https://www.dnvgl.com/services/power-distribution-system-and-electrical-simulation-software-synergi-electric-5005

Documentation URL	https://www.dnvgl.com/Images/Synergi-Electric-brochure_tcm8-59326.pdf
WindMil	
Developer	Milsoft
Availability	Commercial proprietary software can be purchased from Milsoft.
Description	Milsoft's WindMil solution can handle every aspect of electric distribution system planning and analysis. This industry-leading circuit modeling software will accurately represent a fully detailed circuit model including individual customers, inline and endpoint devices, and even distributed generation. The analytical capabilities encompass power flow and voltage drop modeling, reliability analysis, contingency and sectionalizing studies, short circuit and fault current calculations, protective device coordination and arc ash hazard analysis. These and many more analytical tools are combined with full geographic representation and MultiSpeak interfaces to CIS, SCADA and AMR/AMI data sources. WindMil can model a network with all phases, all voltage levels, model looped and radial solutions, model unbalanced loading and impedance, model distributed generation sources, and unlimited number of circuits (or circuit elements). The tool can also perform voltage drop and power flow analysis, short circuit, fault current, fault location analysis, and arc flash hazard analysis.
Major Studies	▪ *Costs and Benefits of Conservation Voltage Reduction, NRECA-DOE Smart Grid Demonstration Project Report*. 2014. https://www.smartgrid.gov/files/NRECA_DOE_Costs_Benefits_of_CVR_0.pdf.
Developer URL	https://www.milsoft.com/utility-solutions/upgrades/milsoft-engineering-analysis-ea-windmil%C2%AE
Documentation URL	https://www.milsoft.com/sites/www.milsoft.com/files/assets/Resources/Milsoft%20EA%20Brochure.pdf

Table B.18: Social Benefit Valuation Tools for Renewable Energy or Storage Integration

Features	Multi-Sector				Single-Sector		
	AMIGA (Argonne)	EPPA (MIT)	E3ME (Cambridge Econ.)	Green Jobs Calculator (UC Berkeley)	JEDI (NREL)	RIMS II (BEA)	WeBEE (Germany)
Output of the model	Production and employment per sector. Income and gross domestic product effects. Energy mixes. Distributional effects (includes household disaggregation). Investment needs in energy infrastructure. R&D issues. Emissions.	Output per sector and per region. Gross domestic product per region. Employment per region. Welfare per region. Emissions per region (greenhouse gases and others). Fossil fuel depletion and prices. Land use (adequate for bioenergy analyses).	Output per sector and per country, including prices and gross value added. Gross domestic product and its components per country. Household consumption per country and income level (i.e., distributional effects of policies). Employment, labor supply, wages and unemployment per sector and country. GHG Emissions per sector and country . Energy demand per sector and fuel, and energy prices.	Employment per sector.	Local/municipal impacts of renewable energy deployment (can also be used for conventional technologies, such as gas or coal-fired, and even for transmission lines). Direct, indirect employment and economic impacts (induced jobs are estimated through multipliers). Tax generation.	Final demand multipliers (final-demand employment multipliers). Direct-effect multipliers (jobs-to-jobs multipliers). Type I (for inter-industry effects) and Type II (for inter-industry and household-spending effects) multipliers. Breakdown tables.	Focus on local (municipal) effects of renewable energy deployment. Company profits (after tax). Net income of employees. Municipal taxes paid (corporate and income taxes). Local employment effects. Activity levels (production) in companies in different segments of the supply chain.

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Features	Multi-Sector			Single-Sector			
	AMIGA (Argonne)	EPPA (MIT)	E3ME (Cambridge Econ.)	Green Jobs Calculator (UC Berkeley)	JEDI (NREL)	RIMS II (BEA)	WeBEE (Germany)
Inputs needed	For the United States, a very detailed social accounting matrix. For other regions in the world, social accounting matrix data from global trade analysis project database. Economic elasticities. Population and productivity forecasts. Bottom up data for energy production and demand sectors.	Social accounting matrix matrices per region from global trade analysis project database. Population and productivity projections per region. Energy efficiency levels per region. Elasticities of substitution for households and firms. Trade elasticities. Fossil fuel resources per region. Emission intensities.	Population. Data on national accounts. Energy and environmental policies. Prices of fossil fuels (e.g., world oil price.) Rest of the world economic activity and prices for the represented goods. Inputs on the power market (technological costs, power prices, etc.).	Direct factors and indirect job multipliers. Percentage of renewables in the energy mix.	Renewable energy deployment (e.g., in MW). Input-output matrix for the municipality or state. Economic multipliers for employment, wages and personal spending. Development and equipment costs. Details on local supply chain. Portion of equipment and services produced locally. Local tax rates.	Final-demand change (purchases by consumer outside region, investment in new buildings, purchases by government and by households). Final-demand industry (the one impacted by change in final-demand). Final-demand region (area impacted by change in final-demand).	Detailed information on value chains for renewable energy technology. Structure of the supply chain (e.g., A supplies B, B supplies C and D, D imports from country X, etc.). Details of all suppliers at different levels of the supply chain (companies, costs, employers, revenues, etc.).
Sectoral scope	Great detail in the U.S. (200 sectors); less detail in the other sectors.	Global computable general equilibrium with greater detail on agriculture and energy sectors. Nine non-energy sectors. Fifteen energy sub-sectors.	Macroeconomic model with 69 sectors.	Single sector.	Single sector input-output (also includes multipliers for induced effects).	Single sector.	Supply chain analysis.
Technological approach	Top-down combined with bottom-up for energy supply and demand sectors.	Top-down (bottom-up detail for the energy sector is being developed).	Top-down with bottom-up detail for the power sector.	Bottom-up.	Top-down.	Top-down.	Bottom-up.

Features	Multi-Sector				Single-Sector		
	AMIGA (Argonne)	EPPA (MIT)	E3ME (Cambridge Econ.)	Green Jobs Calculator (UC Berkeley)	JEDI (NREL)	RIMS II (BEA)	WeBEE (Germany)
Geographical scope	National (U.S.) with great detail; less detailed representation for other world regions.	Global (divided into 16 regions).	Regional European (33 countries). A similar global coverage model also exists.	National (U.S.).	Local (municipal or state-level in the U.S.).	Local (municipal or state-level in the U.S.).	Local (municipal).
Mathematical technique	Simulation combined with optimization.	Optimization.	Simulation (macro econometric).	Simulation.	Simulation.	Simulation.	Simulation.

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Table B.19: Social Benefit Valuation Tools for Renewable Energy or Storage Integration

All Modular Industry Growth Assessment (AMIGA)	
Developer	Argonne National Laboratory
Availability	The latest version of this C-based tool can be obtained by contacting the developers via email.
Description	The AMIGA modeling system is a general equilibrium model that examines the impact of changes in 200 individual sectors in both dollar value and, where appropriate, in physical units. Programmed in the highly structured C language, AMIGA integrates a detailed energy end-use and energy supply market specification within a structural economic model. AMIGA calculates prices and macroeconomic variables such as consumption, investment, government spending, gross domestic product, and employment. The model provides annual equilibrium paths from the present through the year 2100. AMIGA integrates eleven modules that describe the various economic interactions among twenty-one world regions, including the United States. Each of the region's assets includes existing capital stock, labor resources, and exhaustible resources. The model tracks a detailed accounting of major goods and services demanded by households and the various production sectors of the economy that lead to changes in energy use and production, greenhouse gas emissions, and temperature changes. In short, AMIGA combines a bottom-up technology representation in the demand for energy and the many other goods and services sectors available with regional markets together with a detailed interaction among those sectors and among the regions of the world.
Major Studies	• *The Impacts of Meeting a Tight CO_2 Performance Standard on the Electric Power Sector*. 2016. https://www.sciencedirect.com/science/article/pii/S0140988316302183. • *An Adoption Scenario for Carbon Capture in Pulverized Coal Power Plants in the USA*. 2013. https://onlinelibrary.wiley.com/doi/pdf/10.1002/ghg.1359.
Developer URL	http://amiga.dis.anl.gov/
Documentation URL	A license must be obtained from Argonne National Laboratory to access the software and official documentation.
Emissions Prediction and Policy Analysis (EPPA)	
Developer	Massachusetts Institute of Technology
Availability	To download the full public version of EPPA with data, proof of purchase of global trade analysis project 8 data set must be provided to the developer.
Description	The EPPA model provides projections of world economic development at a regional and sectoral level, including the economic implications of GHG emissions, conventional air pollution, land-use change, food demand, and natural resource use. EPPA simulates the evolution of economic, demographic, trade and technological processes involved in activities that affect the environment. It can be used to investigate the economic implications of a wide range of phenomena, including:

