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Energy Storage for Power Systems Applications: A Regional Assessment for the Northwest Power Pool (NWPP)

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Funded by the Energy Storage Systems Program of
the U.S. Department of Energy
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Abstract

This report addresses several key questions in the broader discussion on the integration of renewable energy resources in the Pacific Northwest power grid. Specifically, it addresses the following questions: a) what will be the future balancing requirement to accommodate a simulated expansion of wind energy resources from 3.3 GW in 2008 to 14.4 GW in 2019 in the Northwest Power Pool (NWPP), and b) what are the most cost effective technological solutions for meeting the balancing requirements in the Northwest Power Pool (NWPP). A life-cycle analysis was performed to assess the least-cost technology option for meeting the new balancing requirement. The technologies considered in this study include conventional turbines (CT), sodium sulfur (NaS) batteries, Lithium Ion (Li-ion) batteries, pumped-hydro energy storage (PH), and demand response (DR). Hybrid concepts that combine 2 or more of the technologies above are also evaluated. The report also discusses the value of pumped hydro storage systems in the Bonneville Power Administration's footprint as an energy arbitrage instrument. This analysis was performed with collaboration by the Bonneville Power Administration and funded by the Energy Storage Systems Program of the U.S. Department of Energy.

Summary

Stationary energy storage for power system application has recently attracted significant interest and attention as an enabling technology for integrating the growing capacity of variable renewable energy resources into the electric grid. Energy storage systems are likely to become an essential contributor to grid modernization investments that will transition the North American power system to a modern grid that meets the future needs under low carbon emissions constraints. In the Pacific Northwest as well as in other U.S. regions, the electricity production from wind technology has increased significantly to meet the renewable portfolio standards targets imposed by 24 U.S. States and the District of Columbia.

For the Bonneville Power Administration (BPA) as the major grid operator in the Pacific Northwest, the growing wind generation poses some challenges to generation scheduling and the provision of ancillary services. To study the impacts of the variability in the wind generation on the regional grid operation and the role that energy storage may play to mitigate these grid impacts, Pacific Northwest National Laboratory (PNNL) collaborated with BPA to addresses the following key questions:

a. For the Northwest Power Pool (NWPP) what are the future balancing requirements necessary to accommodate an assumed expansion of wind energy resources from 3.3 GW in 2008 to 14.4 GW in 2019?

b. What are the most cost effective technological solutions for meeting the new balancing requirements?

c. Can energy storage be cost-effectively employed for arbitrage opportunities?

Pacific Northwest National Laboratory applied a stochastic approach to assess the total balancing requirements for the NWPP for the high wind penetration in 2019. A simplifying assumption was applied that reduced the entire NWPP footprint into one single balancing area. With this assumption, the total balancing-up capacity requirements (generation increment) is approximately 3900 MW. The balancing-down capacity (generation decrement) is estimated to be about -3700 MW. These figures are based on BPA's customary 99.5% probability bound that meets 99.5% of all balancing requirements. A fraction of the total balancing requirements were filtered out to represent the intra-hour (within the hour) balancing requirements that require high ramp rates. The intra-hour balance requirements are 1.85 GW in either direction (increment and decrement). By filtering the intra-hour component out of the entire spectrum of balancing requirements, this study focuses only on one specific set of requirements. These requirements by definition require shorter cycling times for energy storage (less than one hour), however, they pose significant challenges on the ramp rate capabilities of steam turbine generators. During the execution of this project, the need and value for follow-on work was recognized that would focus on the remaining spectrum of the new balancing requirements to address the capacity requirements for inter-hour and intra-day balancing.

A life-cycle cost analysis assessed the cost competition of a set of technologies to meet the future intra-hour balancing requirements. The technologies considered for meeting balancing requirements in this study include conventional turbines (CT), sodium sulfur (NaS) batteries, Lithium Ion (Li-ion) batteries, pumped-hydro energy storage (PH), and demand response (DR). Hybrid concepts that combine two or more of the technologies above are also evaluated.

The technology cases considered in this analysis are:

Case 1: CT
Case 2: NaS
Case 3: Li-ion
Case 4: PH with many mode changes per day[1]
Case 5: PH with 2 mode changes per day
Case 6: DR only
Case 7: NaS plus DR
Case 8: Li-ion plus DR
Case 9: PH with many mode changes per day plus NaS
Case 10: PH with 2 mode changes per day plus NaS
Case 11: PH plus NaS batteries plus DR

Extensive systems modeling was performed to estimate the power and energy capacity requirements to meet future (2019) balancing requirements. Each technology and technology group required careful simulation that incorporated the specific technical features of each technology as well as the interaction between technologies. Simulation results are a pairing of power capacity (GW) and energy capacity requirements expressed in gigawatt-hours (GWh) to meet future balancing needs.

Table E.1 presents the energy and power requirements modeled for each of the aforementioned 11 cases. Note that the capacity requirements are based on a 100% battery depth of discharge (DOD). Under this assumption, energy storage is fully utilized or cycled from fully charged to fully discharged. There are economic reasons for upsizing the battery to a DOD of less than 100% to improve the life of the battery, and the tradeoffs between DOD, energy capacity, and economic life are examined later in this report.

Table E.1. Power and Energy Requirements by Technology Case

Cases	Technology	GW	GWh
C1	CT	1.85	-
C2	NaS	1.85	0.91
C3	Li-ion	1.85	0.90
C4	PH with many mode changes per day *	3.06	1.0
C5	PH with 2 mode changes per day *	4.43	21.77
C6	DR	8.64	-
C7	NaS	1.49	0.73
	DR	1.72	-
C8	Li-ion	1.49	0.72
	DR	1.72	-
C9	PH with many mode changes per day	0.5	0.22
	NaS	1.35	0.69
C10	PH with 2 mode changes per day	0.97	5.87
	NaS	1.35	0.67
C11	PH with many mode changes per day	0.5	0.22
	DR	1.72	-
	NaS	0.98	0.50

* PH alone is insufficient to meet balancing requirements because of waiting period during mode changes. Thus additional capacity was applied waiting period. Values represent total capacities

[1] PH has 2 modes: pumping and generating modes. Operation with multiple mode changes per day permits as many mode changes as are required to meet balancing signal.

A cost analysis was performed for each of the 11 technology cases that established capital cost for 2010 and 2019. The analysis considered the costs associated with initial and recurrent capital costs, fixed and variable operations and maintenance (O&M) costs, fuel costs, and emissions costs. All energy storage systems incur energy losses. The electric energy compensating for the storage losses is assumed to be generated by combined cycle plant operating on the margin most of the time. The fuel and emission cost associated with the make-up energy is accounted for in the analysis. Annual costs incurred over a 50-year time horizon were collapsed into a single present value cost for each scenario using a real discount rate of 10.3%.

The results of the cost analysis are presented in Table E.1 and Figure E.1. Of the 11 cases examined in this paper, Case 2, which employs NaS batteries, is the least cost alternative at approximately $1.4 billion, followed by Case 7 (NaS and DR) in second place at estimated cost of about $1.9 billion, or 35.2% more than those for Case 2. The third most cost effective option is Case 9, which is 42.6% more expensive than Case 2. The costs associated with the demand response only case (Case 6) more than double those for the three aforementioned cases at $4.2 billion. The reason for that result was that DR resources were sized to meet the largest balancing requirement at the time of lowest DR resource availability. As a consequence for most of the time, the DR resource remains underutilized. In the pumped hydro case with 40 mode changes per day (Case 4), total costs are also much higher at about $4.0 billion. In most cases, the capital costs associated with the energy storage options are higher than those estimated for the combustion turbine case (Case 1) but these costs are offset by the higher fuel and emissions costs for combustion turbines.

Table E.2. Economic Analysis Results

Case	Capital	Fuel	O&M	Emissions	Total
1	1,759	905	276	312	3,252
2	1,076	125	129	43	1,372
3	2,139	91	122	31	2,383
4	3,720	120	120	41	4,000
5	6,949	422	372	145	7,889
6	4,222	-	-	-	4,222
7	1,619	100	102	34	1,855
8	2,425	73	97	25	2,620
9	1,671	123	121	42	1,957
10	2,550	205	190	71	3,016
11	2,331	98	100	34	2,562

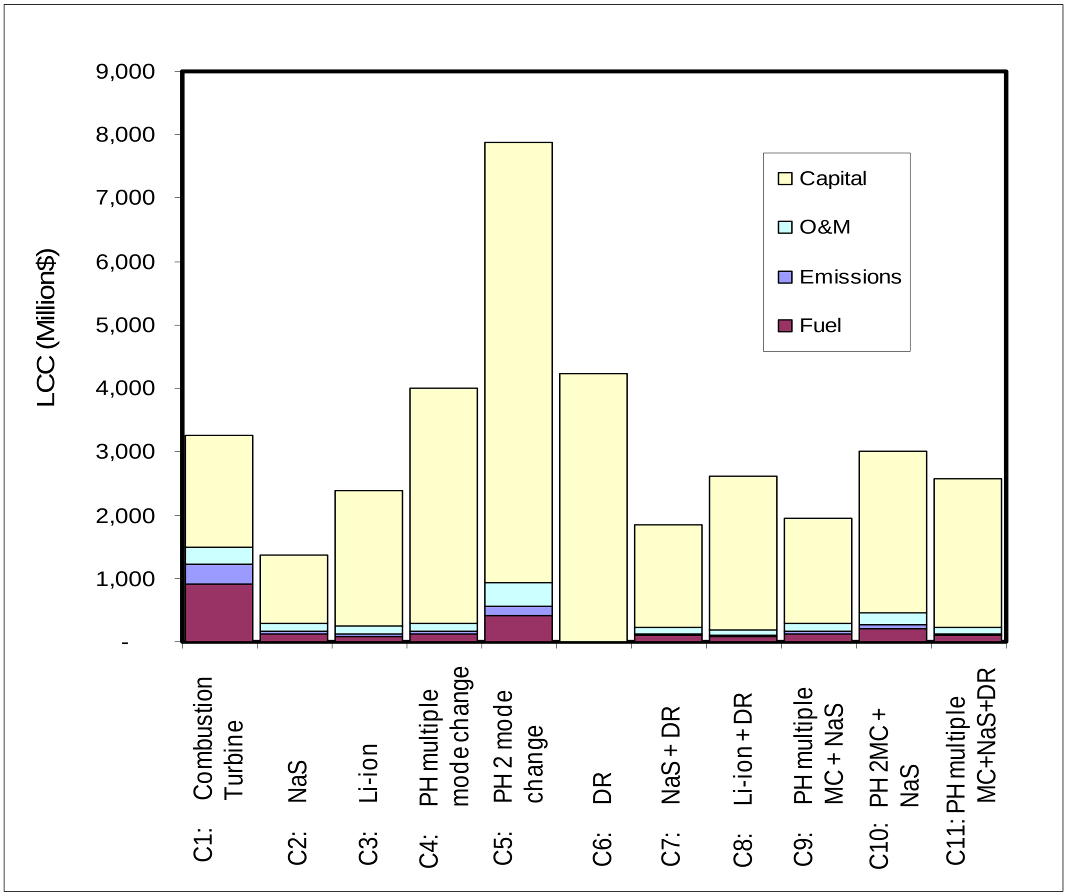

Figure E.1. Scenario Life Cycle Cost Estimates

This report also explores the financial feasibility of using pumped hydro systems for energy arbitrage in the BPA region. Pumped hydro systems are customarily used for energy arbitrage due to their energy storage capabilities. At low demand periods, low cost electric power is used to pump water from a lower reservoir to a higher one. At high demand periods when the cost of generating electric power is high, water is released through a turbine to generate electricity.

This study considers three pumped hydro energy arbitrage scenarios. The first scenario implements a 1 GW, 10 GWh pumped hydro system located at the Grand Coulee bus. The second scenario examines the 1 GW system at Grand Coulee with an additional 3 GW of wind power introduced in the Mid-Columbia Region. The final scenario examines four 0.25 GW, 2.5 GWh pumped hydro systems located at Grand Coulee, John Day, Malin, and Marion. Annual operating income (gross revenue minus operating costs) for the three scenarios were estimated at $2.7 million (Grand Coulee), $5.0 million (Grand Coulee with expanded wind power), and $6.4 million (0.25 GW, 2.5 GWh at four locations). With pumped hydro capital costs estimated at $1,750 per kW, each of these arbitrage scenarios fall significantly short of the revenue necessary for cost recovery. Thus, pumped hydro for arbitrage does not appear to be economically viable.

The results of this study clearly indicate that energy storage, and particularly electro-chemical storage, technologies can compete with conventional combustion turbines when used to meet specific balancing requirements that isolated the high ramp rate requirements in the intra-hour timeframe. This finding has general applicability beyond the investigated Northwest Power Pool footprint. Region-specific were only the amount and characteristics of the balancing requirements that were derived from BPA's understanding about the uncertainties in their load and wind production forecastings.

Energy arbitrage opportunities, however, may not be the key driver for large deployment of energy storage, at least not in the near term (i.e., 2010-2019 time horizon). Placement flexibility could be important for the economics of energy storage given that electro-chemical storage devices are not constrained to a specific geographic topology and hydrological system, unlike pumped hydro systems. In addition, there are other benefits that large-scale energy storage may provide that were not modeled in this study. For example, grid flexibility for transmission outage management is likely to improve with energy storage. Further studies with a particular focus on transmission system impacts are required to better explore these other value propositions.

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Acronyms and Abbreviations

ACE	Area Control Error
AEP	American Electric Power
AEO	Annual Energy Outlook
ANL	Argonne National Laboratory
BA	Balancing Authority
BASF	Badische Anilin- und Soda-Fabrik, Ludwigshafen, Germany
BC	British Columbia
BOP	Balance of Power
BPA	Bonneville Power Administration
CC	Combined Cycle
COB	California Oregon Border
CT	Combustion Turbine
DOD	Depths of Discharge
DR	Demand Response
E/P	energy/rated power
GC	Grand Coulee
GW	Gigawatt
GWh	Gigawatt-hours
ID	Idaho
KEMA	Keuring Electrotechnisch Materieel Arnhem, Global consulting company
kW	Kilowatt
Li-ion	Lithium-ion
LMP	Locational marginal price
LRS	Load and Resource Subcommittee
LTC	Lithium Technology Corp
MT	Montana
MW	Megawatt
MWh	Megawatt-hour
NaS	Sodium-sulfur
NREL	National Renewable Energy Laboratory
NW	Northwest
NWPP	Northwest Power Pool
O&M	operations and maintenance
OR	Oregon
P/E	power to energy
PC1	Planning case

PCS	power conversion system
PG&E	Pacific Gas & Electric
PH	Pumped hydroelectric
PHEV	Plug in hybrid electric vehicles
PNNL	Pacific Northwest National Laboratory
PROMOD	Production cost modeling software by Ventyx
RPS	Renewable portfolio standards
TEPPC	Transmission Expansion Planning and Policy Committee
WA	Washington
WECC	Western Electricity Coordinating Council

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1.0 Introduction

As the Bonneville Power Administration (BPA) and utilities across the United States consider options for reducing their carbon footprint while meeting expanding demand for electricity, service providers are actively searching for more cost effective and less environmentally damaging sources of energy. From 1995 to 2009, installed wind capacity expanded worldwide from less than 10 GW to nearly 150 GW, and the growth trend is forecast to continue reaching roughly 240 GW by 2012 (Thewindpower.net, 2010). Wind power technologies, however, cannot be dispatched because of its intermittent nature. Thus, while wind power presents a significant opportunity to BPA, because of its varying electricity output, integrating high levels of wind resources into power systems brings challenges to system generation scheduling and ancillary services.

Earlier studies have found that energy storage can compensate for the stochastic nature of intermittent energy sources by absorbing the excessive energy when generation exceeds predicted levels and providing it back to the grid when generation levels fall short. Energy storage could also be used to enhance the efficiency of the U.S. power system. During most hours, with the exception of peak hours, less than 50% of electricity system capacity is utilized. Thus, a significant amount of power system assets have been built to meet only a few hundred hours of peak demand each year. Including energy storage could reduce the peak demand by storing energy during off-peak hours and selling it back into the grid during peak times, offering an alternative to expanding power generation capacity.

In recent years, utilities have recognized that energy storage could be an important element of the future power system and have begun to install energy storage units in their systems. Examples of recent installations include:

- Pacific Gas & Electric (PG&E) has installed a flywheel at the Distributed Utility Integration Test (DUIT) development facility in San Ramon, CA and is planning to install a 4 MW, 28 MWh sodium sulfur (NaS) battery for energy, regulation and load following services.
- American Electric Power (AEP) built a 1.2 MW, 7.2 MWh NaS battery in 2006 for peak shaving, and has a goal of achieving 1,000 megawatts of advanced storage capacity on its system in the next decade.
- Austine Energy placed a 4 MW NaS battery into service in 2009.

While these and other recent energy storage investments signal an advance in the efficient management of the electric power system, additional engineering and economic analyses are required as part of grid operator energy storage planning prior to wide deployment of energy storage.

With the growing contributions of intermittent energy resources across the U.S. and in the Northwest Power Pool (NWPP), load balancing requirements are expected to grow. With sophisticated wind production forecasting methods, forecasting errors are expected to decline, however, only to a certain degree. A finite error in the wind production forecast will always remain, such that the total balancing requirements are likely to increase with continuing growth in intermittent energy resources.

In this report, we present a general methodology for estimating balancing requirements for the 2019 timeframe under a 14.4 GW wind scenario in the NWPP. Further, we examine 11 cases for meeting balancing requirements using an array of technologies, including NaS and Li-ion batteries, combustion turbines (CT), demand response (DR), and pumped-hydro energy storage (PH).

This report is divided into seven sections with the first being this introduction. The second section of this report presents overarching study objectives. The third section presents an overview of the technologies designed to provide load balancing services, including cost and performance characteristics. The fourth section of this report provides an overview of the approach and data used to determine balancing requirements for the NWPP in 2019, and presents the results of the load balancing forecast. The fifth section of the report documents the cost analysis framework used in this study as well as cost analysis results for each of the 11 technology cases. Arbitrate opportunities for energy storage are presented in the sixth section of this report. The seventh, and final, section of the report presents conclusions.

2.0 Objectives

This report addresses several key questions in the broader discussion on the integration of renewable energy resources into the Northwestern power grid. In particular, it focuses on the questions of how much total reserve or balancing requirement is necessary to accommodate the intermittent wind energy resources. As an extension of analytical methodology development during the summer of 2009, Pacific Northwest National Laboratory (PNNL) was asked by the Bonneville Power Administration (BPA) to utilize these techniques for a regional assessment of the Pacific Northwest, with a sufficiently high level of spatial resolution to capture key drivers that determine the balancing requirements relevant to BPA. The spatial scope was expanded to include the Northwest Power Pool. Key reasons for that decision were that an expanded scope offered greater diversity in the wind resources and that it would allow the study to assess the transmission impacts in a broader Pacific Northwest context.

The study discussed in this report established the balancing requirements for a time horizon of 2019 postulating a scenario of 14.4 Gigawatt (GW) of wind generation capacity in NWPP, which was based on a 20% Renewable Portfolio Standards (RPS) scenario, primarily composed of wind resources. To provide a sense of reference the installed wind power capacity in NWPP in 2008 was 3.3 GW. The study determines the cost-optimal investment strategies of meeting the new balancing requirements for a high wind penetration scenario. A rich set of technology options is considered; it included conventional combustion turbines, as well as new advance utility-scale battery technologies, comprised of lithium-ion (Li-ion) and sodium sulfur (NaS) batteries, as well as pumped-hydro energy storage and demand response strategies. Hybrid energy storage options, comprised of NaS/pumped hydro and Li-ion/pumped hydro, with and without demand response strategies were comparatively assessed from a life-cycle cost point of view. This provides significant insights into the trade-off of capital cost versus operating cost and externalities such as emissions over the entire life of the storage project. In addition to estimating the balancing requirements and analyzing cost optimal technology investments to meet them, the study explores the cost effectiveness of energy arbitrage opportunities. BPA requested an analysis of the arbitrage value of a specific energy storage system at a specific location in the grid. The net revenue potential from energy arbitrage is quantified using a production cost model that simulated a security-constrained unit commitment and cost-optimal generator dispatch for the Western Electricity Coordinating Council (WECC). To provide credibility of the underlying assumptions of the grid infrastructure for a high renewable energy resource scenario in 2019, we adopted the Transmission Expansion Planning Policy Council (TEPPC) base case model, developed by WECC staff with participation by a broad stakeholder group.

This report addresses the following questions:

- How much capacity is necessary to meet total balancing requirements for the NWPP for assuming 14.4 GW of wind energy?
- What are the cost-optimal technology options to meet the balancing requirements based on a life-cycle cost analysis considering value of emissions (NO_x, SO_x, CO_2)?
- How cost effective is energy storage for a specific location in the BPA footprint for a specific size of energy storage? How sensitive are the results with respect to location and size?
- What are the key lessons learned from this study?

3.0 Technology Choices for Balancing Services

3.1 Introduction

To mitigate the additional intermittency and fast ramps at higher penetration of intermittent energy resources (i.e., wind power in our case) in NWPP, the conventional solution is to build more peaking units such as combustion turbine units. However, the advancement of battery technology, smart grid concept coupled with demand response options, and the anticipated need for carbon reduction, places new emphasis on exploring non-conventional resources and a broader set of technology options for providing the ancillary services requirements that traditionally have been provided by fast-starting and flexible combustion turbines.

The following technologies are considered for this study:

- Combustion turbines, as the base-case technology
- Sodium sulphur (NaS) battery
- Li-ion battery
- Pumped-hydro energy storage
- Demand response

This following section provides a high level overview of the above technologies. A detailed discussion on the cost and performance characteristics of battery technology considered is provided in the Appendix A.

3.2 Technology Overview

3.2.1 Combustion Turbine

Combustion turbines, as applied in this study, are designed to provide an output of about 160 MW while operating at an energy efficiency of 31.5%. The efficiency is expressed in terms of a heat rate of 10,833 British Thermal Units per kilowatt-hour (Btu/kWh) at full load condition. It increases with lower part loads conditions (EIA 2008). In 2019, combustion turbine capital costs are estimated in the 2010 Annual Energy Outlook at $723 per kW (EIA 2010). The economic life of the combustion turbines is estimated to be 15 years.

3.2.2 Combined Cycle Plant

Although the combined cycle plant is not directly applied as a technology option for providing balancing services, it provides the electric energy fed through the energy storage system. It is, thus, the energy provider on the margin that makes up for the energy losses in the storage device. The cost for fuel, operating and maintenance (O&M), and emissions associated with the energy lost in storage are considered in the life-cycle cost analysis.

The typical size of a combined cycle power plants is about 250 -300 MW. The design heat rate is commonly cited 7,196 Btu per kWh (EIA, 2008). The efficiency of a combined cycle power plant is generally higher than that of a combustion turbine. Typical design efficiencies are around 47%. The economic life of the combined cycle power plants is estimated at 15 years. More detail regarding cost assumptions underlying both combustion turbines and combined cycle power plants is presented in Section 5. The capital costs associated with combined cycle power plants is not considered in this analysis because of the assumption that these units would already be on-line and available for use.

3.2.3 Energy Storage Technologies

The largest NaS battery system tested is a 34 MW battery system installed in Rokkasho village in Aomori, Japan(NGK Insulators, LTD), while the corresponding number for Li-ion system is 2 MW (KEMA 2008). A 12-MW energy storage system is being installed by AES using Li-ion batteries supplied by A123 Systems (Parker 2010). Pumped hydro systems are available in the order of hundreds of MW and MWh.

Of the three energy storage technologies considered, pumped hydro energy storage is technologically most matured. The table below provides a perspective of the level of maturity based on installed capacity of grid-connected storage in the US and globally (Nourai 2009).

Table 3.1. Installed Capacity for Various Energy Storage Devices in the US and Worldwide

	US (MW)	Global (MW)
Pumped Hydro	23,000	110,000
Compressed Air	110	477
Batteries	40	300
Other	5	10

The table suggest that there is significant room for cost and performance improvements of the less matured technologies (compressed air and batteries), while pumped hydro technology, due its maturity, are not likely achieve cost reduction – at least on at the same rate as the nascent battery technologies.

3.2.3.1 Sodium Sulphur (NaS) Battery

The response time for both NaS and Li-ion battery systems is in the order of a few milliseconds (Divya and Østergaard 2009). This allows them to provide power instantaneously as demanded by the grid. While numbers as high as 90% have been used for battery efficiency, it is important to use appropriate efficiency values that correspond to power needs for various applications. It would also be useful to take into account battery degradation as a function of calendar and cycle life to incorporate losses in specific power/energy, power/energy density and efficiency losses as battery state of health degrades. For this analysis, a system efficiency of 78-80% was used for both battery systems. This value also includes efficiency losses from the power conversion system (PCS).

NaS batteries currently commercially available are designed to discharge over periods as long as 7to10 hours (Kamibayashi et al. 2002, Nourai 2007). When these batteries are used for very small durations (in the order of seconds to minutes), the batteries can provide power as high as 5 times the rated power, where the rated power is defined as power for a 7-hour discharge (Kamibayashi et al. 2002). For this study, peak power occurs for only 1to 2 minutes, hence the required power rating of the battery that is needed could be as low as 1/5 of the peak power. At present, NaS batteries are commercially available in an energy/rated power (E/P) ratio of 6-7. For this study, it has been assumed that in future, batteries with E/P as low as 1 will be available to avoid over-sizing the batteries.

