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PHASE II/Vol.1

U.S. DEPARTMENT OF ENERGY
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National Assessment of Energy Storage for Grid Balancing and Arbitrage

Phase: II: WECC, ERCOT, EIC

Volume 1: Technical Analysis

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September 2013

Prepared for the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, under Contract DE-AC05-76RL01830

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Funded by the Energy Storage Systems Program of
the U.S. Department of Energy
Dr. Imre Gyuk, Program Manager

Pacific Northwest National Laboratory
Richland, Washington 99352

Executive Summary

Electricity production from wind and other renewables technology has increased significantly to meet the renewable portfolio standards (RPS) targets imposed by 29 U.S. states, the District of Columbia, and 2 U.S. territories. Energy storage is attracting greater interest as an enabling technology for integrating variable renewable power into the electric grid, addressing grid reliability challenges, and increasing overall infrastructure utilization. The integration of renewable energy technology into the U.S. grid is one of the key drivers for the growing interest in stationary energy storage systems. Other countries are also interested in advanced energy storage systems for accommodating the variable nature of renewable resources and the inherent uncertainty in accurately forecasting production. Internationally, significant investments in research and development for advanced energy storage systems are being made to address the perceived need that energy storage will be an important component of the future power grids worldwide.

Motivation for the National Assessment

To provide a better understanding to industry, this *National Assessment of Energy Storage for Grid Balancing and Arbitrage* attempts to estimate the market size for stationary energy storage systems for two specific applications: 1) balancing services necessary to accommodate the growing variations in the generation supply from renewable energy resources, and 2) energy arbitrage that provides congestion management strategies and the potential to lower the cost of delivering electricity. Earlier reports identified a total of 17 applications, in which electric energy storage could provide benefits and value to both end-use customers and the electric grid. The applications not addressed here are either location-specific or difficult to assess without detailed grid modeling capability requiring highly detailed data. To initiate the discussion on the potential market size of grid-connected energy storage that could be plausibly and defensibly integrated into the grid (and considering competing technologies that vie for the same market share and market opportunities of energy storage) a balance was struck. This balance means addressing fewer storage applications, however, for the entire U.S. grid, rather than a set of highly detailed case studies with limited regional scope. Furthermore, significant fundamental work will still need to be done to estimate multiple values of energy storage in a comprehensive manner that avoids double-counting of benefits. Clearly, the market for grid energy storage is expected to be significantly larger than might be estimated solely from this study.

This assessment was performed for the entire U.S. grid. Because of regional differences in the distribution of renewable resources and the structural differences in the transmission and generation mix, the analysis was performed on a regional basis using the North American Electric Reliability Corporation (NERC) 22 sub-regions. This document is the final of two reports that comprise the entire National Assessment of Grid-Connected Energy Storage. The Phase I report discusses the assessment for the western grid under the Western Electricity Coordinating Council (WECC) jurisdiction, published in June 2012[1]. This report (Phase II) includes the results for the remaining U.S. interconnections, Eastern Interconnection (EIC) and the Electric Reliability Council of Texas (ERCOT), as well as results from the WECC to summarize the results from a national perspective. The Phase II report consists of two volumes: *Volume 1: Technical Analysis* – this document, which discusses the analytical methodology and results, and *Volume 2: Cost Assumptions*, which discusses cost/performance assumptions of various

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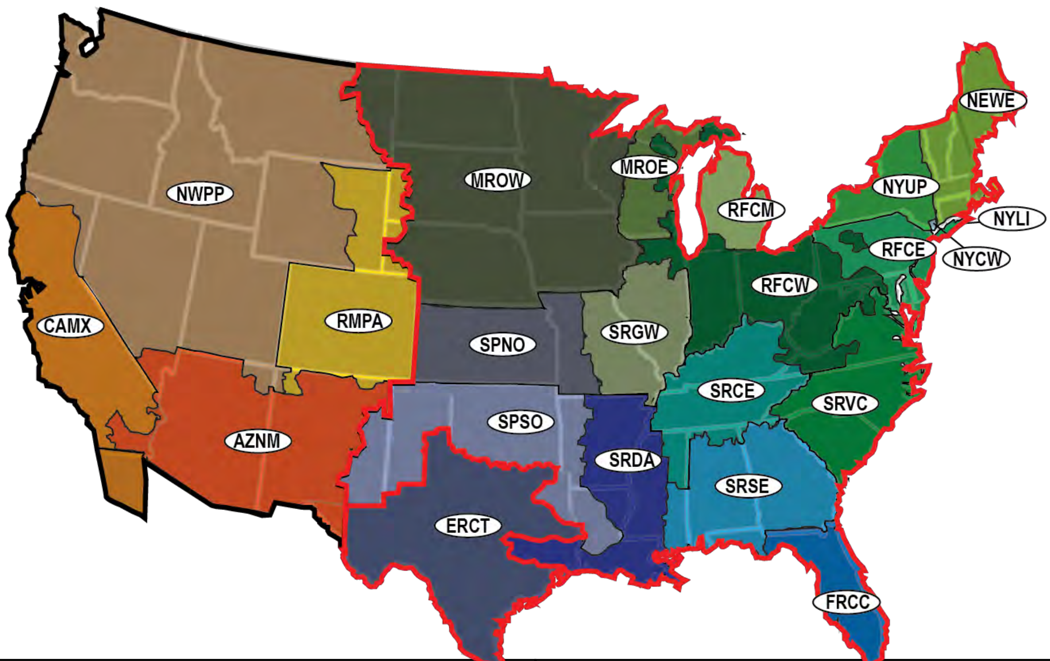
storage technologies, combustion turbine, and demand response resources. The regional disaggregation of the U.S. grid is shown in Figure ES.1.



1 – Texas Reliability Entity (ERCT)	12 – SERC Reliability Corporation / Delta (SRDA)
2 – Florida Reliability Coordinating Council (FRCC)	13 – SERC Reliability Corporation / Gateway (SRGW)
3 – Midwest Reliability Organization / East (MROE)	14 – SERC Reliability Corporation / Southeastern (SRSE)
4 – Midwest Reliability Organization / West (MROW)	15 – SERC Reliability Corporation / Central (SRCE)
5 – Northeast Power Coordinating Council / New England (NEWE)	16 – SERC Reliability Corporation / Virginia-Carolina (SRVC)
6 – Northeast Power Coordinating Council / NYC-Westchester (NYCW)	17 – Southwest Power Pool / North (SPNO)
7 – Northeast Power Coordinating Council / Long Island (NYLI)	18 – Southwest Power Pool / South (SPSO)
8 – Northeast Power Coordinating Council / Upstate New York (NYUP)	19 – WECC / Southwest, Arizona and New Mexico (AZNM)
9 – Reliability*First* Corporation / East (RFCE)	20 – WECC / California and Mexico (CAMX)
10 – Reliability*First* Corporation / Michigan (RFCM)	21 – WECC / NWPP
11 – Reliability*First* Corporation / West (RFCW)	22 – WECC / RMPA

Figure ES.1. Regional Resolution of the National Assessment

Key Questions Addressed

This assessment addresses the following questions:

1. What are the future balancing requirements[1] necessary to accommodate enhanced wind generation capacity, so as to meet RPS targets of about 20 percent of the generation for each interconnection individually in 2020? This analysis assumes that state-specific RPS above 20 percent, such as California's 33 percent RPS target for 2020, will be honored. Estimates are derived and discussed for 22 sub-regions. From a market size perspective it is insightful to estimate both the <u>additional</u> balancing requirement between 2010 and a 2020 grid scenario as well as the <u>total</u> balancing

[1] A balancing market is a niche market within a competitive electricity market for last-minute, just-in-time, rapid-response electricity. This market may demand either increases or decreases in a quantity of electric power. Electricity generators are paid to quickly ramp up or ramp down their electric power in this market. This market results from discrepancies between scheduled electric power generation and actual real-time electric demand and generation. This market is often served by fast-ramping electric power plants like gas turbines and by demand response.

requirements for the 2020 grid scenario. The additional requirements estimate the new demand of balancing services. The total requirement includes replacement options for storage to displace existing generators providing this service.

2. What are the most cost-effective technology options for providing additional balancing requirements today and in 2020 assuming technological progress? Our analysis includes the following technologies:
    i. Combustion turbine as a base case technology
    ii. Na-S (Sodium Sulfur) batteries
    iii. Li-ion (Lithium-ion batteries)
    iv. Flywheel
    v. CAES (Compressed Air Energy Storage)
    vi. Redox Flow batteries
    vii. PHES (Pumped Hydroelectric Storage)
    viii. Demand Response
    ix. Hybrid energy storage systems (configurations of various above mentioned storage technologies)
3. What is the market size (quantified in MW and MWh) for energy storage and its respective cost targets (expressed in $/kWh) for balancing and energy arbitrage applications by regions?

Key Outcomes

Pacific Northwest National Laboratory (PNNL) analyzed a hypothetical 2020 grid scenario in which additional wind power is assumed to be built to meet a nationwide 20 percent RPS target. Several models were used to address the three questions, including a stochastic model for estimating the balancing requirements using current and future wind statistics and the statistics of forecasting errors. A detailed engineering model was used to analyze the dispatch of energy storage and fast-ramping generation devices for estimating capacity requirements of energy storage and generation that meet the new balancing requirements. Financial models estimated the life-cycle cost (LCC) of storage and generation systems and included optimal sizing of energy storage and generation to minimize LCC. Finally, a complex utility-grade production cost model was used to perform security constrained unit commitment and optimal power flow for the WECC.

Outcome 1: Total Intra-Hour Balancing Market for the U.S. is Estimated to be 37.67 GW Assuming about 223 GW of Installed Wind Capacity in 2020

The total amount of power capacity for a 20 percent RPS scenario in 2020 would require a <u>total</u> intra-hour balancing capacity of 37.67 GW. The total market size was estimated for the U.S. by 22 sub-regions based on the potential for energy storage in the high-value balancing market. The energy capacity, if provided by energy storage, would be approximately 14.3 GWh, or a storage that could provide power at rated capacity for about 20 minutes. The <u>additional</u> intra-hour balancing capacity that is required to accommodate the variability due to capacity addition in wind technology and load growth from 2011-2020 was estimated to be 18.57 GW. If these additional balancing services were provided by new energy storage technology, the energy capacity would be about 8.6 GWh, or a storage technology capable of providing electricity at the rated power capacity for about 20 minutes.

The regional distribution of balancing requirements is driven by load forecasting and wind prediction errors. Because of the non-homogeneous distribution of the loads and wind across the nation, the balancing requirements increase with load and wind capacity. As a consequence, for the Western regions Northwest Power Pool (NWPP) and CAMX, these issues increase their balancing requirements significantly. Similarly, for ERCOT and EIC, the northern and central Midwestern regions with the strong wind resources are expected to increase their balancing requirements as the wind energy technology deployment grows. See Table ES.1 for the regional results of the total and additional intra-hour balancing requirements.

Model results also indicate that the new balancing requirements will span a spectrum of variability, from minute-to-minute variability (intra-hour balancing) to those indicating cycles over several hours (inter-hour balancing). This study focused on the intra-hour balancing needs as they include sharp ramp rates that are of significant concern to grid operators. Furthermore, 131 U.S. balancing authority areas were assumed to be consolidated into a more manageable number of 22 NERC sub-regions. This aggregation of balancing area tends to under-estimate both the magnitude and the variability in the balancing market relative to current conditions.[1] As a result, it is reasonable to infer that the analysis shown here may underestimate required levels of storage or generation needed to serve the balancing market. The additional and total intra-hour balancing requirements are presented in Table ES.1 for the four consolidated balancing areas.

This study concludes that the future total intra-hour balancing requirements to address both load and renewable variability are expected to range between 3 percent and 9 percent of the peak load in a given region. Furthermore, on the margin for every additional unit of wind capacity power, approximately 0.07 to 0.36 units of intra-hour balancing need to be added.

[1] The main factor that contributes to the under-estimation of the balancing reserve is the assumption that sharing the variability of resources and loads across a broader region reduces the per unit variability with a resulting reduction in required reserves. At present, neither the markets nor the operations are aggregated to the degree assumed in this study.

Table ES.1. Additional and Total Intra-Hour Balancing Requirements by Sub-Regions in 2020 for 20 percent RPS.

	Additional Balancing Power Required (MW)	Total Balancing Power Required (MW)	Total Balancing Power Required as a Percentage of Peak Load (%)	Marginal Balancing Power Required as a Percentage Wind Capacity (%)	Existing Wind Capacity (MW)	Additional Wind Capacity (MW)	Total Wind Capacity in 2020 (MW)
AZNM	210	1,220	4	22	390	970	1,360
CAMX	530	2,400	4	13	2,430	4,110	6,540
NWPP	280	2,020	3	7	5,560	4,200	9,760
RMPA	510	670	5	10	1,170	5,160	6,330
Total WECC	**1,530**	**6,310**			**9,550**	**14,440**	**23,990**
MROE	20	490	5	13		150	150
MROW	2,750	4,340	6	8	4,470	34,760	39,230
NEWE	610	1,370	5	8	2,900	7,190	10,080
NYLI	420	540	9	17		2,480	2,480
NYUP	840	1,440	9	10	2,530	8,380	10,910
RFCE	880	2,530	4	9	980	10,310	11,290
RFCM	340	600	4	11		2,980	2,980
RFCW	2,280	3,830	4	14	2,470	16,320	18,780
SPNO	2,340	2,760	17	11	2,040	20,820	22,850
SPSO	2,090	2,540	9	11	2,290	18,350	20,640
SRCE	60	1,090	3	36	180	170	340
SRDA	40	830	3	18		220	220
SRGW	2,890	3,290	56	11	4,390	26,670	31,060
SRVC	360	1,780	3	9	210	4,160	4,370
Total EIC	**15,920**	**27,430**			**22,460**	**152,960**	**175,380**
ERCOT	1,120	3,930	5	9	10,950	12,860	23,810
Total US	**18,570**	**37,670**			**42,960**	**180,260**	**223,180**

Outcome 2: Each Technology Option Requires its Own Size to Meet the Future Balancing Needs

The following technology cases were analyzed:

1. Combustion turbines (CT)
2. Na-S (Sodium Sulfur) batteries integrated with combined cycle gas turbine (CCGT)
3. Li-ion (Lithium-ion) batteries integrated with CCGT
4. Flywheels integrated with CCGT
5. CAES integrated with CCGT
6. Redox (reduction-oxidation) flow batteries integrated with CCGT
7. PHES (pumped hydro energy storage) with frequent mode changes per day[1]
8. PHES with two mode changes per day[1]
9. Demand Response technology (only electric vehicle [EV] charging considered).

In technology case 1, the CTs are used to provide balancing with controlled variable power output. In technology cases 2-8, CCGTs are used to compensate for the storage electricity loss of different types of batteries, flywheels, CAES, and PHES[2]. It should be noted that for the Na-S case an assumption was used that battery systems with a ratio of rated energy to rated power (E/P=1) will be available in future, as opposed to the currently available ratio E/P=7.

Table ES.2 presents the sizing results for both the power and energy requirements for each of the aforementioned nine cases based on the additional intra-hour balancing services. Capacity requirements are based on a 100 percent nominal energy storage depth of discharge (DOD). Under this assumption, the energy capacity of the storage device is fully utilized, with the device cycled from a fully charged to a fully discharged state. From a LCC analysis viewpoint, there may be economic benefits to over-sizing the battery, such that it is cycled at a DOD of less than 100 percent to improve the life of the energy storage device. DOD impacts both battery lifetime and size. In turn, battery sizing influences capital costs. The tradeoff between energy storage cycle life and capital costs are examined in this report.

[1] To bridge the waiting period during the mode changes, a small Na-S battery was assumed.
[2] A source of energy is needed to charge the storage technologies. This energy that flows through the storage technologies is assumed to come from existing generation on the margin. CCGT was assumed to be marginal generation most of the time.

Table ES.2. Power and Energy Requirements by Technology Case to Meet <u>Additional</u> Intra-Hour Balancing Requirements.