	• Climate and environmental impacts (e.g., changes in crop yields and human health) • Resource depletion and new technologies • Policies aimed at reducing emissions of GHGs and other pollutants • Policies aimed at limiting trade or land-use change • Deployment of specific technologies (e.g., wind power, solar power, carbon capture and storage, crop yield-enhancing technology) • Simulations of future emissions of GHGs and other pollutants as input for the Massachusetts Institute of Technology Earth System Model
Major Studies	• *The Economic Projection and Policy Analysis Model for Taiwan: A Global Computable General Equilibrium Analysis.* 2017. https://globalchange.mit.edu/sites/default/files/MITJPSPGC_Rpt323.pdf. • *Human Health and Economic Impacts of Ozone Reductions by Income Group*. 2017. https://globalchange.mit.edu/sites/default/files/MITJPSPGC_Rpt323.pdf. • *Modeling Intermittent Renewable Energy Technologies in General Equilibrium Models*. 2015. https://globalchange.mit.edu/sites/default/files/MITJPSPGC_Reprint_15-14.pdf.
Developer URL	https://globalchange.mit.edu/research/research-tools/human-system-model
Documentation URL	https://globalchange.mit.edu/sites/default/files/MITJPSPGC_TechNote16.pdf
Energy-Environment-Economy Global Macro-Economic (E3ME)	
Developer	Cambridge Econometrics, UK
Availability	Can be purchased from Cambridge Econometrics.
Description	E3ME is a global, macro-econometric model designed to address major economic and economy-environment policy challenges. Developed over the last 20 years, it is one of the most advanced models of its type. Its strengths are: • A high level of disaggregation, enabling detailed analysis of sectoral and country-level effects from a wide range of scenarios. Social impacts (including unemployment levels and distributional effects) are important model outcomes. • Its econometric specification addresses concerns about conventional macroeconomic models and provides a strong empirical basis for analysis. It can fully assess both short and long-term impacts and is not limited by many of the restrictive assumptions common to computable general equilibrium models. • Integrated treatment of the world's economies, energy systems, emissions and material demand. This enables it to capture two-way linkages and feedbacks between these components. • Covers most global regions, with a detailed sectoral disaggregation in each one, and projects forwards annually up to 2050.
Major Studies	• *Modeling the Power Sector in East Asia: Economic and Environmental Impacts of the Choices of Power Sources*. 2015. https://www.taylorfrancis.com/books/e/9781317387299/chapters/10.4324%2F9781315677149-13.

	• *An Economic and Environmental Assessment of Future Electricity Generation Mixes in Japan: An assessment Using the E3MG Macro-Econometric Model*. 2014. https://www.sciencedirect.com/science/article/pii/S0301421513012627.
Developer URL	https://www.camecon.com/how/e3me-model/
Documentation URL	https://www.camecon.com/wp-content/uploads/2016/09/E3ME-Manual.pdf
Green Jobs Calculator	
Developer	Renewable and Appropriate Energy Laboratory, University of California Berkeley
Availability	The latest version of this MS Excel based tool can be obtained by contacting the developers via email.
Description	This tool is an analytical job calculator for the U.S. power sector. It can be used to estimate how many jobs energy efficiency, renewable energy, and other low carbon energy options such as nuclear power and carbon capture and storage will generate depending on proposed energy policies and future demand projections.
Major Studies	• *Preliminary Jobs Estimate for CleanPowerSF*. 2011. http://www.localcleanenergy.org/files/CleanPowerSFJobsEstimate.pdf. • *Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the U.S.?* 2010. http://rael.berkeley.edu/old_drupal/sites/default/files/WeiPatadiaKammen_CleanEnergyJobs_EPolicy2010.pdf. • *Wind at Work: Wind Energy and Job Creation in the EU*. 2010. http://www.ewea.org/fileadmin/ewea_documents/documents/publications/Wind_at_work_FINAL.pdf.
Developer URL	http://rael.berkeley.edu/old_drupal/greenjobs
Documentation URL	The software and associated documentation can be accessed by contacting the developers at Renewable and Appropriate Energy Laboratory, University of California Berkeley.
Jobs And Economic Development Impact (JEDI)	
Developer	National Renewable Energy Laboratory
Availability	MS Excel based tools for different types of generating resources can be downloaded online.
Description	The JEDI models, developed by NREL, are user-friendly tools that estimate the economic impacts of constructing and operating power generation projects for a range of conventional and renewable energy technologies. Based on project-specific inputs from the user, the model estimates job creation, earning, and output (total economic activity) for a given power generation project. This includes the direct, indirect, and induced economic impacts on the local economy associated with its construction and operation phases. Project cost and local content data used in the model can be gathered from existing offshore wind projects, literature review, and conversations with industry professionals. Local direct, indirect, and induced jobs and economic impacts can be estimated using economic multipliers derived from Impact Analysis for Planning software.

	By determining the regional economic impacts and job creation for a proposed power facility, the JEDI offshore wind model can be used to answer questions about the impacts of offshore wind power in a given state, region, or local community.
Major Studies	• *Alberta Wind Energy Supply Chain Study*. 2017. https://canwea.ca/wp-content/uploads/2017/09/Delphi-AB-Wind-Supply-Chain-Study-Final-Report.pdf. • *The Benefits of Renewable Energy Industry in Eastern Colorado*. 2016. http://www.portstoplains.com/images/key_research/energy/2016_eastern_co_cleantech_pro-15.pdf. • *Potential Economic Impacts from Offshore Wind in the United States: The Southeast Region*. 2013. http://wind.jmu.edu/research/documents/JEDI%20Paper%20-%20Final%20Draft.pdf • *A Simulation of the Economic Impact of Renewable Energy Development in Morocco*. 2012. https://www.sciencedirect.com/science/article/pii/S030142151200273X.
Developer URL	https://www.nrel.gov/analysis/jedi/
Documentation URL	https://www.nrel.gov/analysis/jedi/models.html
Regional Input-Output Modeling System (RIMS II)	
Developer	Bureau of Economic Analysis, U.S. Department of Commerce
Availability	Multipliers for different regions and industries in the US can be purchased from the developer.
Description	RIMS II, a regional economic model, is a tool used by investors, planners, and elected officials to objectively assess the potential economic impacts of various projects. This model produces multipliers that are used in economic impact studies to estimate the total impact of a project on a region. The idea behind the results of RIMS II is that an initial change in economic activity results in other rounds of spending—for example, building a new road will lead to increased production of asphalt and concrete. The increased production of asphalt and concrete will lead to more mining. Workers benefiting from these increases will spend more, perhaps by eating out at nicer restaurants or splurging more on entertainment. RIMS II multipliers are used to study economic impacts of a wide range of projects, by government agencies (federal, state, and local), economic development organizations and different businesses (to study local impacts of investment projects).
Major Studies	• *Regional Economic Impact of a Commercial Project: A RIMS II Approach*. 2013. https://www.economics-finance.org/jefe/volume12-2/3ArticleStretcher.pdf. • *MPUC RPS Report 2011: Review of RPS Requirements and Compliance in Maine*. 2012. https://www.maine.gov/energy/pdf/RPS%20MPUC%20Final%20Report.pdf. • *Evaluating the Benefits and Costs of a Renewable Portfolio Standard: A Guide for State RPS Programs by Clean Energy States Alliance*. 2012. https://www.cesa.org/assets/2012-Files/RPS/CESA-RPS-evaluation-report-final-5-22-12.pdf.