3.2.3.2 Li-ion Battery

Li-ion batteries are available from various sources, A 2-MW battery from AES, with the battery supplied by Altairnano, was tested under the direction of KEMA recently (KEMA 2008, Altair Nanotechnologies 2008). A battery management system monitored battery cell temperatures, balanced cell voltage and kept track of battery state of charge. Three single phase Parker Hannifin SSD power inverters were coupled to isolation transformers and fed into a step-up transformer with the battery side running at 480 V and the grid side at 13.8 kV. These voltage values are important, since capital cost of PCS depends on the minimum voltage at the battery side, as will be discussed later. These batteries performed well and dispatched power almost instantaneously. It remains to be seen how they would hold up over the long-term and what the impact would be of connecting several batteries in series/parallel configuration to provide the required output voltage and power.

3.2.3.3 Pumped-Hydro Energy Storage

Pumped-hydro (PH) energy storage technology has been used for various utility applications. One of its limitations is the need to wait prior to reversing direction from charge to discharge. Variable speed pumps/turbines allow better control of ramp rates, but cost more. A detailed discussion of PH is provided in the Appendix A.

The response time for pumped hydro systems is fast achieving high ramp rates of 3 MW/s(First Hydro Company 2009). The calendar life was estimated to be 50 years (Schoenung 2001). There is however, a waiting period of several minutes every time the operating mode change. Through several consultations with turbine and pumped hydro storage system experts, it was determined that a delay of 4 minutes to switch operating modes in both directions (pumping to generation and vice versa) is applicable. This delay renders the machine inoperable. Thus, some additional resources must be assigned during that period as a 'back-up' resource. Chosen was a NaS battery to function as back-up resource.

3.2.3.4 Pumped-Hydro Energy Storage Operating Design

To meet the balancing requirements, two operating design options are investigated. The first option emulates the operation of a battery system that permits rapid changes between charging and discharging modes in accordance to the balancing requirements. Advancements in the turbine/pump design allows for frequent mode change between pumping (charging) and generating (discharging) modes. However, as noted above because of the significant hydrodynamic and mechanical inertia in the turbine, a delay of not insignificant duration is required. The estimated 4-minute delay is of sufficient significance for meeting the balancing requirements causing the backup resource to be sized quite large.

The alternative and more commonly observed operation of pumped-hydro storage is a 2-mode operating schedule, whereby the machine is operated in a pumping mode during the off-peak hours and in a generating mode during the day. While in either of the modes, the machine can meet the balancing requirements. However, the pump/generator size must be upsized compared to ‘multiple-mode-changes’ mode because the balancing requirements must be met in both pumping and generating model individually. This requires a pump/generator size the covers the entire swing from full increment to full decrement. A very small NaS battery is applied as backup resource to meet the balancing requirements during the 2 mode change.

3.2.4 Demand Response

Demand response is an unused resource fully capable of providing balancing services. Similar to a generator that provides balancing services, a load customer who operate up and down from an original operating point create a balancing serve value. In fact, PJM allows large load customers to participate in the regulation services markets. Small loads such as residential and commercial customers can also deliver these services to the grid. The challenge is how to coordinate a large number of small devices to operate in a coordinated fashion such that they deliver value reliably at a sufficient scale. Communications technology and smart grid control strategies will advance the access and, thus, the utilization of small residential and commercial end-use devices to deliver value to the grid.

For the purpose of this study, a short list of likely candidates of residential end-uses was selected for this particular demand response service. It was recognized that demand response in the balancing service context, would require end-use appliances to move their operating point according to the balancing signals. This requires the resource to be available 24-hours a day and 365 days a year and include device control technologies that enable these grid services (Lu and Hammerstrom 2006). Residential electric hot water heaters and plug-in hybrid electric vehicles (PHEVs) are selected as the two key candidates for this service, recognizing that other appliances may contribute as well at certain times. Residential hot water heaters have fairly established load profiles (Pratt 1989) and are one of the largest electricity consumers in residential homes. PHEV are not currently mass produced, and it will take some time for the PHEVs and other electric vehicles to gain market share to amount to a sizable load. However, significant efforts in standardizing the communication to the vehicles are underway to enable smart charging strategies. This would make electric vehicles a likely candidate for providing balancing services.

Currently in the entire NWPP footprint, there are 7.3 million housing units and the majority have an electric hot water heater. The number of light-duty vehicles (cars, sports utility vehicles (SUVs), van, pickup trucks) as of 2001 is about 11 million vehicles. The individual load profiles for a hot water and two charging profiles for one PHEVs are shown in Figure 3.1.

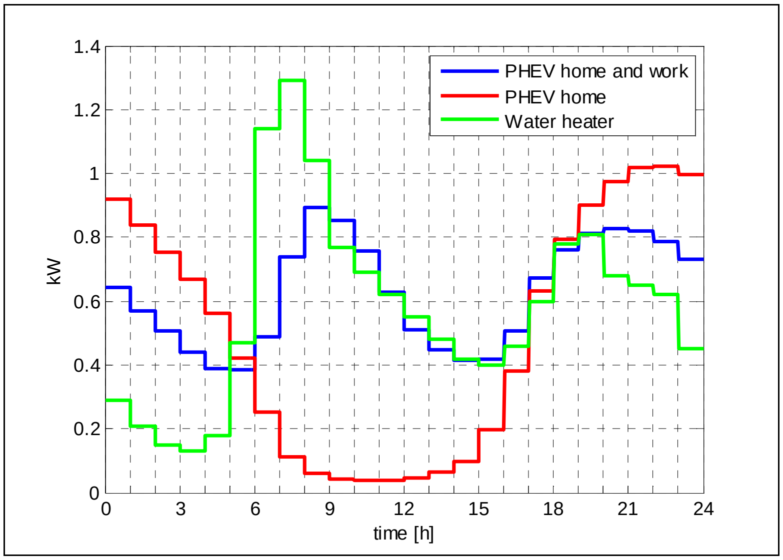

Figure 3.1. Load Curves for PHEV with Home and Work Charging, PHEV With Home Charging[1], and Water Heater

3.3 Technology Cost and Performance Characteristics

3.3.1 General Discussion

Energy storage devices, unlike electric generators, have two capability ratings: 1) the power rating, expressed in kW or MW and the energy rating, expressed in kWh or MWh. This poses a challenge when comparing energy storage equipment with generators, which generally are not energy limited. To fully describe the incremental cost of an energy storage device, generally two specific cost indices must be used: cost per unit power ($/kW) and cost per unit energy ($/kWh). The literature is relatively inconsistent in this regard. Often battery devices are characterized by their incremental cost per unit energy ($/kWh) masking the cost associated with the balance of power (BOP) and PCS, which is scaled by the unit of power, or $/kW. The costs for pumped hydro projects are most commonly specified in $/kW, presuming that the cost associated with setting the energy content of the project is not scalable. In most cases, it is determined by the topology of a given location, which sets the size of the reservoir.

For the purpose of this report, a methodology of describing the incremental cost of energy storage devices was used that reveals both the cost that scales with the power rating ($/kW), and the cost that scales with energy content of the device ($/kWh).

To determine the capital costs, the energy storage device has to be sized based on the power and energy needs of the application. If the power needed is high compared to energy requirements for the application, the battery size is determined by the power; the selected battery clearly will have more energy than needed by the application. However, if the power requirement is much smaller than the energy needs, the battery size is determined by the energy needs of the application. The battery costs are typically given in $/kWh, which can be converted to $/kW, where the kW is rated power of the battery. Typically, *rated power* is continuous power, and is defined as power that can be sustained for at least 15

[1] Based on simulations using the USDOT 2001 National Household Travel Data (DOT 2003).

minutes. *Peak power* typically is defined as pulse power for 2-second duration. The ratio of peak power/rated power is a function of battery chemistry and design.

3.3.2 Summary of Capital, O&M Costs and Efficiency for Batteries and Pumped Hydro Systems

Based on the values obtained from an extensive literature review and through many consultations with domain experts, Table 3.2 summarizes the values used in this study, with 2019 values within parenthesis. More detailed cost and performance characteristics as well as ranges of cost as found in the literature are included in the Appendix A.

Table 3.2. Summary of Capital and O&M Costs for Technologies Analyzed. Note values are representative for 2010 technologies. 2019 values are in parenthesis

Parameter	NaS battery	Li-ion battery	Pumped hydro	Combustion turbine	Combined cycle	Demand response
Battery Capital cost $/kWh[1]	415(230)	1000 (510)				
System Capital cost $/kW			1750 (1890)	695 (723)	Not used	489
PCS ($/kW)	200 (150)	200 (150)				
BOP ($/kW)	100	100				
O&M fixed $/kW-year	0.46[2]	0.46	4.6	12.75	13.79	
O&M fixed $/kW-year (PCS)	2	2				
O&M variable cents/kWh	0.7	0.7	0.4	0.376	0.217	
Round trip efficiency	0.78	0.80	0.81	0.315		

3.4 Definition of Technology Options

The set of technologies mentioned above can be applied individually or in combination with other technologies. Technology ‘packages’ of up to three technologies are investigated. These technology packages can be thought of as a portfolio of resources that in most cases will be dispersed through the NWPP area. Only in the case of pumped hydro energy storage would a single location, or potentially a few locations be viable based on the topology to support upper and lower reservoirs. For most of technologies, the actual capacity will be widely disperse. This is particularly the case for demand response. Table 3.3 shows the 11 single technology packages, which we will call ‘cases’.

[1] The battery capital cost is per unit energy, while PCS and BOP costs are per unit power
[2] $/kWh

Table 3.3. Definition of Technology Cases

	Case	Technology	Comments
Individual Technologies	C1	Combustion turbine	Conventional technology considered as the reference case
	C2	NaS	Sodium-sulfur battery only
	C3	Li-ion	Lithium-ion battery only
	C4	PH with multiple mode changes	Pumped hydro with a 4-minute waiting period for mode changes (pumping-generation and vice versa). This machine allows to multiple mode changes during the day. NaS battery is assumed to make up operations during 4 minute waiting period.
	C5	PH with 2 mode changes	Same as (C4), except only two mode changes. Balancing services will be provided during pumping mode at night (8pm-8am) and during generation mode during the day (8am-8pm). NaS battery is assumed to make up operations during 4 minute waiting period.
	C6	DR	Demand response only. This assumes that balancing services will be provided as a load. Only considered are two residential end-uses: 1) hot water heating and 2) PHEV charging at home. Resources will expressed in MW of DR capacity as well as in numbers of homes having one hot water heater and one PHEV
Technology packages	C7	NaS DR	Sodium-sulfur battery and demand response combined
	C8	Li-ion DR	Lithium-ion battery and demand response combined
	C9	PH with multiple mode chances NaS	Pumped hydro with no constraints for mode changes with NaS battery. The balancing requirement is allocated to 25% to pumped hydro and 75% to NaS battery. This share is set arbitrarily.
	C10	PH with 2 mode changes NaS	Pumped hydro with two mode changes per day (see C5) with NaS battery. The balancing requirement is allocated to 25% to pumped hydro and 75% to NaS battery. This share is set arbitrarily.
	C11	PH with multiple mode changes NaS/DR	Pumped hydro with no constraints for mode changes with NaS battery and DR. The balancing requirement is allocated to 25% to pumped hydro, 20% DR (about 1 million homes and PHEVs) and 55% to NaS battery. This share is set arbitrarily.

4.0 Balancing Requirements

4.1 Overview of Analysis Framework

PNNL developed a stochastic analysis framework to estimate the balancing requirements associated with forecasting errors for both load and for generation from intermittent energy resources. This analysis framework includes tools for estimating balancing requirements expressed in terms of maximum power required and maximum energy required (if energy storage is chosen) to meet the requirements. It provides a set of sizing tools to dispatch one or several resources to meet the balancing requirements. The resources can be energy limited, such as energy storage devices, commonly used generator or demand response strategies. Several different dispatch strategies have been developed to dispatch an ensemble of several storage devices or bundled resources comprised of demand response, energy storage systems, and generators. The output of this tool are size requirements of all resources, as well as dispatch profile by resource, fuel requirements, and emissions. The size requirements are expressed as a pairing of power and energy capacities necessary to meet the balancing requirements. As part of the analytics suite, a life-cycle cost optimizer was developed that compares different hybrid energy storage system options based on a life-cycle cost to seek the lowest cost technology option.

4.2 Approach and Data Used to Determine Balancing Requirements

The fundamental approach of the PNNL methodology is outlined below. A full description of the methodology can be found in (Makarov et al. 2010). The approach uses historic load data and understanding of how the load forecasting errors are statistically distributed. In addition, wind profile data are necessary both from existing wind farms and new hypothetical wind resources that are presumed to be developed in the foreseeable future. The analytical approach includes the following components and individual steps:

1. Determine a future renewable portfolio standard (RPS) scenario and determine the necessary intermittent resource requirements to approximately meet the standards. Selection of wind resources for meeting the RPS standards.
2. Placement of resources: Place hypothetical wind farms at plausible wind sites that have high capacity factors.
3. Scale existing wind and load forecasting errors from BPA's existing wind sites to new hypothetical wind sites to obtain new balancing requirement components from intermittency of the wind resource. Combine load forecasting error from BPA with that of the NWPP load.
4. Develop a stochastic process that generates a minute-by-minute balancing requirement for the entire NWPP footprint. This assumes a consolidation of all of the existing balancing authorities into one unified balancing area. Furthermore, the output will be the total balancing requirements, derived from total loads and the entire wind capacity.
5. Define a set of technology options that will meet the total balancing requirements.
6. Analyze the life-cycle cost of technology options over a 50-year time horizon.

4.2.1 Wind Datasets

As a starting point, BPA's existing wind production data (with a 1-minute time scale) was used within the BPA footprint. For the wind capacity additions (both within BPA service territory and outside), the National Renewable Energy Laboratory (NREL) Wind Integration Datasets (NREL 2009) were utilized, which provided 10-minute interval production schedules for over 30,000 hypothetical wind sites. The projection of BPA's wind capacity addition as seen in Figure 4.1, guided the approach to allocate sufficient new wind resources into the BPA service territory.

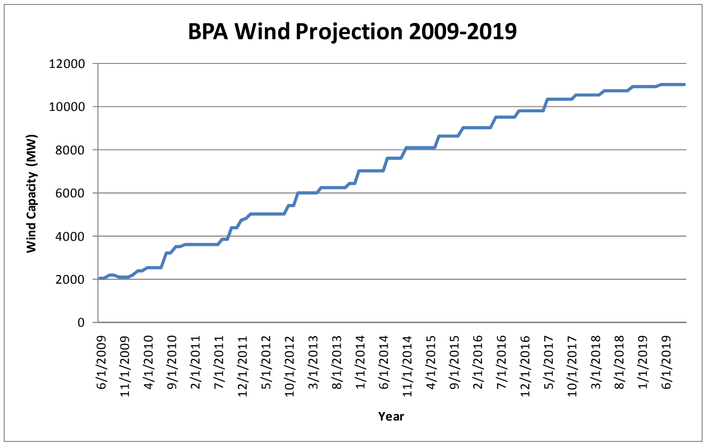

Figure 4.1. BPA Wind Projection 2009-2019

The Wind Integration Datasets from NREL are wind production simulated for 32,043 wind sites in the WECC system with 10-minute intervals. The information of the datasets is briefly shown in Table 4.1.

A 20% wind penetration scenario is hypothesized. In other words, the installed capacity of wind generation will reach 14.4 GW in NWPP by 2019. The placement of the new wind capacity is done by considering both the best wind resource and proximity to load or transmission lines. The selection of wind sites is done with some degree of arbitrariness. Even when selecting only the best wind class (6 and 7) land areas in proximity to transmission above 230kV, the supply of available wind resource was significantly larger than what was needed for the 14.4 GW addition. Figure 4.2 shows the selected wind capacity distribution by state. The average capacity factor (CF) of the new wind sites is around 35%. Figure 4.3 illustrates all the planned wind sites and currently existing wind sites in NWPP.

Table 4.1. Information About NREL Wind Integration Datasets

	Western Dataset
Produced by	3Tier
Mesoscale Model	WRF
Number of Output Points	32,043
Size of Output Point	1 arc-minute^2
Output Point Capacity (MW)	30
Model Output Heights (m agl)	100m
Turbine Power Curves	Vestas V-90 3MW

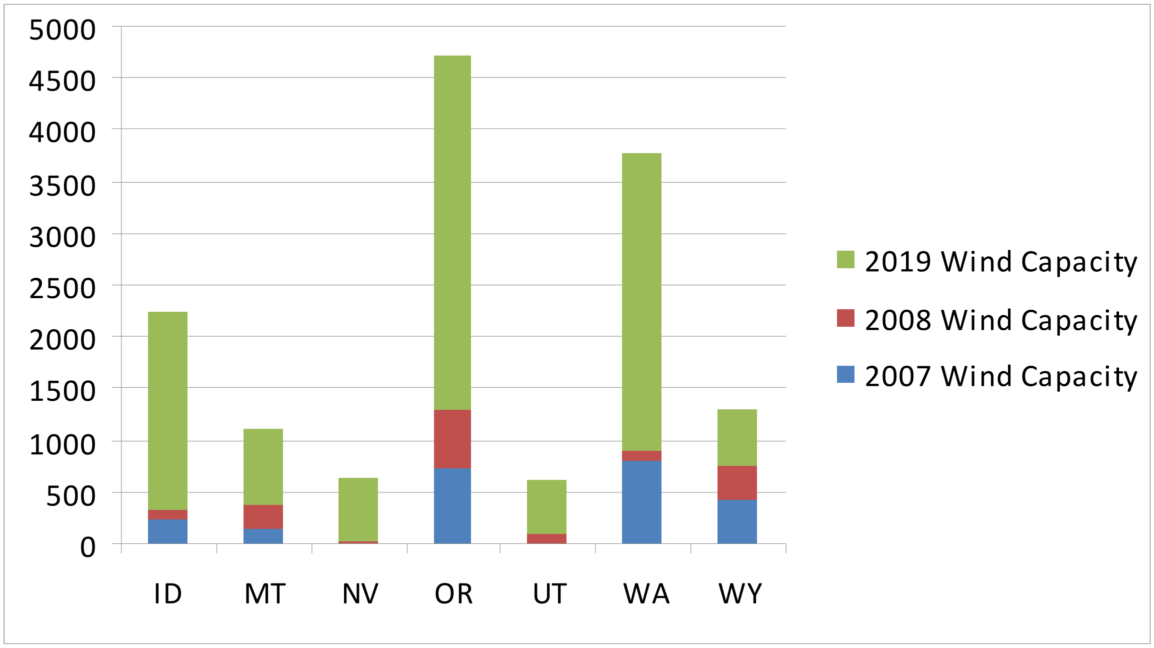

Figure 4.2. Distribution of Wind Capacity by States

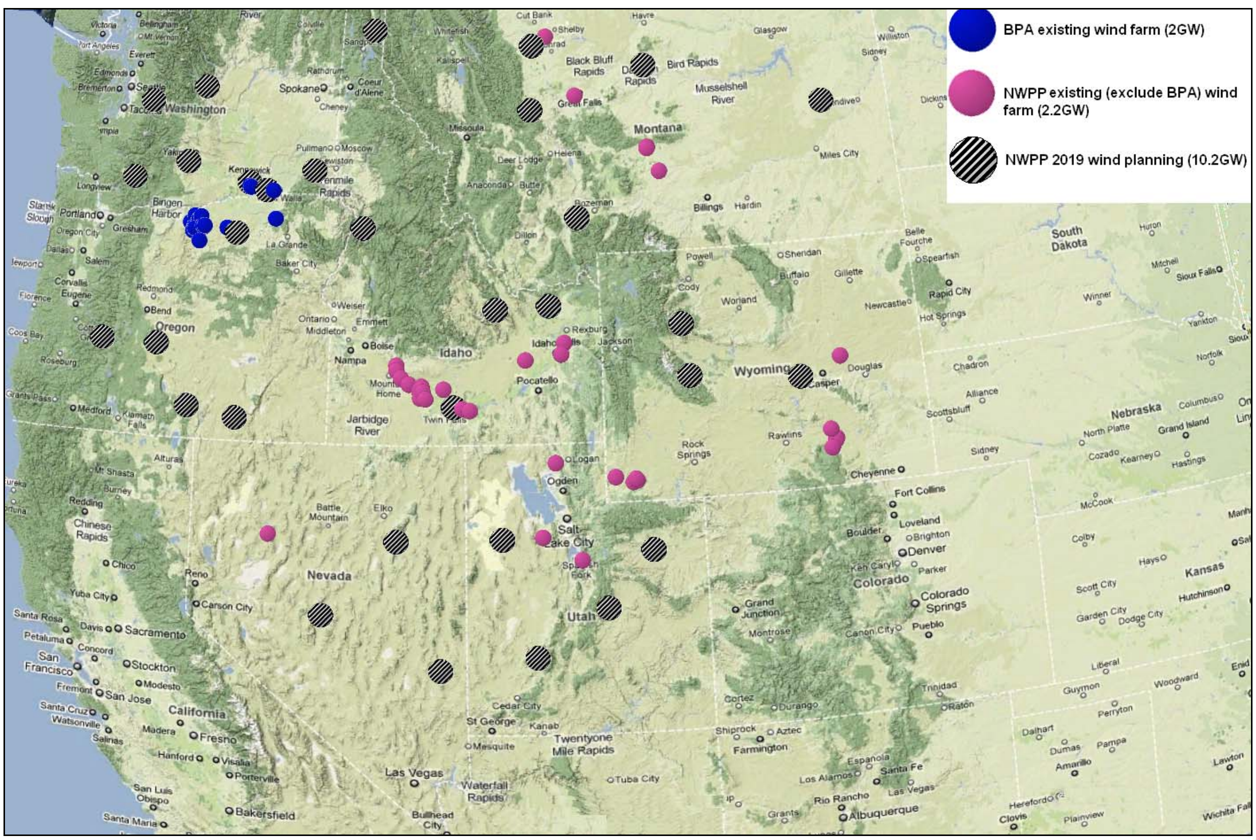

Figure 4.3. Location of Existing and Arbitrarily Sited Future Wind Plants. Total NWPP Capacity Assumed to be 14.4 GW in 2019

To obtain the balancing requirements, minute-by-minute wind production data are desirable. However, for the hypothetical wind sites, only 10-minute interval datasets are available. Therefore, the 10-minute interval data are interpolated to generate the required minute by minute data. The implication of the interpolation is that we underestimate the balancing requirements for fluctuations with a period of less than 10 minutes (or 1/600 Hz). Wind hourly forecast is obtained by averaging wind production of every hour and superimposing BPA wind forecast error on the hourly average. Wind production in 2019 of each wind plant is assumed the same as that of today, and the statistical characteristics of the wind forecast error match the truncated normal distribution (parameters of the distribution such as mean, standard deviation, and autocorrelation are consistent with the statistical features of the BPA wind forecast). The statistical information of BPA hour-ahead wind forecast error is shown in Table 4.2.

4.2.2 Load Datasets

The minute-by-minute actual load data and hour-ahead load forecast for the BPA service territory are obtained from BPA. In this analysis, we assume the hourly generation schedule is the same as the hour-ahead load forecast. BPA's annual load growth projections throughout the period to 2019 is used, which is assumed to be about 1.19% annual growth. No modifications of the current load shape were assumed. For the remaining balancing authorities within the NWPP, hourly load data from Ventyx PowerBase® are utilized with similar annual load growth assumptions as used for the BPA footprint.

Hourly data are interpolated to generate minute-by-minute actual load data. For the whole NWPP, the hourly load forecast is generated by adding load forecast error to the hourly average of load. The load forecast error is assumed to have a truncated normal distribution with the same statistical characteristics as BPA current load forecast. Table 4.2 shows the statistics for both the load and wind production forecast errors.

Table 4.2. Statistics of Hour-Ahead Forecast Error

	Wind Forecast	Load Forecast
Mean error	0%	0%
Standard deviation	7%	2%
Auto correlation	0.6	0.9

4.2.3 Balancing Service Requirement

The power system control objective is to minimize its area control error (ACE) to the extent that complies with the North American Electric Reliability Corporation (NERC) Control Performance Standards. Therefore, the "ideal" regulation/load following signal is the signal that minimizes deviations of ACE from zero when they exceed a certain thresholds:

$$\begin{aligned} -ACE &= -(I_a - I_s) + \underbrace{10B(F_a - F_s)}_{Neglected} \\ &\approx G_a - L_a \rightarrow \min \end{aligned} \tag{4-1}$$

where the a subscript denotes actual, s denotes schedule, G_a is the actual generation, and L_a is the actual load within the control area. Extending the generation component in the ACE equation,

$$G_a = G_s + G_{IB} \tag{4-2}$$

is obtained where the subscript s denotes hour-ahead schedule, and IB denotes the generation required to meet intra-hour balancing requirement. The generator output is assume to not deviate from its schedule. That is,

$$G_s = L_{f\_ha} \tag{4-3}$$

where f_ha denotes hour-ahead forecast, and set ACE to zero. The intra-hour balancing signal can be calculated by equation below.

$$G_{IB} = L_a - L_{f\_ha} \tag{4-4}$$

When wind generation is included, wind is counted as negative load. Therefore,

$$G_{IB} = L_a - L_{f\_ha} - (G_a^w - G_{f\_ha}^w) \tag{4-5}$$

Figure 4.4 illustrates the concept of over- and under-generation as a result of the forecasting errors for both the load and the wind energy production. The over-and under-generation is then the balancing signal, which balances generation and load and minimizes the ACE.