Case		C1	C2	C3	C4	C5		C6	C7		C8		C9
Technology		Combustion turbine	Na-S	Li-ion	Flywheel	CAES 2 modes 7-min waiting period	Na-S	Flow battery	PHES, multiple modes 4-min waiting period	Na-S	PH 2 modes 4-min waiting period	Na-S	DR (demand response)
Total	GW	1.54	1.53	1.53	1.53	2.8	0.61	1.52	1.53	0.53	2.8	0.42	5.02
WECC	GWh	0	0.58	0.57	0.53	17.01	0.06	0.59	0.54	0.08	17.1	0.04	0
Total	GW	15.92	15.83	15.83	15.88	29.18	7.17	15.8	15.83	6.61	29.18	5.65	52.82
EIC	GWh	0	7.31	7.16	6.64	167.82	0.78	7.55	6.81	1.14	168.53	0.42	0
Total	GW	1.12	1.15	1.15	1.13	2.17	0.69	1.15	1.14	0.67	2.17	0.57	4.06
ERCOT	GWh	-	0.7	0.7	0.67	12.96	0.1	0.71	0.66	0.12	13.04	0.05	-
Total	**GW**	**18.58**	**18.51**	**18.51**	**18.54**	**34.15**	**8.47**	**18.47**	**18.5**	**7.81**	**34.15**	**6.64**	**61.9**
US	**GWh**	**0**	**8.59**	**8.43**	**7.84**	**197.79**	**0.94**	**8.85**	**8.01**	**1.34**	**198.67**	**0.51**	**0**

The two storage technologies (C5, C8), which require a distinct mode change from charging to discharging, demand significantly higher power capacities than those that can switch instantaneously between charging and discharging. Because the entire balancing requirements (from maximum increment to maximum decrement) must be provided in one mode, the power and the energy capacity of such technologies must be significantly increased. The large power capacity requirement for DR (demand response) resources is attributable to low resource availability during the early morning, low load conditions, when there are few resources available. To compensate for this low availability, the resources have to be increased. In this particular case, where we assumed that all of the DR resources are provided by EV charging, a significant number of EVs must be engaged to overcome the low load condition in early morning hours when most of the EVs are fully charged.

The size requirements for each technology can be considered its market potential. For storage without mode change constraints (Na-S, Li-ion, Flywheel, Flow batteries), the storage market size potential is about 18.58 GW (in terms of power) and about 8.6 GWh (in terms of energy) to meet the <u>additional</u> balancing services necessary from 2011-2020. This assumes that about 180 GW of wind capacity will be added to the current 42 GW nationwide. The energy to power ratio (E/P) or the duration of the energy storage at rated power for the balancing application would be about 27 minutes. For the CAES and PH 2 modes technologies that meet the balancing requirements in a single mode (either charging or discharging) require 34.15 GW, about twice the capacity of the other technologies that can flexibly transition between the charging and discharging modes. The E/P ratio of the two technologies is about 5.8 hours.

An optimistic market size estimation for intra-hour balancing services could be derived from the <u>total</u> balancing requirements as shown in Table ES.1, which presumes that storage technologies captures all market shares of existing generation assets that already provide balancing services today, as well as those required for the 2011-2020 timeframe. That market size for storage is estimated as large as 37.67 GW and 14.3 GWh. The regional distribution of these results is shown in Figure ES.2 below.

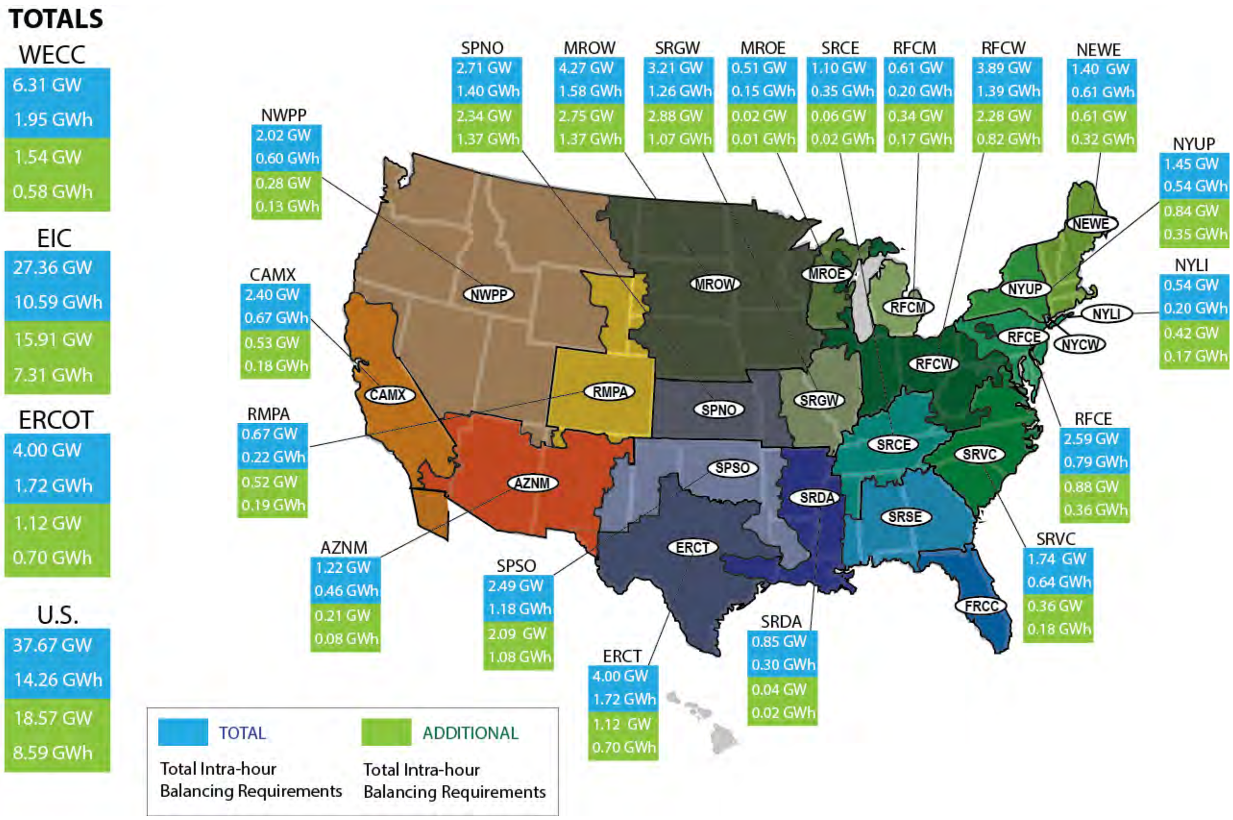
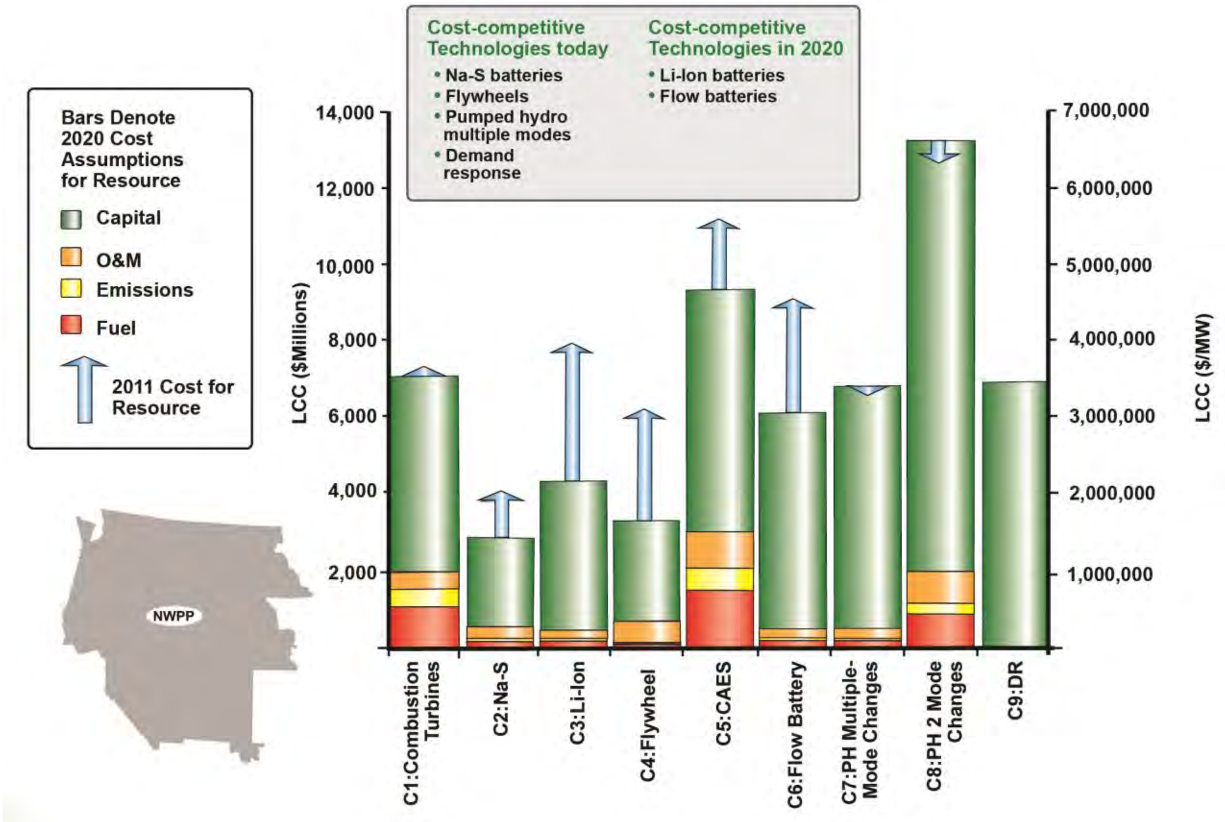


Figure ES.2. Market Size Estimates for Storage Technologies necessary to Meet Additional and Total Intra-Hour Balancing Requirements for a 2020 Grid with 20 percent RPS.

Outcome 3: Competitiveness of Storage Technologies: Na-S Batteries, Flywheels Pumped Storage, and Demand Response compete today, Li-Ion and Redox Flow are likely to be competitive in 2020

Various technologies compete for the growing balancing market opportunities, not only energy storage, but also demand response. The base case technology is a gas-fueled CT, which may be attractive particularly under low-cost gas projections for the next several decades. The LCC analysis for intra-hour service indicated that Na-S, flywheel storage technologies, pumped hydro storage with multiple mode changes, and DR are under current cost estimates are already cost-competitive (lowest LCC). Li-ion and redox flow will follow under cost reduction assumptions for the 2020 timeframe. The results of the LCC analysis indicate that of the nine cases examined in this report, Case 2, which employs Na-S batteries, is expected to be the most economical alternative in 2020. It is important to note, however, that this analysis assumes that Na-S batteries in 2020 will be available in the required energy to rated power ratio of ~1:1. Currently, this ratio is about seven. If Na-S systems cannot be manufactured at energy to rated power ratios of unity by 2020, flywheels (Case 4) would appear the most cost-effective option for both 2011 and 2020. Li-Ion-based and redox flow are estimated to become cost-competitive in the 2020 timeframe with a lower LLC than CTs. It must be noted that mode change PH energy storage and demand response are already cost-competitive compared to the CT technology.

These findings are consistent across the regions included in this assessment. They differ in scale and absolute LLC values, but not in the relative ranking of each technology. Figure ES.3 presents the results of the LCC analysis and the effects of capital, O&M (operations and maintenance), emissions, and fuel costs on the total LCC for each case, as applied in the NWPP. Under the scenarios explored in this report, capital costs drive the outcome, and the CAES and PH cases with their corresponding high capital costs do not perform well. Both options appear ill-suited for providing balancing services alone.



Note: Cost ranges include key uncertainties in the 2011 and 2020 cost assumptions

Figure ES.3. Scenario LCC Estimates for NWPP[1].

The detailed LCC modeling effort was used to assess the cost competitiveness of different technologies to address the future, intra-hour balancing requirements. The cost analysis considered the costs associated with initial and recurrent capital costs, fixed and variable O&M costs, emissions costs, and fuel costs. Annualized costs incurred over a 50-year time horizon were collapsed into a single present value cost for each scenario using a nominal discount rate of 8 percent, across all cases. The 50-year time horizon was chosen based on the estimated lifetime of the longest lived technology, which is PHES with a lifetime of 50 years. During this time, several replacements of the nascent technologies would need to occur to provide services over a 50 year timeframe.

[1] Note that the costs of implementing DR are assumed to be $50.70 per kW per year as estimated in EPRI (2009). This value includes all costs required to install, operate, and maintain DR and DR-enabling equipment.

There is a significant degree of capital cost uncertainty associated with the energy storage technologies, especially for cases evaluated farther into the future. The future cost ranges were determined on an individual basis, based on conversations with vendors, assessment of novel materials that would enable cost cutting, and the risk of these assumptions not coming to fruition.

LCC results are strictly applicable for intra-hour balancing services with a maximal cycle time of 20-30 minutes. For other applications that require longer cycle times with higher energy capacity, capital costs and production cost will change, affecting the LCC results and the relative cost competitiveness.

Outcome 4: Energy Storage Devices are not Expected to Achieve Cost Recovery when Deployed for Arbitrage Services

Energy arbitrage alone is insufficient to provide enough revenue to make new energy storage installations economically viable, even in congested transmission paths such as the transfer into Southern California and in the Northeast area. Although this result was based on the production cost modeling that estimates the cost differential between peak and off-peak, and not on market price differentials, which tend to be higher than the cost differentials. The frequency and duration of transmission congestion was simply not sufficient to make energy storage technologies a viable business proposition as an energy product.

The results agree with common understanding that the energy value across the nation is small and perhaps one of the lowest values for energy storage. However, there are significant regional differences in the revenue expectations primarily based upon the level of congestion and level of reserve margins in each interconnect. The results indicated for ERCOT (a relatively small system) the highest energy arbitrage revenues, followed by the EIC and lastly the WECC. In the WECC, the revenue projections for energy arbitrage were about 10 times lower than that for ERCOT, primarily based on the large supply in the WECC given all of the additional wind capacity that tends to the suppress the overall energy value in the entire interconnect.

For arbitrage applications, the energy storage requirement is significantly larger with respect to its energy capacity than a storage device that just provides balancing services. As such, it can provide its rated power for several hours and, thus qualify as a capacity resource. The revenues from a capacity market would likely dwarf the expected revenue from the energy sales. When capacity values of $150/kW-year are included in the economic assessment, only pumped hydro generates profits at energy storage capacities up to 35,122 MW for the total US.

For a simplified case without performing complex production cost modeling, we determined the capital cost target of an energy storage device on a $/kWh basis, given that it would receive a capacity payment of $150/(kW-year) and engage in energy arbitrage with a peak to off-peak ratio of 1.5 every weekday (260 days per year). The capital cost of the energy storage could not cost more than $150/kWh in order to break even. This is a challenging cost target and will most likely continue as trends in the energy markets are pointing downward with the increasing deployment of no-fuel cost wind generation and low natural gas prices for the foreseeable future.

Therefore, additional applications and services will need to be bundled with energy arbitrage to capture multiple values and benefits from the use of energy storage. These services include load following, transmission and distribution upgrade deferral, grid stability management, power quality enhancements, and electricity service reliability. The valuation of these services and grid benefits, particularly when provided simultaneously, is immature or highly site-specific and, thus, beyond the scope of this assessment. Additional research is therefore necessary to examine the full revenue potential of energy storage used in multiple applications.

Outcome 5: Hybrid System Offer No Technical Performance Advantages, Therefore Will Have to Compete on Cost Alone

The analysis of the optimal hybrid energy storage system offered results that were solely driven by cost. The minute-by-minute simulation did not provide sufficient resolution in the time domain to expose ramping limits of all of the tested energy storage technologies. Thus, differences in the ramp rates across all studied technologies were not a differentiator in the optimal hybridization of storage systems. The results clearly indicated a “winner-take-all” solution. As a consequence all of the attempts to optimally pair two individual technologies resolved to one, and only one, of the two technologies. There was only one particular case, where the cost-optimal solution indicated a bundling of two technologies.