Developer URL	https://bea.gov/regional/rims/rimsii/home.aspx
Documentation URL	https://www.bea.gov/regional/pdf/rims/RIMSII_User_Guide.pdf
Wertschöpfung und Beschäftigung durch Erneuerbare Energien (WeBEE)	
Developer	German Renewable Energies Agency
Availability	The tool is run by the developer-owner, hosted by the German Renewable Energies Agency (www.unendlichviel-energie.de/), and analyses can be performed through fully specified projects or via individual queries. A simplified online version can be accessed and used free of charge.
Description	WeBEE is a supply-chain analysis simulation tool that focusses on the components and services necessary to produce, install and operate a renewable energy technology. Value chains are represented in four segments in which value added can be created: the systems manufacture, and planning & installation stages reflect one-time impacts, while the O&M and system operation stages include annually recurring effects. Two main value-added components are calculated, which yield a local value-added impact: profits of the participating companies, and net incomes of the employees involved. The tool also calculates municipal taxes paid on business profits and on adjusted gross employee income; hence, it allows one to understand the distribution of the created value added among households, firms and local government.
Major Studies	• *Regional Value Creation by Renewable Energies in Two Selected Municipalities in North Rhine-Westphalia*. 2012. https://www.ioew.de/fileadmin/user_upload/BILDER_und_Downloaddateien/Publikationen/2012/Wei%C3%9F_et_al.__2012__-_Kommunale_Wertsch%C3%B6pfung_durch_EE_in_zwei_Modellkommunen_in_NRW.pdf. • *Value Added and Employment Creation of Renewable Energies in Mecklenberg-West Pomerania 2010 and 2030*. 2011. https://www.ioew.de/fileadmin/user_upload/BILDER_und_Downloaddateien/Publikationen/2011/Studie-Wertsch%C3%B6pfung_EE-MV.pdf.
Developer URL	https://www.ioew.de/en/under-the-ioews-spotlight/value-added-and-employment/
Documentation URL	Official documentation is currently unavailable.

Appendix C: Capacity Expansion Planning

C.1 Introduction

Capacity expansion planning deals with the development of a power system in the long term. The planning horizon is typically 15–20 years or longer. Prior to the 1970s, capacity expansion planning was a relatively straightforward activity. The demand growth from year to year was steady and rather predictable, so capacity expansion analysis focused mostly on supply-side resources: providing enough generating capacity to meet growing demand. In the 1970s and 1980s, expansion planning became more complex due to several factors, including dramatic changes in oil prices ("oil price shocks"), greater uncertainty in electricity demand growth, delays and cost overruns in the construction of coal and nuclear plants, assumed depletion of natural gas resources (e.g., restrictions on gas use for electricity generation), increasing concerns about emissions and other environmental impacts, and other factors.

C.1.1 Integrated Resource Planning

An improved capacity expansion methodology, integrated resource planning or IRP, emerged in the 1980s in states that required their vertically integrated utilities to prepare a comprehensive least-cost expansion plan. The IRP approach is a planning methodology that integrates both supply- and demand-side options to develop a least-cost expansion plan or strategy that will meet projected future electricity demand while satisfying all reliability, environmental, fuel, and other constraints. IRP develops a long-term resource strategy by considering all available supply and demand options, including large-scale generating technologies (fossil and nuclear plants, hydropower plants, wind and solar plants, etc.), distributed generation resources, energy efficiency resources (e.g., conservation), demand-side management programs, long-term power purchase contracts, and others. The objective of IRP is to determine the optimal power system development strategy by evaluating the cost-effectiveness of all available supply and demand resource options on a consistent, integrated basis, taking into account reliability, operational, environmental, and other constraints. The IRP methodology is a very complex approach that requires a significant amount of data and sophisticated analytical tools to develop an optimal long-term expansion plan.

C.2 Analytical Approaches for Capacity Expansion Planning

C.2.1 Screening Curve Analysis

Depending on needs, capacity expansion analysis can be performed at different levels of detail. The simplest approach is to perform a screening analysis of potential expansion options using screening curves. The screening curve method provides a simplified approach for the analysis of relative economic competitiveness of different technology options by calculating their annualized investment and operating costs as a function of their utilization (i.e., capacity factor). This approach considers one investment at a time and has numerous limitations, as it does not consider the existing resource mix or reliability of power system operation. Screening curves are used to compare candidate projects representing different technologies, without simulating or modeling the power system in which they will be operating. This approach may be appropriate for an initial comparison or screening of different technology options, but is not a substitute for detailed system expansion planning.

C.2.2 Financial Option-Based Valuation (Real Options Analysis)

Another project-level planning approach is financial option-based valuation or real options analysis. It takes an investor's perspective and provides for explicit treatment of investment uncertainties and risks, while focusing on expected profits rather than on levelized costs. Real options analysis was developed for the analysis of investments in uncertainty (future costs and revenues are uncertain) and computes expected profits and profit distributions. Various options can be valued with regard to actions related to the specific investment, such as invest now, invest later, staged or modular investments, abandon project, uprate project, etc. While more complex than screening curve analysis, real options analysis still has numerous limitations: It does not simulate system operation and dispatch and does not capture other system aspects that can be captured through system-level analysis.

C.2.3 System-Level Analysis

System-level planning is more appropriate for long-term capacity expansion analysis as it includes the modeling of the power system and simulation of its operation. While project-based screening curves and real options analysis can be used as auxiliary tools in the capacity expansion process, system-level analysis is a must for the proper application of the IRP approach to long-term system expansion planning. Different types of models for system-level planning can be summarized as follows.

Deterministic Optimization Models

Deterministic optimization models typically use linear programming (LP) and or mixed-integer programming (MIP) algorithms to optimize power system development over the planning horizon. The tools typically include a dispatch or production cost module that simulates system operation for various expansion scenarios. The representative models in this group are ReEDS, MESSAGE, Aurora, and others.

Probabilistic Optimization Models

Probabilistic optimization models typically include two key modules: (1) a probabilistic or stochastic dispatch module for the simulation of system operation, and (2) a dynamic programming (DP) module for the optimization of system expansion. The probabilistic dispatch analysis attempts to capture certain operational uncertainties by applying stochastic modeling (e.g., Monte Carlo simulation) of system loads, unit outages, variable generation, or other system uncertainties. The DP optimization module provides an optimal (i.e., least cost) capacity expansion solution by examining numerous (hundreds to thousands) of possible future expansion paths that satisfy user-specified operational, reliability, and other constraints. The representative models in this group include WASP-IV, EGEAS, and others.

New Methods for Restructured Electricity Markets

The restructuring of electricity sector and participation of multiple generating companies in restructured electricity markets require different approaches to expansion planning. In contrast to deterministic and probabilistic optimization models, which typically assume a single decision-maker, a new class of analytical approaches is being developed to simulate the independent decision-making of multiple market participants. One of these new approaches is agent-based modeling and simulation (ABMS), which used for simulating the independent decision-making of multiple market participants in competitive markets. In an ABMS modeling environment, each market participant is trying to optimize its own corporate utility function with limited information about the actions of other competitors. While ABMS approaches may provide a realistic simulation of decision-making and actions of market participants in a competitive electricity market environment, they may not provide an optimal least-cost solution for the system as a whole. The representative model in this group is the EMCAS model.

Table C.1 provides a summary of key characteristics, typical applications, and the advantages and disadvantages of the main resource planning approaches.