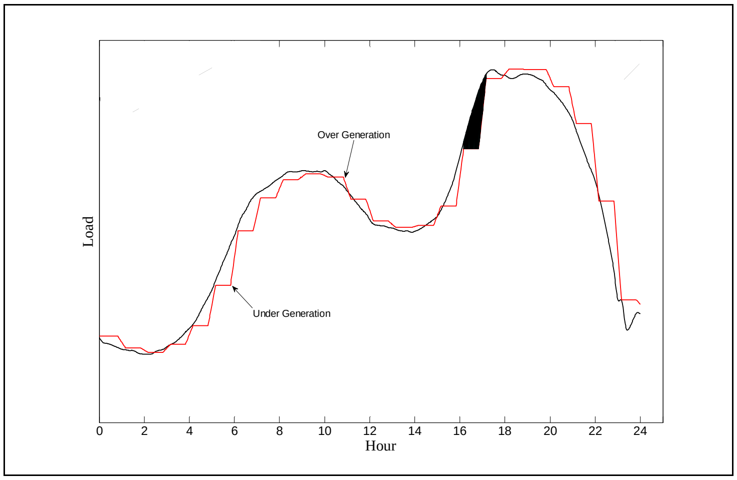

Figure 4.4. Illustration of Intra-Hour Balancing Signal

4.2.4 Consolidation of Balancing Areas

To simplify the analysis, one single consolidated balancing authority (BA) comprised of all individual balancing authorities in the NWPP is assumed. This simplification reduce the analysis complexity significantly. Instead of performing a BA-by-BA analysis and combining the results for the NWPP, the consolidation collapsed the complexity into a single zone. There are implications to this simplification.

The consolidation of balancing authorities will provide greater sharing of balancing and reserve resources among all constituents and offer opportunities to more effectively utilize the higher degrees of diversity of the intermittent renewable energy resources across the entire NWPP footprint. As a consequence, the balancing requirements are likely to be smaller in a consolidated large BA area than the sum of all individual BA areas as they currently exist. This will lead to an underestimation of the future requirements under the existing BA regime.

4.2.5 Resulting Total Balancing Signal

The total balancing requirements of the NWPP are estimated utilizing the wind and load datasets as discussed above. Figure 4.5 and Figure 4.6 illustrate the resulting balancing requirements signal for the NWPP for the whole month of August 2019 and one typical day in August 2019, respectively. These estimated values represent the total requirements, as opposed to additional requirements. The balancing-up (in BPA parlance: increment or inc.) power capacity requirement is 3916 MW and the balancing-down (in BPA parlance: decrement or dec.) power capacity is -3683 MW. These figures are based on BPA's customary 99.5% probability bound that meets 99.5% of all balancing requirements. That means that 0.5% of all of the anticipated balancing capacity exceeds that bound. For a 100% probability bound, the maximal balancing requirements are about 5000 MW in for the increments and about -4000 MW for the decrement.

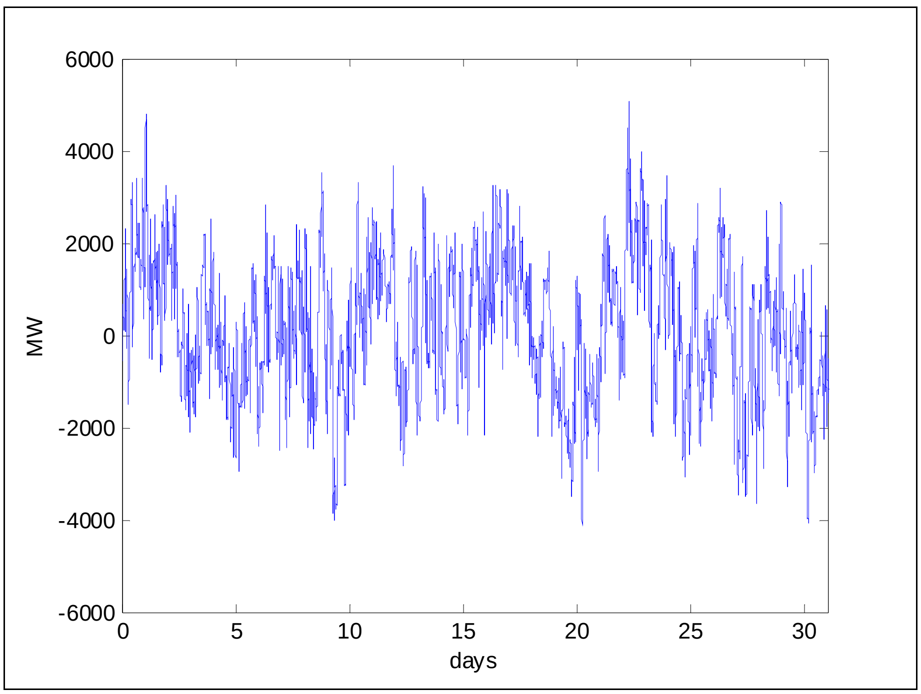

Figure 4.5. Total Balancing Requirements for NWPP for the Month of August 2020

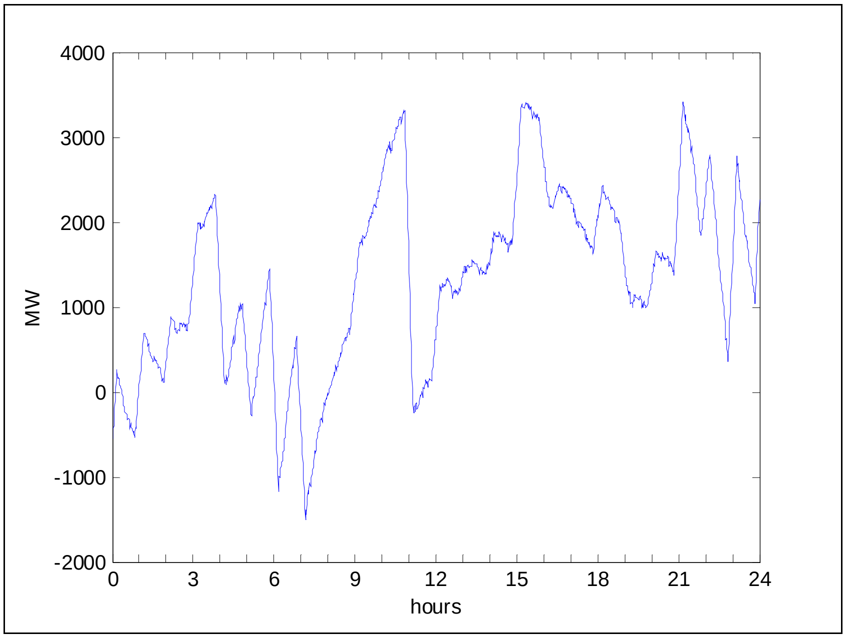

Figure 4.6. Total Balancing Requirements for NWPP for One Typical Day in August 2020

The balancing signal shown in Figure 4.6 exhibits a spectrum of cycling or oscillatory content. Cycles at lower frequencies with periods of several hours (intra-day) are considered to be addressed by the energy markets that re-dispatch generators on an hourly basis. The deviations from the day-ahead schedule generally do not require fast ramp rates and, thus, are not considered part of the balancing requirements in this study. Cycles within the hour (intra-hour balancing) are a key focus of this analysis. The following section discusses the filtering strategies to the extract the intra-hour cycling from the original balancing signal.

4.2.6 Spectral Analysis and Extraction of Intra-Hour Balancing Signal

A high-pass filter was designed to filter out the fast cycles (intra-hour and real-time components) from the original balancing signal (Makarov et al. 2010). The cut-off frequencies for the filter were f_l=1.157e-5 Hz and f_u=0.2 Hz. The spectral analysis of the balancing signal illustrates the oscillatory content in the signal. The results of the spectral analysis are shown conceptually in Figure 4.7 and Figure 4.8. Table 4.3displays the frequency limits for the high-pass filter design.

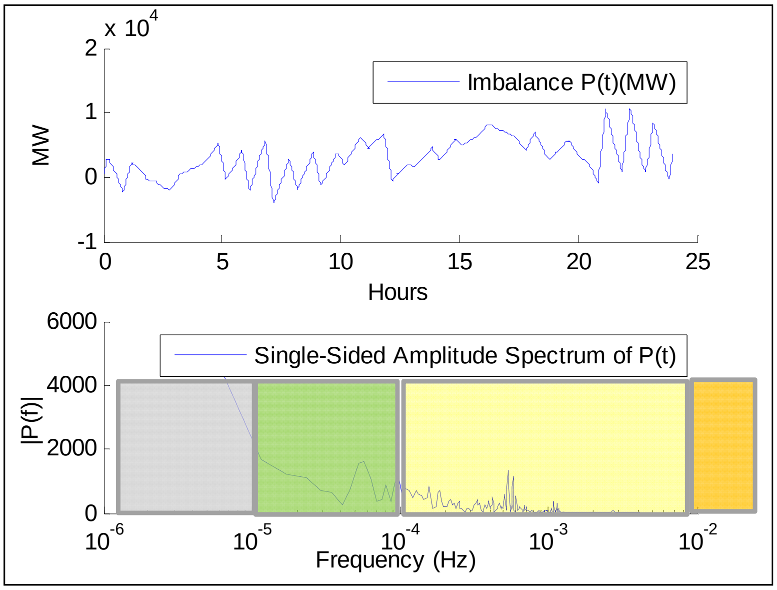

Figure 4.7. Spectral Analysis of Balancing Signal

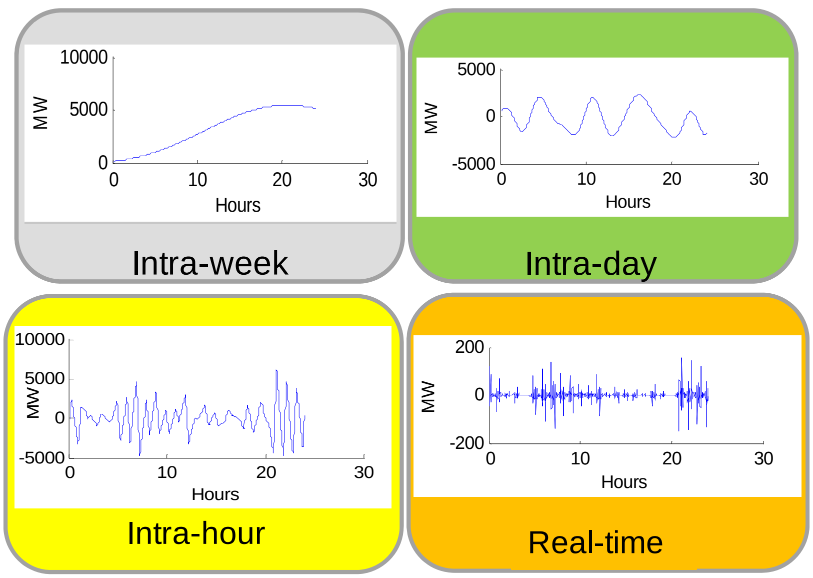

Figure 4.8. Components of Decomposed Balancing Signal

Table 4.3. Frequency Limits of Components of the Balancing Signal

No.	Component	f_l (Hz)	f_u (Hz)	Period of f_l	Period of f_u
1	Intra-week	0	1.157e-05	Inf	24 hours
2	Intra-day	1.157e-05	1.388e-04	24 hours	2 hours
3	Intra-hour	1.388e-04	0.0083	2 hours	2 minutes
4	Real-time	0.0083	0.2	2 minutes	5 seconds

4.2.7 Capacity Requirements for Meeting 2019 Balancing Needs

Extensive systems model were performed to estimate the power and energy capacity requirements to meet the future balancing needs. Each technology and technology group required careful simulation that incorporated the specific technical features of a technology, as well as the interaction with each other if more than one technology was modeled. The results of the simulations were a pairing of power (GW) capacity, and energy (GWh) capacity requirements to meet future balancing needs. A detailed discussion of how the technologies were dispatched individually or within an ensemble of other technologies, can be found in the Appendix B.

Table 4.4 and Figure 4.9show the results of energy and power requirements for all the scenarios in this study. It should be noted that the capacity requirements or the minimal size of the battery is based on 100% DOD of the battery. This means that the size of the energy storage is fully utilized. The storage will be cycled from fully charged to fully discharged. As will be discussed, there are good economic reasons for upsizing the battery to a DOD of less than 100% to improve the life of the battery. For instance, a battery with a DOD of 50% only uses its energy storage capability to 50%. Significant simulation efforts were performed to determine the minimal capacity (power and energy rating) for the various technology options. The key driver that set the size of the technology was specific operational constraints that force the technology to be operated in a certain way, for instance, the limited change modes and the change over delay of the pumped-hydro technology.

Table 4.4. Power and Energy Requirements for Each Scenario. Note: the energy capacity (GWh) for the batteries is nominated at a depth of discharge of 100%.

Cases	Technology	GW	GWh
C1	CT	1.85	-
C2	NaS	1.85	0.91
C3	Li-ion	1.85	0.90
C4	PH with multiple mode changes	1.85	0.83
	Backup NaS battery to cover 4 minute delay during mode change	1.21	0.17
C5	PH with 2 mode changes	3.61	21.72
	Backup NaS battery to cover 4 minute delay during mode change	0.82	0.05
C6	DR	8.64	-
C7	NaS	1.49	0.73
	DR	1.72	-
C8	Li-ion	1.49	0.72
	DR	1.72	-
C9	PH with multiple mode changes	0.5	0.22
	NaS	1.35	0.69
C10	PH with 2 mode changes	0.97	5.87
	NaS	1.35	0.67
C11	PH with multiple mode changes	0.5	0.22
	DR	1.72	-
	NaS	0.98	0.50

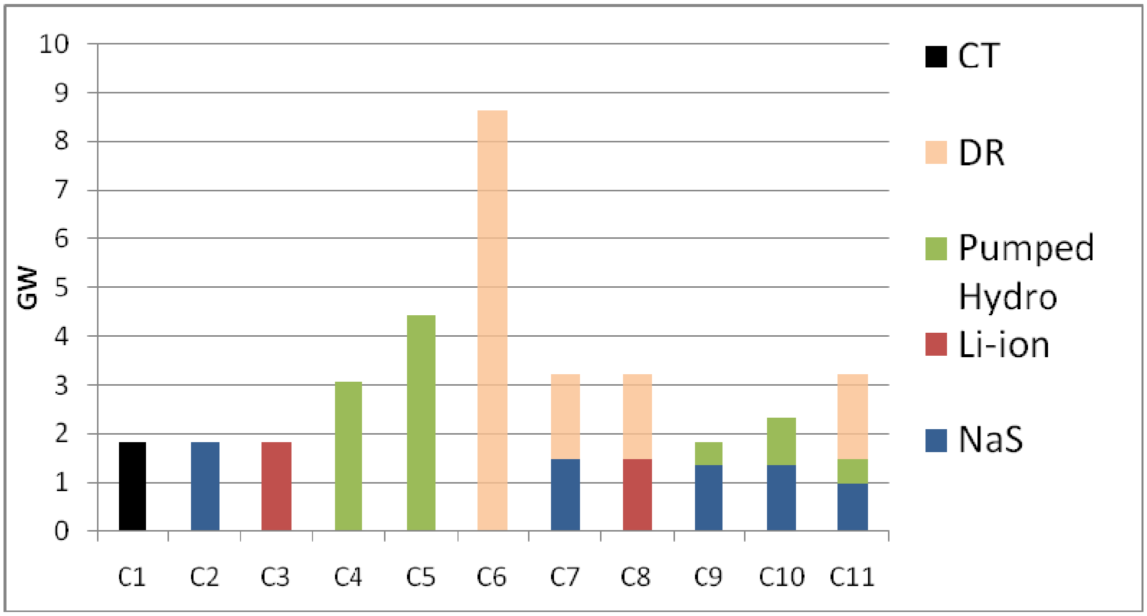

Figure 4.9. Power Requirements for all the Technologies to Meet Balancing Signal

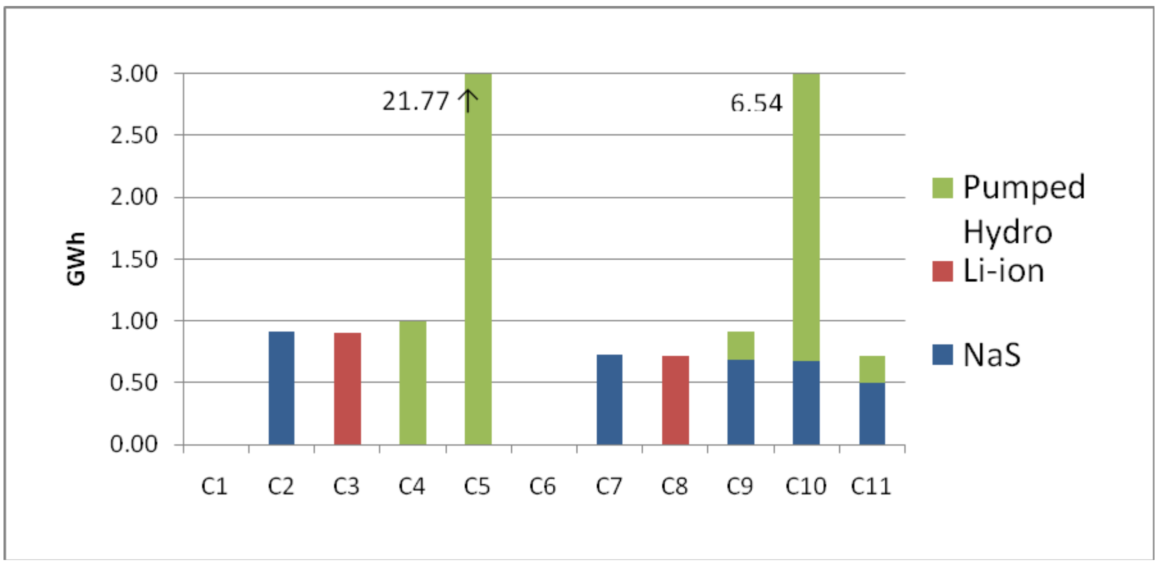

Figure 4.10. Energy Requirements for Storage Technologies to Meet Balancing Signal

The size for the combustion turbine is set by the requirements for generation increment, not the sum of increment and decrement. This is based on the notion that the existing combustion turbine capacity is operating at the zero balancing point already and would be able to provide generation decrements.

5.0 Economic Analysis Methodology and Results

5.1 Cost Analysis Framework

The cost model used to support this analysis has the capacity to examine all initial and recurrent costs, property and income taxes, depreciation, borrowing costs, and insurance premiums. The cost model expresses cost in terms of constant 2010 dollars, treats interest and inflation in a systematic manner, and distinguishes between costs that occur annually and those that occur in a single year. The cost model generates total cost estimates required to meet the balancing requirements in the BPA region, with total costs expressed in a lump-sum present value manner.

Based on input provided by BPA analysts, much of the cost elements typically considered in utility financial analysis (e.g., property and income taxes, depreciation, borrowing costs, and insurance premiums) were excluded from this analysis. Thus, this analysis considers the annual costs associated with initial and recurrent capital costs, fixed and variable operations and maintenance costs, fuel costs, and emissions costs.

These annual costs were, in turn, collapsed into a single present value cost using a real discount rate of 10.3%. This discount rate was computed by subtracting a 1.7% inflation assumption from a 12% nominal discount rate.

5.2 Economic Parameters

The cost analytical framework outlined in the previous section and the cost model supporting this research rely on a number of assumptions regarding major cost elements, including capital costs, operations and maintenance (O&M) costs, fuel costs, and emissions costs. Costs are segmented according to each of these four cost categories within each of the cases considered in the results section of this report. The remainder of this section details the assumptions underlying each cost component.

5.2.1 Capital Costs

Section 3 presents capital cost estimates for each technology, and documents the basis for each estimate. Based on the economic lives of each technology, interim capital costs are incurred as necessary to provide required service over the 50-year analysis time horizon. For each option, results are examined using forecast 2019 prices, as outlined in Section 3. In all cases, with the exception of sensitivity analyses presented in Section 5.3, present value costs of investments made in future years are discounted at a real rate of 10.3% and are expressed in 2010 constant dollars.

In addition to the capital costs outlined in Section 3, one case considers the capital costs of combustion turbines and several cases include capital costs associated with demand response. Note that the costs of implementing DR are assumed to be $50.70 per kW per year (EPRI 2009). Over 50 years, the present value of DR capital costs is $489 per kW, discounted at 10.3%. Combustion turbine capital costs are estimated at $723 per kW based on the latest estimates presented in the 2010 Annual Energy Outlook (EIA 2010). Note that combined cycle capital costs are not included in this analysis, because those costs are assumed to be sunk within the existing system. Thus, no additional investments in combined cycle plants are required to meet the requirements of the examined cases. The costs of operating those combined cycle plants are included in the cost estimates presented for each case.

5.2.2 Operations and Maintenance Costs

For combustion and combined cycle turbines, O&M costs are expressed in variable terms based on data presented in the 2009 Annual Energy Outlook. For combustion turbines, fixed O&M costs are $12.75 per kW and variable O&M costs are $3.76 per MWh. Combined cycle O&M costs are estimated at $13.79 per kW and $2.17 per MWh for fixed and variable, respectively (EIA 2010).

For batteries technologies, O&M costs were also split into fixed and variable components. The fixed component is incurred every year regardless of the energy requirement, while the variable component is proportional to electrical energy (kWh) discharged through the energy storage system. Fixed O&M costs are estimated at $0.50 per kWh of energy storage capacity while variable O&M costs are estimated at $0.007 per kWh for all battery types. These costs are detailed in Section 3.3.2. In addition to these costs, power conversion system (PCS) O&M costs are included and estimated at $2 per kW of installed capacity.

Pumped hydro O&M costs are expressed in terms of fixed and variable components as well. Fixed O&M costs are estimated at $4.60 per kW of installed capacity, while variable O&M costs are estimated at $0.004 kWh through the pumped hydro station.

5.2.3 Fuel Costs

Fuel costs for each alternative were developed using average daily energy requirements as measured in million Btu (MMBtu). These energy requirements were generated based on the combustion and combined cycle turbine production schedules designed to meet load balancing requirements for the BPA region in 2019.

In each scenario, fuel costs associated with combustion turbine alternatives are higher than those estimated for each of the combined cycle turbine, pumped hydro, or battery alternatives. Fuel cost differentials are caused by varying heat rates. The energy requirements of the combined cycle plus battery alternatives were calculated as the product of the efficiency levels associated with each component.

Average monthly energy requirements were expanded to annual energy requirements, which were in turn multiplied by natural gas prices ($9.34 per MMBtu) to compute annual fuel costs for each alternative. The fuel price used in this analysis represents the average real price forecast for the 2010 to 2040 time horizon.[1] Unlike for the CT scenario, the fuel component of the storage alternatives represents the electric energy lost during a full round-trip charge/discharge cycle. The energy is assumed to be provided by a combined cycle power plant operating at the margin. The combustion turbine requires fuel to meet the balancing requirements.

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[1] Natural gas prices from 2010 to 2030 are based on EIA (2010). Prices were extended from 2030 to 2039 using the average annual growth rate reflected in the EIA 2009 forecasts.

5.2.4 Emissions Costs

Fuel combustion levels assigned through the approach described previously were used to establish emissions levels through the application of U.S. Environmental Protection Agency (EPA) coefficients for converting quadrillion Btus into metric tons, as outlined in Table 5.1 (EPA 1995). These emissions levels were, in turn, used to construct emissions cost estimates.

Prices for emissions allowances for NOx, SO_2, and CO_2 are presented in Table 5.1. NO_x prices were obtained from the July 2009 NO_x Market Monthly Market Update (annual NOx allowances) published by Evolution Markets (Evolution Markets 2009). SO_2 prices were also obtained through Evolution Markets in the June SO_2 Monthly Market Update. Prices for CO_2 allowances ($45 per ton) were derived from the Sixth Northwest Power Plan (Northwest Power and Conservation Council 2010).

Table 5.1. Emissions Cost Data

Emissions Data		SO_2	NOx	CO_2
Allowances	$/metric ton	$71.75	$600	$45
EPA Coefficients	Metric tons / quadrillion Btu	267	978	53,060,000

5.3 Optimizing Battery Capacity

An important in minimizing the costs associated with each alternative involving energy storage is optimizing the battery capacity. In effect, one could size up the energy storage capacity to reduce the depth of discharge during each cycle and increase the life of the battery systems, as demonstrated in Table 5.2.

The minimum battery SOC, SOC-min, was set to various levels in the 5 to 95% range during battery operation to do tradeoff between life time and battery size. The effective DOD for the battery is then defined as 1-SOC_min. Clearly, as effective DOD decreases, a larger battery size is needed. This decreases the DOD for each cycle during the intra-hour balancing, thereby increasing the cycle life of the battery.

While increasing the battery capacity drives up initial capital costs, it also reduces the depth of discharge requirements, thus extending the cycle life of the batteries and reducing interim capital costs. It is important to note that the life cycle calculations presented in Table 5.2 do not account for the natural rate of decline associated with material components of a battery occurring regardless of the energy storage requirements. To address this component, the maximum life for Li-ion batteries was constrained to 10 years, while the maximum life cycle for NaS batteries was constrained to 13 years.

For each case considered in this analysis, the research team prepared a table similar to Table 5.2 comparing the effective depth of discharge as defined above, battery capacity, and life cycle. Table 5.2 presents the data computed for Case 2 – NaS plus combined cycle.

While essential, the data in Table 5.2 are not sufficient to determine the optimum battery capacity required to minimize costs. Though increasing the effective depth of discharge (or reducing SOC_min) reduces the initial capital costs associated with investments in energy storage options, the cycle life falls significantly, thus requiring numerous interim capital investments in future years.