For the lithium-ion (Li-ion) and DR case under the 2011 price scenario, the cost-optimal bundling suggested 60 percent of DR and 40 percent of Li-ion because of a non-constant availability of the demand response resource. The DR resource was assumed to be smart charging strategies of EVs (i.e., variable charging about an operating point of charging). The availability of the resource is high after the morning commute when the vehicles are assumed to be recharged at work, likewise, when the vehicles come home and being recharged at home for the next day. There are times when the EV fleet is almost fully charged (e.g., very early in the morning 3-5 a.m.), thus the DR resource is very low. At that time the Li-ion stationary batteries must be used to offset the lack of DR resource. The optimum tradeoff between DR and stationary Li-ion batteries for the 2011 cost estimates was a 60/40 share of DR and battery. As the cost for the Li-ion stationary battery drops relative to the DR (as for the 2020 cost estimate) the optimal pairing suggested a transition to a 0/100 share between DR and the battery.

The key message of the hybrid storage analysis suggests that hybridizing storage technologies will only be meaningful if there is a wide spectrum of cycles expected with sharp transients with sub-one-minute time resolution, which this analysis did not expose. Alternatively, energy storage may function in concert with DR or other generators (as a virtual hybrid system) to compensate for their lack of availability or ramping capability.

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Acronyms and Abbreviations

ACE	area control error
AEO	Annual Energy Outlook
ANL	Argonne National Laboratory
AZNM	Arizona-New Mexico-Southern Nevada (sub-region of the WECC)
BA	balancing authority
BASF	Badische Anilin- und Soda-Fabrik, Ludwigshafen, Germany
BC	British Columbia
BOP	balance of plant
Btu	British Thermal Unit
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CAMX	California-Mexico. Only a small region of the Baja peninsula is included (sub-region of the WECC)
CC	combined cycle
CCGT	combined cycle gas turbine
CT	combustion turbine
CAES	compressed air energy storage
DOD	depth of discharge
DR	demand response
EIA	Energy Information Administration
EIC	Eastern Interconnection
E/P	energy/rated power
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESPC	Energy Storage and Power Corporation
ESS	Energy Storage Systems
EV	Electric Vehicle
GW	gigawatt
GWh	gigawatt-hours
ID	Idaho
ICAP	installed capacity (NYISO capacity market)
ISO	independent system operator
KEMA	Keuring Electrotechnisch Materieel Arnhem
kW	kilowatt
kWh	kilowatt-hour

LCC	life-cycle cost
LHV	lower heating value
Li-ion	lithium-ion
LMP	locational marginal price
LTC	Lithium Technology Corp
MRL	manufacturing readiness level
MW	megawatt
MWh	megawatt-hour
MISO	Midwest Independent Transmission System Operator
Na-S	sodium sulfur
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NERC	North American Electric Reliability Corporation
NWPP	Northwest Power Pool (sub-region of WECC)
NYISO	New York Independent System Operator
O&M	operations and maintenance
OR	Oregon
P/E	power to energy
PCS	power conversion system
PH	pumped hydroelectric
PHES	pumped hydro energy storage
PHEV	plug-in hybrid electric vehicles
PNNL	Pacific Northwest National Laboratory
PROMOD	production cost modeling software by Ventyx
redox	reduction-oxidation
RPS	renewable portfolio standards
RMPA	Rocky Mountain Power Area (sub-region of the WECC)
RD&D	research, development, and demonstration
SA	Sensitivity Analysis
SCE	Southern California Edison
SO_2	sulfur dioxide
TRL	technology readiness level
TEPPC	Transmission Expansion Planning and Policy Committee
TSI	Tribology Systems Inc.
USABC	US Advanced Battery Consortium
V2G	vehicle-to-grid
V_2O_5	vanadium oxide
WECC	Western Electricity Coordinating Council

Contents

Executive Summary ii
Acknowledgments xiii
Acronyms and Abbreviations xv
1.0 Introduction 1.1
2.0 Objectives and Scope 2.1
3.0 How is this Assessment Different from Other Studies? 3.1
4.0 Methodology for Estimating Balancing Requirements 4.1
4.1 Overview of Analysis 4.1
4.2 Approach and Data Used to Determine Balancing Requirements 4.1
4.2.1 Balancing Service Requirement 4.2
4.2.2 Consolidation of Balancing Areas 4.3
4.2.3 Resulting Total and Additional Balancing Signals 4.4
4.2.4 Spectral Analysis and Extraction of Intra-Hour Balancing Signal 4.5
4.3 Sizing Storage to Meet Balancing Requirements 4.7
4.3.1 Sizing Hybrid Technology Options for Balancing Services 4.7
5.0 Datasets for Wind Generation and Loads 5.1
5.1 WECC Wind Datasets 5.1
5.2 WECC Load Datasets 5.3
5.3 EIC and ERCOT Wind Datasets 5.4
5.3.1 EIC 5.4
5.3.2 ERCOT 5.4
5.3.3 Placement of Hypothetical Wind Sites 5.4
5.3.4 Load Datasets 5.8
6.0 Technology Choices for Balancing Services 6.1
6.1 Definition of Technology Options 6.1
7.0 Results: Projected Balancing Requirements 7.1
7.1 Total Balancing Requirements for the US 7.1
7.2 Additional Projected Balancing Requirements for US 7.4
7.3 Market Size for Energy Storage for Balancing Services 7.6
8.0 Arbitrage Opportunities for Energy Storage 8.1
8.1 Introduction and Methodology 8.1
8.2 Arbitrage Analysis Framework 8.3
8.2.1 General discussion 8.3
8.2.1 Modeled Revenue Estimations 8.6
8.3 WECC 8.7
8.3.1 Assumptions 8.7

8.3.2 Results 8.10
8.4 ERCOT 8.11
8.4.1 Results 8.12
8.5 EIC 8.14
8.5.1 Comparison to NREL's Eastern Wind Integration and Transmission Study (EWITS) 8.19
8.5.2 EIC Results 8.20
8.6 Arbitrage Results for Total US 8.21
8.6.1 Differences across Interconnections 8.25
8.6.2 Final Observations on Arbitrage Results 8.25
9.0 Summary and Conclusions 9.1
9.1 Intra-Hour Balancing Requirements for 2020 .... 9.1
9.2 Market Size for Energy Storage for Balancing Services 9.2
9.3 Life-Cycle-Cost Analysis of Various Technology Options to Meet Future Balancing Requirements 9.3
9.4 Hybrid Storage Systems 9.6
9.5 Energy Arbitrage Opportunities 9.7
9.6 Overall Conclusions 9.7
10.0 References 10.1
Appendix A – Detailed Balancing Requirements and Storage Sizing by Zone A.1
Appendix B – Specific Operational Strategies to Meet Balancing Requirements B.1

Figures

ES.1 Regional Resolution of the National Assessment iii

ES.2 Market Size Estimates for Storage Technologies necessary to Meet Additional and Total Intra-Hour Balancing Requirements for a 2020 Grid with 20 percent RPS ix

ES.3 Scenario LCC Estimates for NWPP........ x

1.1. Energy storage and market assessment, conducted by Sandia National Laboratories (Eyer and Corey, 2010). 1.2

2.1. Spatial Definition of Regions based on NERC-Regionalization (DOE/EIA 2011)........2.2

4.1. Illustration of Intra-Hour Balancing Signal. 4.3

4.2. An Example of Total Balancing Requirements for the Month of August 2020. ....4.4

4.3. An Example of Total Balancing Requirements for One Typical Day in August 2020.........4.5

4.4. Spectral Analysis of Balancing Signal.........4.6

4.5. Components of Decomposed Balancing Signal.........4.6

4.6. Division of Balancing Signal for Two Storage Technologies........4.8

4.7. Storage Sizes in Terms of Energy Requirement (kWh) for Two Storage Technologies. 4.8

4.8. Storage Sizes in Terms of Power Requirement (kW) for Two Storage Technologies........4.9

4.9. Storage Sizes in Terms of Maximum Ramp Rate Requirement (MW/min) for Two Storage Technologies.........4.9

4.10. Total 50-Year LCCs for Li-ion +DR Technology Shares for 2020 Cost Assumptions. “Winner takes all” situation present in most cases studied........4.11

4.11. Total 50-Year LCCs for Li-ion +DR Technology Shares for 2011 Cost Assumptions. Optimal combination (technology share 6) only present in two cases under 2011 cost assumptions........4.11

5.1. Wind Projection 2011-2020 for NERC regions in WECC 5.1

5.2. Distribution of Wind Capacity by States 5.2

5.3. Location of Existing and Hypothetical Future Wind Plants in WECC.........5.2

5.4. Wind Projection 2011-2020 for NERC regions in EIC and ERCOT........5.5

5.5. Distribution of Wind Capacity by States in EIC and ERCOT 5.5

5.6. Location of Existing and Hypothetical Future Wind Plants in EIC.........5.6

5.7. Location of Existing and Arbitrarily Sited Future Wind Plants in ERCOT........5.7

7.1. Size Requirements for Storage Technologies to Meet the Total and Additional Intra-Hour Balancing Services for a 2020 Grid with 20 percent RPS. 7.6

8.1. (a) LMP Differential per Hour of Operation ($/MWh) and (b) Marginal Revenue per Hour of Operation ($/MWh) 8.2

8.2. Dependency of Capital Cost for Storage Component C_{sto} in ($/kWh) on Peak-Off Peak Ratio and Efficiency. Assumed: p_o = $40/MWh, D = 260 days, $\alpha = 0.12$. 8.4

8.3. Dependency of Capital Cost for Storage Component C_{sto} in ($/kWh) on Peak-Off Peak Ratio and Efficiency. Assumed: p_o = $40/MWh, D = 260 days, $\alpha = 0.12$, and capacity value of $150 per kW per year........8.5

8.4. Dependency of Capital Cost for Storage Component C_{sto} in ($/kWh) on Peak-Off Peak Ratio and Capacity Value. Assumed: p_o = $40/MWh, D = 260 days, $\alpha = 0.12$, and efficiency of $\eta = 0.85$ 8.5
8.5. Key Congested Paths in WECC 8.8
8.6. Determination of Storage Size 8.9
8.7. Transmission Path Across 4 Regions in Texas. (Congested paths are marked with red star) 8.12
8.8. Revenue per year for Texas 8.13
8.9.a EIC Path Flow Changes to Accommodate 20 percent RPS Provided primarily by Wind Energy 8.16
8.10. Key Congested Paths in EIC Indicated by Red Stars 8.18
8.11. Arbitrage Profits per Year for EIC Zones 8.20
8.12. Average and Marginal Arbitrage Revenues per MW per Year 8.23
9.1. Market Size Estimates for Storage Technologies Necessary to Meet the Total and Additional Intra-Hour Balancing Services for a 2020 Grid with 20 percent RPS 9.2
9.2. LCC Estimates for NWPP 9.5
9.3. Total 50-Year LCCs for Li-Ion +DR Technology Shares for 2011Cost Assumptions. Optimal combination (technology share 6) only present in two cases under 2011 cost assumptions 9.6

Tables

ES.1 Additional and Total Intra-Hour Balancing Requirements for WECC Sub-Regions in 2020 for 20% RPS……vi
ES.2 Power and Energy Requirements by Technology Case to Meet Total Intra-Hour Balancing Requirements……viii
3.1. Characterization of Major Storage Studies 3.2
4.1. Frequency Limits of Components of the Balancing Signal. 4.6
5.1. Information About NREL Wind Integration Datasets 5.1
5.2. Statistics of Hour-Ahead Wind Forecast Error (the percentage values are based on installed wind capacity)......5.3
5.3. Statistics of Hour-Ahead Load Forecast Error (the percentage values are based on peak load)5.3
5.4. Statistics of Hour-Ahead Wind Forecast Error (the percentage values are based on installed wind capacity)......5.7
5.5. Statistics of Hour-Ahead EIC Load Forecast Error (the percentage values are based on peak load) 5.8
6.1. Definition of Technology Cases 6.2
7.1. Intra-hour Balancing Requirements in US by Sub-Regions 7.2
7.2. Balancing Requirements (Intra-hour) for NERC Sub-Regions caused by Wind Variability Only (without considering load variability)......7.3
7.3. Balancing Requirements (Intra-hour) for NERC Sub-Regions caused by Load Variability Only (without considering wind variability)......7.4
7.4. Additional Intra-Hour and Total Intra-Hour Balancing Requirements for Every Sub-Region in US. 7.5
8.1. Existing and Additional Installed Capacity (MW) for AZNM, CAMX, NWPP, and RMPA for the Case of 30 percent Reserve Margin......8.7
8.2. Number of Hours at 100 percent Transfer Limits......8.9
8.3. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro - WECC ($Millions) 8.11
8.4. Existing Capacity (MW) for the ERCOT 8.11
8.5. Additional Installed Capacity (MW) for the ERCOT......8.11
8.6. Number of Hours at 100 percent Transfer Limits......8.12
8.7. Annual Arbitrage Revenues by Energy Storage Capacity ($Thousands) 8.13
8.8. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro – ERCOT (2020 dollars in Millions) 8.14
8.9. Existing and New Path Limits 8.15
8.10. Existing Installed Capacity (MW) for 17 Sub-Regions of the EIC......8.17
8.11. Additional Installed Capacity (MW) for 17 Sub-Regions of the EIC......8.17
8.12. Number of Hours at 100 percent Transfer Limits......8.18
8.13. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro – EIC in 2020 (in Millions in Million 2011 Dollars)......8.21

8.14. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro - U.S. Totals in 2020 (in Millions 2011 Dollars)... 8.22
8.15. Average and Marginal Arbitrage Revenues in U.S. (per MW per year)............................. 8.23
8.16. Pumped Hydro Capacity and Profit at Profit Maximizing Levels by Region...................... 8.24
8.17. Arbitrage revenue expections without capacity value 8.25
9.1. Total and Intra-Hour Balancing Requirements for every NERC Region in WECC in 2020... 9.1
9.2. Definition of Technology Cases 9.4
9.3. Arbitrage revenue expections without capacity value 9.7

1.0 Introduction

Energy storage systems have the potential to improve the operating capabilities of the electricity grid. Their ability to store energy and deliver power can increase the flexibility of grid operations while providing the reliability and robustness that will be necessary in the grid of the future – one that will be able to provide for projected increases in demand and the integration of clean energy sources while being economically viable and environmentally sustainable.

Driven by the current renewable portfolio standards (RPS) established in 31 of the nation's states, the total contribution of renewable resources to the electricity generation portfolio in the United States is expected to grow significantly in the 2015 to 2025 timeframe. The President's clean energy goals of 80 percent renewable energy by 2050 will require further accelerated deployment of renewable resources. The projected increase of these sources will necessitate the deployment of technologies that can address renewable variability in an environmentally sustainable fashion. Energy storage embraces a suite of technologies that have the potential for deployment to assist the increasing penetration of renewable resources. While other technologies, such as gas turbine and transmission upgrades can provide operational flexibility, energy storage has the unique ability to both improve asset use and meet the flexibility needs with one technology. Most energy storage systems have superior ramping characteristics compared to rotary turbo-machinery such as combustion or steam turbines, and provide more effective area control error (ACE) compensation than do turbine-based generators (FERC NOPR 2011; Makarov 2008b).

The Energy Storage Systems (ESS) Program within the U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability (DOE-OE) is taking a lead role in the research, development, and demonstration (RD&D) of energy storage technologies to accelerate the deployment of storage as a cost-effective technology to support the transition of the grid to a modern electric infrastructure with a low carbon footprint. Part of the ESS Program is a systems analysis element, supporting the core engineering and development elements of the program and addressing the technical, economic, and policy challenges of deploying and integrating storage technologies. Integral to this analysis is this *National Assessment of Grid-Connected Energy Storage* (hereafter referred to as the National Assessment) that attempts to estimate the potential market size for grid-connected energy storage in two distinct markets and distinct applications: 1) the energy balancing application, and 2) energy arbitrage. While many other individual grid benefits can be delivered by energy storage systems, this assessment focuses on the two key storage applications that are large, well-defined, already being targeted by advanced storage vendors, and manageable from a data requirements and analysis point of view (Rastler 2010). This is not to say that applications other than balancing and arbitrage services are less important, or even smaller in size. The choice of the two distinct applications was primarily motivated by the fact that we have some ability to quantify the magnitude of their market potential, whereas others are more difficult to quantify or require highly detailed and infrastructure-specific data.