Table C.1: Summary of Main Resource Planning Approaches

Planning Approach	Scope of Analysis	Description	Pros/Cons	Representative Models/Tools
Screening Curves	Individual projects	Comparison of annualized levelized costs across range of capacity factors	• Quick and simple analysis • Identifies clear winners and losers • Does not consider power system characteristics • No dispatch analysis No reliability analysis Does not create optimized plan	Spreadsheet models
Financial Option-Based Valuation	Individual projects (usually)	Evaluation of resource options against market prices, accounting for uncertainty. Comparison of different investment options based on their expected value, considering flexibility in operational or investment decisions.	• Fast analysis • Captures financial risks of investment options • Considers the option value of flexibility • Usually no dispatch analysis • No reliability analysis • Usually applied to individual projects, does not create optimized generation portfolio	Spreadsheet models, stochastic dynamic optimization models, stochastic simulation tools

Planning Approach	Scope of Analysis	Description	Pros/Cons	Representative Models/Tools
Deterministic Optimization	Power system (e.g., utility)	LP or mixed-integer programming optimization of system development over a period of time. Typically includes a simple generation dispatch model which allows the optimization algorithm to determine optimized (e.g., least-cost) plan.	• Fast solution (single iteration) • Requires less input data than DP models • Can be computationally intensive (large number of variables and equations) • Dispatch model rather simple (usually annual or multi-annual time step) • Inaccurate reliability analysis • Highly non-linear problems may not have solution.	Aurora, ReEDS, MESSAGE
Probabilistic Optimization	Power system (e.g., utility)	Stochastic modeling of power system operation and dynamic programming optimization of system expansion. The objective is to find the expansion plan that minimizes all operating and investment costs for the system over the study period, while satisfying all reliability and other constraints.	• Detailed dispatch analysis (can be simplified to minimize computer run time) • Rigorous optimization solution for the system as a whole • Accurate reliability analysis • Can be computationally intensive (iterative optimization process) • Requires large amount of input data	WASP, EGEAS, Strategist

Planning Approach	Scope of Analysis	Description	Pros/Cons	Representative Models/Tools
New Approaches for Restructured Markets	Power system (e.g., generation company or electricity market)	Modeling and simulation of investment decision-making in restructured electricity markets. Models try to simulate independent decision-making of multiple market participants (e.g., generation companies) trying to maximize their individual utility functions (e.g., profit), while having limited knowledge about the actions of their competitors.	• Applicable to competitive electricity markets (e.g., bid-based dispatch) • Investment decision-making of multiple generation companies represented in a single model run • Multiple objective functions can be simulated • Realistic representation of competitive market operation and behavior of market participants • Can be computationally intensive • Requires large amount of input data, including market rules and decision-making logic for market participants • Does not produce an optimized solution for the system as a whole	EMCAS, NEMSIM

C.3 Expansion Planning in Vertically Integrated Utilities

In a traditionally regulated power system with one vertically integrated utility company, all supply and demand expansion options are evaluated based on the cost and reliability parameters. This approach assumes a system perspective with a single decision-maker optimizing the expansion of the system as a whole. The objective of the planning process is to develop a power system expansion plan that has the minimum NPV for all operating and investment costs over the study period. The analytical process typically starts with developing a demand forecast, analyzing potential supply and demand expansion options, performing the simulations of system operations for various expansion paths, and determining the optimal or least-cost development path over the planning horizon. The results of the planning process include the types and quantities of new generating capacity additions or demand-side options, and the timing of their additions over the study period. System reliability parameters are also calculated to make sure that all reliability and other operational constraints are met.

C.4 Expansion Planning in Restructured Electricity Markets

IRP typically does not occur in restructured power markets, as multiple generation companies evaluate their options based on their expected profitability and investment risk. In this process, they apply the company perspective rather than the perspective of the system as a whole. Companies maximize their own objectives individually and independently of each other. Their perspectives may vary depending on the company objectives, risk perception or tolerance, and other factors. For example, some companies may put a priority on maximizing profits, while others may put a priority on increasing their market share. In a competitive electricity market, generating companies typically perform independent capacity expansion planning analysis (i.e., investment decision-making) while having only limited knowledge of the plans and actions of their competitors. Companies typically try to identify investments characterized by high profit potential with limited downside risk. Investment decisions may also consider locations of new capacity (where to build) due to congestion issues and the risk of stranded assets.

Appendix D: Cost-Benefit Analysis

D.1 Introduction

Cost-benefit analysis (CBA) is commonly applied in the economic evaluation of new projects, policies, or decisions. The CBA methodology involves systematic accounting for and comparing of expected project costs and benefits over time to determine whether the present value of benefits will outweigh the present value of costs. For a proposed project, policy, or decision to be considered economically viable, its net benefits (i.e., benefits minus costs) should be positive. Thus, CBA helps with decision-making to determine whether to invest and develop the project or not. In addition to the economic viability, which typically assumes an economic analysis from a societal or public perspective, the financial viability of the project is also important. Financial analysis typically assumes the perspective of the company or investor that is developing the project, and a project is financially viable if it offers an attractive investment opportunity for that company or investor.

In principle, CBA can be performed to analyze the costs and benefits from the perspective of a specific stakeholder. For example, CBA for utility projects can be performed from the perspective of a project developer (e.g., a utility), regulatory agency (e.g., public utility commission), or from a societal point of view. Different perspectives are taken into account by including the analysis of costs and benefits that are relevant to particular stakeholders.

General economic analyses are normally performed from the societal perspective to determine whether the proposed project is beneficial for the economy and society as a whole, without regard to the distribution of benefits. On the other hand, financial analyses are generally focused on returns to investors and include only costs and benefits that are relevant for the project developer. In between are the analyses commonly used by traditionally regulated utilities, in which the focus is on the utility and electricity customer costs. These analyses typically utilize a public perspective, which minimizes the cost of electricity service for consumers while assuming a reasonable return on investment for the utility.

D.2 Methodology

D.2.1 Calculate Net Present Value

The objective of CBA is to determine the NPV of the project, which helps determine whether the project is economically viable or not. The NPV is calculated as the difference between the discounted project benefits and costs, either over the lifetime of the project or over the selected CBA analysis period. If the NPV is positive, the overall benefits of the project exceed its costs and the investment can be economically justified. The most general formula for calculating the NPV is shown in in the following equation.

$$NPV = \frac{B_0 - C_0}{(1+r)^0} + \frac{B_1 - C_1}{(1+r)^1} + \cdots + \frac{B_T - C_T}{(1+r)^T} = \sum_{i=0}^{T} \frac{B_i - C_i}{(1+r)^i}$$

Where:
B_i = total value of project benefits in year i
C_i = total costs in year *i*
r = discount rate
T = analysis period

In practice, the differences between the costs and benefits in any year are frequently expressed as the difference between the cash inflows (benefits) and outflows (costs) in that year. Therefore, the NPV formula is often expressed using the equation below:

$$NPV = F_0 + \frac{F_1}{(1+r)^1} + \cdots + \frac{F_T}{(1+r)^T} = F_0 + \sum_{i=1}^{T} \frac{F_i}{(1+r)^i}$$

Where:
F_i = net cash flow in year *i*
r = discount rate
T = analysis period

Cash flow and NPV can be calculated in constant dollars (without the effects of inflation) or in current dollars (with inflation). If applied properly, both methods will produce the same result for NPV. The difference is that when the NPV is calculated in constant dollars, only the real escalation of costs and benefits is taken into account, while the CBA in current dollars deals with the apparent escalation of costs and benefits. The apparent escalation rate is defined as the total annual increase in cost and includes the effects of both inflation and real escalation. CBA is often calculated in constant dollars because it is rather difficult to predict future inflation rates, especially for longer analysis periods.