Table 5.2. Relationship between Effective Depth of Discharge, Battery Capacity, and Lifecycle – Case 2

Effective DOD	Battery Capacity(kWh)	Life Cycle(Years)
5.0%	21,001,908	390.0
10.0%	10,500,954	132.0
15.0%	6,983,134	69.8
20.0%	5,250,477	44.7
25.0%	4,200,382	31.4
30.0%	3,465,315	21.9
40.0%	2,625,238	12.9
50.0%	2,100,191	8.5
75.0%	1,396,627	4.3
85.0%	1,234,912	3.5
95.0%	1,104,700	3.0

Parameters in this cost minimization problem include effective depth of discharge, battery capacity, lifecycle, cost reductions resulting from battery technology advancement, and relevant discount rates. These parameters are used to establish the optimum battery size based on an assessment of the present value costs for each effective depth of discharge level, as demonstrated in Figure 5.1. Figure 5.1 demonstrates the cost minimizing effective depth of discharge level (50%) under Case 3.

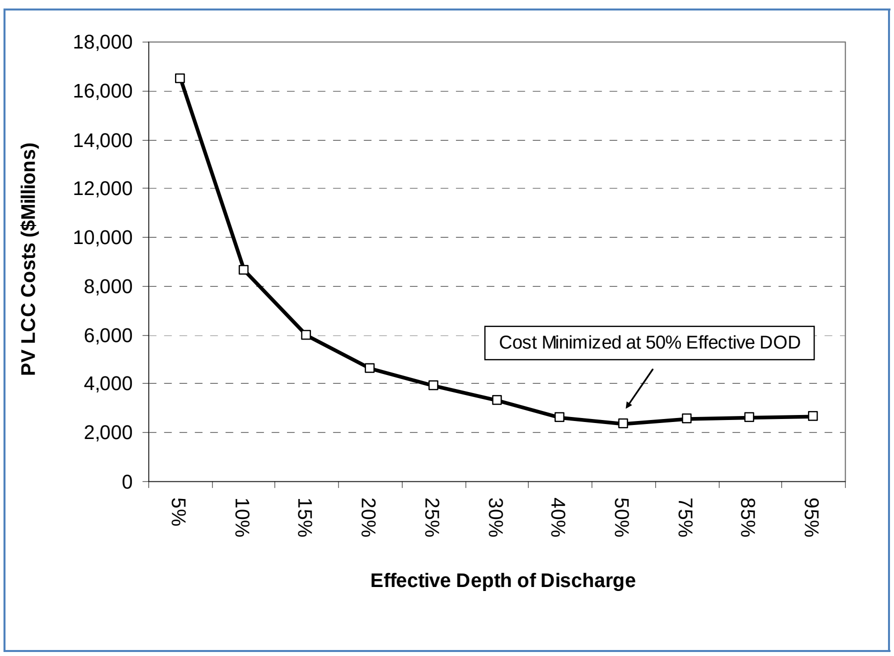

Figure 5.1. Case 3 Life Cycle Cost Estimates

For each of the 11 cases, costs are computed for depth of discharges ranging from 5 to 95%. Results for the cost-minimizing effective depth of discharge for each case are presented in Table 5.3. As shown, the cost minimizing effective depth of discharges fall between 40 and 50% for all scenarios with the exception of Cases 4 and 5. For both of these cases, the cost minimizing depth of discharge is 95%. The higher effective depth of discharge under these scenarios is due to the heavy reliance on pumped hydro with minimal demand placed on the battery systems. In the absence of heavy use, these systems can withstand higher effective depths of discharge.

Table 5.3. **Cost Minimizing DOD, Battery Capacity and Economic Life by Case.**

Case	Effective DOD	Battery Capacity (GWh)	Economic Life
1	--	--	--
2	0.40	2.6	9.3
3	0.50	2.5	8.1
4	0.95	0.2	13[a]
5	0.95	0.1	13[a]
6	--	--	--
7	0.40	1.8	12.9
8	0.50	1.4	8.4
9	0.50	1.4	8.7
10	0.40	1.7	12.9
11	0.50	1	8.7

(a) The maximum battery life is 13 years regardless of energy throughput

5.4 Results

The economic assessment methodology detailed in the preceding section of this report was used to compute cost estimates for 11 cases using combinations of several energy generation or storage technologies – combustion turbines, combined cycle, NaS and Li-ion batteries, pumped hydro and demand response. For each case, the objective was to meet the load balancing requirements for the NWPP region over a 50-year time horizon. As outlined previously in Section 3.4, the cases considered within this analysis are as follows:

Case 1: CT

Case 2: NaS

Case 3: Li-ion

Case 4: PH with many mode changes per day[1]

[1] PH has 2 modes: pumping and generating modes. Operation with multiple mode changes per day permits as many mode changes as are required to meet balancing signal.

Case 5: PH with 2 mode changes per day

Case 6: DR only

Case 7: NaS plus DR

Case 8: Li-ion plus DR

Case 9: PH with many mode changes per day plus NaS

Case 10: PH with 2 mode changes per day plus NaS

Case 11: PH plus NaS batteries plus DR

The results of the economic analysis for the base or reference case are presented in Table 5.4 and Figure 5.2. Of the 11 cases examined in this paper, Case 2, which employs NaS batteries plus combined cycle plants, is the least cost alternative at $1.4 billion. Note that the values presented in Table 5.4 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2019 capital cost value presented in Section 3.3.2, discounted at 10.3%.

Total costs under Case 7 are estimated at $1.9 billion, or 35.2% more than those for Case 2. The third most cost effective option is Case 9, which is 42.6% more expensive than Case 2. The costs associated with the demand response only case (Case 6) more than double those for the three aforementioned cases, registering at $4.2 billion. In the predominantly pumped hydro case with 40 mode changes per day (Case 4), total costs are also much higher at $4.0 billion.

In nearly all cases, the capital costs associated with the energy storage options are higher than those estimated for the combustion turbine case (Case 1) but these costs are offset by the higher fuel and emissions costs estimated for combustion turbines.

Table 5.4. Economic Analysis Results

Case	Capital	Fuel	O&M	Emissions	Total
1	1,759	905	276	312	3,252
2	1,076	125	129	43	1,372
3	2,139	91	122	31	2,383
4	3,720	120	120	41	4,000
5	6,949	422	372	145	7,889
6	4,222	-	-	-	4,222
7	1,619	100	102	34	1,855
8	2,425	73	97	25	2,620
9	1,671	123	121	42	1,957
10	2,550	205	190	71	3,016
11	2,331	98	100	34	2,562

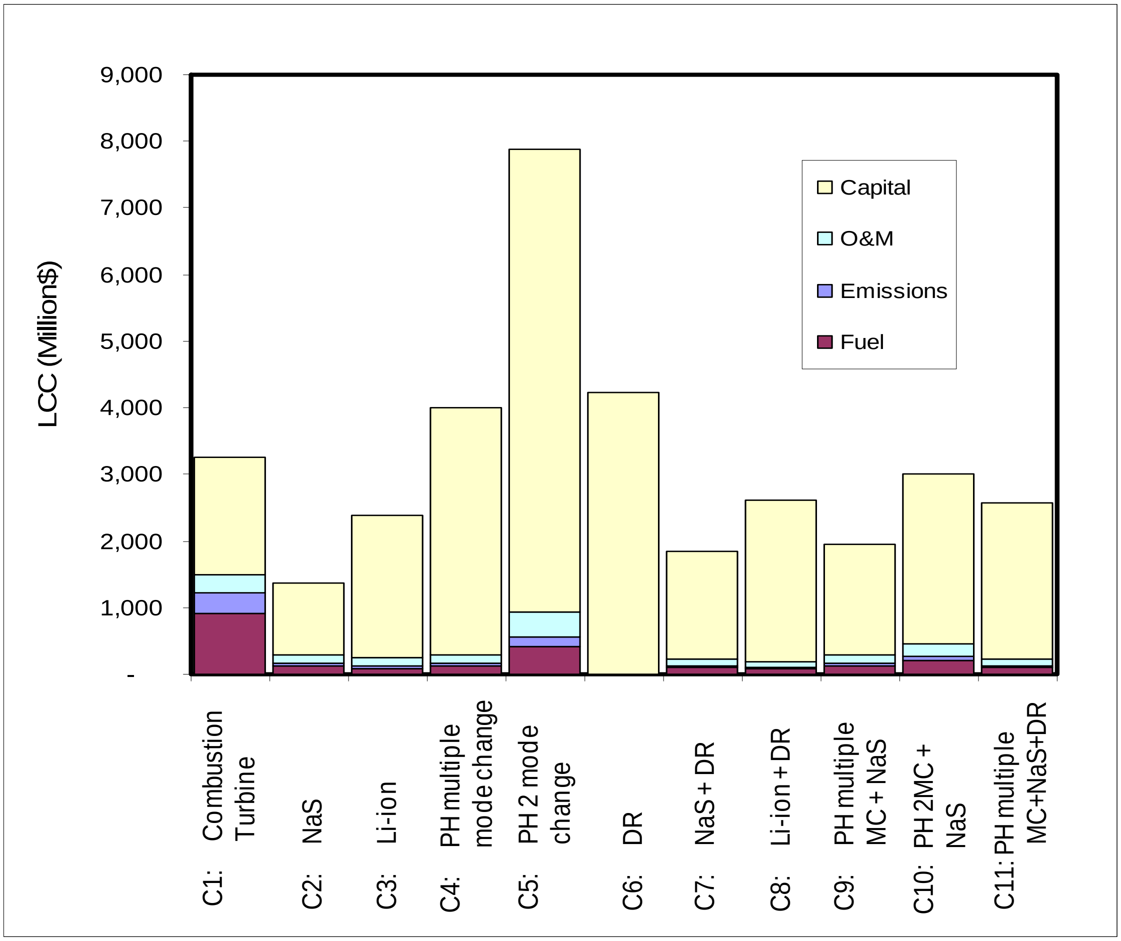

Figure 5.2. Scenario Life Cycle Cost Estimates

5.5 Sensitivity Analysis

To explore the sensitivity of the results to varying a small number of key assumptions, the research team conducted a sensitivity analysis. Sensitivity analysis was performed by making the following adjustments to the assumptions underlying the results:

1. Use capital cost for each technology estimated for current state-of-the-art technology in 2010
2. Decrease the discount rate to 4 and 7%
3. Consider minimum plausible variation around the capital costs for battery technologies and PH
4. Significantly increase variable O&M costs for PH. Applied to PH cases with multiple mode changes.

Table 5.5 presents the results of the four sensitivity analyses. Note that the 2nd sensitivity analysis, which focuses on discount rate adjustments, includes two options.

Table 5.5. Sensitivity Analysis Results

Case	Base Case	SA 1	SA 2 (7% DR)	SA 2 (4% DR)	SA 3	SA 4
1	3,252	3,184	4,228	6,097	3,252	
2	1,372	2,091	1,686	2,277	1,269-1476	
3	2,383	4,254	3,041	4,270	2,004-2,762	
4	4,000	3,818	4,144	4,415	3,292-4,708	4,387
5	7,889	7,420	8,306	9,080	6,522-9,255	
6	4,222	4,222	6,046	9,411	4,222	
7	1,855	2,362	2,454	3,566	1,783-1,928	
8	2,620	3,991	3,474	5,061	2,343-2,897	
9	1,957	2,364	2,237	2,758	1,700-2,215	2,064
10	3,016	3,342	3,337	3,938	2,582-3,450	
11	2,562	2,841	3,141	4,214	2,324-2,801	2,669

In the first sensitivity analysis case, current technology prices are used. The underlying assumption governing this first case is that the cost adjustments forecast in the base case are not realized. The capital cost forecasts for combustion turbines, combined cycle plants and hydro are taken from the U.S. Department of Energy's Annual Energy Outlook (AEO) 2010 reference case, which includes forecast costs out to 2030 (EIA 2010).

The costs for these technologies are forecast to grow in real terms over the next 5 to 6 years because construction costs for all plant types have risen significantly in recent years.

This cost growth is forecast based on a commodity cost index that was implemented for the AEO 2009. Growth in the cost index is tied to rising commodity prices, such as steel, copper, cement, and other construction materials. In the long-run, the commodity prices do decline and technology growth leads to cost reductions in the latter years of the forecast. On balance, however, the AEO 2010 reference case forecasts cost growth for combustion turbines, combined cycle plants, and hydro power during the 2010 to 2019 time horizon.

The battery costs used in the base case ($415 per kWh for Li-ion and $230 per kWh for NaS) reflect significant cost reductions forecast over the 2010 to 2019 time period. When using current (2010) cost data for these battery types, costs are significantly higher ($1,000 per kWh for Li-ion and $415 per kWh for NaS).

As a result of the forecasts underlying the base case, which include cost reductions for battery technologies and cost increases for all other systems, using current prices makes scenarios involving pumped hydro and demand response more cost efficient. The results of Sensitivity Analysis 1 show a closing gap between Case 2 and Cases 7 and 9, which are both 13% more expensive when using 2010 price data. Note that under the base case, Cases 7 and 9 were 35.2% and 42.6% more expensive than Case 2, respectively.

The discount rate was reduced in the Sensitivity Analysis from the 10.3% used in the base case to 4 and 7%. By reducing the discount rate, the present value of the interim capital costs associated with battery replacement in the out years of the 50-year analysis time horizon is increased. When the discount rate is reduced, the pumped hydro scenarios become more cost efficient because the asset is long-lived (50 years) and does not require interim capital costs. Reducing the discount rate to 4% increases the costs associated with Case 2 (NaS batteries plus combined cycle) from $1.4 billion to $2.3 billion but increases the costs for Case 9 (NaS batteries plus combined cycle plus pumped hydro with 40 mode changes per day) from $2.0 billion to $2.8 billion.

The final two sensitivity analyses, which include variability with respect to capital costs and increased variable O&M costs for pumped hydro, do not appear to lead to a re-ordering of the most cost efficient options. Under Sensitivity Analysis 3, Li-ion battery costs are varied by +/- 20%, NaS battery costs are varied by +/- 12.4%, and pumped hydro capital costs are varied by +/- 20%. Under Sensitivity Analysis 4, O&M variable costs for pumped hydro are increased from $0.004 per kWh to as high as $0.04 per kWh under Cases 4, 9, and 11.

6.0 Arbitrage Opportunities for Energy Storage

Pumped hydro systems are customarily used for energy arbitrage opportunities because of their significant energy storage capabilities. At low demand periods, low cost electric power is used to pump water from a lower reservoir to a higher reservoir. At high demand periods, where electric power price is high, water is released through a turbine to generate electricity. Only when the differential between peak and off-peak prices is sufficiently large to compensate for the energy losses incurred during round-trip charge/discharge cycle, does it make economic sense to dispatch energy storage.

Besides the energy arbitrage potential, energy storage can provide operating reserves (contingency reserves) and system balancing services to the grid because of its fast response characteristics. Its competitiveness among other technology options has been discussed for the system balancing service in the previous section. Of interest here is the discussion about the cost-effectiveness of energy storage as an arbitrage instrument to mitigate congestion-induced high electricity prices and/or to reduce potential low load conditions in cases, when there is insufficient load (commonly at night) coincident with large electricity production by the growing wind generation capacity. This discussion solely focuses on the arbitrage value proposition, excluding the valuation of the balancing services as part of the ancillary services. The exclusion of the balancing service value is made primarily based on the difficulty of valuing ancillary services in the future. The cost-effectiveness of a 1 GW/10 GWh storage facility in the BPA footprint is discussed. The size of the unit was recommended by BPA staff from preliminary analyses performed by BPA. Likewise, a recommendation for a potential location of a pumped hydro storage plant was made. Banks Lake was suggested as a potential location. Impacts of an alternative storage size, as well as a distributed placement of the total energy storage size into four locations were analyzed and their impacts to the overall results discussed.

6.1 Arbitrage Analysis Framework

To quantify the arbitrage value of energy storage, it was decided to apply a cost-effectiveness approach that contrasts the annual revenue requirements from the capital expenditure to the revenue potential from arbitrage. The revenue potential analysis is based on a production cost approach using PROMOD IV[1] from Ventyx as an analysis tool. PROMOD is a production cost software that solves security constrained unit commitment and dispatch problems in power systems at either zonal or nodal transmission level. In this analysis, a WECC system model developed by the Western Electricity Coordinating Council's Transmission Expansion Planning and Policy Committee (TEPPC) was used for the 2019 time horizon. This model was slightly modified in this analysis to implement a 1 GW, and 10 GWh energy storage resource at the Grand Coulee bus. This model has been vetted by TEPPC and can be considered as a plausible and best-judgment scenario for the 2019 WECC system. The particular case analyzed was based on the TEPPC 2019 PC1 RPS Base Case. This is the nodal transmission model of the WECC system. This case was built based on 2012 PC6 case (median hydro case), and then updated generation, load, and transmission lines for the 2019 case. The load forecasts for 2019, reported by BA submissions to the Loads and Resource Subcommittee (LRS), were used as the base case loads; updated resources were based on LRS submittal. Over 61% of the incremental generation added to 2019 PC1 is renewable generation. Updates to transmission lines were based on Studies Working Group transmission

[1] PROMOD IV is an Energy Planning and Analytics Software developed by Ventyx http://www.ventyx.com/analytics/promod.asp

team's work. A total of 24 transmission projects were added to the 2019 PC1 basecase. The TEPPC base case assumes a total of about 9.1 GW of wind capacity in the NWPP. As will be discussed later, we analyze a case with additional 3 GW in the Columbia Gorge region increasing the total wind energy capacity12.1 GW. This is a slightly lower capacity value than what was assumed for the balancing service analysis (14.4 GW). The existing and additional installed capacity for WECC, NWPP, and BPA is shown in Table 6.1.

Table 6.1. Existing and Additional Installed Capacity (MW) for WECC, NWPP, and BPA

	WECC		NWPP		BPA	
Category	Existing (2008) [MW]	New capacity [MW]	Existing (2008) [MW]	New capacity [MW]	Existing (2008) [MW]	New capacity [MW]
Biomass	944	1020	257	121	47	53
CC	47456	7673	6704	0	2766	0
Coal	37162	2085	4477	0	1456	0
Conventional hydro	63514	3161	33496	0	21553	0
CT	18589	6468	1106	192	102	0
Demand Side Management (DSM)	4484	0	0	0	0	0
Geothermal	2753	2354	0	52	0	0
Internal Combustion (IC)	544	163	24	0	0	0
Negative Bus Load	549	0	148	0	0	0
Nuclear	9681	0	1161	0	1160	0
Other, steam	658	7	298	0	131	0
Pumped storage	3601	40	0	0	0	0
Pumping load	2543	0	0	0	0	0
Small Hydro RPS	1690	419	406	139	272	0
Solar	538	12062	0	0	0	0
Steam	19982	60	0	0	0	0
Wind	7804	19411	2771	6349	1679	5221
Total	**222492**	**54923**	**50847**	**6853**	**29166**	**5274**

Simulation results of the base case reveal that there are several congested paths in the system. The most congested path is the interface between Alberta and British Columbia (BC). A few congested paths (in red) in NWPP and between NWPP and neighboring areas are shown in Figure 6.1.

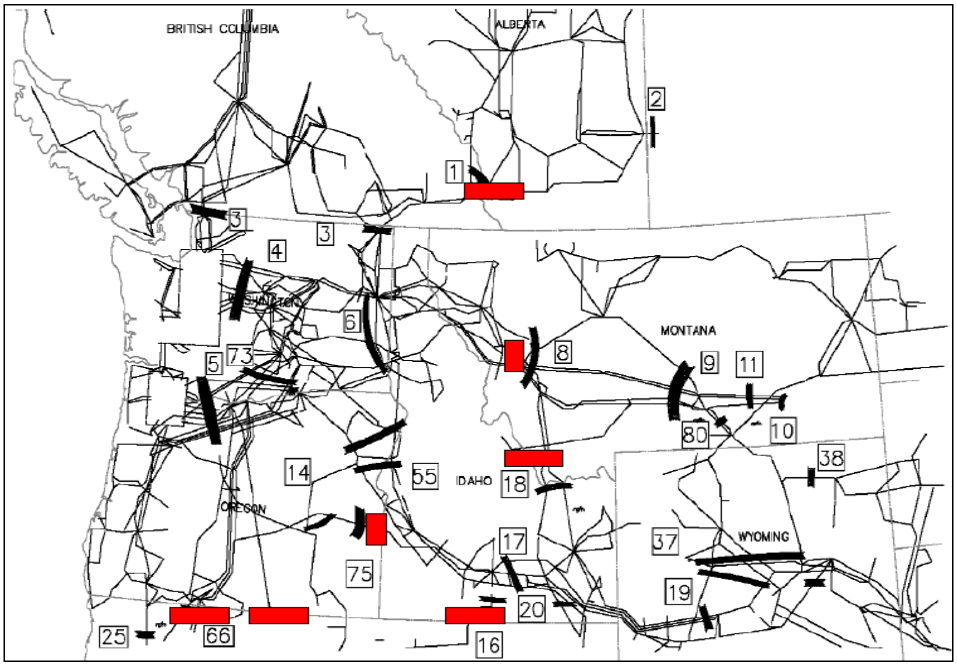

Figure 6.1. Key Congested Paths in NWPP and Neighboring Areas

6.2 Simulation Results for a 1 GW, 10 GWh Pumped Storage at Grand Coulee

To study arbitrage value of a pumped storage, a 1 GW and 10 GWh pumped hydro system with 75% efficiency is added at Grand Coulee (GC) bus. PROMOD is used to run the simulation for the entire year of 2019. A typical optimal weekly schedule of the pumped-hydro system is shown in Figure 6.2.

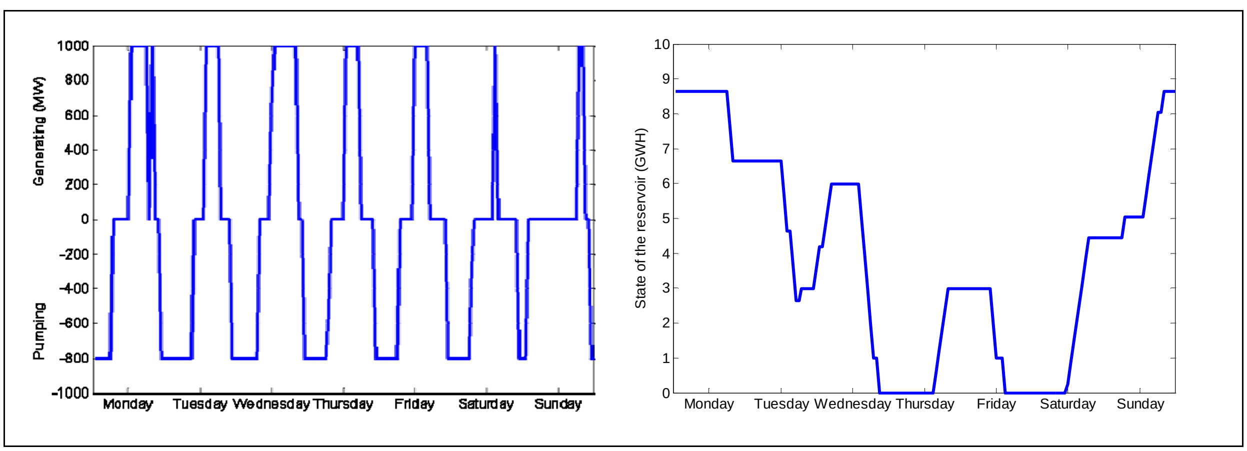

Figure 6.2. Typical Weekly Pumped Hydro Operation (note: during the charging mode system is assumed to be de-rated by 20% to 800 MW)

To analyze the cost effectiveness of energy storage as an arbitrage instrument, the revenue potential of this 1 GW/10 GWh hypothetical resource is examined The revenues are calculated for the Grand Coulee bus as:

$$\text{Revenue} = \sum_{i=1}^{8760} (G_i - L_i) LMP_i \tag{6-1}$$

where G_i, L_i, and LMP_i are the generation in [MWh], pumping load in [MWh], and Locational Marginal Price (LMP) in [$/MWh] at hour *i*, respectively. The revenues obtained from the storage operation in this case are $2.67 M.

The status of congested paths does not change much from that of the base case, although the California-Oregon Border (COB) and Midpoint-Summer Lake interfaces are slightly less congested. The path between Alberta and BC is still the most congested path, and operates at its limit most of the year, as in the base case. Lower cost generation in BC and the Northwest is dispatched to displace higher cost resources in Alberta. Because the storage resource is placed at the source-side (Northwest) of the congested path, there is no congestion relieve on the Alberta-BC path. In fact, the Grand Coulee placement of the storage increases the hours of congestion on this path. To have a mitigating effect the storage must be on the receiving side of a congested path (in Alberta). Table 6.2 shows the number of hours per year that transfer paths identified in Figure 6.1 are at 100% of their limits.

Table 6.2. Number of Hours at 100% Transfer Limits

Interface	Without Storage [h]	With 1 GW/ 10 GWh Storage [h]
Alberta-BC (from BC to Alberta)	8286	8470
COB (from North to South)	771	500
Idaho-Montana (from MT to ID)	153	156
Idaho-Sierra (from Sierra to ID)	153	126
Montana-Northwest (from MT to ID)	440	477
Midpoint-Summer Lake (from Midpoint to SL)	44	30
PDCI South (from North to South)	2631	2463

Next, the simulations are carried out for different pumped storage sizes at Grand Coulee bus. The revenue is computed for each case using equation (6-1). The results are shown in Table 6.3.