The National Assessment is the first attempt to estimate the market size on a region-by-region basis, with a total of 22 regions, as defined by the North American Electric Reliability Corporation (NERC) and then further subdivided into sub-regions as defined by the Energy Information Administration (EIA) and the Environmental Protection Agency (EPA)[1] (DOE/EIA 2011).

[1] http://www.epa.gov/egrid.

The results will be delivered in two Phases: Phase 1 addresses the Western Electricity Coordinating Council (WECC); Phase 2 includes all 3 US interconnections WECC, Electric Reliability Council of Texas (ERCOT), and the Eastern Interconnection (EIC).

While load balancing is an important service that yields significant value, it is only one in a larger set of services offered by energy storage. Research into a broad spectrum of energy storage value streams conducted by the Sandia National Laboratories, the Electric Power Research Institute and other groups indicates that the market size for energy storage in the U.S. could be significantly greater than the market captured by balancing services alone.

The results of an energy storage and market assessment guide, conducted by Eyer and Corey (2010) of Sandia National Laboratories, are presented in Figure 1.1. As shown, the study identified a number of distinct services with benefits ranging from $86 per kW for transmission congestion relief to $2,400 per kW for substation on-site power. The U.S. market potential was also estimated for each service. For several of the services, the market size exceeded 15 GW nationally, with time-of-use energy cost management topping the list at 64.2 GW. While the size of these estimates is significant, additional detailed analyses will need to be performed to substantiate the results and provide additional insights into the regional aspects of the market and the competitiveness of technological alternatives.

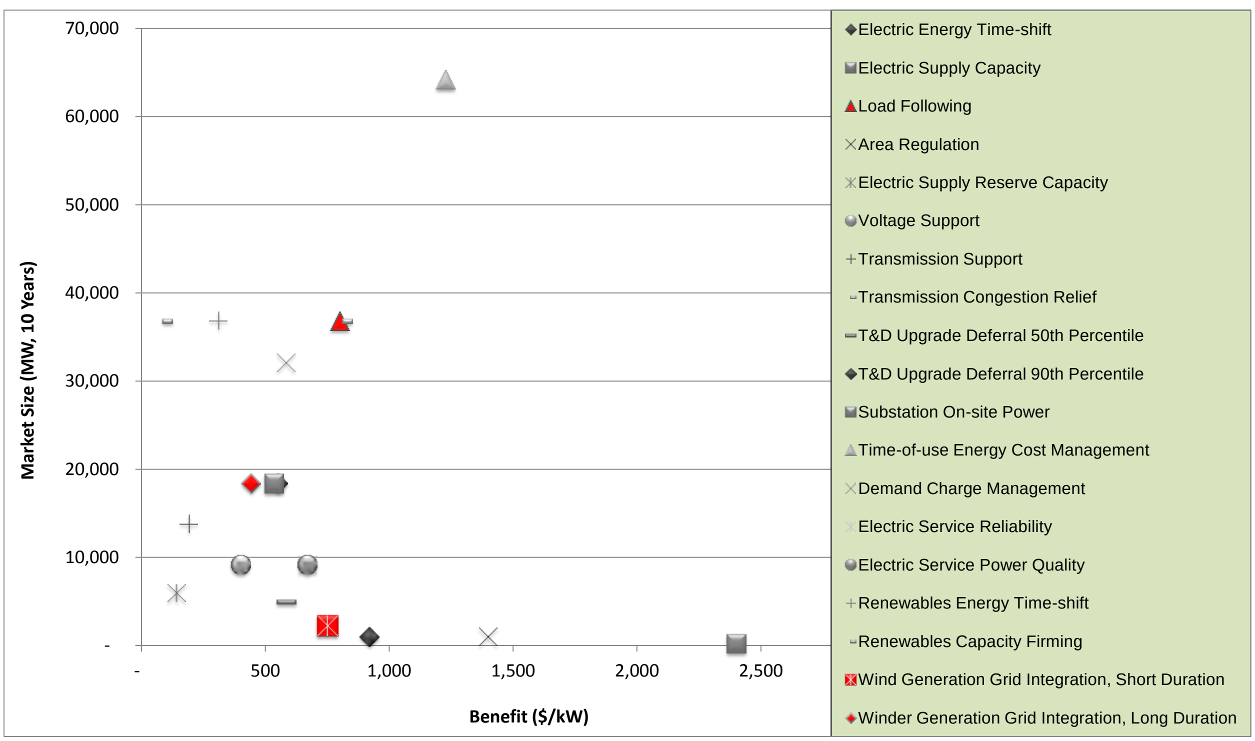


Figure 1.1. Energy storage and market assessment, conducted by Sandia National Laboratories (Eyer and Corey, 2010).

2.0 Objectives and Scope

The objectives of this National Assessment are to address several questions raised in the electricity industry, brought forward in a 2010 DOE-sponsored workshop and summarized in *Electric Power Industry Needs for Grid-Scale Storage Roadmap* (Nexight 2010). The workshop revealed several grid applications of interest for applying energy storage technologies, including: a) area and frequency regulation (short duration), b) renewable integration (short duration), c) transmission and distribution upgrade deferral (long duration), d) load following (long duration), e) electric energy time shift (long duration).

This assessment addresses area and frequency regulation (short duration) and renewable integration in an aggregated form – balancing services. This assessment focuses on imbalances between demand and supply, and spans the entire spectrum of cycles from seconds to minutes. The longer duration applications are captured by analyzing operational benefits of arbitrage strategies that store low cost electrical energy during off-peak periods and dispense it during high-cost periods during system peak periods. When operating storage in this manner, energy will be time-shifted. The capital cost benefit of deferring infrastructure upgrades are difficult to quantify and are <u>not</u> studied in this assessment. Evaluating infrastructure alternatives would require very specific studies with highly spatially resolved data that considers distribution system or transmissions system expansions and alternatives, which are highly case-specific. Although the capital deferment benefit of storage is important, it is out of scope for this assessment. In summary, the assessment will address the following set of questions:

1. What are the additional balancing requirements[1] necessary to accommodate enhanced wind generation capacity, so as to meet the RPS of about 20 percent of the generation for each interconnection in 2020? This analysis assumes that state-specific RPS above 20 percent, such as California's 33 percent RPS target for 2020, will be honored[2]. Estimates are derived and discussed for 22 NERC sub-regions.
2. What are the most cost-effective technology options for providing additional balancing requirements? Our analysis includes the following technologies:
   i. Combustion turbine as the base case technology
   ii. Na-S (Sodium Sulfur) batteries
   iii. Li-ion (Lithium-ion batteries)
   iv. Flywheels
   v. CAES (Compressed Air Energy Storage)
   vi. Redox Flow batteries
   vii. PHES (Pumped Hydroelectric Storage)
   viii. Demand Response
   ix. Hybrid energy storage systems (configurations of various above mentioned storage technologies)

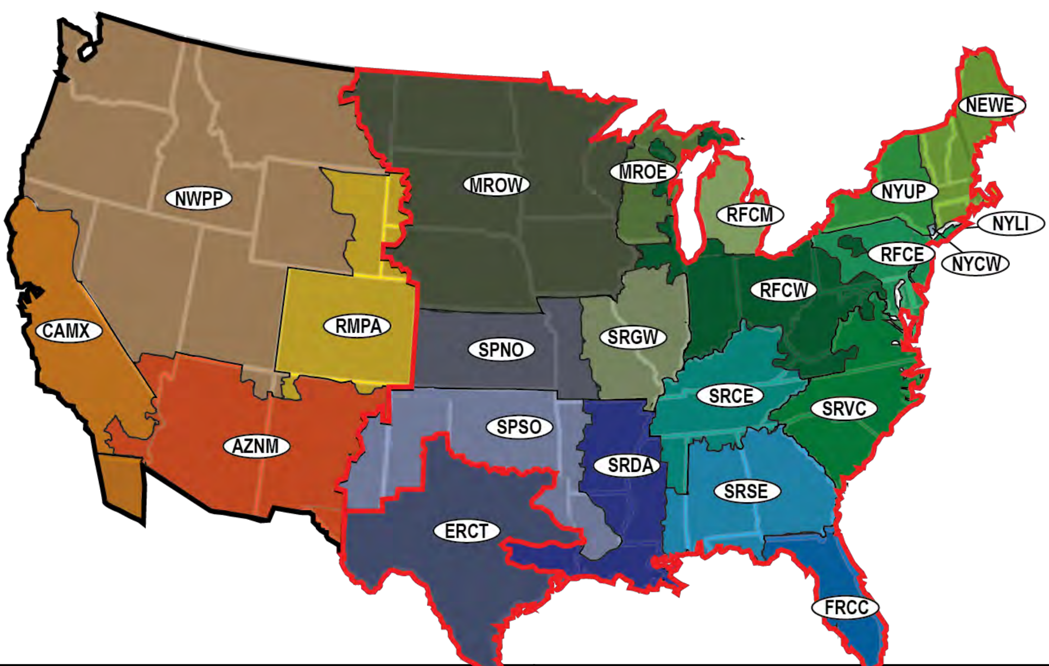
[1] A balancing market is a market segment within a competitive electricity market for last-minute, just-in-time, rapid-response electricity. This market may demand either increases or decreases in a quantity of electric power. Electricity generators are paid to quickly ramp up or ramp down their electric power in this market. This market results from discrepancies between scheduled electric power generation and actual real-time electric demand. This market is often served by fast-ramping electric power plants like gas turbines, hydro power plants, and by demand response.

[2] California's 33% RPS by 2020 was put into law by SBX1 2 signed by Governor Brown on April 12, 2011.

3. What are the market size for energy storage and its respective cost target for balancing and energy arbitrage applications by regions?

The questions above address the two time scales in which storage is usually applied: short duration, which requires storage capacities for 15-30 minutes, and long duration storage that provides charging or discharging capabilities at rated capacity for several hours (e.g., 4-10 hours, or potentially more).

As a National Assessment, the study needs to be broad in scope – providing a meaningful picture of the opportunities and potential market sizes from a national perspective – while still providing sufficient resolution to consider some of the regional specifics that drive the results. For instance, wind resources are non-uniformly distributed throughout the United States. Furthermore, existing available generation capacities and their generation mix vary across the regions and load profiles vary in accordance to populations, economic activities, and climate conditions. To consider some of these key drivers suggested an assessment by region (Figure 2.1). A 22-region envelope provided sufficient spatial resolution to capture the distribution and diversity of the wind resource potential, the load profiles and existing installed generation capacity, and the inter-regional transfer limits within the bulk power transmission network.



1 – Texas Reliability Entity (ERCT)	12 – SERC Reliability Corporation / Delta (SRDA)
2 – Florida Reliability Coordinating Council (FRCC)	13 – SERC Reliability Corporation / Gateway (SRGW)
3 – Midwest Reliability Organization / East (MROE)	14 – SERC Reliability Corporation / Southeastern (SRSE)
4 – Midwest Reliability Organization / West (MROW)	15 – SERC Reliability Corporation / Central (SRCE)
5 – Northeast Power Coordinating Council / New England (NEWE)	16 – SERC Reliability Corporation / Virginia-Carolina (SRVC)
6 – Northeast Power Coordinating Council / NYC-Westchester (NYCW)	17 – Southwest Power Pool / North (SPNO)
7 – Northeast Power Coordinating Council / Long Island (NYLI)	18 – Southwest Power Pool / South (SPSO)
8 – Northeast Power Coordinating Council / Upstate New York (NYUP)	19 – WECC / Southwest, Arizona and New Mexico (AZNM)
9 – Reliability*First* Corporation / East (RFCE)	20 – WECC / California and Mexico (CAMX)
10 – Reliability*First* Corporation / Michigan (RFCM)	21 – WECC / NWPP
11 – Reliability*First* Corporation / West (RFCW)	22 – WECC / RMPA

Figure 2.1. Spatial Definition of Regions based on NERC-Regionalization (DOE/EIA 2011)

3.0 How is this Assessment Different from Other Studies?

This National Assessment fills an essential gap in the analysis landscape of grid-connected energy storage and generation. Early in the scoping discussion of the National Assessment, it was decided that this assessment would provide the most value by focusing on modeling and analysis depth with sufficient breadth to address the fledging stationary storage industry. Prior studies have chosen to explore the values of energy storage in all of its various application areas with an emphasis on being comprehensive in breadth. These studies have evaluated various sub-segments of the electricity market and the variety of sources of financial value garnered from grid connection. The methodologies emphasized either 1) a literature review of what other organizations had published already, or 2) economic analysis, generally without thorough computer simulations of the physics of the grid and underlying current and future storage and generation technologies. Some grid operators have performed thorough grid simulations to quantify the regulation and ramping services (what is termed in this report as "balancing services" includes both regulation and ramping services). Most notable among these are the studies by the Midwest Independent Transmission System Operator (MISO), the California Independent System Operator (CAISO), and the Bonneville Power Administration (BPA). Furthermore, Southern California Edison (SCE) has performed screening studies and economic analytics for both distributed energy storage and central plant (megawatt (MW)-sized) storage applications. These studies were regionally defined by their specific service area and did not provide comprehensive U.S.-wide scenarios that were based on common assumptions across the entire U.S. electricity infrastructure.

The National Assessment looks out to the 2020 time horizon and provides an evaluation of the potential market sizes by 22 regions for future storage and generation technologies for two specific sub-segments of the electricity market – the balancing market and the arbitrage market. The underpinnings of this assessment are model-based using a suite of specialty models that focus on specific drivers for this assessment. Furthermore, this analysis researched one of the most sensitive input variables to this modeling work, namely the incremental cost of energy storage and generation technologies, both for today and projected into the future. These costs were researched in-depth, with approximately 100 literature citations and personal conversations with leading industry professionals and leaders in the research communities (see Volume 2 of the National Assessment). Also, unlike prior studies, costs were differentiated according to the applications, with balancing service more strongly influenced by the costs of achieving a high rate of electricity transfer per unit time (i.e., the cost per MW), and arbitrage services more greatly influenced by the cost of storing a certain quantity of total energy (i.e., the cost per MWh).

To provide an overview of how this National Assessment differentiates itself from other studies in the growing storage analysis landscape, we developed Table 3.1 that characterizes the studies by their depth (i.e., the detailed development and deployment of models describing the physics and economics of energy systems) and by their breadth (i.e., extent of market sub-segments covered). The columns indicate different studies conducted. These are referenced in the References section and discussed in detail in Section D of the Phase I report [Kintner-Meyer, et al., 2012]. The rows of the table indicate key differentiating factors of these studies. The color 'green' indicates that a study covers application area or applied a particular methodology. Color 'red' means that the study did NOT address this subject at all or not comprehensively.