D.2.2 Benefit-to-Cost Ratio

Another value that is frequently calculated using CBA is the benefit-to-cost ratio (BCR). BCR represents the ratio of discounted project benefits and costs. A BCR that is greater than one (BCR > 1) indicates that the project is economical. Since BCR is the ratio of discounted project benefits and costs, it is frequently used for comparison of different projects, because it is not much affected by the project size as NPV can be. A general formula for calculating BCR is shown below.

$$BCR = \frac{\sum_{i=0}^{T} \frac{B_i}{(1+r)^i}}{\sum_{i=0}^{T} \frac{C_i}{(1+r)^i}}$$

Where:
B_i = total value of project benefits in year *i*
C_i = total costs in year i
r = discount rate
T = analysis period

D.2.3 Internal Rate of Return

Internal rate of return (IRR) is often calculated using CBA. IRR represents the discount rate at which the present value of project costs equals the present value of project benefits. In other words, IRR is the discount rate for which the NPV equals zero. IRR is commonly used to decide whether to proceed with an investment by comparing the project IRR with the minimum acceptable rate of return (hurdle rate). The hurdle rate typically represents the rate of return of the next best alternative (e.g., the opportunity cost of capital). IRR is not recommended for ranking of different projects, as it implicitly assumes reinvestment of returns at the IRR. IRR is calculated with the equation below:

$$0 = NPV = F_0 + \sum_{i=1}^{T} \frac{F_i}{(1+IRR)^i}$$

Where:

NPV = net present value of the project
F_i = net cash flow in year *i*
IRR = internal rate of return
T = analysis period

D.2.4 Payback and Return on Investment

Simple and discounted payback periods are often calculated. Simple payback period (SPB) is the number of years necessary to reach the breakeven point—the point at which where cash generated from the project covers the investment costs. SPB does not take into account the time value of money. SPB can be calculated using the averaging method or the subtraction method. In the averaging method, SPB is calculated by dividing the investment costs by average annual cash flows. In the subtraction method, each individual annual cash inflow is successively subtracted from the initial cash outflow until the payback point has been reached. The discounted payback period (DPB) is the number of years necessary to recover the cost of a project or investment while accounting for the time value of money. Calculating the DPB is preferred for projects where risk is an issue, as it allows for a quick assessment of the period during which the investor's capital is at risk.

Return on investment (ROI) is a percentage that measures the gain or loss generated from an investment as compared to the money invested. ROI is calculated by estimating future earnings generated from an investment and dividing those earnings by total investment costs. ROI can be used to compare the performance of different projects for comparable time periods.

D.3 Uncertainties in Cost-Benefit Analysis

The two greatest sources of uncertainty in CBA are related to the estimation of costs and benefits over the analysis period and the choice of discount rate.

D.3.1 Estimation of Costs and Benefits

The value of most projects' costs and benefits over the project lifetime are very uncertain. The analyst may have a good estimate of project investment costs, which are typically determined with a sufficient degree of accuracy in detailed engineering studies before the start of project construction. However, construction of any project bears the risk of schedule delays and cost overruns, with higher risks for projects with longer construction timelines.

Similarly, analysts may have good estimates of project operational costs and benefits during early operating years. However, in future years, estimates of costs and benefits may be less reliable, especially for projects with long lifetimes. Therefore, for longer-lived projects, operational costs and benefits are usually projected by extrapolating estimated costs and benefits from the early years of operation. Projecting costs and benefits over the project lifetime should also take into account any known or anticipated trends that may influence the future value of costs and benefits. For technologies with very long lifetimes, such as conventional and pumped storage hydropower (PSH plants, CBA over the project lifetime is often impractical due to the huge uncertainties in estimating project costs and benefits over 50- or 60-year time horizons. Therefore, the CBA for long-lived projects is usually performed for a shorter CBA period (e.g., 30 years or less), while accounting for the remaining value of the asset at the end of the CBA period.

D.3.2 Choice of Discount Rate

The discount rate is used to determine the present value of various costs and benefits that occur in different years of the CBA period. Using the discount rate, all costs and benefits occurring in various years are brought to the present worth and expressed in dollars of present-year worth. The discounting method allows for the comparison of all costs and benefits from different years on the same basis (expressed in dollars of present-year worth), regardless of which year they occur in. Cost discounting methods can be used to move costs and benefits forward and backward in time, depending whether they occur before or after the selected present year. While theoretically any year can be selected as the "present" year for cost discounting, typically it is the year in which the project starts operation, or the year that was used during the analysis as the base year for cost calculations.

In principle, the discount rate serves to determine the value of money over time, compared to the value at present. For example, most people would agree that having $100 today is worth more than having a $100 next year, or in ten years. The $100 today can be invested, or put in the bank to earn interest, resulting in a next-year value of, say, $105 in current dollars. Therefore, one factor in determining the discount rate is the opportunity cost of capital, or what are the other potential ways to use the money or invest into other projects that may provide return on investment. Obviously, the opportunity cost of capital depends on who is investing and the availability of other options for growing capital.

Another factor influencing the choice of the discount rate is the borrowing cost of capital. Most energy projects are capital-intensive and require a significant amount of money to be borrowed from commercial banks and other financial sources in order to develop the project. Borrowing costs are often used as a proxy for the discount rate in the CBA and will differ depending on funding sources and loan arrangements. When a project developer looks to analyze whether to invest into a certain project, it usually uses its weighted average cost of capital (WACC) as the discount rate for NPV analysis.

The choice of the discount rate also depends on who is investing or developing the project. Discount rates can be different for investments made by new market entrants (e.g., independent power producers, or IPPs), utilities and for government-funded public projects. A new market entrant may be looking for projects with higher potential ROI, so the assumed discount rate may be higher than what may be typically appropriate for utilities and much higher than for public projects. In addition, new market entrants are likely to face higher borrowing costs from commercial banks than other companies, such as utilities. Utilities are traditionally considered to be risk-averse and financially conservative with regard to investments. Regulated utilities may also have a pre-defined approved rate of return, resulting in project discount rates that are typically lower than discount rates for new market entrants and IPPs. In addition, based on their financial track record, utilities may have access to lower cost loans and better borrowing terms than some other companies. Lastly, societal discount rates that are used for government-funded public projects are typically the lowest and are often tied to or related to the interest rates that commercial banks pay to borrow money from the government.

The choice of discount rate for CBA analysis is not straightforward and depends on many factors. Therefore, in addition to the discount rate that is used for the baseline analysis, it is always recommended to perform sensitivity analyses for higher and lower values for the discount rate. The NPV analysis is generally very sensitive to the choice of discount rate.

D.4 Economic Versus Financial Analysis

Economic and financial analyses are similar, as they both estimate project costs and benefits based on the differences between cases with and without the project under consideration. The main difference is the perspective used in the analysis. Economic analysis is usually conducted from a societal perspective, while financial analysis is typically conducted from the perspective of a particular investor or project developer. Both economic and financial analyses estimate the net benefits of a project. The key difference is that economic analysis accounts for all costs and benefits of the project to the society, regardless of who is the beneficiary, while financial analysis deals only with the costs and benefits that are relevant to the project developer or investor.

The objective of economic analysis is to determine the true value of the project for the economy or society as a whole, including the indirect project benefits that may occur in other sectors of the economy. In addition, economic analysis takes into account the costs and benefits of goods and services that are not sold in the market and have no market price. Therefore, it may be possible for a project to be economically viable, but financially not sustainable. This happens in cases when the project developer is not able to recover its investment due to the lack of market mechanisms that would provide sufficient revenue streams. In such cases, if the project is financially not viable but the economic value and societal benefits of the project are clearly positive and recognized, a government may decide to provide certain subsidies (i.e., tax credits) to make the project financially sustainable.

Another difference between economic and financial analyses is that financial analysis uses market prices to determine the cash flows and financial viability of the project, while economic analysis uses economic prices that are derived from market prices by excluding taxes and subsidies. Taxes and subsidies are financial levies or incentives imposed by a government and do not represent the true economic value or cost of the product.