It can be seen that the maximum revenue is obtained at the size of 700 MW. This presumes that the storage is cycled to maximize revenue from arbitrage. For the Grand Coulee location, a size of 700 MW appears to be optimal from a revenue maximization objective of this particular storage project. As the size is increased beyond 700 MW, the feedback of energy arbitrage becomes increasingly apparent. The discharge of energy during peak periods reduces the higher cost generation sufficiently, such that the overall price differential at the margin is decreasing, reducing the very economic incentive for energy storage in the first place. While any larger energy storage size beyond 700 MW is undermining the key revenue mechanism from the economic perspective of this individual project, there may be system-wide benefit that may warrant a size larger than the optimal size.

Furthermore, the sensitivity with respect to placement of energy storage is explored. The following case is considered where the 1 GW/10 GWh resource is distributed over four different locations in equal size. 4 x 0.25 GW, 2.5 GWh energy storage systems are modeled at 4 different locations shown in Figure 6.3: Grand Coulee, John Day, Marion, and Malin. The revenue in this case is $3.7 Million, an increase of about 40% over that at the Grand Coulee location.

Table 6.3. Revenue vs. Storage Size

	Capacity of Storage [MW]	Annual Revenue [$]
	25	100,000
	50	550,000
	100	1,040,000
	200	1,960,000
	300	2,660,000
	400	3,130,000
	500	3,450,000
	600	3,550,000
Max revenue	700	3,660,000
	800	3,070,000
	900	3,010,000
	1000	2,670,000

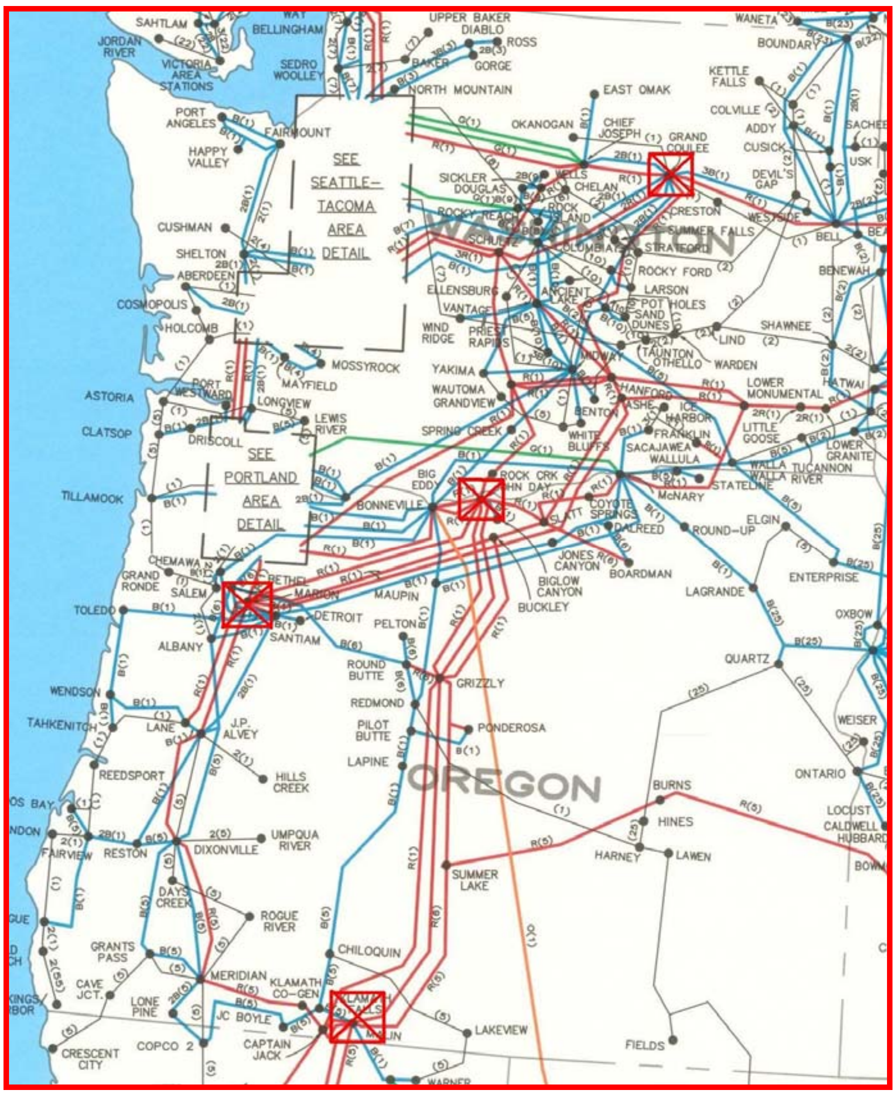

Figure 6.3. Storage Locations at four Arbitrarily Selected Locations

6.3 Basecase Variations

To see the effect of more wind power in the system, an additional 3 GW (half in Washington and half in Oregon) of wind is introduced in the Mid-Columbia. Two side-cases with total storage size of 1 GW, 10 GWh are considered:

- 1 GW, 10 GWh at Grand Coulee
- Four 0.25 GW, 2.5 GWh at 4 different locations: Grand Coulee, John Day, Malin, and Marion

Revenue for the two side-cases along with the original base cases is shown in Table 6.4. The revenues for the two side-cases are larger than those for the basecase. Also, revenues are larger for the distributed storage scenario. This clearly indicates that the additional 3 GW of wind generates more congestion for the transfer of 3 GW to California and Alberta which in turn drives up the price differential between peak and off-peak in the NW region. Whether the expected revenue potential derived from the arbitrage is sufficient to meet the cost recovery requirements will be discussed in the following sections.

Table 6.4. Revenue from 1 GW/10 GWh Storage for the Base Case and the Two Side-Cases

Case Description	Revenue
Original TEPPC case	$2,670,000
Original TEPPC case. Add 3000 MW wind in OR and WA. Add 1GW energy storage at Grand Coulee	$5,020,000
Original TEPPC case. Add 3000 MW wind in OR and WA. Add 4 x 250 MW energy storage at Grand Coulee, JD, Malin, and Marion	$6,380,000

6.4 Cost Effectiveness of Energy Storage as Arbitrage Instrument

Cost effectiveness is defined here as meeting the debt servicing obligation from the capital investment by the revenue stream from energy arbitrage transactions of a 1 GW/10 GWh pumped hydro energy storage project.

Figure 6.4 shows a histogram of the LMP differences at Grand Coulee between peak and off-peak periods as a result of the TEPPC case with additional 3 GW of wind resources. The average peak and off-peak LMP are $52/MWh and $41/MWh, respectively. The average difference in LMP is $11/MWh. The storage is operated as generator (1 GW) for about 1000 hours and as load (0.8 GW) for about 1500 hours during the year, yielding an overall utilization of about 28%.

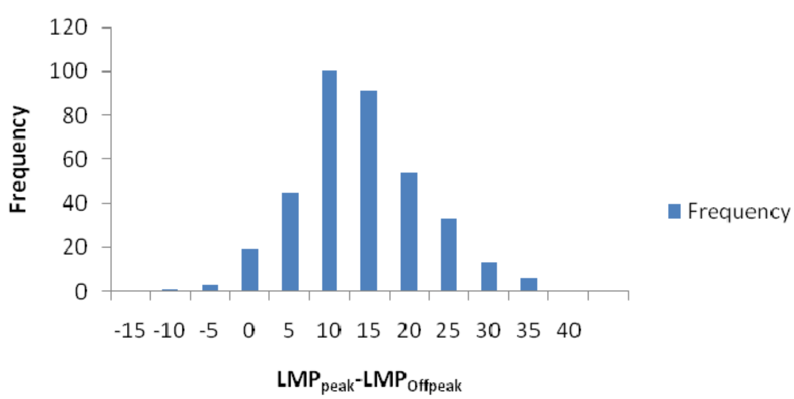

Figure 6.4. Histogram of LMP Difference Between Peak and **O**ff-Peak Periods

As seen in Figure 6.5, the arbitrage revenue expectations are falling significantly short of the necessary revenue requirements for cost recovery assuming similar economic considerations (discount rate, live of the project) as discussed in Section 5. It would take a significant increase in peak-to-off-peak differential for extended periods of time for this project to breakeven (see red line in Figure 6.5). Under the current projections of LMPs at the Grand Coulee bus, even in the 3 GW of additional wind resources beyond the TEPPC base-case scenario, region is not sufficiently congested for energy storage to become cost effective. One key driver for this result is the location of the storage. Grand Coulee (Banks Lake) is not located at the end or sink of the congested path, where energy storage renders the largest benefits for congestion management, but rather at the source. With major congestions at the BC-Alberta path (from BC to Alberta), the COB (from Northwest to California), and Pacific DC Intertie South (Northwest to California), the Northwest (NW) does not appear to be heavily congested based on the infrastructure projections for generation and transmission capacity expansions developed by TEPPC for the 2019 time horizon.

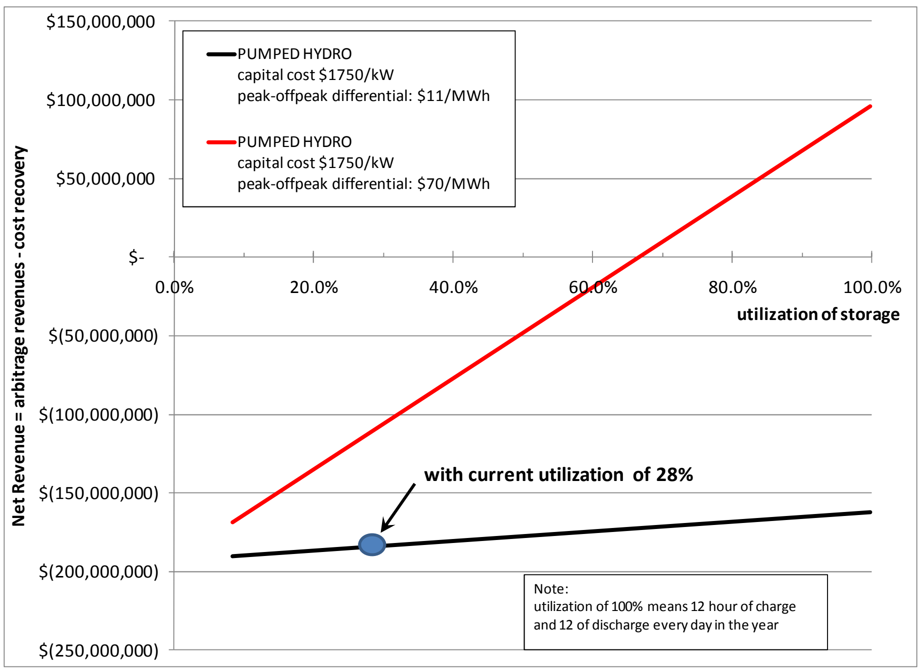

Figure 6.5. Cost-effectiveness Results of Pumped Hydro of 1 GW/10 GWh

The outcome of this analysis was qualitatively discussed with WECC/TEPPC members[1], who were in general agreement with PNNL's findings of relatively little congestion in the NWPP footprint for the definition of the 2019 TEPPC base case. For an energy arbitrage opportunity to be cost effective as a sole revenue source, significant congestion must be prevalent for extended periods to warrant the high capital cost. With relatively little congestion inside the NWPP footprint, and the fact that the NWPP has a considerable low-cost generation resources that keep both the peak and off-peak prices relatively low, it is difficult for energy storage to generate sufficient revenues to pay for itself on energy transactions. Additional higher-valued ancillary services must be bundled to become economically attractive and viable.

[1] Phone conversation with Heidi Pacini, Mark Landauer, Bradley Nickell on 3/12/2010.

7.0 Summary and Conclusions

The study estimated the total balancing requirements for the NWPP for a scenario of 14.4 GW of wind energy in the 2019 time horizon. Under the assumption that the current individual balancing authorities (BAs) are consolidated to one single large balancing area, new total balancing requirements were determined. This assumption is likely to underestimate the new requirements if the current status quo in the grid operation for the pool is maintained. This assumption was made for no other reason but to manage the workload of this highly complex analysis. The results of this study estimated a total balancing requirement of approximately 4 GW of inc. capacity and about 3.6 GW of dec. capacity, using the BPA's customary 99.5% probability bound.

The intra-hour balancing requirement was filtered out of the total balancing signal. The intra-hour balancing requirement is smaller than the total requirements, and tends to have higher ramp rate requirements. The intra-hour balancing requirements were estimated to be about 1.85 GW in both directions (increment and decrement).

A life-cycle cost analysis was performed that sought the cost optimal technology investment to meet the total intra-hour balancing requirements of a 50-year lifetime. Considered were capital, O&M costs, as well as fuel prices and typical prices for criteria emissions. The CO_2 emissions were valued at a cost of \$45/ton CO_2. Assumed was that all of the estimated balancing requirements will be met with new investments. Significant emphasis was placed on reviewing the literature regarding the characterization of storage option for grid applications, and on choosing plausible and defensible cost performance characteristic of the technologies under considerations. NaS, Li-ion batteries, and pumped-hydro energy storage, as well as demand response strategies, and conventional combustion turbine were considered in the analysis.

This study revealed several insights into the technology ranking under life-cycle cost optimality. First, the reference technology (CT) is not the least expensive option. Both batteries types (NaS and Li-ion) were comparatively less expensive to the CT. The following ranking (least cost to highest cost) was established for the base cases: NaS only, NaS+DR, NaS+pumped-hydro with many mode changes, Li-ion+DR, NaS+pumped-hydro with many mode changes+DR. The most costly cases were pumped-hydro with 2 mode changes and demand response alone.

The design of how pumped-hydro system is operated is critical for the overall size and, thus has direct impact on the lifecycle cost. For the 2-mode-change per day operation, the power rating must be doubled the size compared to the multiple-mode-change design. When only changing the mode twice a day, the machine must provide the full increment-to-decrement swing (inc/dec swing) in one single mode (pumping or generating). However, if the machine remains unconstrained in the number of mode changes a day, the full inc/dec swing (from maximum generation to full load pumping) can be utilized. The 4-minute delay between modes, in which the machine is neither pumping nor generating, necessitates other resources to substitute (back-up resource). The size of the back-up is considerable for the multiple-mode-change operation and relatively small when the pumped-hydro system changes modes only twice a day. Both the oversizing as well as the back-up resource requirements drive up the total life-cycle cost of pumped-hydro system when compared to a battery system.

Demand response strategies by itself appears costly. The reason for this result follow a similar logic as for the 2-mode-change pumped-hydro storage. Unlike battery energy storage, which can be a load and a generator at times, DR must be large in capacity to perform the balancing only in the load mode. Thus, the total capacity size tends to be larger than the rate capacity of a battery. The size of the DR capacity (number homes) is determined by the lowest load condition just meeting the balancing requirement leaving a lot of capacity under-utilized for the remainder of the day. The most advantageous load profile for providing balancing services would be a flat profile achieving maximal utilization of the demand response resource. Because of a typical residential load shape, meeting all balancing requirements with demand response is unlikely to be economical. However, some DR capacity can reduce the energy requirements of the battery. There is an interesting trade-off between DR power capacity and the storage energy capacity when combining storage and demand response. Interesting shifts are seen in the optimal battery size as one adds demand response resource to the technology mix.

The economic analysis of arbitrage opportunities in the BPA service with a large 1GW/10GWh pumped hydro storage facility is unlikely to be economically viable. The revenue expectations are small for the case examined. The location analyzed at the Grand Coulee bus may not provide an optimal placement for the energy storage. Storage locations on the sink-side of a congested path provide better opportunities for congestion mitigations and energy arbitrage. The Grand Coulee location is situated on the source side of the major bulk power flows. Distributing energy storage with the BPA transmission network appeared to improve the economics somewhat by increasing the range of influence to mitigate congestion. Furthermore, it was found that a 1GW/10GWh storage facility may not be an optimal size for arbitrage. A storage size at 700 MW achieved the maximum revenue expectations for the Grand Coulee location. This outcome is very intuitive, reflecting the feedback of arbitrage on the cost differential between peak and off-peak. This confirms that maximizing the value of energy storage for arbitrage requires an optimal sizing and placement analytics.

The results clearly indicate that energy storage and particularly the electro-chemical storage technology are likely to compete with conventional combustion turbine technologies with and without accounting for the emission externalities. Energy arbitrage opportunities may not be the key driver for large deployment of energy storage, at least not in the near-term (2019 timeframe). Placement aspects appear very important for the economics of energy storage, giving electro-chemical storage devices an advantage over pumped-hydro system by not being constrained to a particular geographic topology and hydrological system. However there are other values that large scale energy storage may provide, that are difficult to model, which may support the economics. Grid flexibility for transmission outage management is likely to be improved with energy storage. Further studies with a particular focus on transmission system impacts are necessary to better reveal these values.

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Appendix A

Detailed Technology Discussion

Appendix A

Detailed Technology Discussion

A.1 Sodium-sulfur (NaS) Battery

A.1.1 Battery Sizing Method

Battery sizing depends on depth of discharge (DOD), which depends on the number of cycles needed from the battery during its life. The only NaS battery commercially available is from NGK Insulators, Ltd., which has an energy content of ~ 6.8 times the rated power (i.e., it has a storage capacity of 6.8 hours at rated power)(Nourai, 2007). Hence it is best suited for applications where a low DOD is desired for long life. As will be discussed later in section 3.0, the batteries will be sized to cycles that are much shorter than 6.8 hours; they will be in the order of ½ -1 hour. NaS batteries with a storage duration of ½ hour don't currently exist. As a consequence we provide a discussion that adjusts the cost for the shorter duration battery storage given the battery sizes currently available.

Typically, NaS batteries can provide five times the *rated* power for up to 5 minutes (Kamibayashi et al. 2002). In our application, (as will be discussed in Section 3.2.3.1), the peak power occurs for only short durations of 1-2 minutes. Hence, using the peak power (rather than the rated power) would still be conservative as a sizing criterion for the battery. If the peak power needed is 1 MW and energy needed is 1 MWh, the battery size currently available and sufficient for the 1MW/1MWh requirements would be 0.2 MW/1.36 MWh, because the E/P ratio is 6.8 for NaS batteries. Hence, sizing of the battery is determined by the peak power needs.

While the sizing discussion above is appropriate for batteries currently available, we have assumed that as energy storage applications in utilities become more diverse, NaS will be available in various energy/rated power ratios, with the batteries being able to deliver peak power equal to twice the energy content (1to 2MW/MWh) for 1-2 minutes. For Li-ion, the ability of batteries to provide 1to 2MW/MWh has been well demonstrated. Hence the batteries were sized per the energy requirements.

A.1.2 Capital Cost

The cost of the PCS was estimated from the $/kW values available in the literature. It should be noted that the rated power of PCS is typically specified for continuous power. For durations of seconds to minutes, the peak power would be at least two times higher than rated power for PCS, which would bring costs down.

An extensive search for capital costs of the NaS battery system was conducted. In some publications, the battery energy storage system costs were given in terms of $/kW, while they were given as $/kWh in others. For NaS batteries, the long-term cost was ~ $250/kWh(Shoenung and Hassenzahl 2003, Schoenung 2001, Gyuk and Eckroad 2003, Boyes, Kamibayashi et al. 2002) , while the cost for power conversion systems (PCS) was $150 to 260/kW. The cost of the batteries was $1800 to 2000/kW (Greenberg et al., Kamibayashi et al. 2002), and $3080/kW (EAC 2008). The cost for the battery system including PCS and BOP was $2400 to 2500/kW(Nourai 2007, Kishinevsky 2006). While these numbers vary widely, it should be noted that the long-term costs provided in $/kWh are only projections, and are not necessarily reflective of actual costs.

A detailed explanation of PCS and BOP costs was provided by Gyuk and Eckroad (2003). Type I PCS is maintained in hot standby and is operated continuously for durations greater than 30 seconds. Type II PCS may be employed for applications allowing 10 minutes advance notice, while Type III is used for durations less than 30 seconds. For this work, Type I describes the PCS most closely. The cost for Type I PCS as a function of output power P is given by equation 3-1:

$$\frac{\$}{kW} = 300 \cdot p^{-0.3} \tag{3-1}$$

This provides a range of $40-300/kW for applications needing 1 GW-1MW power. Clearly, as the system power increases, costs for PCS drops. Type I PCS costs are also given by equation 3-2:

$$\frac{\$}{kW} = 13500 \cdot V^{-0.59} \tag{3-2}$$

where V is the minimum voltage on the battery side, and ranges from 300-3000V. Since the power needs in this study are in the order of a few GWs, for a minimum voltage of 3000V, the PCS cost would be $120/kW. For this work, we have assumed a cost of $200/kW, where the power corresponds to half the peak power, (or $100/kW based on peak power).

BOP costs include various components: systems integration (in $/kW) not covered by PCS, costs for project engineering, grid connection (transformers), land, foundation, buildings(Gyuk and Eckroad 2003). The BOP systems integration cost accounts for any underestimation of integration costs for PCS and energy storage, especially for pre-commercial systems. A value of $100/kW was proposed for pre-commercial systems, and $50/kW for commercial systems(Gyuk and Eckroad 2003). For this work, only systems integration costs in terms of $/kW are included with the cost being $100/kW, based on power corresponding to half of peak power.

Table A.1 summarizes the literature review of current and future capital cost for NaS battery systems. The value of $180-250/kWh provided by various sources is a long-term estimate. The $2500/kW value correspond to installed cost in the year 2006 for the Long Island Bus Project [9], while the $3000/kW provided by Nourai(Nourai 2010) was the actual installed cost for the year 2009 for a 7MW/48MWh battery system. The latter value was used for current price of a NaS system. The cost of the battery portion was estimated by subtracting $200/kW for PCS and $100/kW for BOP, to yield $2700/kW. Using a factor of 6-6.8 for E/P_{rated} for NaS batteries, the unit energy cost for the battery works out to $390-440/kWh. Since the energy/power ratio varies for the different scenarios addressed in this report, the batteries have been costed using $/kWh numbers. For long-term cost, $250/kWh was used for the battery, along with $150/kW for PCS and $100/kW for BOP.

Table A.1. Summary of Current Capital Cost Diversity for NaS systems

\$/kWh current	\$/kW current	\$/kWh future	Notes	Source
		180-250	Battery	(Boyes, Kamibayashi et al. 2002, Shoenung and Hassenzahl 2003, Gyuk and Eckroad 2003, Schoenung 2001)
		818	System	(Gyuk and Eckroad 2003)
	1800		Battery	(Greenberg et al)
	3080		Battery	EAC 2008
	2400-2500		System	(Nourai 2007[1], Kishinevsky 2006[2])
	3000		System	(Nourai 2010)
	150-240		PCS	(Shoenung and Hassenzahl 2003, Schoenung 2001, Kamibayashi et al. 2002, Boyes)
	100		BOP	(Kamibayashi et al. 2002)
50			BOP	Boyes
	100		BOP	(Gyuk and Eckroad 2003)
	150-450		PCS[3]	(Gyuk and Eckroad 2003)

The life cycles relationship with DOD of NaS battery is depicted in Figure A.1.Therefore, in the battery sizing model, we put one variable called sizing factor to size up or size down the battery energy capacity , thus determining cycle life. It is also assumed that the calendar life of the batteries is 15 years.

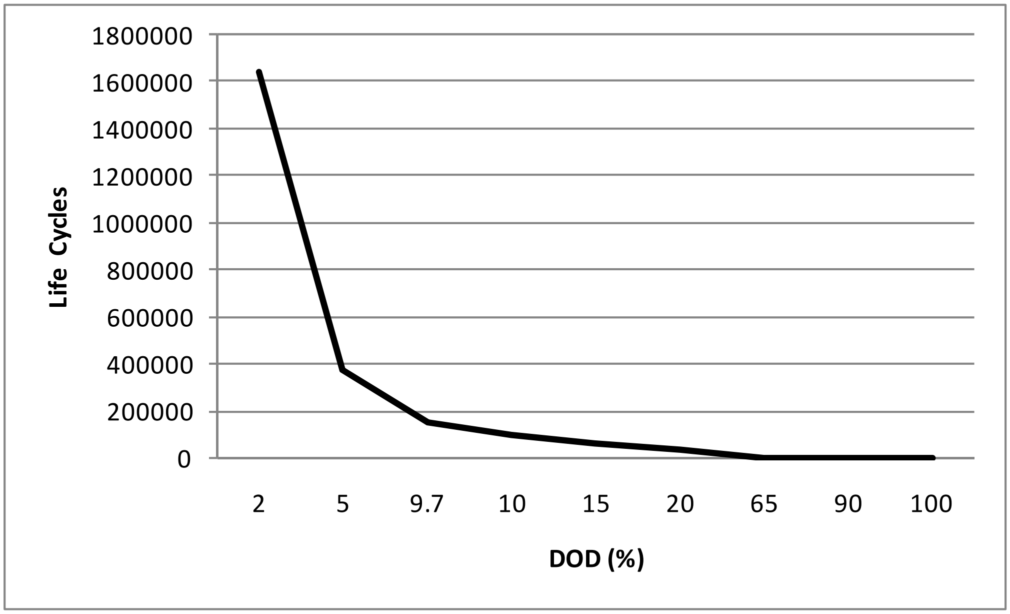

Figure A.1. NaS Life Cycles Versus DOD Curve

[1] more reliable 2007 numbers
[2] Reliable – 2006 Long Island Bus actual installation numbers
[3] For short duration application, cost is low, for long duration cost is higher

A.1.3 Fixed O&M Cost

The PCS consists of equipment necessary for energy transfer between the grid and energy storage system. The BOP is a catch-all for anything not covered by PCS. This includes project engineering, construction management, transformers for grid connection, land, foundation, building etc. The O&M costs for BOP has not been included in this analysis, since such costs are expected to be uniform across all technologies. For NaS batteries, fixed O&M costs given in the literature varied from over a wide range without any consistency on what services are included and which are excluded from the fixed O&M cost. The low figures start at $0.5/kW-year(Lamont 2004, Gyuk and Eckroad 2004) and go up to $51/kW-year (Shoenung and Hassenzahl 2003, Gyuk and Eckroad 2003), which includes insurance and property taxes. For the purpose of this study, we used $3/kW-year as the fixed O&M cost, which corresponds to $0.46/kWh for E/P of 6.5. Since the E/P ratio for the batteries used varies, we have used $0.46/kWh as fixed O&M cost in this report.