Key Differentiating Factors		(1) PNNL 2012	(2) EPRI 2010 & 2012	(3) MISO 2011	(4) Sandia 2002, 2004, 2008, 2010	(5) Southern California Edison	(6) Kema 2010	(7) Vosen 1999, Lemofouet 2006, Lukic 2006, Henson 2008 1999
Depth of Modeling								
Stochastic model to determine balancing requirements:								
Wind/load uncertainties		Covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Diversity due to spatial relations		Covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Energy Storage Cost Characterization		Covered						
Extensive literature search and industry analysis on capital cost of storage technologies		Covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Estimate minimum and maximum values for 2020 projected Cost		Covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Market size in MW and MWh		Covered	Covered	Not covered	Covered	Not covered	Covered	Not covered
Optimal Storage Sizing Model								
Differentiation between MW and MWh sizing approach for Balancing		Not covered	Not covered	Not covered	Covered	Not covered	Not covered	Covered
Hybrid system – cost optimizes Life Cycle Costs		Not covered	Not covered	Not covered	Not covered	Not covered	Not covered	Covered
Considers Batterery life characterization efficiency		Not covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Ramp rates		Not covered	Not covered	Covered	Not covered	Not covered	Covered	Not covered
Plethora of technologies considered – DR, PH		Not covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Arbitrage:								
Production cost modeling considering:								
Transmission congestion		Covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Existing and future generation		Covered	Not covered	Not covered	Not covered	Not covered	Not covered	Not covered
Efficiencies storage		Covered	Not covered	Not covered	Covered	Not covered	Not covered	Not covered
Breadth of Applications								
End-user	Power quality	Not covered	Covered				Not covered	
	Power reliability	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	Retail TOU Energy Charges	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	Retail Demand Charges	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
Distribution	Voltage support	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	defer distribution investment	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	distribution loss	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
Transmission	VAR support	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	Transmission congestion	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	transmission access charges	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	defer transmission investment	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
System	local capacity	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	system capacity	Not covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	renewable energy integration	Covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
ISO markets	fast regulation (1 hour)	Covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	regulation (1 hour)	Covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	regulation (15 min)	Covered	Covered	Not covered	Covered	Covered	Not covered	Not covered
	spinning reservess	Not covered	Covered	Not covered	Not covered	Covered	Not covered	Not covered
	non-spinning reserves	Not covered	Covered	Not covered	Not covered	Covered	Not covered	Not covered
	black start	Not covered	Covered	Not covered	Not covered	Covered	Not covered	Not covered
	price arbitrage	Covered	Covered	Covered	Covered	Covered	Not covered	Not covered

Table 3.1. Characterization of Major Storage Studies

Covered by analysis: [green] Not covered by analysis: [red]

(1) This document; (2) EPRI (2009), Rastler (2010, 2011a); (3) MISO (2011), Rastler (2011b); (4) Butler (2002), Eyer (2004), Schoenung (2008), (Eyer 2010); (5) Ritterhausen (2011); (6) KEMA (2010); and (7) various papers on hybrid storage systems

4.0 Methodology for Estimating Balancing Requirements

4.1 Overview of Analysis

PNNL developed an analytical framework for the National Assessment for the purpose of:

1. Estimating the total balancing requirements associated with forecasting errors both for load and for generation from variable renewable energy resources
2. Sizing grid resources (generation, storage, DR) to meet the new balancing requirements
3. Minimizing the LCC associated with technology options and the economic dispatch to meet the new balancing requirements. The balancing requirements are expressed as a time series of fluctuating power injections (increments) into and power absorptions (decrement) out of the bulk power system on a minute-to-minute basis. Balancing services compensate the over- and under-predictions of scheduled generation to meet the load.

The analytical framework provides a set of sizing tools to dispatch one or several resources to meet the balancing requirements. The resources can be energy storage devices, commonly used generator or DR strategies. Several different dispatch strategies have been developed to dispatch an ensemble of storage devices or bundled resources comprised of DR, energy storage systems, and generators. The outputs 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 LCC optimizer was developed that compares different hybrid energy storage system options based on a LCC 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. (2008a). 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 (Jacobson et al. 2005; Colella et al. 2005). The analytical approach includes the following components and individual steps:

1. Define a plausible wind capacity scenario by region. A 20 percent nation-wide RPS scenario for 2020 was selected, that was met primarily with new wind capacity. States with more aggressive RPS legislatures (i.e., California) were incorporated.
2. Placement of resources: Place hypothetical wind farms at plausible wind sites that are either at various stages in the permitting process or, alternatively, selected by the analyst based on resource potential and judgment.
3. Apply the statistics of wind and load forecasting errors. Insights gained from PNNL's work with the CAISO were utilized and extrapolated to the entire WECC. For the eastern interconnection, the statistics of MISO were applied. ERCOT used its own forecasting error statistics, which were applied.

4. In addition, NREL wind datasets of hypothetical wind sites were utilized to develop a stochastic process that generates a minute-by-minute balancing requirement for every sub-region with the 2020 wind capacity and load projections. The analysis assumes a consolidation of the balancing authorities into 22 sub-regions (see Figure 2.1). The output of this process was the total balancing requirement applicable for the 2020 load and assumed total renewable energy capacity.
5. Define a set of technology options that will meet the total balancing requirements.
6. Analyze the LCC for technology options over a 50-year time horizon.

4.2.1 Balancing Service Requirement

The power system control objective is to minimize its ACE to the extent that complies with 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
I = interchange
F = frequency
a subscript = actual
s = schedule
G_a = actual generation
L_a = actual load within the control area.

Extending the generation component in the ACE equation,

$$G_a = G_s + G_{IB} \tag{4.2}$$

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

$$G_s = L_{f\_ha} \tag{4.3}$$

where f_ha denotes hour-ahead forecast.

In Equation (5.1), set ACE to zero, the intra-hour balancing signal G_{IB} 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,

$$G_{IB} = (L_a - L_{f\_ha}) - (G_a^w - G_{f\_ha}^w) \qquad (4.5)$$

The first part of the equation above $(L_a - L_{f\_ha})$ is also called the balancing requirements caused by load uncertainty, and the second part $(G_a^w - G_{f\_ha}^w)$ is also called the balancing requirements caused by wind uncertainty.

The terms in Equation (5.5), L_{f_ha} and $G_{f\_ha}^w$, are then generated using a stationary multivariate Markov Chain, that meets all of the statistics including the standard deviation, mean, and autocorrelation of current wind and load forecasting errors.

Figure 4.1 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 in each of the four sub-regions in the western interconnection. Hence, a positive balancing signal represents over-generation, and vice versa.

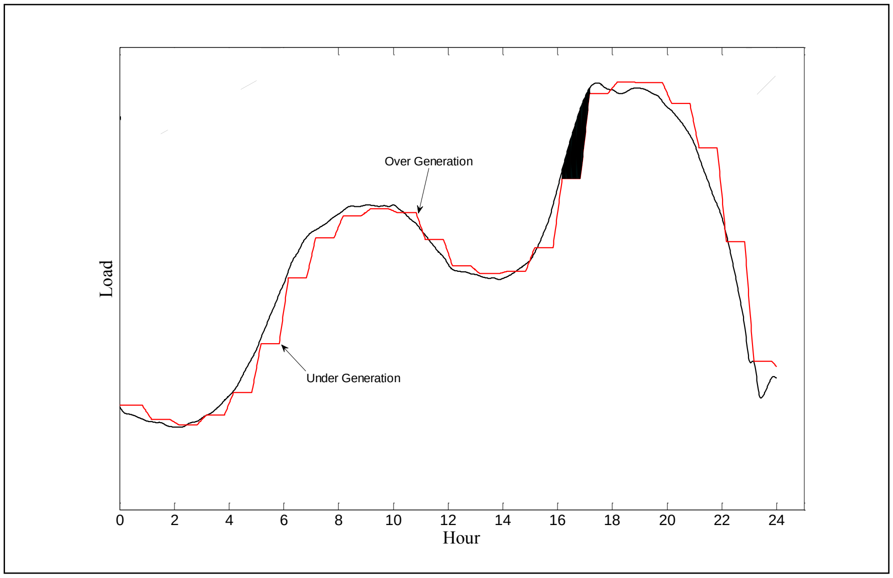


Figure 4.1. Illustration of Intra-Hour Balancing Signal.

4.2.2 Consolidation of Balancing Areas

To simplify the analysis, balancing authorities (BA) are assumed to be consolidated into 22 NERC sub-regions. This simplification reduces the analysis complexity significantly. For instance, for the WECC, instead of performing a BA-by-BA analysis for the 32 BAs and combining the results for the WECC, the consolidation collapsed the complexity into four zones (i.e., AZNM, CAMX, NWPP, and RMPA). There are implications to this simplification. The consolidation of BAs will provide greater sharing of balancing and reserve resources among all constituents and offer opportunities that more effectively utilize the higher degrees of diversity of the variable renewable energy resources across the entire WECC. As a consequence, the total balancing requirements of each interconnection in this assessment are likely to be underestimated. This, in turn, will lead to an underestimation of the future resource requirements under the existing BA regime.

4.2.3 Resulting Total and Additional Balancing Signals

The total balancing requirements for each sub-region are estimated utilizing the wind and load datasets as previously discussed. In addition, the balancing requirements caused by incremental demand and hypothetical wind capacity are also estimated. Figure 4.2 and Figure 4.3 illustrate an example of the resulting balancing requirements signal of a NERC region for the whole month and one typical day, respectively. These estimated values represent the total requirements, as opposed to additional requirements. These figures are based on BPA's customary 99.5 percent probability bound that meets 99.5 percent of all balancing requirements. That means that 0.5 percent of all of the anticipated balancing capacity exceeds that bound. For a 100 percent probability bound, the maximum balancing requirements are likely to increase.

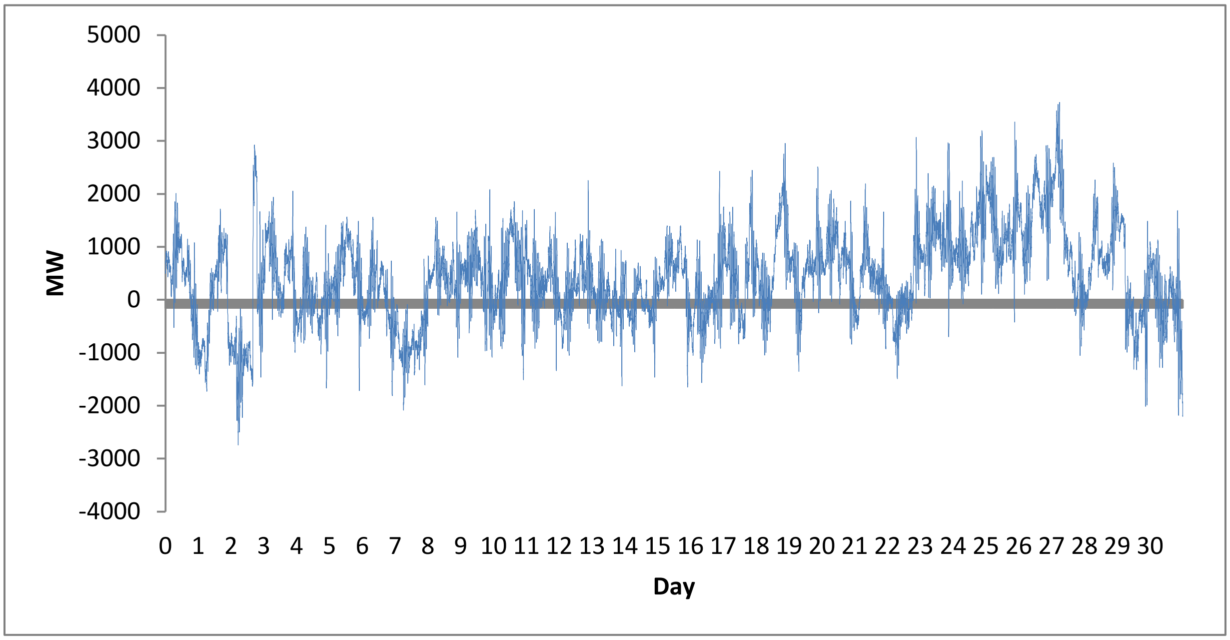


Figure 4.2. An Example of Total Balancing Requirements for the Month of August 2020.

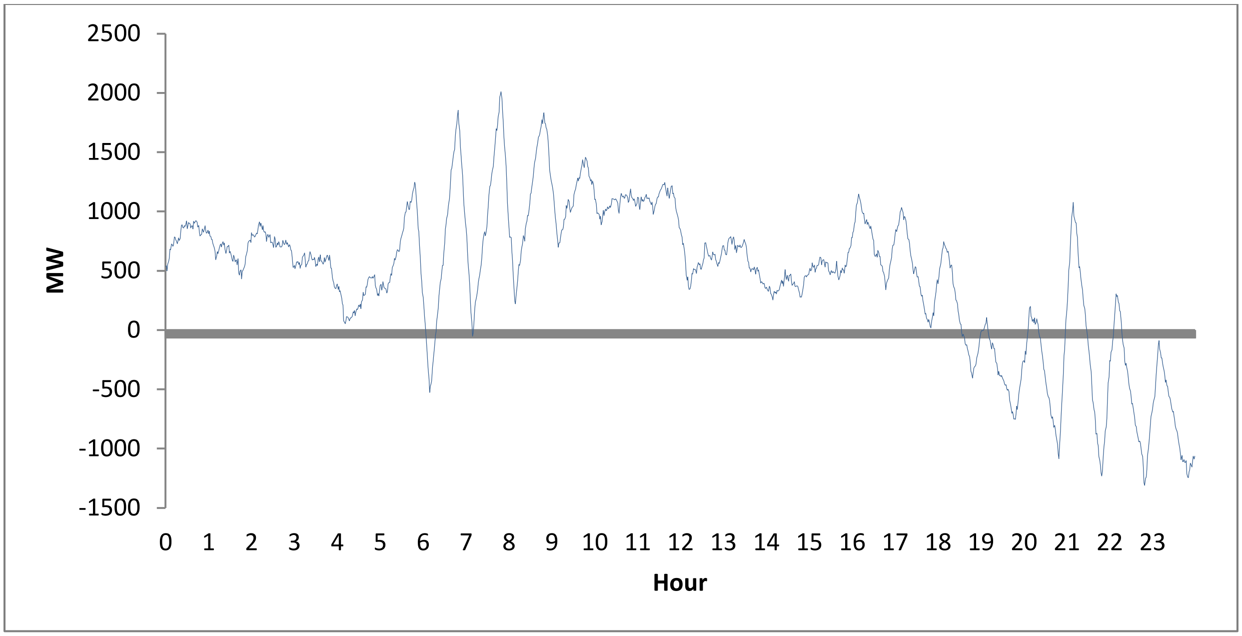


Figure 4.3. An Example of Total Balancing Requirements for One Typical Day in August 2020.

The balancing signal shown in Figure 4.2 and Figure 4.3 exhibits a spectrum of cycling or oscillatory content. Cycles at lower frequencies with periods of several hours (inter-hour) are less challenging to be managed. They can be accommodated in real-time energy markets (for competitive wholesale markets) or in a re-dispatch process when the generation schedule deviates too much from the load conditions. Balancing cycles of lower frequency are not considered in this study. Cycles within the hour (intra-hour balancing) are the key focus of this analysis. They are more challenging to provide because of their high ramping rates, which require grid assets that have a high degree of flexibility to be ramped up and down within short period of time. The rest of this section discusses the filtering strategies that extract the intra-hour cycling from the original balancing signal. The value of deploying energy storage for energy arbitrage is also investigated in this study and presented in Section 8.0 of this report.

4.2.4 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 2010a). The cut-off frequencies for the filter were f_{lower}=1.157e-5 Hz and f_{upper} =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 4.4 and Figure 4.5. Table 4.1 displays the frequency limits for the high-pass filter design.

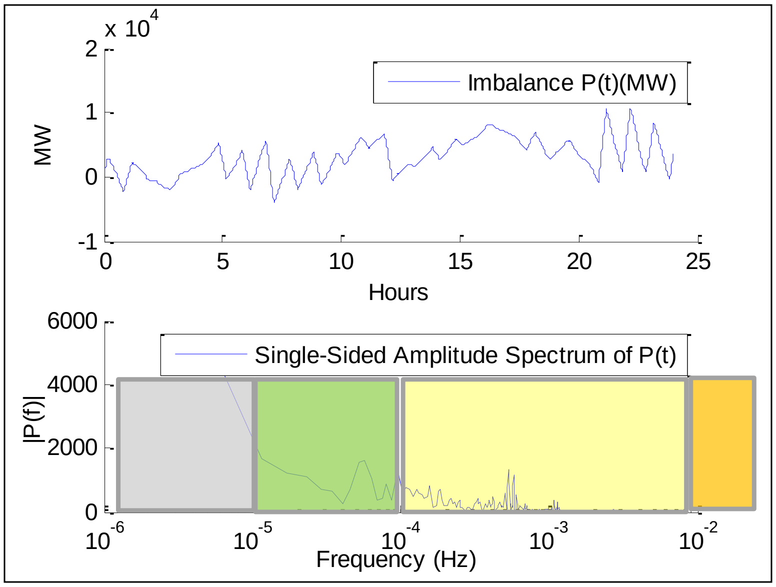


Figure 4.4. Spectral Analysis of Balancing Signal.