Economic and financial analyses also differ in their treatment of externalities like environmental and health impacts. Economic analysis often attempts to estimate the value of these externalities in order to account for their true costs and value to the society, despite the challenges in monetizing the effects of externalities and their impacts on the society. Financial analysis typically does not include valuation of externalities, unless there is a clear financial impact that affects the project cash flow.

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Appendix E: Multi-Criteria Decision Analysis

E.1 Overview of Decision Analysis

While decision analysis can be defined in different ways, in principle it is a systematic and logical set of procedures for analyzing complex, multi-objective decision problems. A decision-making environment is typically complex and needs to take into account multiple factors. Some of the factors that impact decision-making include:

- Multiple objectives
- Long time horizons
- Intangibles and factors that are difficult to measure or estimate
- Many affected groups
- Risk and uncertainty
- Interdisciplinary nature of the problem
- Several decision-makers
- Value trade-offs
- Risk attitude
- Sequential nature of decisions

Decision analysis is applicable to many different types of problems and is routinely applied in many different fields. Typically, decision analysis problems have the following fundamental or underlying characteristics:

- A need to accomplish some decision objectives
- A choice to be made among several alternatives, one of which has to be selected
- Different consequences associated with different alternatives
- Uncertainties related to the consequences of alternatives
- Different values, or impacts, of consequences associated with different alternatives

The above characteristics describe many complex decision problems. Although certain features describing particular decision problems may differ, there are several aspects that are increasingly common to many of today's decisions:

High stakes: The selection of alternatives may involve high monetary values (e.g., millions of dollars) or other impacts (e.g., environmental impacts).

Complicated structure: Many decision problems are very complex, with multi-attribute alternatives.

Multidisciplinary nature: Decision problems are increasingly characterized by their multidisciplinary nature, with the attributes and impacts of alternatives involving many different fields. Because of this, it is necessary to include in the decision process multiple experts, with expertise in different disciplines (e.g., economics, engineering, environment, etc.) since it is difficult to find experts with expertise in everything.

Need to justify decisions: The decision-making process needs to be objective and transparent. The resulting decisions may need to be explained, understood, and justified to governmental and regulatory authorities, the public, corporate boards, shareholders, and other stakeholders.

E.2 Decision Analysis Methodology

MCDA provides analysts with a decision-support system that allows them to deal with decision problems that involve multiple attributes, or factors, that are relevant for decision-making on a specific decision problem. The basic strategy is to divide the overall decision problem into smaller parts, analyze each part separately, and then integrate the parts in a logical manner to produce a meaningful overall solution.

In a most general way, the MCDA can be described as a four-step procedure (Figure E.1):

Step 1: Define objectives and attributes

Step 2: Determine impacts

Step 3: Quantify preference of decision-makers or stakeholders

Step 4: Evaluate and compare alternatives

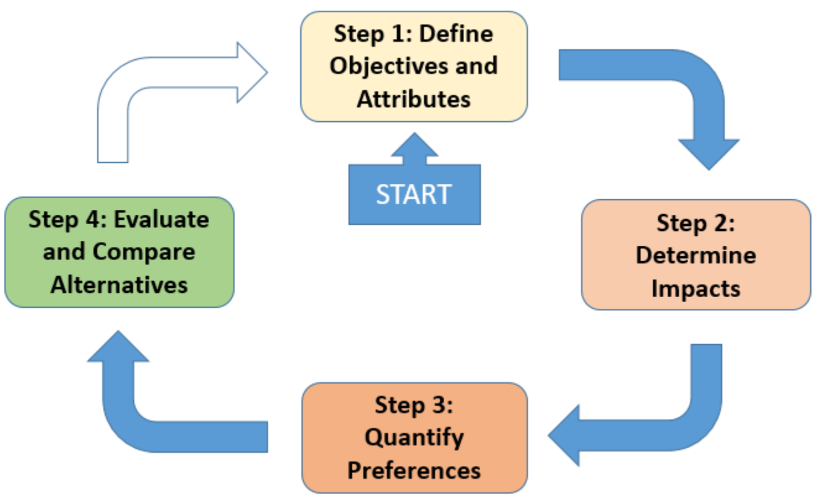

Figure E.1: Key steps in decision analysis.

Step 1: Specify a Comprehensive Set of Objectives and Measures

Step 1 serves to structure the decision problem, including the generation of alternatives and the specification of objectives. Specifically, Step 1 involves defining 1) a comprehensive set of objectives that reflects all concerns relevant to the decision, and 2) measures for achieving those objectives. Such measures are called attributes. A measurement scale must also be established for each of the attributes. The degree to which the objectives are met, as measured by the attributes, is the basis for comparing the alternatives.

Step 2: Assess Possible Impacts of Each Alternative

Step 2 involves determining possible levels of various impacts in terms of the attributes for each alternative. Uncertainties must be quantified when levels of impacts are not known exactly. Therefore, when it is not possible to precisely forecast impact, a probability distribution function needs to be determined for each attribute. Ultimately, this process will result in a set of probability distribution functions for the set of attributes for each alternative.

The complexity of impact assessment is increased if there are probabilistic dependencies among attributes for given alternatives. If two attributes are probabilistically dependent, the impact specified for one will also affect the other. In such cases, it is important to either properly model these dependencies and develop probabilistic assessments based on the output of the model or to bound the possible probability distributions utilizing logic and understanding of the problem. It is essential to investigate whether and how the dependencies affect the evaluation of alternatives.

Additional difficulties may occur if multiple experts are estimating potential impacts of certain attributes. The expert opinions may differ even though they may largely utilize the same knowledge base, data sources, or studies.

Developing probability distribution functions for different attributes addresses the risk and uncertainty aspects of the decision problem. Long time horizons can also be addressed by specifying the time in which the impacts might occur. Interdisciplinary aspects are also addressed by utilizing the expertise of various experts to develop and structure models, provide information and professional judgment on the impacts of various attributes, and help develop probability distribution functions for attributes relevant to their expertise.

Step 3: Quantify Preferences

Step 3 involves determining decision-maker preferences or the value of different attributes to decision-makers. It involves the creation of a model of values to evaluate the alternatives. This is typically done through an elicitation process, which is a structured discussion between a decision analyst and the decision-maker to quantify value judgments about possible impacts of various attributes. Ideally, the elicitation process should be conducted with multiple decision-makers but in separate individual sessions, so that their judgements for attribute preferences and values are not influenced by the answers of other decision-makers. The elicitation process should also determine decision-maker risk attitudes concerning different attributes and include provisions for consistency checks.

After completing the elicitation process, the responses of decision-makers are then used to develop trade-off coefficients and utility functions for different attributes. Individual utility functions are assessed for each of the attributes and integrated into an overall multi-attribute utility function. This multi-attribute utility function is a mathematical representation of a decision-maker's preferences. It measures the decision-maker's degree of satisfaction with a particular alternative.

Step 4: Evaluate and Compare Alternatives

After the decision problem has been defined and structured in Step 1, the magnitude and associated likelihoods of attribute impacts determined in Step 2, and the decision-makers' preferences established in Step 3, the information must be synthesized in a logical manner to evaluate the alternatives. Step 4 brings together the results of the previous three steps and uses the multi-attribute utility function as a guide for decision-making. Thus, in cases involving multiple alternatives, the best alternative is the one that maximizes the expected value of the utility function. When a number of alternatives is large, optimization techniques can be used to identify the alternative with the highest expected utility.

If a decision cannot be made during this step (e.g., two or more alternatives result in a similar value or their relative values cannot be sufficiently differentiated), the results are fed back into Step 1 to begin a second iteration of the decision analysis process. This iterative process is called the decision analysis cycle.