A.1.4 Variable O&M Cost

Variable costs have traditionally been reported in cents/kWh, and ranged from 0.4-0.7 cents/kWh, where kWh is the cumulative energy out of the battery (Lamont 2004, Schoenung et al. 1996). The variable O&M cost for NaS systems for various applications ranged from $2.6-13.4/kW-year (Gyuk and Eckroad 2003). An average of these values yields $7/kW-year, while conversion of this to $/kWh yields 0.4-0.8 cents/kWh. Table A.2 summarizes the O&M cost estimates as found in the literature.

Table A.2. Summary of O&M fixed and Variable Costs for NaS Battery

Fixed O&M ($/kW-year)	Variable O&M	Reference
3	16.9 ($/kW-year)	Gyuk and Eckroad 2004
20		(Shoenung and Hassenzahl 2003)
13-51 ($2/kW-year for PCS)	2.6-13.4 ($/kW-year)	(Gyuk and Eckroad 2003)
0.5	0.7 cents/kWh	(Lamont 2004)
1.5	0.5 cents/kWh	(Schoenung et al. 1996)
$0.46/kWh	**0.7 cents/kWh**	**Selected for study**

A.1.5 Efficiency

For NaS batteries, the AC-AC efficiency was in the range of 0.75-0.85(Kishinevsky 2006, Shoenung and Hassenzahl 2003, Schoenung 2001, Technology Insights 2005). We chose a roundtrip efficiency of 0.78. For the Li-ion battery, the efficiency was estimated to be 0.8 Rastler et al. 2007. These figures correspond to battery system efficiencies that include all of the losses in the PCS. The specific PCS efficiency was estimated to be 0.95. The roundtrip efficiency is expected to change as a function of charge and discharge rate. For this analysis, the efficiency is kept constant for all rates.

A.2 Li-ion Battery

A.2.1 Battery Sizing

Li-ion batteries from various applications have various power to energy (P/E) ratios, ranging from 60 for hybrid electric vehicles (HEVs) to 4-16 for plug-in hybrid electric vehicles (PHEV) batteries[1]. In the transportation sector, P is defined as the power delivered by the battery for 2 seconds. For our application, the minimum resolution is 1 minute. Typically, Li-ion batteries can be discharged continuously at the maximum rate of 2C for ~ 20 minutes, with a P/E ratio of 1.3, where C is the energy capacity of the battery in Wh. For 1-2 minute duration, it can be assumed that the P/E for Li-ion batteries is ~ 2. This value will vary with the battery design, with high power battery having larger P/E ratios. Hence, in order to determine actual cost of battery, it must be determined whether power or energy is limiting, needs to be done. It is important to consider not just the maximum power requirements, but how long this maximum power will be needed continuously. This will fix the smallest battery energy content that would meet the power requirement after taking into account battery degradation.

A.2.2 Capital Costs

Present day Li-ion batteries cost ranges from $1015-1450 /kWh (Divya and Østergaard 2009)and $1000/kWh (Howell 2009). Other cost values given in $/KW are ~ $1070/kW(EAC 2008) and $970/kW (Gyuk and Eckroad 2003) with the higher cost including PCS and BOP costs. These numbers can be confusing, since the $/kW cost would equal $/kWh for a 1-hour application, while it would be twice the $/kWh value for a 2-hour application. Telephone conversations with various battery manufacturers yielded a current price of $700 to 1500/kWh, with the price for large volume sales of 1000 batteries or more in 5 years estimated at $600/kWh. Cost estimation models from Argonne National Laboratory (ANL), Tiaxx and The US Advanced Battery Consortium (USABC) (Nelson et al. 2009, Barnett et al. 2009, USCAR 2007), , when normalized to the same total energy, provided a cost of $440, 415 and 450/kWh respectively for large-volume production, or ~ $420/kWh. Taking the average of $600/kWh and $420/kWh, the cost to be used for this study was assumed to be $510/kWh long-term for high volume production. The long-term costs were $510/kWh * 2.35 = $1200/kW. Table A.3 summarizes the cost information for Li-ion batteries:

[1] http://www.transportation.anl.gov/pdfs/HV/434.pdf

Table A.3. Summary of Current Capital Cost Diversity for Li-ion Systems

$/kWh current	$/kW current	$/kWh high volume	Source
700-1000 Euros	--	--	(Divya and Østergaard 2009)
1000	--		(Howell 2009)
	1070 includes PCS and BOP		(EAC 2008)
	970		(Gyuk and Eckroad 2003)
1500 (60,000 cells/year)		1000-1250 (180,000 cells/year)	Lithium technology Corp. (LTC) (Hazel 2010)
700			Lithium technology Corp. (LTC) (Hazel 2010)
1000-1200 (1000+ batteries/year)		500-700 (5 years from now)	Compact Power (Riedel 2010)
1000			BASF (Chintawar 2010)
		415	ANL(Nelson et al. 2009)
		440[a]	TIAXX (Barnett et al. 2009)
		450	USABC (USCAR 2007)

(a) Analysis done for 5.5 kWh, number in table corresponds to 17 kWh battery

The life cycles versus DOD curve of Li-ion batteries is shown in Figure A.2.

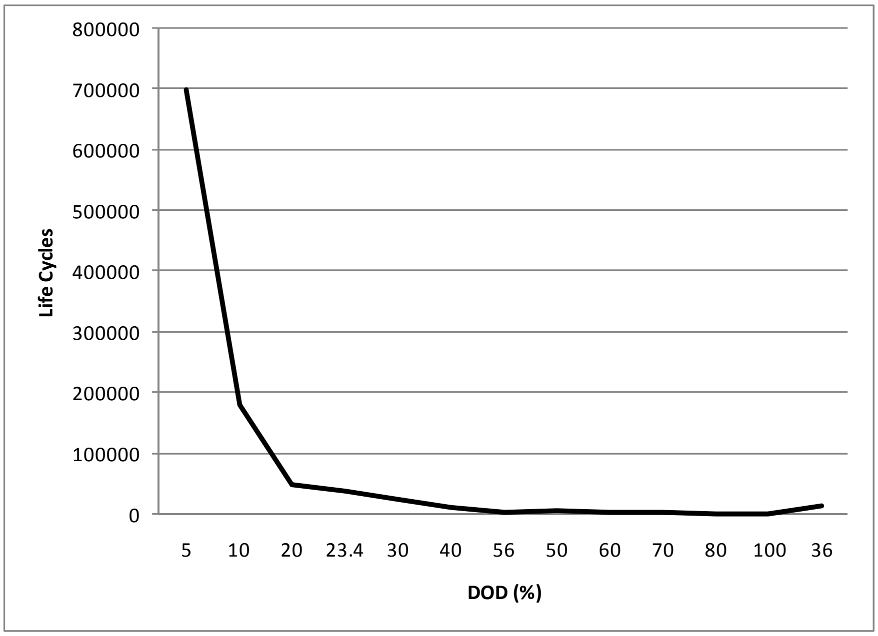

Figure A.2. Li-ion Battery Life Cycle versus DOD Curve

A.3 Pumped Hydroelectric (PH) Systems

A.3.1 Capital and O&M Costs

For PH systems, the capital cost are provided in $/kW. Most systems provide this information by including PCS and BOP costs. For this analysis, BOP costs for PH will be neglected, since the values provided in the literature are as small as $4/kWh. Additional capital cost information was provided by Rick Miller of Renewable Energy Services in several email communications (Miller 2010) [19, 25]. The capital costs for single speed PH systems is in the range of $1500 to 2500/kW , while the range for variable speed pumps is $1800 to 3200/kW. This cost is broken down into three parts:

1. pump/turbine and motor/generator costs, ($600/kW for single-speed and $850/kW for variable-speed units)
2. Hydro-mechanical equipment, transformers, switchgears, remaining BOP
3. owner's costs, engineering/design services, civil construction, excavations and construction for water conveyance system, upper and lower dams and reservoirs.

The pump and turbine costs typically for pumped hydro projects varies significantly, and has been reported to be as low as $78/kW to 264/kW (GE Energy 2004, Alstom 2009). Since these costs are about 33% of total system cost, they also contribute to large variation in system cost, in addition to siting related contribution.

A range of values was obtained from the literature on capital costs, O&M fixed and O&M variable for PH systems is shown in Table A.4. While replacement costs are minimal the generators need rewinding every 20-25 years.

The overall efficiency is 80 to 82%, and does not include transmission losses. It should be noted that the reported 75% efficiency probably includes transmission losses.

Table A.4. Capital Costs for Pumped Hydro Systems

$/kW	O&M fixed $/kW-year	O&M Variable cents/kWh	Efficiency AC-AC	Reference
1000	2.5	Very small	0.75	(Shoenung and Hassenzahl 2003)
600	3.8	0.38	0.87	(Schoenung 2001)
1483				(Geadah 2009)
1552				(Geadah 2009)[a]
> 350 €/kW			0.70-0.80	Fodstad
		2	0.75	(Rahman 1990)
			0.75	(First Hydro Company 2009, Jenkinson 2005)[b]
1500			0.82	(NHC 2007)[c]
1000				(Boyes)
1800-3200[d]			0.78-0.82	(Miller 2010)
517, 583[e]	4.6		0.80[f]	(Figueiredo et al. 2006)
1100-2000[g]	4.3	0.43[h]	0.60-0.78	(Lipman et al. 2005)
1700[i]				(Miller 2010)

(a) 2016-2020 costs
(b) At Dinorwig (1800 MW 1.5 min start-up)
(c) 500 MW fully dispatchable in 15 seconds with unit spinning, 10 min black start
(d) $1500-2500/kW for single speed
(e) $517/kW Grand Cache 218 MW, $583/kW Kneehills 194 MW
(f) Efficiency set at 0.8, not measured
(g) Projected cost for year 2020 was $800/kW
(h) Referenced Schoenung et al. 1996
(i) $245/kW for pump turbine, motor generator and power electronics

A.3.2 Duration between various modes

The response time for PH systems is fast, achieving high ramp rates as high as3 MW/s (First Hydro Company 2009). The calendar life was estimated to be 50 years (Schoenung 2001). Figure A.3 shows typical start and stop times for PH systems.

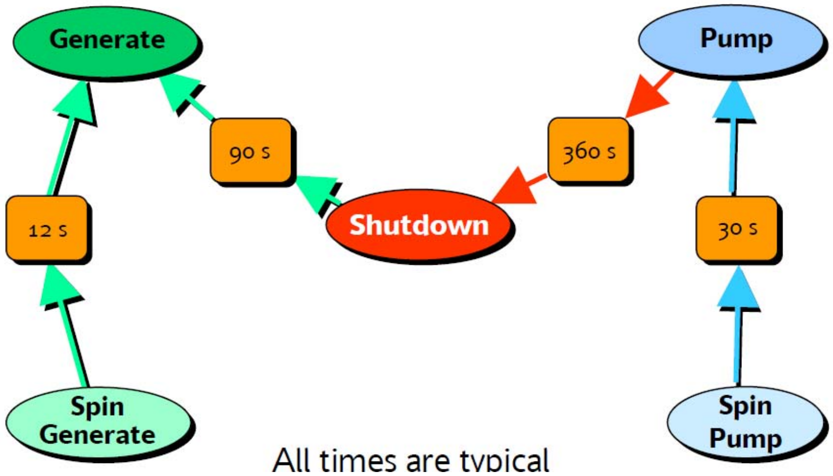

Figure A.3. Typical duration between various modes at Dinorwig PH system (Jenkinson 2005)

After several consultations with turbine and pumped hydro storage system experts, we assume a delay of 4 minutes to switch operating modes in each direction (pumping to generation and vice versa).

Appendix B

Specific Operational Strategies to Meet Balancing Requirements

Appendix B

Specific Operational Strategies to Meet Balancing Requirements

To explore different operational strategies and how their selection will impact balancing requirements, several technology cases were introduced in Section 3.2. Table 3.4 provided a brief outline of the different cases, and is replicated on the next page as Table B.1 for convenience. A more detailed description of each case in Table B.1 is presented in the sections of this appendix.

B.1 Case 1: Combustion Turbines

The base case for operational strategies involves the use of only combustion turbines (CTs) for energy balancing requirements. Part load efficiencies are considered in the CT implementations. This scenario represents a case similar to current operational procedures.

B.2 Case 2: NaS batteries + CC

The second scenario utilizes NaS batteries and combined cycle (CC) generation to meet balancing requirements. Figure B.1 shows the power output of the NaS battery storage and combined cycle generator over a two-day period. Combined cycle generation is used to compensate for the efficiency loss of the batteries, and to provide a constant energy source for the batteries to assure a net zero energy change over the course of the entire day. As such, the NaS contributions are actually the difference between the blue line and red line at each interval. If above the red line, the NaS battery is discharging into the system. If below the red line, the storage is charging.

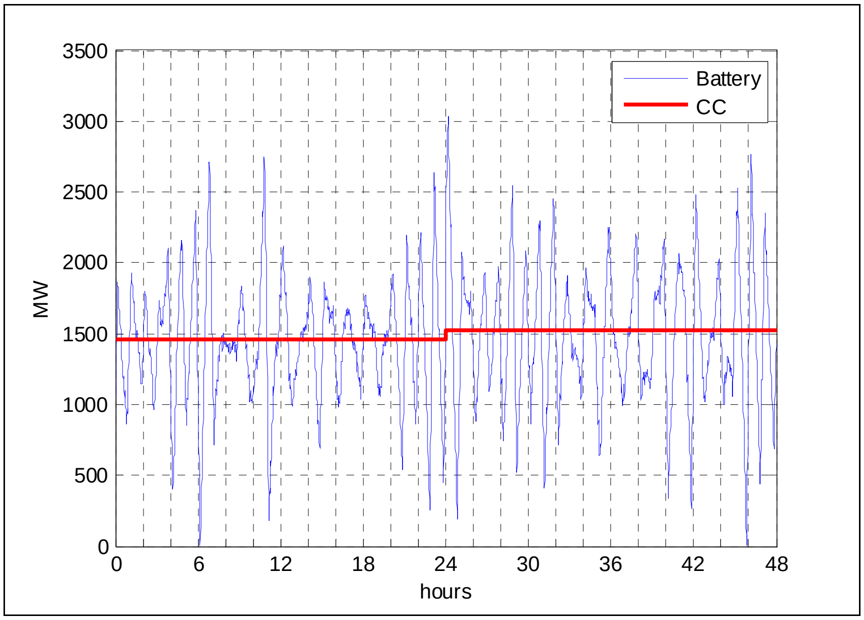

Figure B.1. Power Output of NaS Battery and Combined Cycle Generation for 2-day Period

Table B.1. Definition of Technology Cases

	Case	Technology	Comments
Individual Technologies	C1	Combustion turbine	Conventional technology considered as the reference case
	C2	NaS	Sodium-sulfur battery only
	C3	Li-ion	Lithium-ion battery only
	C4	PH with multiple mode changes	Pumped hydro with a 4-minute waiting period for mode changes (pumping-generation and vice versa). This machine allows to multiple mode changes during the day. NaS battery is assumed to make up operations during 4 minute waiting period.
	C5	PH with 2 mode changes	Same as (C4), except only two mode changes. Balancing services will be provided during pumping mode at night (8pm-8am) and during generation mode during the day (8am-8pm). NaS battery is assumed to make up operations during 4 minute waiting period.
	C6	DR	Demand response only. This assumes that balancing services will be provided as a load. Only considered are two residential end-uses: 1) hot water heating and 2) PHEV charging at home. Resources will expressed in MW of DR capacity as well as in numbers of homes having one hot water heater and one PHEV
Technology packages	C7	NaS DR	Sodium-sulfur battery and demand response combined
	C8	Li-ion DR	Lithium-ion battery and demand response combined
	C9	PH with multiple mode chances NaS	Pumped hydro with no constraints for mode changes with NaS battery. The balancing requirement is allocated to 25% to pumped hydro and 75% to NaS battery. This share is set arbitrarily.
	C10	PH with 2 mode changes NaS	Pumped hydro with two mode changes per day (see C5) with NaS battery. The balancing requirement is allocated to 25% to pumped hydro and 75% to NaS battery. This share is set arbitrarily.
	C11	PH with multiple mode changes NaS/DR	Pumped hydro with no constraints for mode changes with NaS battery and DR. The balancing requirement is allocated to 25% to pumped hydro, 20% DR (about 1 million homes and PHEVs) and 55% to NaS battery. This share is set arbitrarily.

B.3 Case 3: Li-ion + CC

The third scenario focuses on the use of Li-ion batteries and combined cycle generation. The scenario is executed in an identical manner to Case 2 above, but the higher efficiency NaS batteries are replaced with Li-ion batteries. Combined cycle generation is once again utilized to compensate for efficiency losses in the battery storage and to ensure a balanced energy transfer over the day. The efficiency of Li-ion batteries was nearly identical to that of NaS batteries for this case (78.9% compared to 80%), so the power output of Figure B.1 is representative of the Li-ion battery and combined cycle case as well.

B.4 Cases 4: Pumped Hydro with Multiple Mode Changes + CC

Technology Case 4 utilizes pumped hydro generation for the primary balancing requirement. For this particular case, the pumped hydro has no mode switching limit. The pumped hydro storage can switch between pumping and generation modes as many times as necessary during the day. This results in approximately 40 mode changes a day, which can cause a considerable drop in the expected lifetime of the equipment (Spitzer and Penninger 2008). Mode changes experience a 4-minute changeover delay. During the changeover, NaS batteries are utilized to cover the balancing requirements. Figure B.2 demonstrates this implementation. As with the previous cases, combined cycle generation is utilized to compensate for the efficiency losses of both the NaS battery and pumped hydro, as well as balance the energy consumption in the storage.

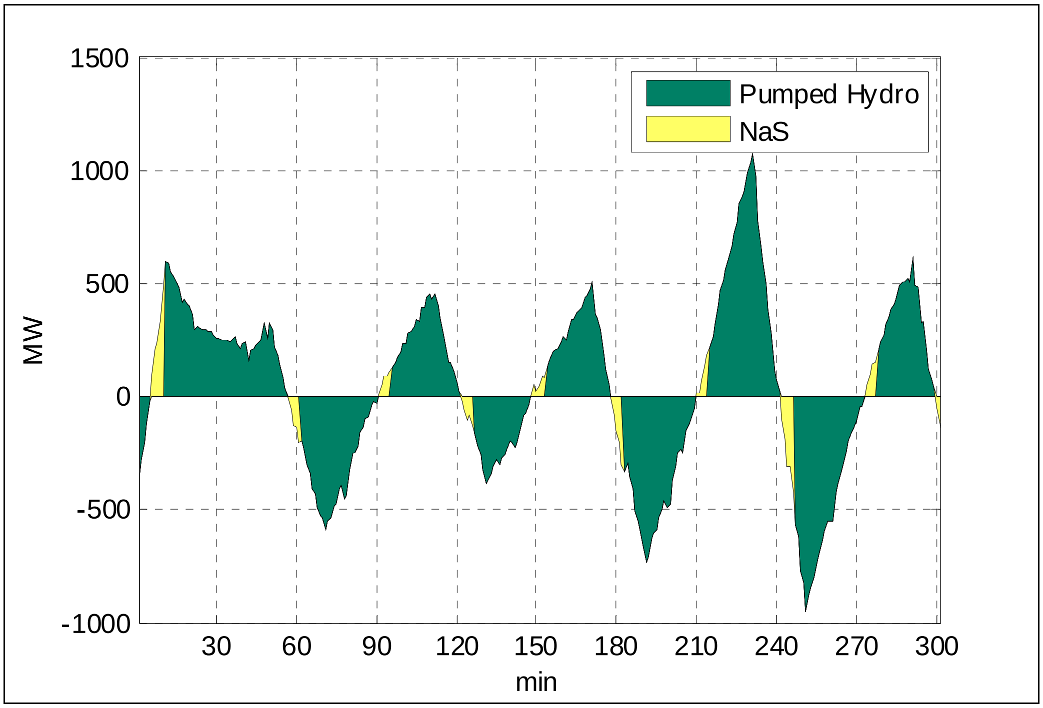

Figure B.2. Balancing Signal Taken by Pumped Hydro and NaS Battery When the Changeover Delay is Modeled

B.5 Case 5: Pumped Hydro with Two Mode Changes + CC

Technology Case 5 is very similar to scenario in Case 4. However, the pumped hydro storage is restricted to two mode changes per day. The pumped hydro operates in pump mode from 8 PM to 8 AM, and operates in generation mode from 8 AM to 8 PM each day. This reduced number of mode changes increases the expected lifetime of the equipment, when compared to Case 4. As with Case 4, a 4-minute changeover delay is incorporated into the pumped hydro system. This changeover delay is again handled by supplementary NaS battery storage. Combined cycle generation is not only utilized to compensate for efficiency losses in the battery and pumped hydro storage, but also to provide additional pumping power. Figure B.3 represents the power output of the pumped hydro storage when restricted to only two operating modes. The yellow areas associated with the NaS storage are not visible on this plot, as they only represent 8 minutes out of the 24-hour period.

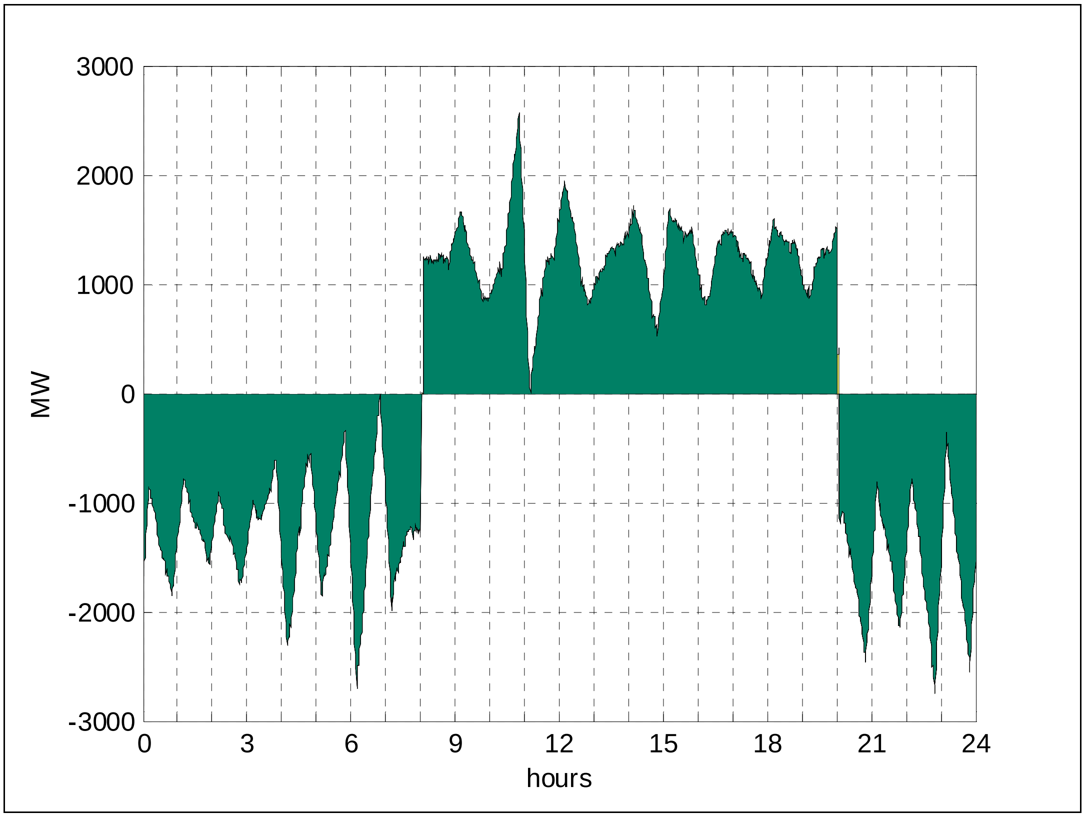

Figure B.3. Power Output of Pumped Hydro with Only Two Mode Changes Per Day

B.6 Case 6: Demand Response

Technology Case6 utilizes a different scenario to meet the balancing requirements. Using demand response, the load of the system is adjusted to meet the varying energy demands of the system, rather than using an energy storage solution. Pure demand response balancing was accomplished using three different device combinations: PHEV charging where both home and work charging was assumed available; water heater control; and a combination of home-only PHEV charging and water heater control.

The energy capabilities of the demand response studies were based on two basic assumptions. The first is the overall loading curves for the PHEV charging scenarios and water heater control follow the trends shown in Figure B.4. Theses curves represent the load from a single device of each type. This capacity was then scaled by number of devices required to meet the balancing requirements for the simulation interval. These quantities are shown in Table B.2.