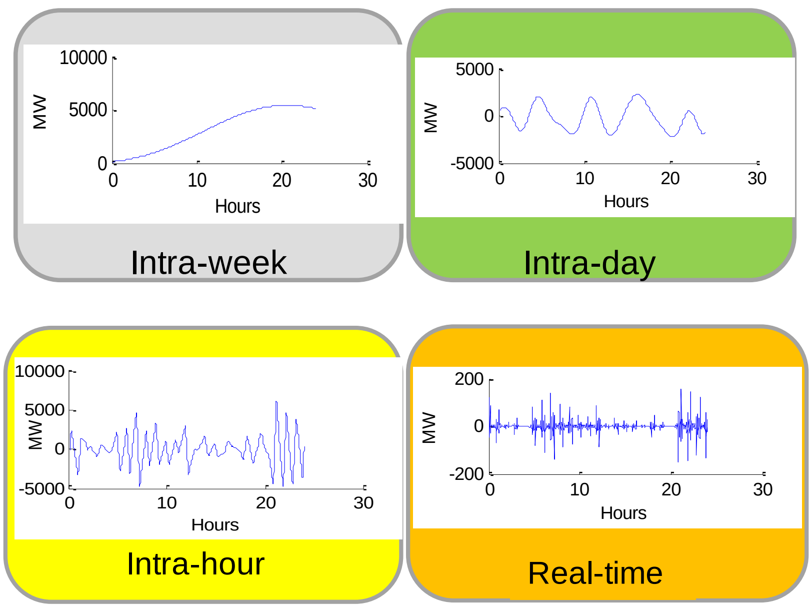


Figure 4.5. Components of Decomposed Balancing Signal.

Table 4.1. Frequency Limits of Components of the Balancing Signal.

No.	Component	f_{lower} (Hz)	f_{upper} (Hz)	Period of f_{lower}	Period of f_{upper}
1	Intra-week	0	1.157e-05	Infinity	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

4.3 Sizing Storage to Meet Balancing Requirements

Sizing energy storage equipment requires determining and selecting two capacity parameters: the power rating (MW) to meet a load or power target, and an energy rating (MWh) that is expected to be delivered to the grid or absorbed from the grid during any given cycle. Because generators are not as energy limited as storage systems are, the energy rating or energy capacity is not a design criterion (e.g., it is assumed there is an unlimited supply of natural gas, coal, uranium, etc.). However, for storage and demand resources, the energy capacity is a very important selection and design criterion and determines the control strategy for a storage device.

To estimate the power and energy capacity for storage technologies to meet the balancing requirements an engineering model was applied to determine the minimal size requirements in terms of MW and MWh, that meet both the maximum power requirements and the electric energy necessary for load balancing as shown in Figure 4.2. The principal products of the sizing analysis are a pair of power and energy capacities or ratings for each technology.

4.3.1 Sizing Hybrid Technology Options for Balancing Services

To determine power and energy requirements for two storage technologies, the intra-hour balancing signal, is divided into two components: a "slow storage" and a "fast storage" component. These balancing components are satisfied by two storage technologies with different technical and economic characteristics. In this study, 12 combinations of "slow storage" and "fast storage" components are defined, including the extreme cases of a single technology. To determine optimal combinations, the 12 technology shares are further optimized using the economic procedure discussed in Section 6.0.

The lower frequency content of the intra-hour balancing signal are assigned to the "slow storage" component, while the higher frequency content of the intra-hour balancing signal are assigned to the other component ("fast storage"). The "slow storage" component is satisfied by a storage technology with limitations in ramp rate caused by technical capabilities and/or wear and tear considerations. An example of "slow storage" technology is CAES with a ramp rate limitation of 30 percent rated power per minute. The "fast storage" component is satisfied by a storage technology with a very high ramp rate and cycling capabilities such as flywheels (with a ramp rate of more than 100 percent rated power per minute).

The methodology used to assign the portions of the intra-hour balancing signal is as follows. In the frequency domain, a cut frequency fc is defined; where fc marks the limit between the slow storage component and the fast storage component. The frequency contents of the balancing signal larger than fc belong to the fast storage component while the frequency content lower than fc belongs to the slow storage component. Technology share options are defined by choosing 12 different values of fc along the frequency spectrum of the intra-hour balancing signal. When fc equals and arbitrary frequency $f2$ ($fc = f2$), all the balancing is provided by the fast storage. In contrast, when the cut frequency fc is smallest fc=(1/(2*60*60)Hz, all the balancing is provided with the slow storage technology. Figure 4.6 illustrates this procedure using the balancing signal from the area CAMX, for a slow storage with 70% efficiency and 95% efficiency for the fast storage.

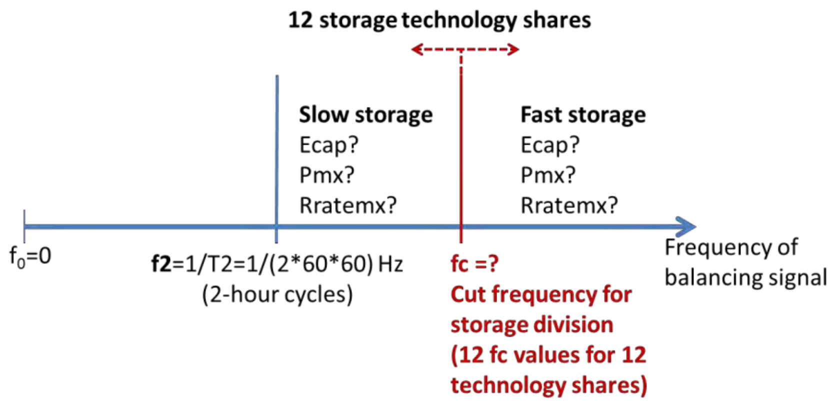


Figure 4.6. Division of Balancing Signal for Two Storage Technologies.

Each value of *fc* defines a pairing of slow and fast storage sizes, together adding up to the total storage size. The sum of all technology pairings is always the same. The storage size of the two technologies is described by the energy requirement (kWh) and power requirement (kW). Figure 4.7 and Figure 4.8 display the storage sizes in terms of energy requirement (kWh) and power requirement (kW) for the two storage technologies as a function of *fc*, going from f_2 (2-hour cycle) to the maximum frequency (half the sampling frequency (1/60 Hz)). Figure 4.9 shows the ramp rates that each storage technology faces as a function of *fc*. The ramp rate was checked against the ramp rate limitations of each technology. No ramp rate constraints were binding in the cases studied.

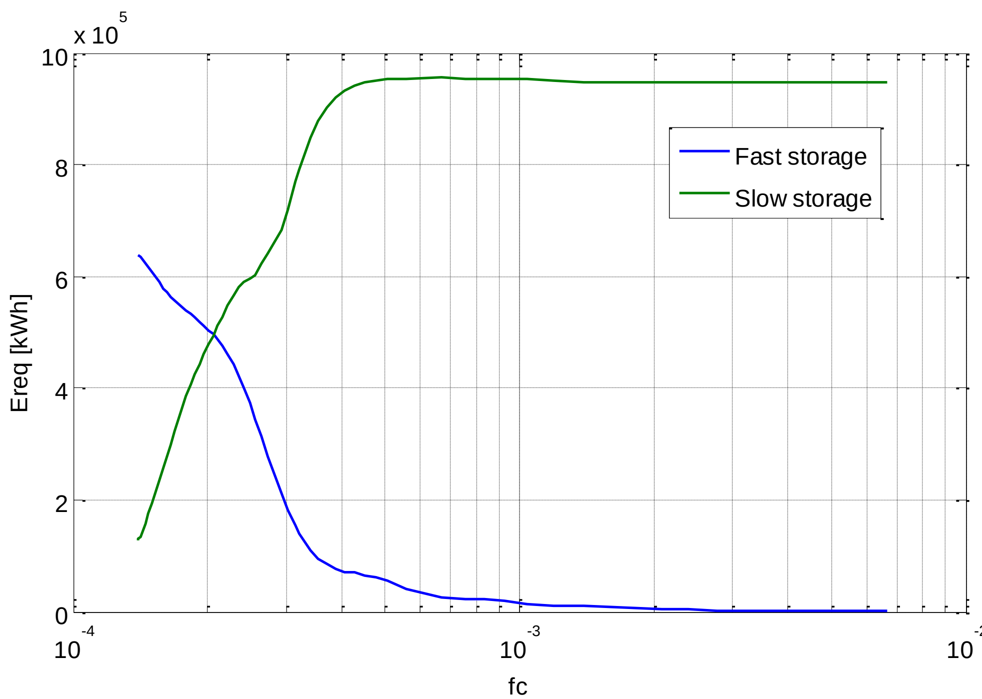


Figure 4.7. Storage Sizes in Terms of Energy Requirement (kWh) for Two Storage Technologies

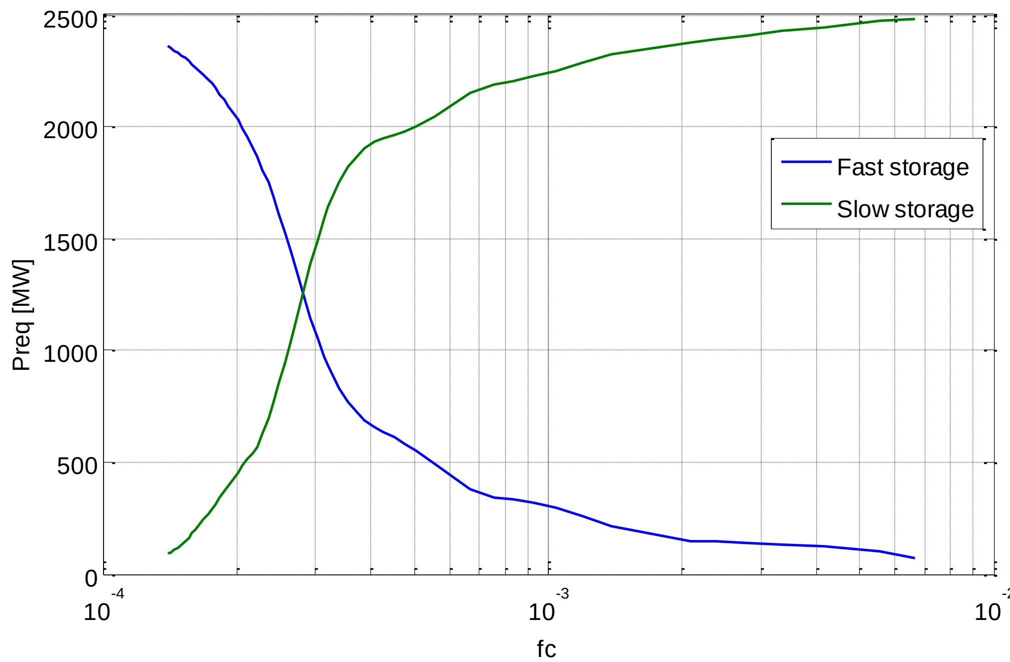


Figure 4.8. Storage Sizes in Terms of Power Requirement (kW) for Two Storage Technologies

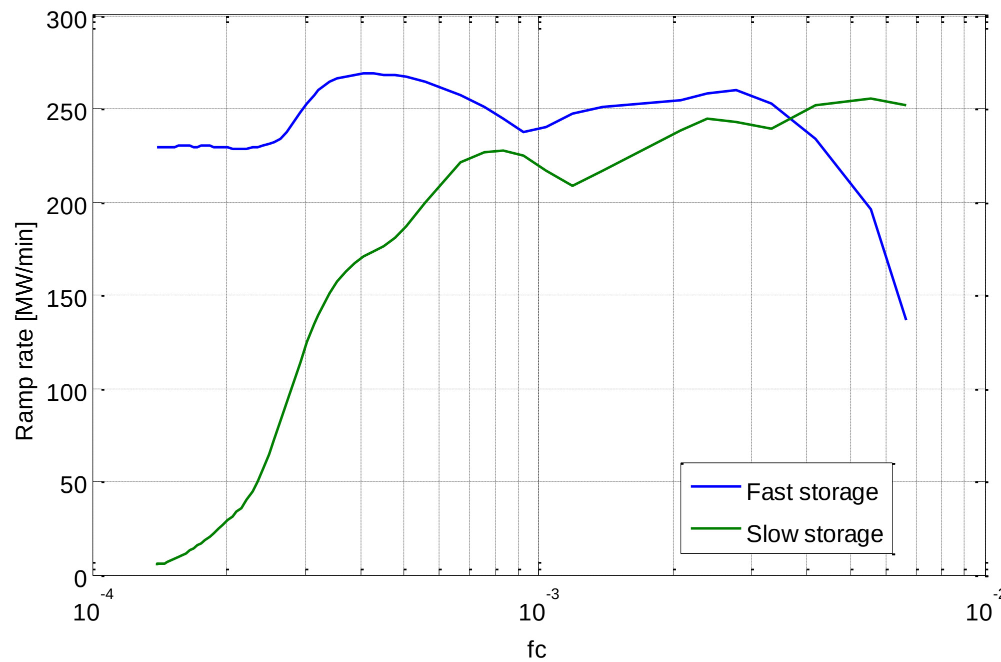


Figure 4.9. Storage Sizes in Terms of Maximum Ramp Rate Requirement (MW/min) for Two Storage Technologies

The optimal combination of fast storage and slow storage technologies was based on total LCC analyses, as discussed in Section 6.0. For each technology share, the battery capacity and DOD is varied from 0 percent to 100 percent and the least cost alternative is selected. The least cost alternative for each technology share is, in turn, identified and compared against the least cost alternative for every other technology share in order to determine the most cost-effective technology share for each case.

As shown in Figure 4.7, in each case, the technology shares are designed with heavy reliance both on one technology at one end of the frequency spectrum and on an alternative technology at the other end. For example, under Technology Share 1 the slow storage technology requires 140 MW, while the fast storage technology requires 2,311 MW, which can be seen in the left hand side of the x axis of Figure 4.8 . While technology share 10 requires 2,425 MW for the slow storage and 129 MW for the fast storage. Note that the sum of capacities of both storage technologies remains the same, with differences only in efficiencies (70% for the slow storage and 95% for the fast storage). Another more interesting example is for Li-ion (as fast storage) and DR (as slow storage) options, the power demand for DR is 470 MW (about 5 percent of DR needed to provide all the balancing) while the power demand for Li-ion is 2,340 MW (about 95 percent of Li-ion needed to provide all the balancing). Near the other end of the spectrum, Technology Share 10 assigns 8,210 MW of power demand (about 95 percent of DR needed to provide all the balancing) to DR and 130 MW (about 5 percent of DR needed to provide all the balancing) of power demand to Li-ion. Note that in this second case the sum of the capacities of the two technologies does not remain the same. This is because the availability patterns of DR taken as availability of EV (see Figures B.5 and B.6 in Appendix B). This second example provides interesting results regarding the optimal economic choice as explained below.

The results for the DR + Li-ion, for CAMX, are presented in Figure 4.10and Figure **4.11**(for 2020 cost and 2011 costs, respectively). In Figure 4.10, the least cost alternative (Technology Share 0) is the one with 100 percent Li-ion (and 0 percent DR). This outcome is driven by the relatively lower capital costs associated with the Li-ion technology considering the 2020 cost assumptions (that is, 100 percent Li-ion (Technology Share 0) is less expensive than 100 percent DR (Technology Share 11)). The cost curve is upward sloping.

However, the results change for the 2011 cost assumptions, where the cost for Li-Ion technology is higher compared to the expected cost in 2020 (see Figure 4.11). The minimal LLC is a combination of Li-ion and DR. The cost curve has a more irregular shape. Notice that the 100 percent Li-ion technology is now more expensive than 100 percent DR. This is in clear contrast to the results shown in Figure 4.10 only because of the different 2011 and 2020 cost assumptions for Li-Ion technology. Additionally, notice that a non-linearity emerges in Figure 4.11; this non-linearity is due to the technical sizing and operating assumptions of DR and economic costs model. On the technical side, DR availability from EVs (see Figures B.5 and B.6 in Appendix B) is different from the availability of stationary storage; DR resource availability changes throughout the day according to driving and charging patterns of EVs. On the economic side, DR has capital costs that depend only on power capacity, while stationary storage capital costs depend on both energy and power capacity. The nonlinearities in the LCCs as a function of change size pairing between Li-Ion and DR are still present in the results in Figure 4.10; however, they are masked due to the 2020 cost assumptions.