E.3 Practice and Usefulness of Decision Analysis

The main purpose of decision analysis is to help decision-makers make better decisions by taking into account multiple factors and attributes characterizing different alternatives. While MCDA is a relatively straightforward process, a significant amount of time is involved in generating alternatives, specifying objectives, eliciting professional and value judgments from decision-makers or experts, and interpreting the results and implications of the analysis. A considerable amount of time is required for interaction between the analyst and decision-makers for the elicitation process to understand their value judgments, determine weight coefficients for trade-offs among different attributes, and develop utility functions. In many cases, the elicitation process deals with information of sensitive nature (e.g., business-sensitive preferences), or the respondent may have a stake in certain outcomes which may influence their thinking or responses.

The greatest benefit of decision analysis is the systematic and methodical evaluation of alternatives. While systematic and methodical evaluation is common to most analytical approaches, the strength of decision analysis is that it allows for a comparison of alternatives that are characterized by various attributes (e.g., monetized, non-monetized, qualitative, etc.) and estimates their values in a systematic methodical manner. By being able to utilize and combine in a consistent evaluation framework both objective and subjective data and information, decision analysis provides the analysts and decision-makers with valuable insights about the decision problem and its alternatives.

E.4 Simplified Decision Analysis Example

We will use an extremely simplified example to illustrate the MCDA process. Let us assume a decision problem with the overall objective of selecting the best alternative for the development of a PSH project. The specific objectives are defined as follows:

1. Maximize the NPV of the project
2. Maximize project's contribution to system reliability
3. Minimize environmental impacts from project development and operations
4. Maximize project's support for integration of variable energy resources (VERs) by reducing their curtailments
5. Maximize the overall socio-economic benefits resulting from project development

For each objective, an attribute should be selected that will determine how well the objective is met. The attribute should have a measure (quantitative or qualitative, natural scale of constructed scale) that is used to compute the achievement of the objective in each alternative. The attributes used to measure the achievement of above objectives can be specified as follows:

1. **NPV value:** The NPV of the project expressed in monetary units ($).
2. **Reliability benefits**: Project's contribution to grid reliability expressed as a qualitative score, using a constructed scale from 1 to 3, with 1 being low contribution (bad) and 3 being the highest contribution to system reliability (good).
3. **Environmental impacts**: Project's estimated environmental impacts expressed as a qualitative score, using a constructed scale from 1 to 3, with 1 being the lowest environmental impact (good), and 3 being the highest environmental impact (bad).
4. **VER support:** Project's contribution to reduction of VER curtailments, expressed in GWh of electricity generation that is not curtailed due to PSH operations.
5. **Socio-economic benefits:** Project's contribution to social and economic development of the region in which it is located, expressed as qualitative score using a constructed scale from 1 to 3, with 1 being a low contribution (poor score) and 3 being the highest contribution (good score).

Let us also assume that the analysis is performed for three alternatives from which the decision-makers need to select the best one. These three alternatives are characterized with the following values and scores for the above attributes, as shown in Table E.1.

Table E.1: Attribute Values and Scores for each Alternative

	Attributes and Metrics				
	NPV of Monetized Costs and Benefits ($M)	Reliability Benefits (Qualitative Score 1-3)	Environmental Characteristics (Qualitative Score 1-3)	Reductions of VER Curtailments (GWh)	Socio-Economic Benefits (Qualitative Score 1-3)
Alternative 1	14.7	1 (Low)	1 (Low)	40	3 (High)
Alternative 2	12.5	3 (High)	2 (Medium)	55	1 (Low)

	Attributes and Metrics				
	NPV of Monetized Costs and Benefits ($M)	Reliability Benefits (Qualitative Score 1-3)	Environmental Characteristics (Qualitative Score 1-3)	Reductions of VER Curtailments (GWh)	Socio-Economic Benefits (Qualitative Score 1-3)
Alternative 3	11.2	2 (Medium)	3 (High)	45	2 (Medium)

Note that attributes for different objectives are expressed in different units, from monetized ($) for NPV, to non-monetized values for other four attributes. The non-monetized values are also further expressed using different metrics, from physical units (GWh) for VER curtailment reductions, to qualitative metrics using constructed scales for reliability, environmental, and socio-economic impacts.

In the next step, key decision-makers need to be identified for the elicitation process. The elicitation process consists of interviews with individual decision-makers in order to obtain their views on the relative importance and priorities of above objectives, as well as on the trade-offs between different attributes. In addition, the elicitation process serves to determine the possible range, and worst and best value for each of the above attributes.

As many as possible of the key decision-makers should be included in the elicitation process. Each decision-maker should be interviewed individually. Group interviews are not desirable as decision-makers can be influenced by the views and opinions of other decision-makers. The minimum number of interviews is three.

Using the interview results, the utility functions of each of the decision-makers can be computed, both for individual attributes and the combined utility function for each decision-maker. These utility functions are then used to determine the relative importance of different attributes to decision-makers and calculate their weight coefficients. The weight coefficients obtained for different attributes are shown in Table E.2.

Table E.2: Weight Coefficients for Different Attributes

	NPV		Reliability Benefits		Environmental Characteristics		Reduced VER Curtailments		Socio-Economic Benefits	
	$M	Weight	Score	Weight	Score	Weight	GWh	Weight	Score	Weight
Alt. 1	14.7	0.55	1 (L)	0.15	1 (L)	0.20	40	0.05	3 (H)	0.05
Alt. 2	12.5	0.55	3 (H)	0.15	2 (M)	0.20	55	0.05	1 (L)	0.05
Alt. 3	11.2	0.55	2 (M)	0.15	3 (H)	0.20	45	0.05	2 (M)	0.05

In the next step, the metrics and scores for individual attributes are normalized over the potential range for that attribute. Preferably, the potential range of attribute values would be determined from the interviews with decision-makers and/or additional analysis. Here, for simplicity, we will use the minimum and maximum attribute values obtained for different alternatives to define potential attribute ranges. The normalized attribute values are presented in Table E.3. The sum of normalized values for each attribute should equal one.

Table E.3: Normalized Data for Different Attributes

	NPV		Reliability Benefits		Environmental Characteristics		Reduced VER Curtailments		Socio-Economic Benefits	
	Norm. Value	Weight	Norm. Value	Weight	Norm. Value	Weight	Norm. Value	Weight	Norm. Value	Weight
Alt. 1	0.38	0.55	0.17	0.15	0.17	0.20	0.29	0.05	0.50	0.05
Alt. 2	0.33	0.55	0.50	0.15	0.33	0.20	0.39	0.05	0.17	0.05
Alt. 3	0.29	0.55	0.33	0.15	0.50	0.20	0.32	0.05	0.33	0.05

Using the normalized values obtained for each alternative, these three alternatives can be graphically represented, as shown in Figure E.2. As each of the alternatives is good with regard to some objectives and less favorable with regard to others, there is no clear winner that dominates all other alternatives in every aspect or attribute (i.e., Pareto dominance), so it is difficult to determine which alternative is the best overall.