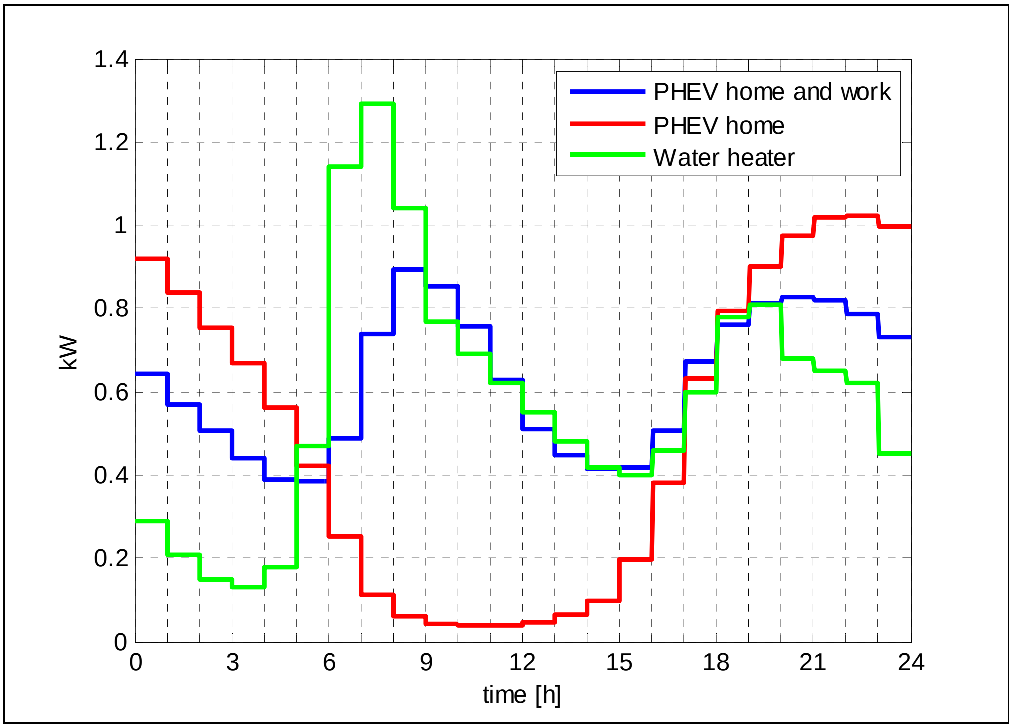

Figure B.4. Load Curves for PHEV with Home and Work Charging, PHEV with Home Charging, and Water Heater

Table B.2. Number of Demand Response Devices Necessary to Provide Total Balancing Services

Demand Response Scenario	Description	Number of Devices	Maximum Resource
PHEV only	PHEV - home & work	9 Million	8 GW
Water heaters only	Water heaters - Week day	21.8 Million	28 GW
PHEV + Water heaters	PHEV - home	5 Million	8.6 GW
	Water heaters - Week day	5 Million	

B.6.1 DR – PHEV with Home and Work Charging

The first equipment demand response equipment scenario utilizes PHEV charging that is available both at home and during work hours. After scaling by the number of devices in Table B.2, the demand curve seen in red in Figure B.5 is produced. The numbers obtained in Table B.2 represent the number of devices (PHEVs), *M*, that are required to meet the balancing requirement. The balancing signal available from this PHEV charging scheme is shown in blue in Figure B.5.

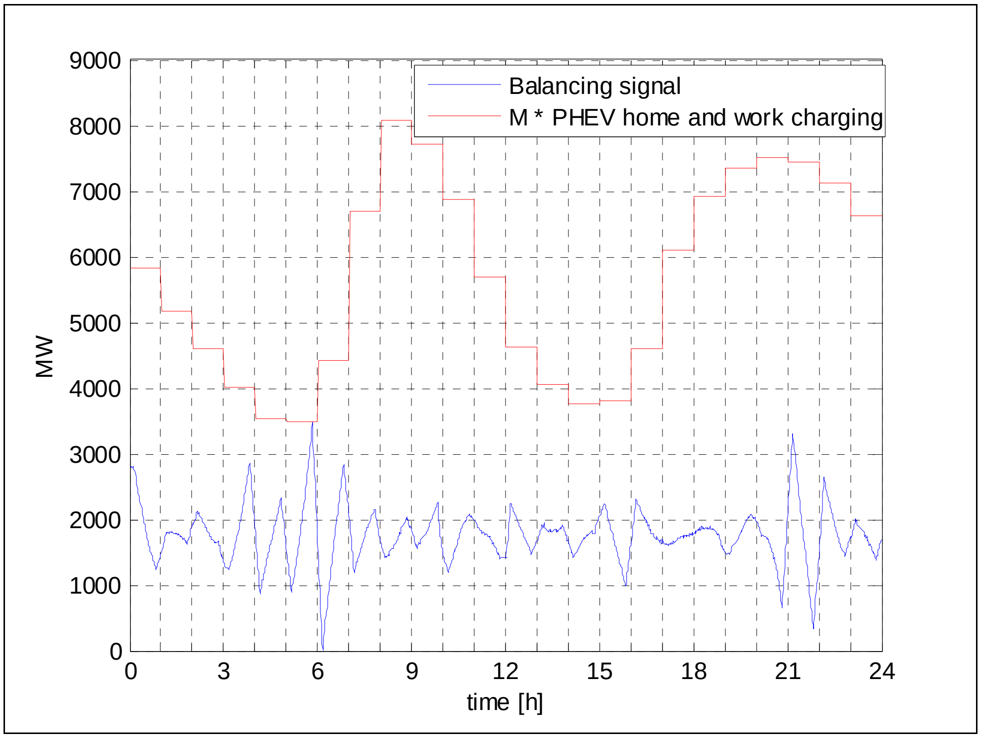

Figure B.5. Balancing Signal and Demand Response Requirement from PHEV Only With Home and Work Charging

B.6.2 DR – Water Heaters

The second equipment scenario utilizes only water heaters for demand response capabilities. The larger peak value and larger number of available water heaters results in the demand curve shown in Figure B.6. It is useful to point out the difference in the load curve means significantly more water heater load is required for demand response to meet the balancing requirements.

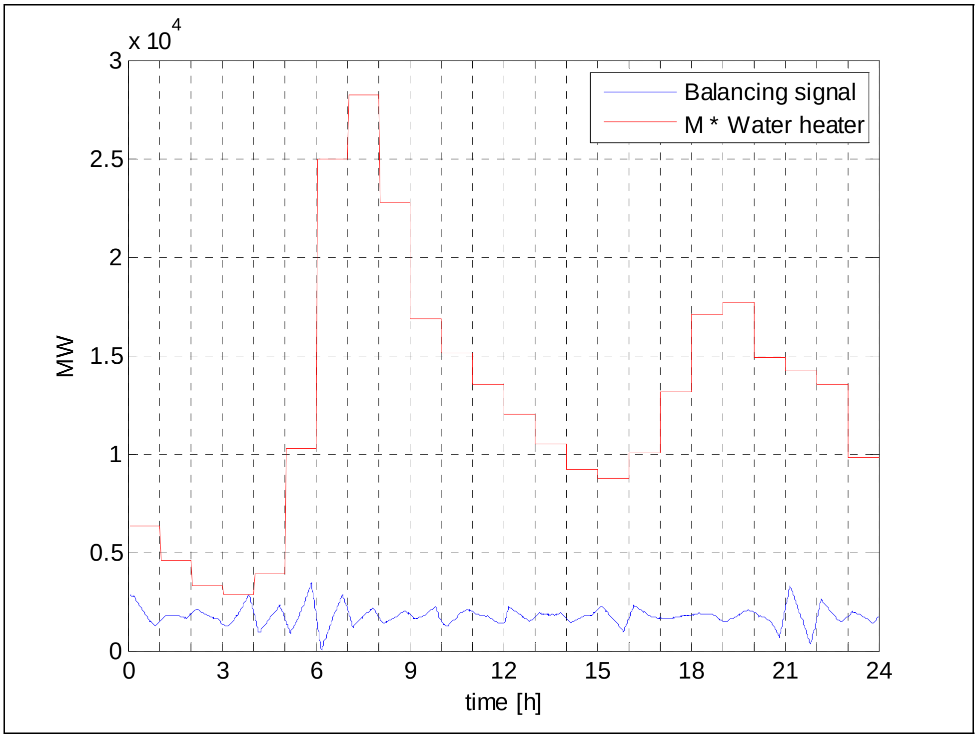

Figure B.6. Balancing Signal and Demand Response Requirement From Water Heaters Only

B.6.3 DR – Water Heaters

The final equipment scenario utilizes both PHEV-charging and water heaters for demand response. Unlike the first equipment set, the PHEV is assumed to only charge when it is at home. The combination of the PHEV and water heater loading curves results in the curve of Figure B.7. As Figure B.7 indicates, the peak associated with the demand response devices is significantly lower than the curve associated with the water heater-only scenario. Table B.2 reinforces this observation with a much smaller requirement in the number of demand-response capable devices.

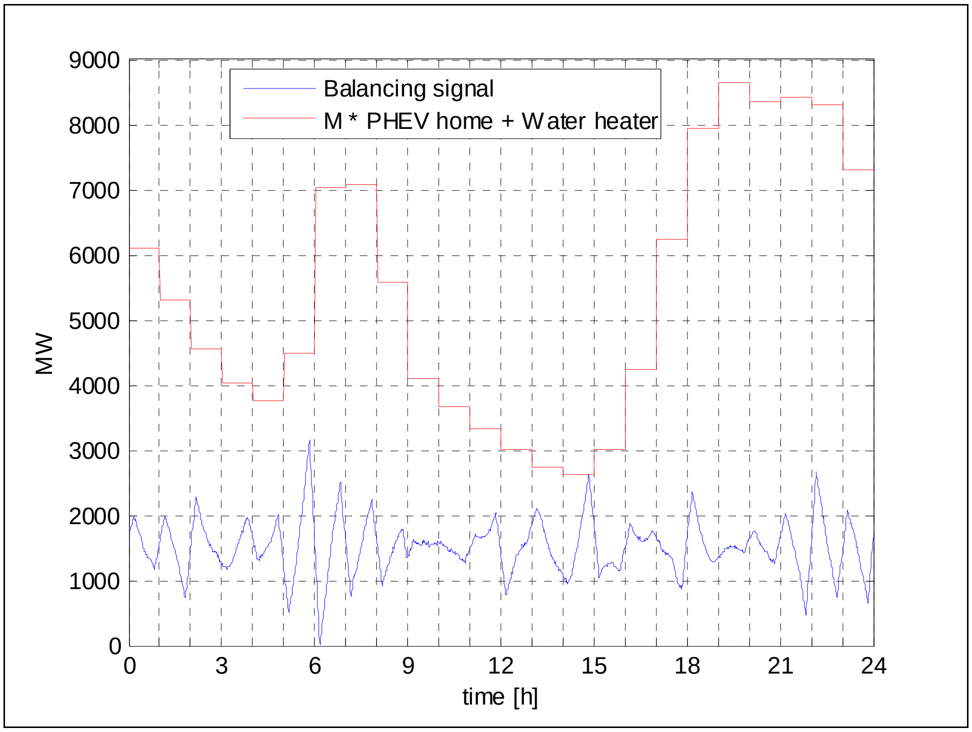

Figure B.7. Balancing Signal and Demand Response Requirement from Water Heaters and PHEV with Home Charging

B.7 Case 7: CC + NaS + DR

The seventh technical case utilizes a combination of combined cycle generation, NaS battery storage, and demand response to meet the balancing requirements. Without ramp-rate constraints, the balancing requirements were divided proportionally between the NaS storage and demand response. Demand response capabilities were modeled after the "PHEV-home charging and water heater control" example of the previous technology case. Figure B.8 shows the required scaling to meet the demand response portion of the balancing requirement. Supplemented with NaS battery storage, the amount of demand response required is significantly less than the previous technology case. Figure B.9 shows the NaS battery storage portion of the balancing requirement. As with the previous battery cases, combined cycle generation was used to compensate for battery efficiencies, as well as meet the net energy constraints for the battery storage.

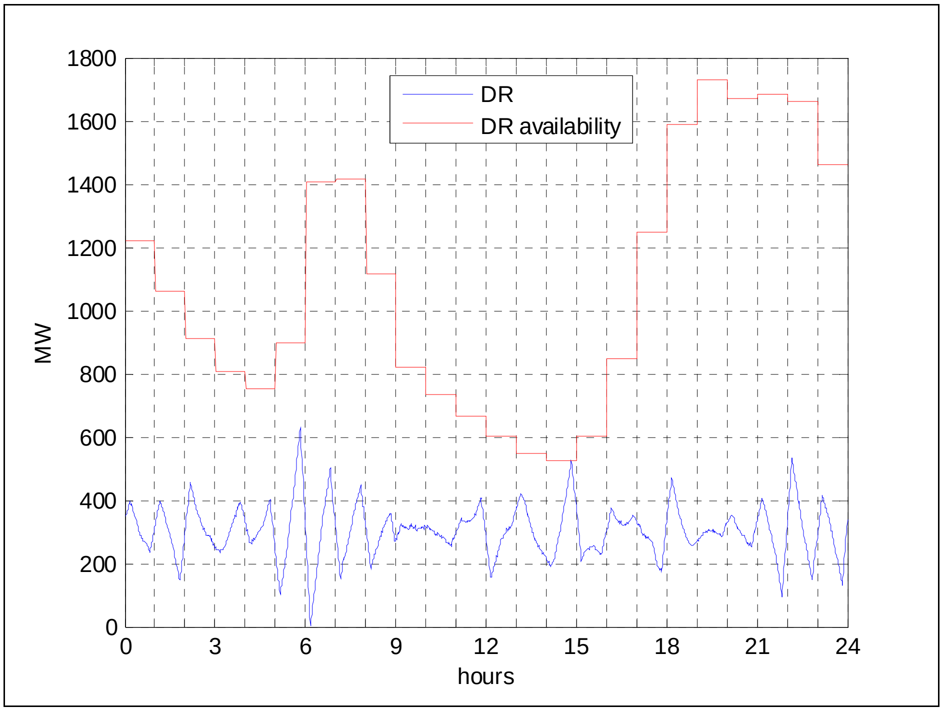

Figure B.8. Demand Response (DR) Availability and Balancing Signal Followed by DR

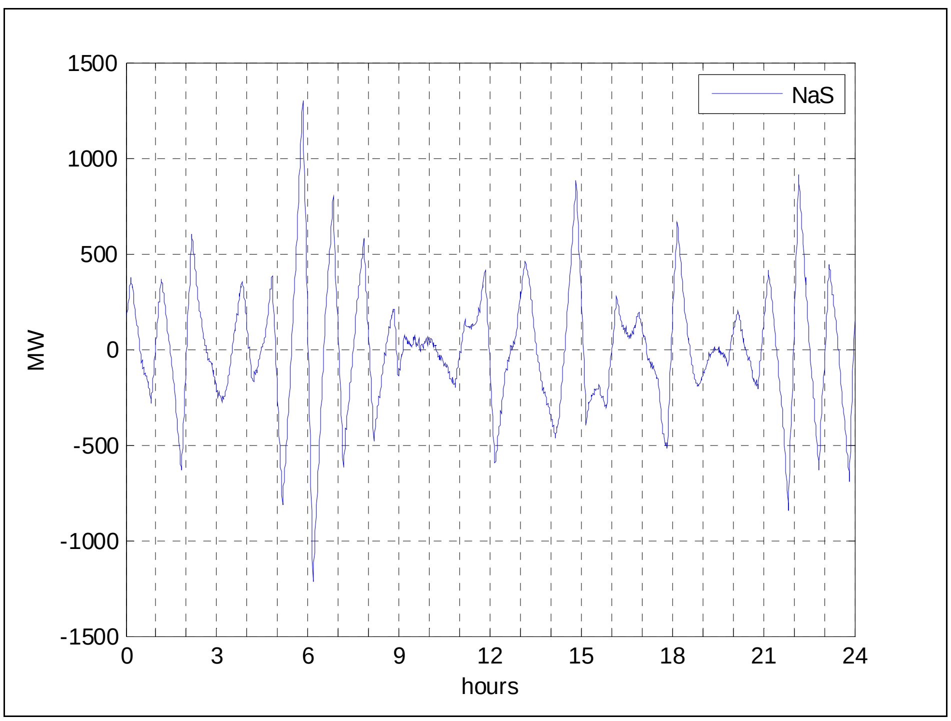

Figure B.9. Balancing Signal Followed by NaS Battery for the First Day

B.8 Case 8: CC + Li-ion + DR

This case is similar to Case 7 discussed in the previous subsection; there is only a difference in the battery efficiency. The results shown for Figures B.8 and B.9 are representative of the Li-ion battery storage as well.

B.9 Case 9: NaS + CC + Pumped Hydro with Multiple Mode Changes

Technology Case 4 earlier utilized pumped hydro storage with multiple mode changes in a day, which was supplemented by NaS battery storage. This technology case supplements that analysis with a larger amount of NaS battery storage available. Unlike Case 4, the balancing requirements are divided between the NaS and pumped hydro storage. As such, the NaS is providing part of the balancing requirement continuously, not just during the 4-minute long changeover periods of the pumped hydro storage. Combined cycle generation is again utilized for energy balance, as well as compensating for battery efficiency.

Figure B.10 shows the power output of the pumped hydro for one day of analysis. Figure B.11 shows the power output of the NaS battery storage for the same day. Due to the proportional division of the balancing requirements, the two signals are nearly identical in shape. The largest difference is the flat periods on the pumped hydro, which are associated with mode changes.

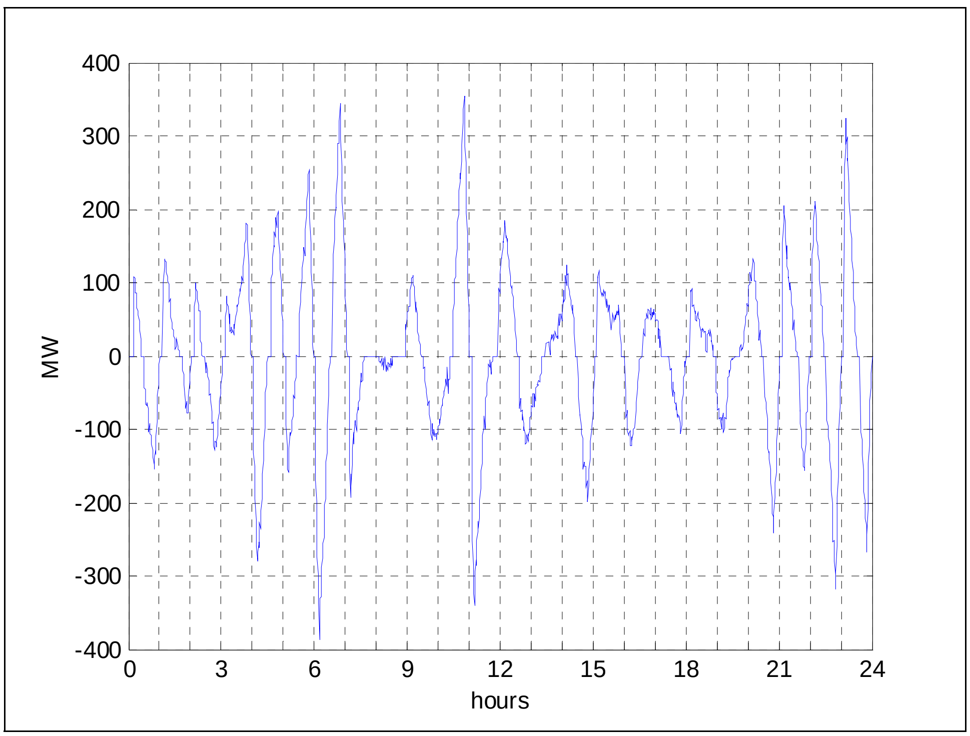

Figure B.10. Power Output of Pumped Hydro with Multiple Mode Changes per Day with NaS + CC

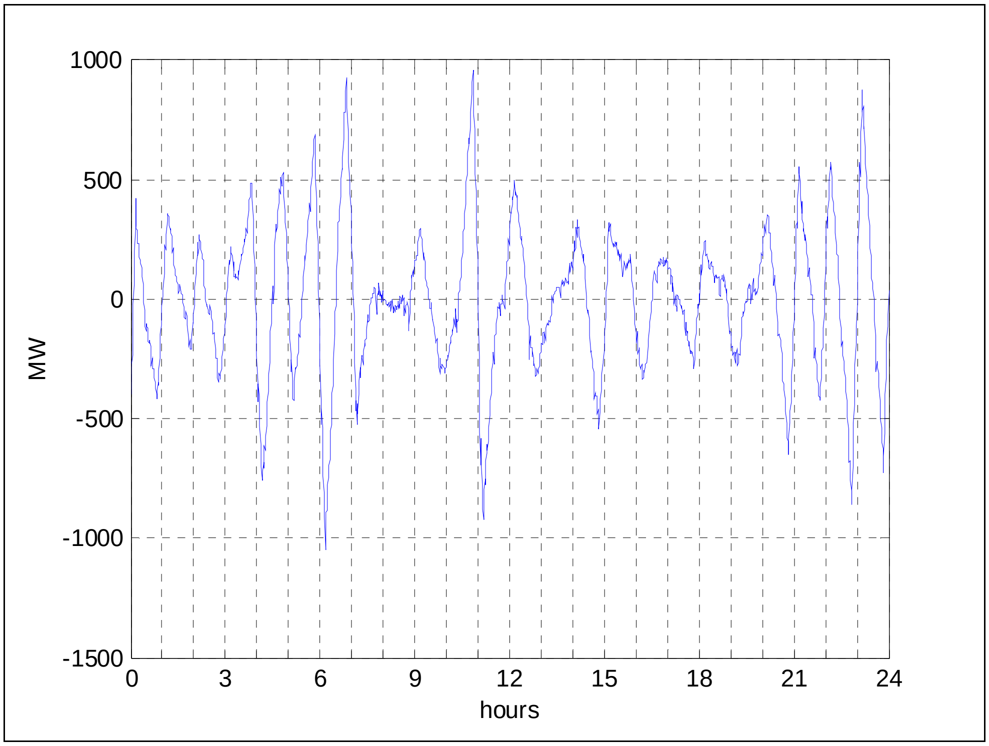

Figure B.11. Power Output of NaS Battery for NaS + Pumped Hydro + CC scenario

B.10 Case 10: NaS + CC + Pumped Hydro with Two Mode Changes

Similar to Case 9, the pumped hydro and NaS battery technology Case 5 was re-evaluated with large NaS storage available. The pumped hydro storage was restricted to a night pump and day generation cycle, as per Case 5. However, the NaS battery storage capacity was increased. As with Case 9, these two storage technologies divided the balancing requirements proportionally. Combined cycle generation was utilized for energy balancing, and compensating for battery efficiency.

Figure B.12 shows the power output of the pumped hydro for this technology case. Figure B.13 shows the power output for the NaS battery storage. As with Cases 4 and 5, the pumped storage requirement is higher in the two mode change-only case. However, the addition of the NaS battery storage helps alleviate the amount of pumped storage required. It is useful to note that the proportions of the balancing requirements handled by each storage device were the same as Case 9, so the NaS storage output looks nearly identical. Closer inspection would reveal slight differences around the changeover times of Case 9, as Case 10 only has two changeovers during the course of the day.