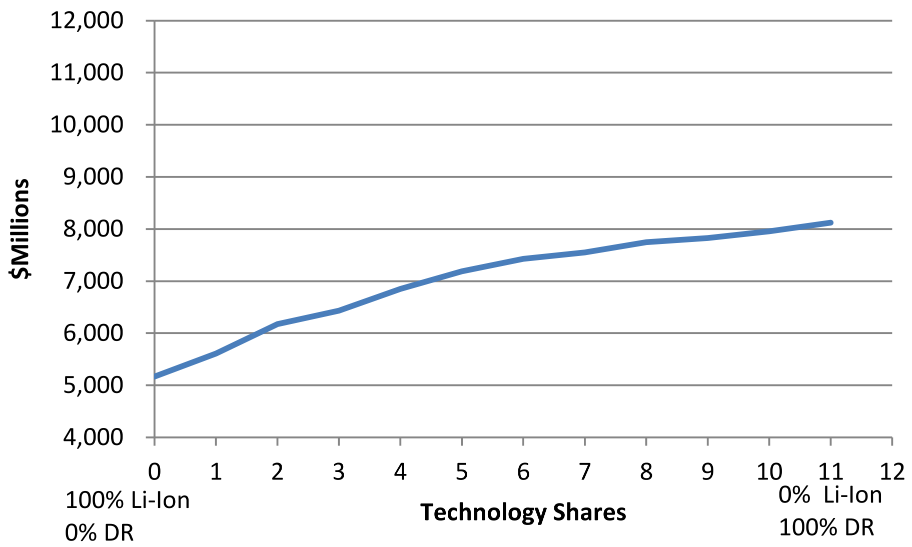


Figure 4.10. Total 50-Year LCCs for Li-ion +DR Technology Shares for 2020 Cost Assumptions. "Winner takes all" situation present in most cases studied.

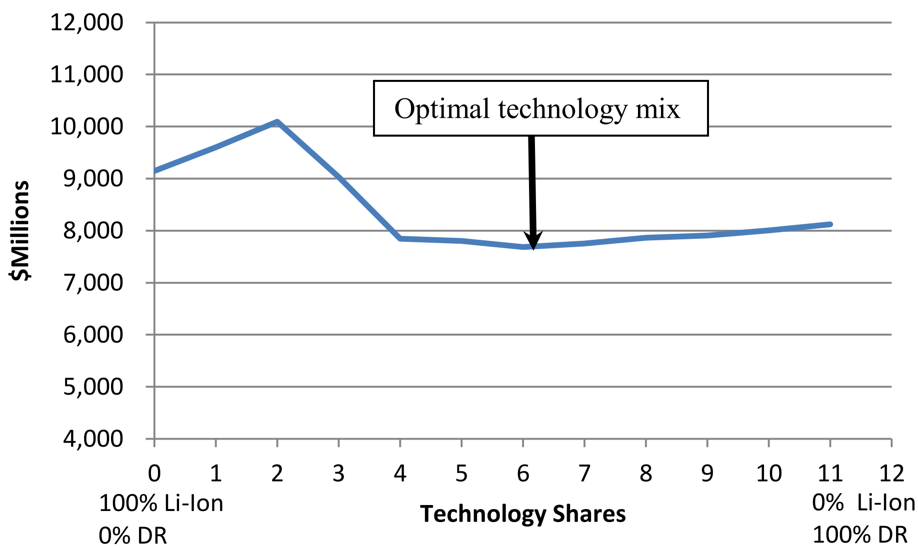


Figure 4.11. Total 50-Year LCCs for Li-ion +DR Technology Shares for 2011 Cost Assumptions. Optimal combination (technology share 6) only present in two cases under 2011 cost assumptions.

There are two possible causes for the cost-optimal sizing of hybrid energy storage to result in a combination of technologies instead of a "winner takes all" situation: a) the influence of technical constraints such as ramp rate that would delineate the balancing operation into fast and slow movements based on technology capabilities; and b) nonlinearities in the LLC function due to technical operating strategies and cost modeling. In all cases we investigated the technical constraints (such as ramp rate limitations) were non-binding, meaning that ramp rate characteristics was not a differentiating feature of any of the technologies analyzed. This indicated that the balancing requirements represented by minute-to-minute changes could be met by all technologies.

For two hybrid technology pairings, the optimization indicated a non-trivial solution in which a winner did not take all shares. As can be seen in Figure 4.11, the optimum is a suggestion of 60/40 sharing between Li-ion and DR technologies for 2011 cost estimates. This solution was primarily attributable to the non-constant DR resource availability (EV charging occurs primarily at night and after the morning commute) and the cost differential between the DR and Li-ion options.

The other technology pairing with a non-trivial solution was PH with multiple mode changes and flywheels. The underlying basis for the optimum is very similar to the DR and Li-ion case. It is primarily driven by the unavailability of the hydro resource during the mode switching and the relative cost of PH compared to flywheels.

In addition to the case comprised of Li-ion and DR, the research team also examined the following cases: Na-S + DR, CAES + flywheels, PH with multiple mode changes + Na-S, PH with two daily mode changes + Na-S, PH with multiple mode changes + flywheels, and PH with two daily mode changes + flywheels. Each case was also examined using 2011 cost assumptions and was run through each sensitivity analysis, as described in Section 6. The primary conclusions drawn from this analysis are as follows:

Under the 2020 price scenario and all sensitivity analyses described in Section 6 (with the exception of the 2011 price scenario), a "winner takes all" condition is present where the technology share comprised primarily of the least cost technology is always the most cost-effective hybrid solution. This condition also holds true for each case under the 2011 price scenario with the exception of combinations of Li-ion and DR technologies, and combinations of pumped hydro with multiple mode change and flywheels. This result stems from the non-linearity in these two combination cases. For the Li-ion and DR combination case under the 2011 price scenario, the least cost technology share was 60 percent DR and 40 percent Li-ion in most regions. A non-linearity was found that is caused by the availability of DR. For the "pumped hydropower with multiple mode changes plus flywheels" combination case, the least cost technology share was 60 percent PH and 40 percent flywheel for the CAMX area and under the 2011 price scenario. The non-linearity in this case stemmed from the waiting period between PH mode changes. The non-linearity influences the technology share outcome when the costs of the two technologies are comparable.

5.0 Datasets for Wind Generation and Loads

5.1 WECC Wind Datasets

The NREL Wind Integration Datasets (NREL 2009) were utilized to estimate the production of all wind sites in every NERC region. NREL datasets provided 10-minute interval production schedules for over 30,000 hypothetical wind sites. Wind production data are based on mesoscale wind simulation assuming the Vestas V-90 3MW wind turbine and a hub height of 100 meters above ground. Electricity production data are available for one year. Existing and additional (hypothetical) wind capacities are shown in Figure 5.1.

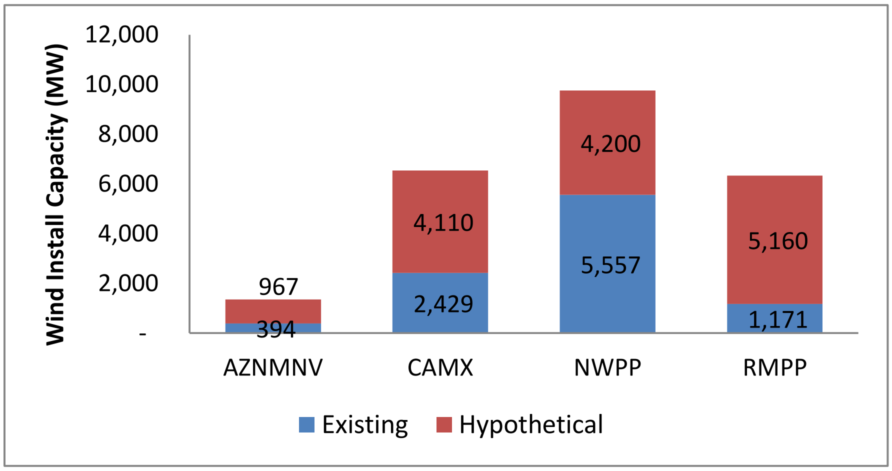


Figure 5.1. Wind Projection 2011-2020 for NERC regions in WECC

The Wind Integration Datasets from NREL project wind production simulated for 32,043 wind sites in the WECC system at 10-minute intervals. The information of the datasets is summarized in Table 5.1. The western wind datasets were produced by the 3Tier Company using the Weather Research and Forecasting (WRF) mesoscale model. The modeled data were temporally sampled every 10 minutes and spatially sampled every arc-minute (around 2 kilometers).[1]

Table 5.1. Information About NREL Wind Integration Datasets

Produced By	Western Dataset
3Tier Company	
Mesoscale Model	WRF
Number of Output Points	32,043
Size of Output Point	1 arc-minute[(a)]
Output Point Capacity (MW)	30
Model Hub Heights (m)	100
Turbine Power Curves	Vestas V-90 3MW

(a) One arc-minute of latitude is 1.825 km at any meridian. One arc-minute of longitude is exactly 1.852 km at the equator.

[1] http://www.nrel.gov/wind/integrationdatasets/western/methodology.html.

The placement of the new wind capacity is done by considering several factors, including information from grid operators about planned wind sites that are at various permitting stages, and judgment considering the best wind resources and proximity to load or transmission lines. Based on NREL wind datasets, even when selecting only the best wind class (6 and 7) land areas in proximity to transmission lines operating at 230 kV and above, the suitable hypothetical wind farm sites and total capacity is significantly larger than what is needed for the generation capacity additions. Figure 5.2 shows the selected wind capacity distribution by state. The average capacity factor of the new wind sites is around 35 percent. Figure 5.3 illustrates all additional and currently existing wind sites in the WECC.

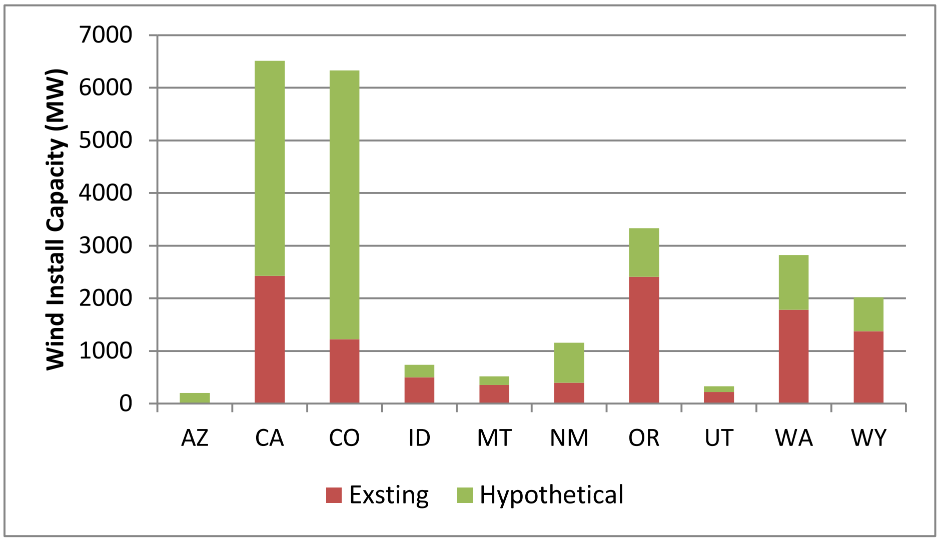


Figure 5.2. Distribution of Wind Capacity by States

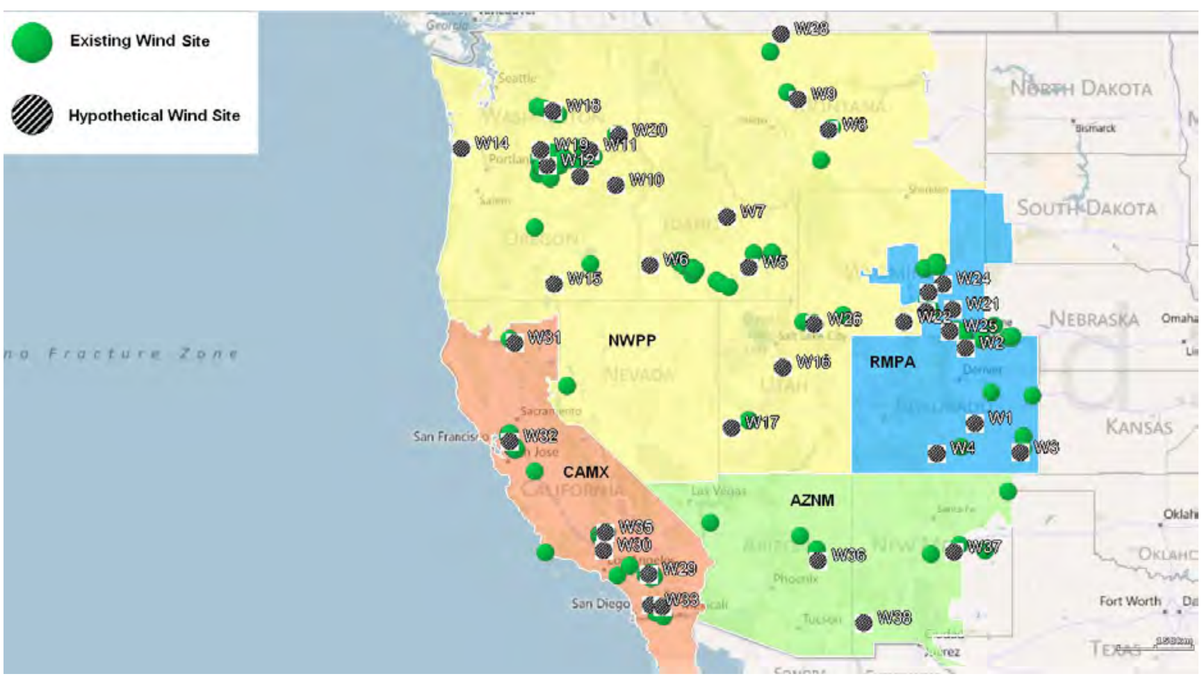


Figure 5.3. Location of Existing and Hypothetical Future Wind Plants in WECC.

To estimate balancing requirements, minute-by-minute wind production data are needed. However, NREL wind datasets are created with 10-minute interval. Therefore, the 10-minute interval data were interpolated to generate the required minute-by-minute data by using interpolation method provided by the 3Tier Company. The hourly wind forecast is obtained by averaging wind production of every hour and superimposing wind forecast error on the hourly average. Wind power generation in 2020 for each wind plant is assumed to be the same as it was in 2006. The wind forecast error is generated by using a multivariate stationary Markov Chain to reproduce the statistical characteristics including the standard deviation, mean value, and autocorrelation of current wind forecast error (Makarov 2010b). The statistical information of hour-ahead wind forecast error is shown in Table 5.2.

Table 5.2. Statistics of Hour-Ahead Wind Forecast Error (the percentage values are based on installed wind capacity)

	Mean (%)	Standard Deviation (%)	Auto Correlation
AZNM	-0.03	7	0.8887
CAMX	-0.68	7	0.9386
NWPP	-0.56	7	0.9388
RMPA	-0.05	7	0.9143

5.2 WECC Load Datasets

The minute-by-minute actual load data of 2009 and hour-ahead load forecast of 2020 for every balancing authority were obtained from the WECC. The within-hour variations of the 2009 load are added to the 2020 hourly load to get minute-by-minute load data for the year 2020. Then, the loads are aggregated to obtain the minute-by-minute load data for every NERC region. In this analysis, we assumed the hourly generation schedule is the same as the hour-ahead load forecast. Load growth assumptions are utilized from the Transmission Expansion Planning and Policy Committee (TEPPC) 2020 15 percent renewable case (WECC-TPPC, 2009).

The hourly load forecast is obtained by adding load forecast error to the hourly average of load. The load forecast error is generated by using a multivariate stationary Markov Chain to reproduce the statistical characteristics including the standard deviation, mean value, and autocorrelation of current load forecast error. Table 5.3 shows the statistics for the load forecast errors, respectively.