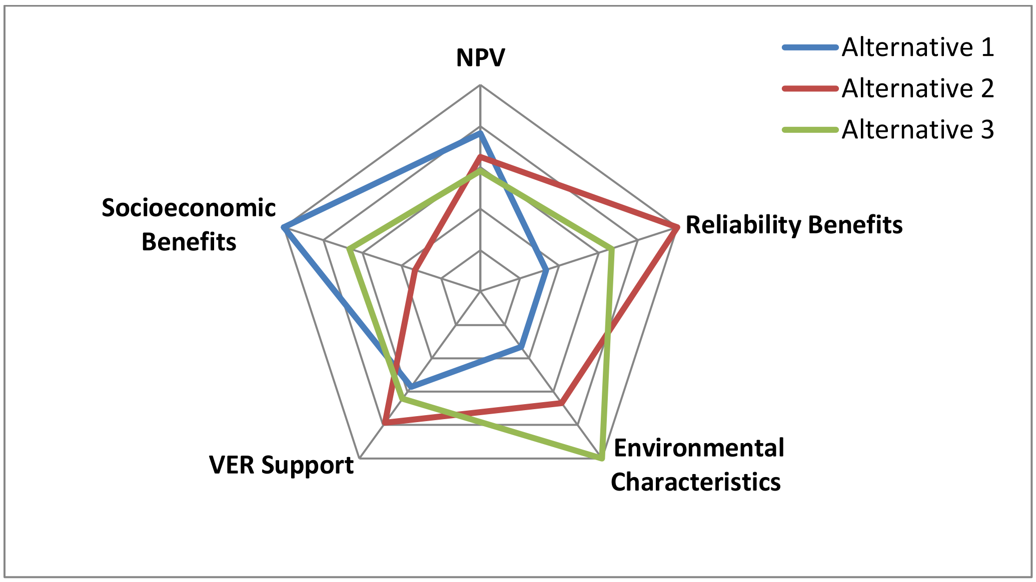

Figure E.2: Relative value of attributes for each alternative

To obtain the overall score for each alternative, the normalized values for each attribute are multiplied by their respective weight coefficients. Table E.4 shows the relative weights of each attribute and overall scores for each alternative.

Table E.4: The Weights for Each Attribute and Overall Score for each Alternative

	Attributes					Overall Score
	NPV	Reliability Benefits	Environmental Characteristics	Reduced VER Curtailments	Socio-Economic Benefits)	
Alternative 1	0.21	0.03	0.03	0.01	0.03	**0.31**
Alternative 2	0.18	0.08	0.07	0.02	0.01	**0.35**
Alternative 3	0.16	0.05	0.10	0.02	0.02	**0.34**

Therefore, based on the inputs received from decision-makers on the relative importance and trade-offs among different objectives and their attributes, the multi-criteria decision analysis results show that Alternative 2 has the highest overall score. In addition to identifying the best alternative, the this type of analysis also allows for ranking of alternatives and identifies Alternative 3 as the second best, followed by Alternative 1. While the analyst has performed the analysis, the results need to be presented to decision-makers to inform the selection process and provide the justification for the selection of best alternative.

Note that this is a very simplified example designed for illustration purposes. If only the NPV of monetized costs and benefits were used in decision-making, Alternative 1 would be the clear winner, followed by Alternatives 2 and 3. However, if non-monetized benefits and impacts are also taken into account, the results show that Alternative 2 has the highest overall score, followed by Alternative 3 and then Alternative 1.

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Appendix F: 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, taking into account scheduled and reasonably expected unscheduled outages of system components.

Advanced Distribution Management System
An advanced distribution management system (ADMS) supports the adoption levels of distributed energy resources (DERs) and assists in maintaining reliability and enhancing resilience across the distribution grid. ADMSs add levels of communication, intelligence, and visibility to the distribution grid for the distribution utility to better understand real-time conditions across its distribution service territory. ADMSs provide utilities with several specific functions, such as automated fault location, isolation, and service restoration (FLISR), conservation voltage reduction, and volt/VAR optimization. Installing an ADMS is not merely about better integrating DER; rather, an 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, AMI, and customer information systems, into one, enterprise-wide system.

Advanced Metering Infrastructure
An electricity metering system that records 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 are capable of measuring consumption in 15-minute to one-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 differs from 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, which allows the meter to communicate with the utility, send information like consumption, and 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 at the end of the month.

Adverse Reliability Impact
The impact of an event that results in bulk electric system instability or cascading.

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[1] 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 a 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 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 facility's functions. The new facilities, in 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 value of future net earnings that are expected to result from the ownership of that property.

Original cost and *historical cost* also are sometimes used to estimate the value of an asset.

Automatic Generation Control
A process designed and used to adjust a balancing authority area's demand and resources to help maintain the area control error within the bounds required by applicable 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 geographical 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, that is normally operated 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 which has the ability to 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 100kV 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
The maximum load that a generating unit or generating station can carry in 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 the customer's peak load (kW) within the specified billing period.

Capacity Credit
The amount of system load that can be supplied by a generation resource 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, and 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 building-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 car pooling.

Constraints
Constraints or system requirements are a subset of outcomes that are real-world operational requirements (or their modeling approximations) that 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 in any operating condition or anticipated mode of operation.
>
> *Most severe single contingency:* That single contingency that results in the most adverse system performance in 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 ten minutes) to permit system adjustment in response to any of the losses.

Contingency Reserve
The 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 composed 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 one type of demand-side management, which 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, etc.) 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.

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[1] https://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp

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 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
That portion of revenue that remains after all charges, including interest, have been satisfied.

Economic Dispatch
The allocation of demand to individual generating units on line 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 kWh, MWh, GWh, 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 the customer's energy consumption in kWh), electric rates may also include a capacity or demand charge (based on customer's peak demand in kW), and a service charge. Common types of electric rates are the following:

> *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 kWh–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 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 specific kind of the time variant rate, a TOU rate charges customers different prices according to a pre-determined 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: In 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. RTP is available to residential customers in the Illinois service territories for Commonwealth Edison (ComEd) and Ameren. The real-time rates for these programs are based on the day-ahead hourly wholesale price for the given utility zones.

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 are 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 pumped storage hydropower (PSH) operation in electricity markets when they pump during the hours with low electricity prices and generate during the hours with high electricity prices. Some other energy storage technologies can also perform energy arbitrage.

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 floor space, 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 to 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 one 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 used or consumed in one year or less (e.g., fuel, operation, maintenance, etc.).

Federal Energy Regulatory Commission
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 Department of Energy 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 causes 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 in 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 ratepayers through a decrease in rates, or to 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 to accounting for and comparing costs and benefits.

Frequency Bias
A value, usually given as MW/0.1 Hz, associated with a balancing authority area, which 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 assists 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 within minutes. Secondary frequency control is accomplished using 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.
>
> *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
Frequency regulation, also known as frequency control, maintains 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 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 so remain unmonetized.

Heat Rate
The amount of input energy (e.g., usually expressed in kJ or Btu) required to produce one kWh 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 by just one unit. If the output is increased or decreased by just one unit (single kW or kWh), 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 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 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
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. MIRR 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 one 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 the stock of which 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 where the energy is delivered or received.

Long-Term Transmission Planning Horizon
Transmission planning period that covers years six through 10 or beyond, when required, to accommodate any known long-time projects that may take several 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 for which 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, the marginal cost is the change in total costs resulting from the production of one additional kW or kWh 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 in 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 one through five.

Net Present Value
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, or heating or cooling season, and usually for not more than one year.

Non-Energy Impacts
Costs or benefits beyond those relating 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 ten 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. Non-utility 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
The successor to the North American Electric Reliability Council, a nonprofit corporation formed in 2006 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 processes, 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 repay 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, MWh, job-years, etc.)

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 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 one-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 regulators to efficiently coordinate electric transmission planning (and expansion), operation and use on a regional (and interregional) basis. Operation of transmission facilities by the RTO must be performed on a non-discriminatory basis.

Regulating Margin
The amount of spinning reserve required in non-emergency conditions by each control area to bring the area control error to zero 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 that 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 a 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 one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a planning authority area.

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

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.

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, project risk, and portfolio risk:

> *Financial risk*: Risk associated with the funding (i.e., total cost of capital) used to invest into 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 of 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 Hz in Europe, 60.0 Hz 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, using 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. 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 that can defer or avoid additional distribution upgrades.

Spark Spread
A measurement of the difference between the price that a generator can obtain from selling one MWh of electricity and the cost of the natural gas needed to generate the MWh 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 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, etc.).

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 MWh for energy and dollars per kWh 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 Service 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.

Trade-off Analysis
Seeks to determine how the value of certain outcomes compares to the value of other outcomes, which are of different nature and measured by different metrics.

Trade-offs
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 in 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 forecast 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. A valuation process accounts for the value of benefits 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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