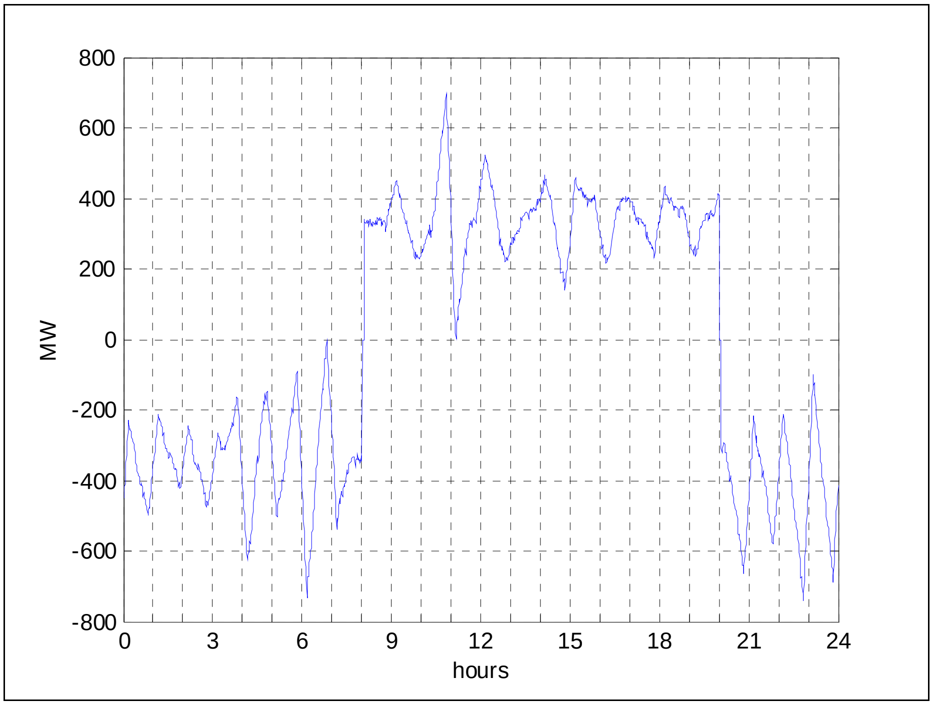

Figure B.12. Power Output of Pumped Hydro with Only 2 Mode Changes per Day

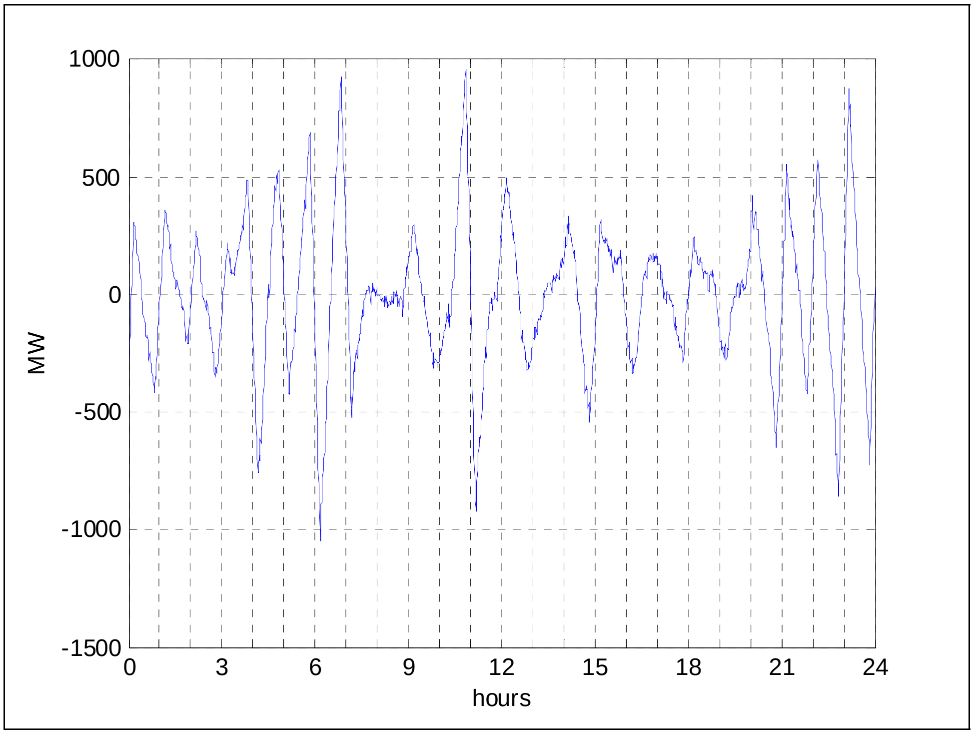

Figure B.13. Power Output of NaS battery for 2 Mode Changes per Day

B.11 Case 11: Pumped Hydro + NaS + CC + DR

In the final technology case presented, a combination of pumped hydro, NaS battery storage, demand response, and combined cycle generation are proportionally utilized for the balancing requirements. The pumped hydro handles 27% of the requirements and is a multiple changeover per day scenario, with approximately 40 mode changes every day. The NaS batteries handle about 53% of the balancing requirements. Demand response, based around the PHEV-home charging and water heater control method presented earlier, handles the remaining 23%. The NaS battery and demand response cover the full balancing requirements during the pumped hydro's 4-minute changeover periods.

Figure B.14 represents the power output for the pumped hydro over the course of the day, which is identical to Case 9's pumped hydro output. Figure B.15 shows the NaS battery output over the course of the day, and Figure B.16 represents both the balancing requirement and availability of the demand response portion. Compared with earlier cases, amount of demand response availability and NaS battery output required is significantly smaller.

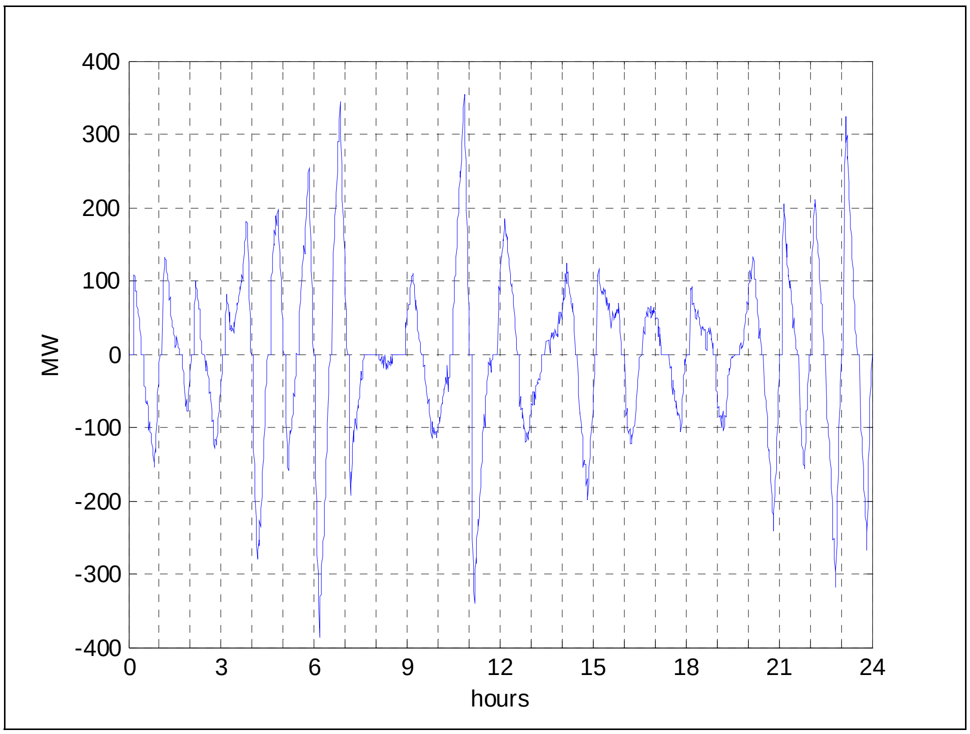

Figure B.14. Power Output of Pumped Hydro with Only 2 Mode Changes per Day with NaS + CC

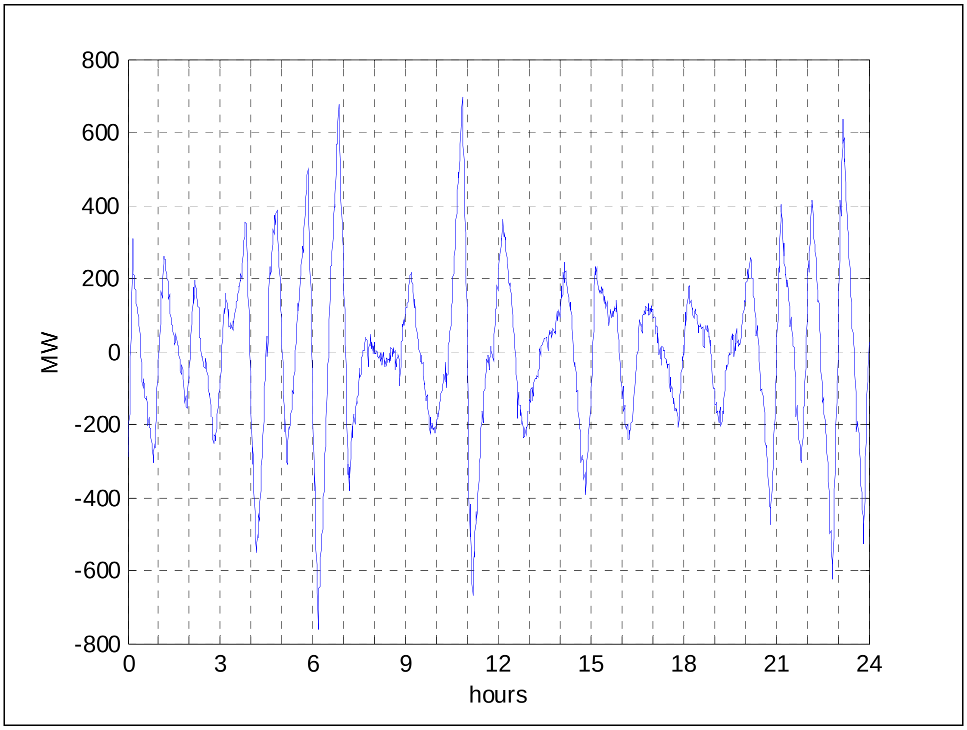

Figure B.15. Balancing Signal Taken by NaS Battery in the First Day

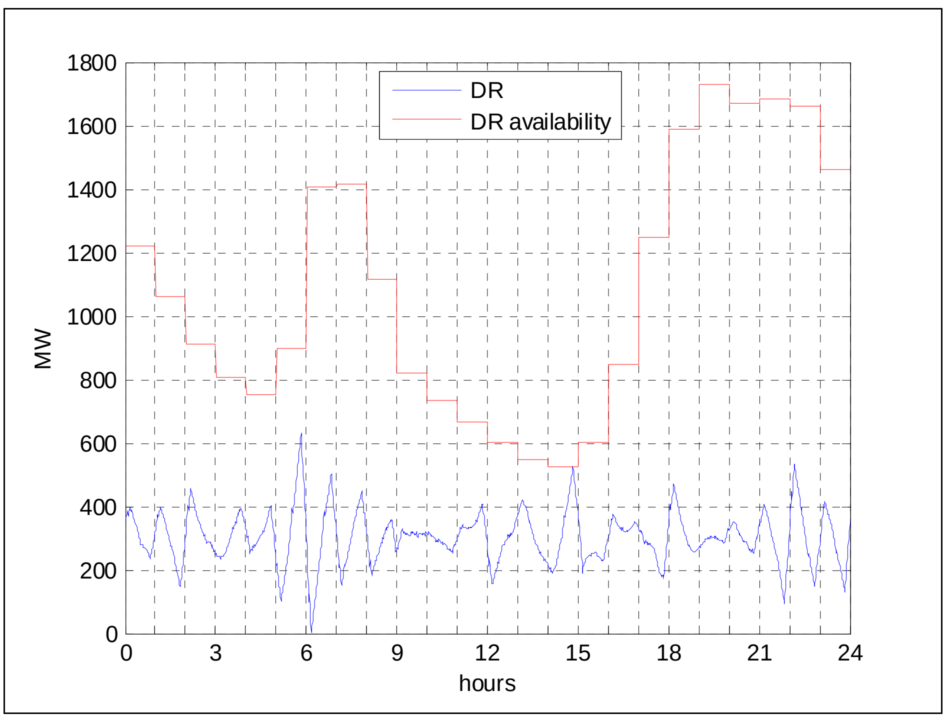

Figure B.16. Demand Response (DR) Availability and Balancing Signal Followed by DR

B.12 Wind Spillage

The balancing requirements are produced when there is over-generation and under-generation in the system. Balancing requirements caused by over-generation can be compensated using wind spillage, that is, wind generators can be controlled to generate less power than the available wind resource would allow. This action is called wind spillage in this study. Wind spillage can curtail the peaks of the over-generation balancing signal. However, as it is illustrated in this section, wind spillage does reduce the capacity requirements (MW) slightly, but increases the energy capacity requirements (if energy storage is used). This is an non-intuitive result and is explained below.

Wind spillage introduces asymmetry to the balancing signal, since the peaks curtailments are only performed when there is over-generation and the under-generation peaks remain unchanged. As a result, the power requirements for balancing services are not considerably reduced. What is more, the energy requirements for balancing services increase due to the introduction of asymmetry in the balancing signal. An illustration of this phenomenon is given in this section.

Consider the case where the balancing requirements are meet by NaS batteries only (Case 2, Section B.2). If the complete over-generation part of the balancing signal is curtailed by wind spillage, the balancing signal taken by the NaS batteries is as shown in Figure B.17. Charging and discharging of the NaS batteries is decided by the difference between the balancing signal and a daily fixed power output of a combined cycle (CC) generator as shown in Figure B.18. It can be seen from Figure B.18 that the maximum power requirement for NaS batteries (difference between balancing signal and constant power output of CC) is not considerably reduced by curtailing half of the balancing signal using wind spillage. What is more, the energy requirements for NaS batteries are larger than the energy requirements without wind spillage as it can be seen comparing Figure B.19 and Figure B.20.

Figure B.21 and Figure B.22 show the energy and power requirements for several levels of wind spillage. 100% wind spillage means that the complete over-generation side of the balancing signal is curtailed by wind spillage. It can be seen in Figure B.21 and Figure B.22 that wind spillage increases the energy requirements while it does not considerably reduces the power requirements. Therefore wind spillage by itself is not a good strategy to provide balancing services.

A reduction in the energy balancing requirements through wind spillage could be only achieved if the balancing signal is also curtailed in the under-generation peaks. Demand response can be used to curtail under-generation peaks. Symmetry in the balancing signal can be maintained by using both demand response and wind spillage.

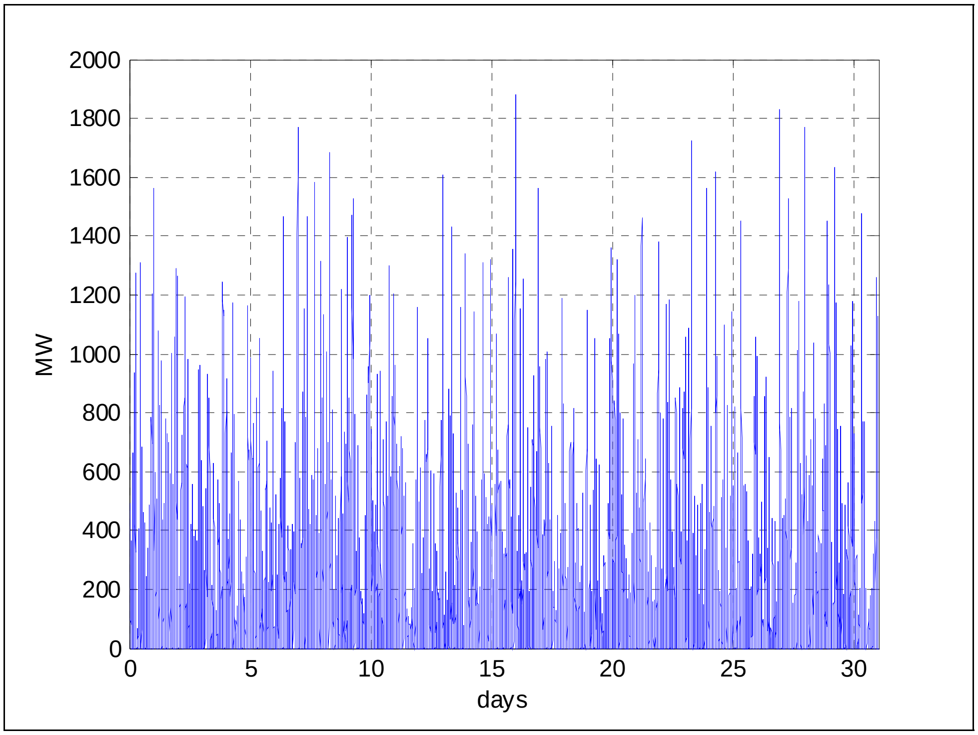

Figure B.17. Balancing Signal Taken by NaS Batteries After the Complete Over-Generation Component is Curtailed by Wind Spillage

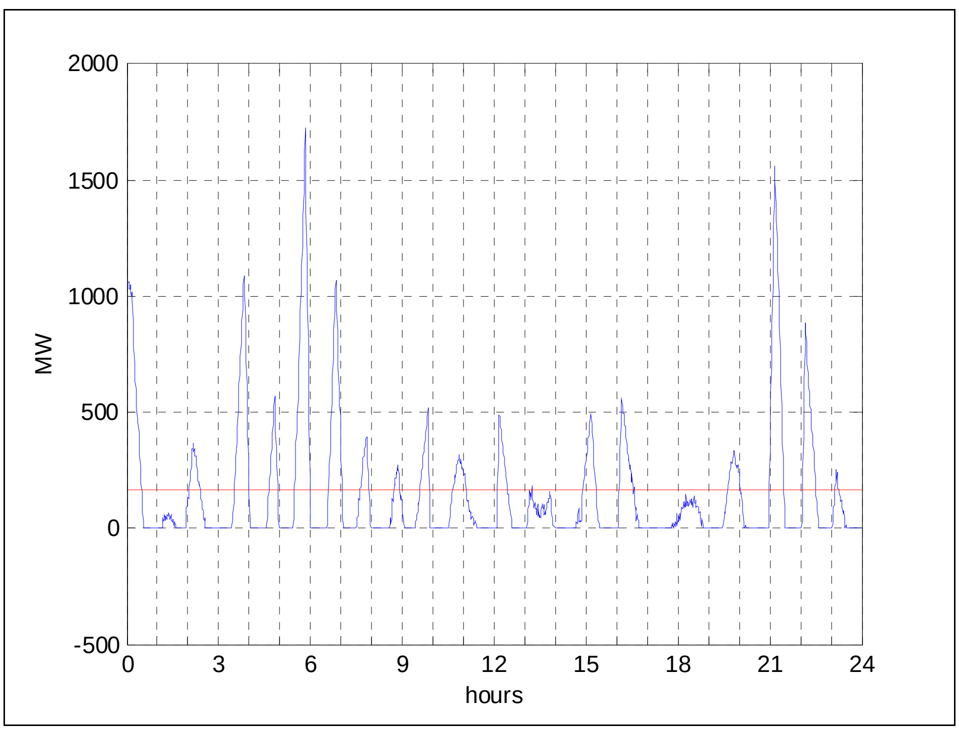

Figure B.18. Balancing Signal Taken by NaS Batteries After the Complete Over-Generation Component is Curtailed by Wind Spillage, and Constant Power Output of Combined Cycle Generation

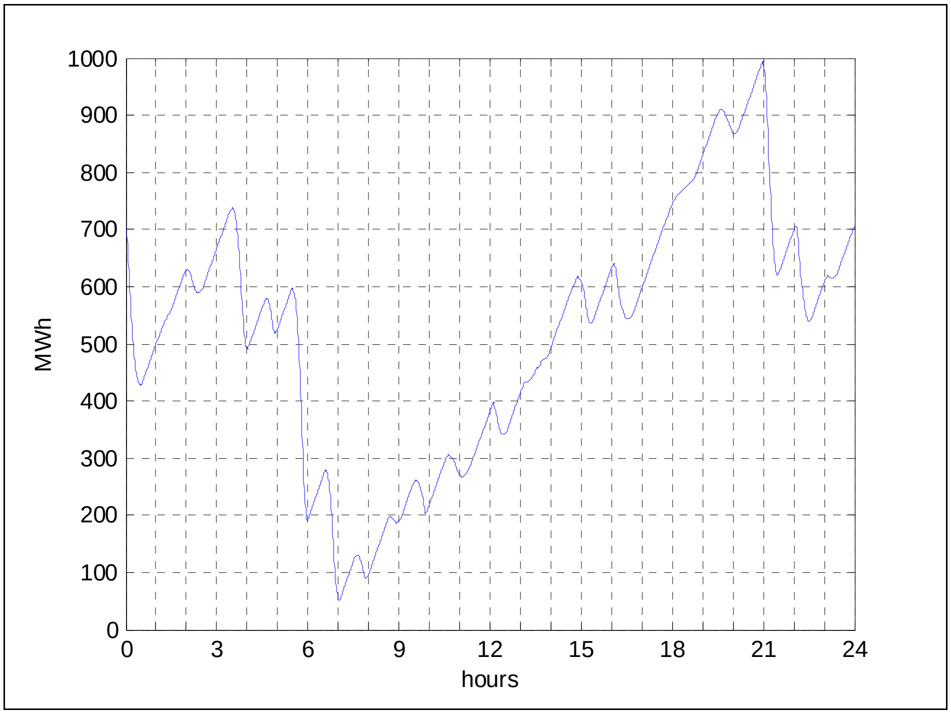

Figure B.19. Charging Status of NaS Batteries, for Day 24, After the Complete Over-Generation Component is Curtailed by Wind Spillage

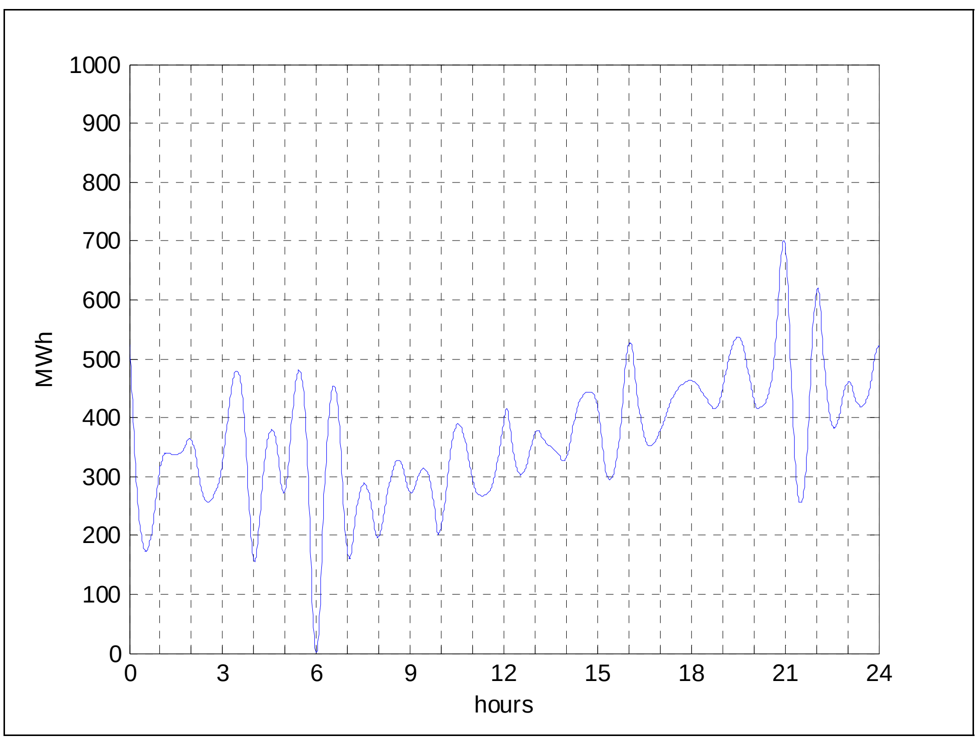

Figure B.20. Charging Status of NaS Batteries Without Wind Spillage for Day 24

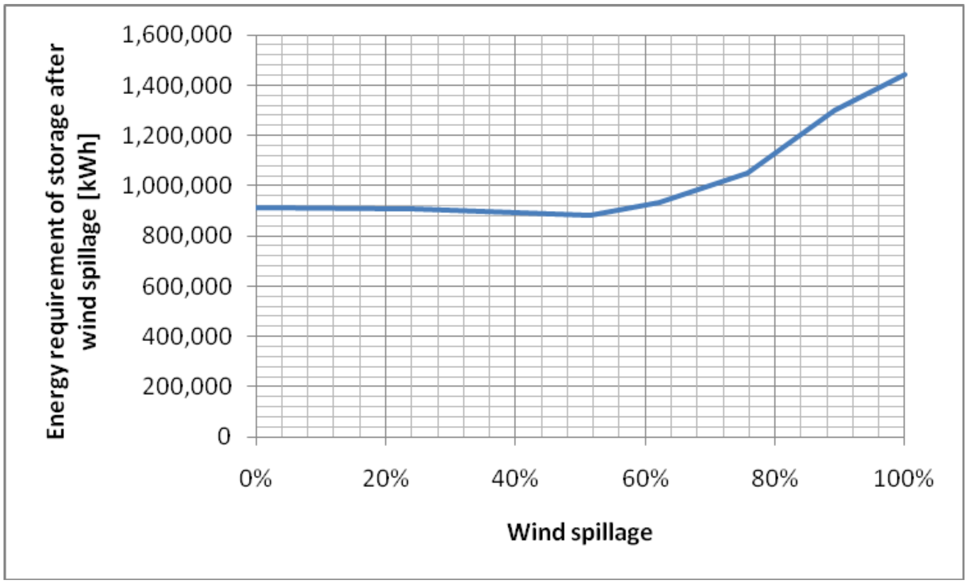

Figure B.21. Energy Requirements for Storage after Wind Spillage is Applied

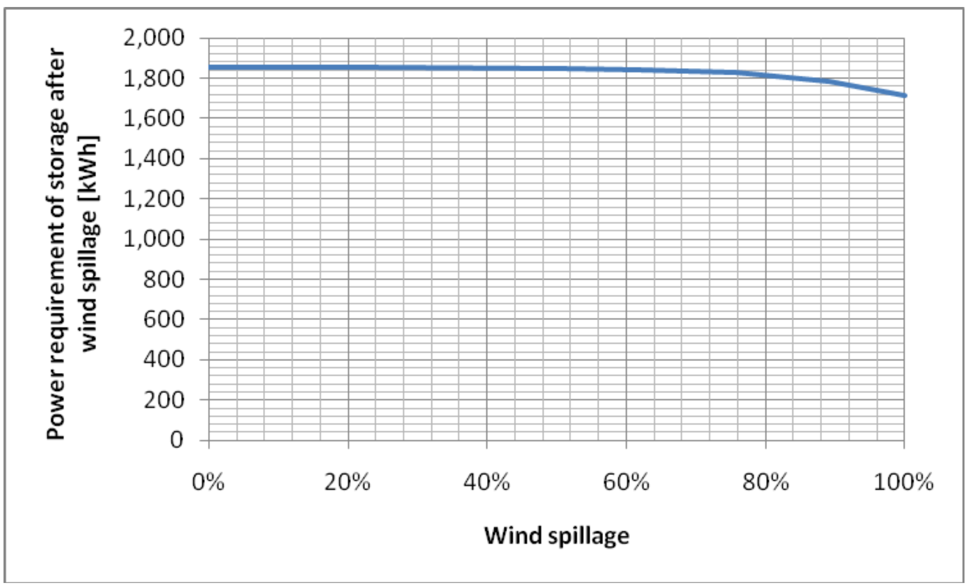

Figure B.22. Power Requirements for Storage After Wind Spillage is Applied

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