Table 5.3. Statistics of Hour-Ahead Load Forecast Error (the percentage values are based on peak load)

	Mean (%)	Standard Deviation (%)	Auto Correlation
AZNM	-0.61	1.99	0.9559
CAMX	0.42	1.17	0.9282
NWPP	0.14	1.04	0.937
RMPA	1.93	2.83	0.9255

5.3 EIC and ERCOT Wind Datasets

The NREL Wind Integration Datasets (NREL 2009) were also utilized to estimate the production of all wind sites in every NERC region in the EIC. NREL datasets provided 10-minute interval production schedules for 1,326 hypothetical wind sites on shore and 4,948 off shore in the EIC. The on shore sites are more highly aggregated than western wind dataset, which consists of 30,000 wind sites on shore.

5.3.1 EIC

The Wind Integration Datasets from NREL are wind production simulated for 1,326 wind sites on land and 4,948 sites off shore in the EIC system at 10-minute intervals. The capacity of most wind sites on land falls between 100 and 600 MW. There are 150 very large sites where capacity exceeds 1,000 MW. The offshore sites were chosen from 2-km grid, each grid cell represented 20 MW of offshore wind capacity. The selected grid cells were in the Atlantic Ocean and four of the five Great Lakes and were at least 8 km from shore and in water no deeper than 30 m. The EIC wind datasets were produced by AWS Truepower Company using the MASS model. A wind turbine power curve was created by taking the average of three commercial megawatt-class wind turbine power curves which had been normalized to their rated capacity. The three classes of wind turbines are IEC Class 1, 2 and 3.

5.3.2 ERCOT

The NREL dataset did not cover ERCOT. Therefore, an alternative data approach was used to generate minute-by-minute wind production profiles. Hourly wind generation outputs for multiple individual hypothetical wind plants in Texas' competitive renewable energy zones (CREZ) are used and adjusted to reflect five-minute data obtained for one wind farm for 2012. The minute-by-minute data were when generated by an interpolation scheme using 3TierCompany's interpolation method.

ERCOT wind generation data were created by AWS Truepower using the Mesoscale Atmospheric Simulation System (MASS) V.6.8 model. Some 716 potential wind sites were identified in 25 CREZs. Wind power generation in 2020 for each wind plant is assumed to be the same as that of the year 2008. The same method was used to generate wind forecast error for ERCOT as for EIC and WECC.

5.3.3 Placement of Hypothetical Wind Sites

The placement of the new wind capacity was undertaken by considering several factors, including information from grid operators about planned wind sites that are at various permitting stages, and judgment considering the best wind resources, and proximities to load centers and/or transmission lines. The distribution of wind capacity is based on the existing wind capacity and EIA wind capacity projections for 2020. Additional wind capacity are distributed proportionally in NERC sub-regions and located based on NREL wind datasets. Additionally, judgment was used to place some additional wind capacity as off-shore in the Great Lakes regions and in the Mid-Atlantic. Figure 5.4 shows the allocation of hypothetical wind plant additions by NERC sub-regions in the EIC and ERCOT. Figure 5.5 shows the selected wind capacity distribution by state. The average capacity factor of the new wind sites is about 35 percent. Figure 5.6 and Figure 5.7 illustrate all currently existing and hypothetical wind sites in the EIC and ERCOT, respectively.

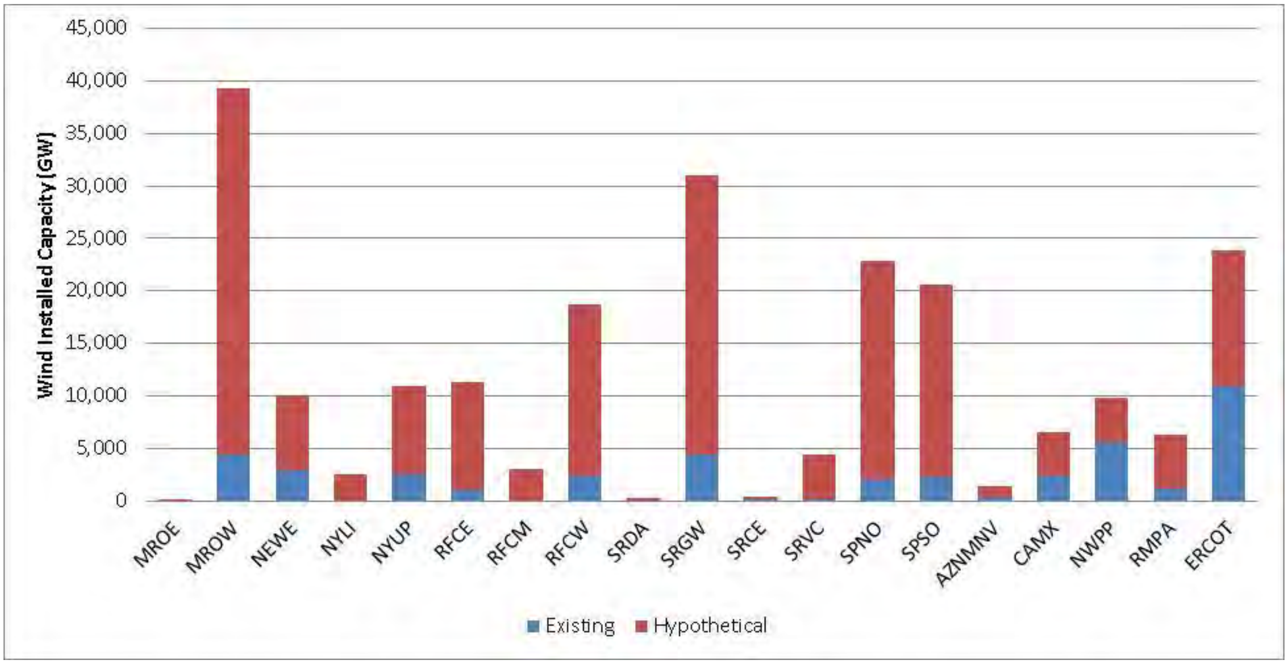


Figure 5.4. Wind Projection 2011-2020 for NERC regions in EIC and ERCOT

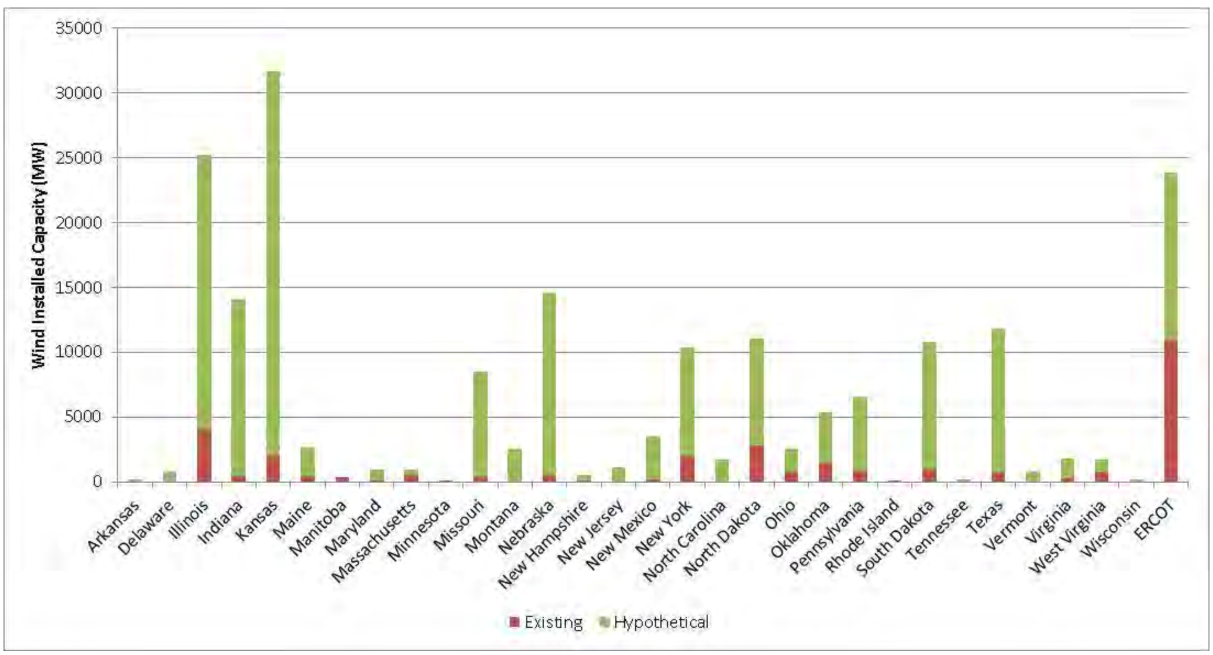


Figure 5.5. Distribution of Wind Capacity by States in EIC and ERCOT

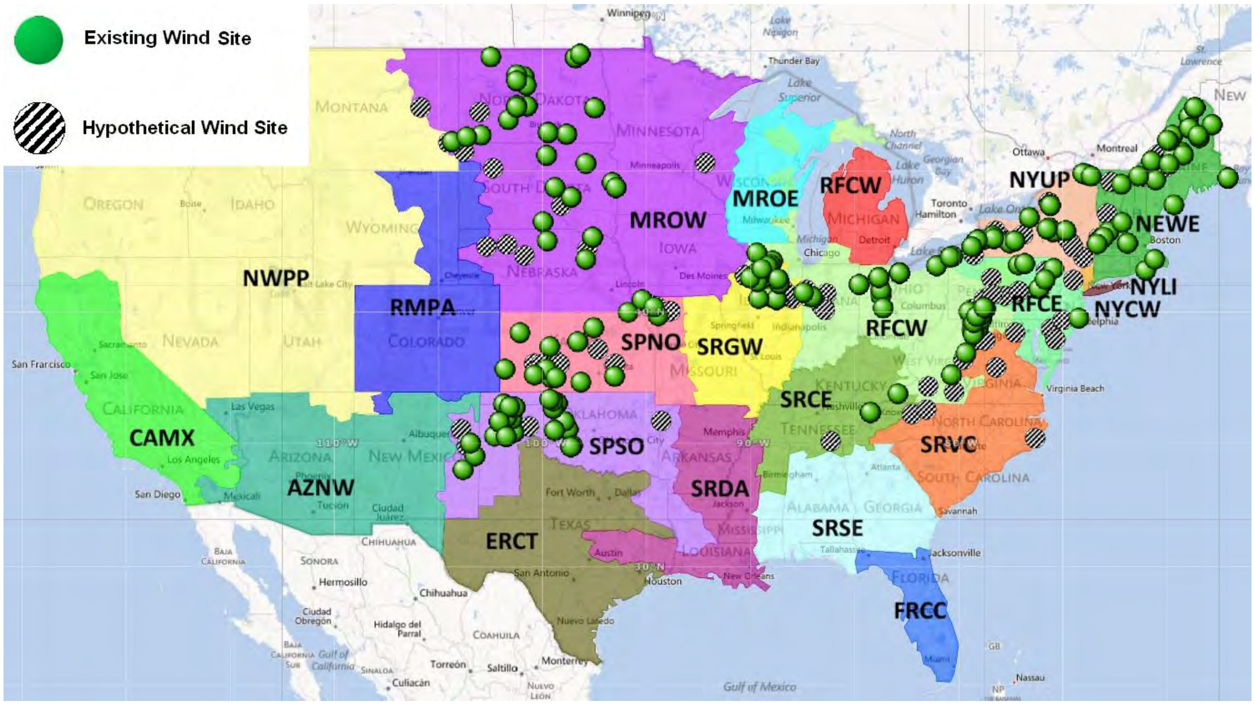


Figure 5.6. Location of Existing and Hypothetical Future Wind Plants in EIC.

In the eastern interconnection, the onshore wind resources are concentrated in the South Power Pool (SPNO and SPSO), which are far away from the coastal load center. Therefore, significant transmission expansion would be needed to transfer the wind energy to the east coast. Section 8.5 discusses the transmission needs further for the Easter Interconnect.

Offshore wind farms are usually more technically challenging and more expensive than onshore ones; Nevertheless, we selected 3 GW offshore wind capacity in the Great Lakes and 8.4 GW in the Atlantic ocean due to proximity to load centers and the ability to avoid transmission upgrades.

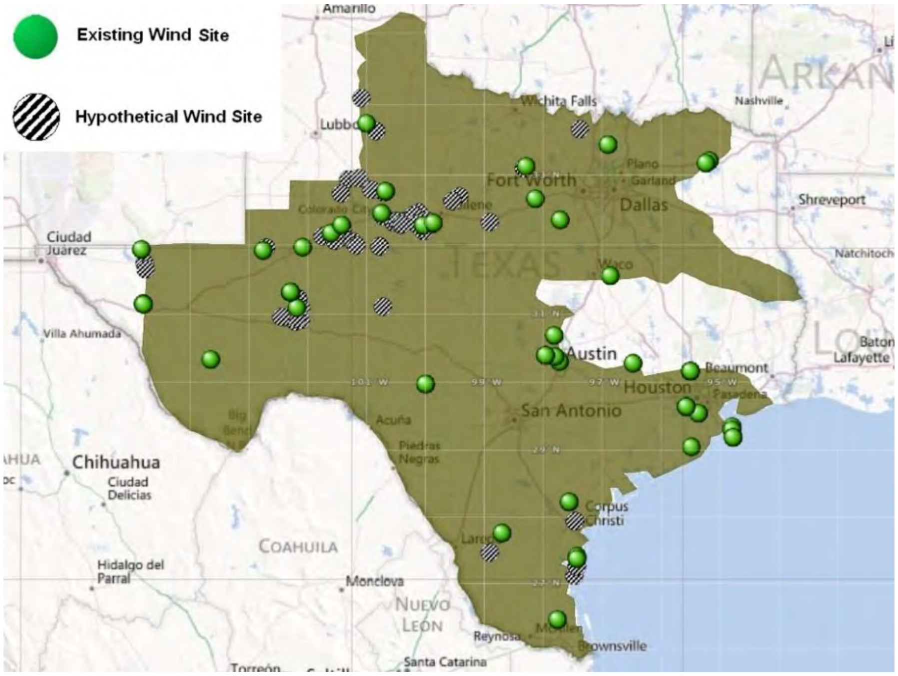


Figure 5.7. Location of Existing and Arbitrarily Sited Future Wind Plants in ERCOT.

To obtain the balancing requirements, minute-by-minute wind production data are needed. However, for EIC, NREL wind datasets are created with a 10-minute interval. As described in the section above, the 10-minute interval data were interpolated to generate the required minute-by-minute data by using the interpolation method provided by the 3Tier Company. The same methodological approach as applied for the WECC was used here (Makarov 2010b). The hourly statistical information of hour-ahead wind forecast error is shown in Table 5.4.

Table 5.4. Statistics of Hour-Ahead Wind Forecast Error (the percentage values are based on installed wind capacity)

	Mean (%)	Standard	Auto Correlation
MROE	-0.02	7	0.7954
MROW	-0.03	7	0.9422
NEWE	-0.02	7	0.9358
NYLI	-0.03	7	0.9095
NYUP	-0.01	7	0.9393
RECM	-0.01	7	0.9318
RFCE	0.00	7	0.9427
RFCW	-0.01	7	0.9222
SPNO	-0.04	7	0.9263
SPSO	-0.05	7	0.9208
SRCE	-0.03	7	0.8516
SRDA	-0.01	7	0.8450
SRGW	-0.02	7	0.9235
SRVC	0.01	7	0.9279
ERCOT	0.08	7	0.6128

5.3.4 Load Datasets

Hourly actual load data for 2011 and 15-minute actual load of one week, and hourly load forecast for the same week in 2012 were obtained from the ERCOT information team. First, the 2011 load was scaled to the 2020 load, then the within-hour variations of the 2012 load were added to the 2020 hourly load to get minute-by-minute load data for the year 2020. In this analysis, we assumed the hourly generation schedule is the same as the hour-ahead load forecast. Load growth assumptions are based on ERCOT CDR report (Report on the Capacity, Demand, and Reserves in the ERCOT Region) (ERCOT CDR, 2011) released in December 2011.

The hourly load forecast is obtained by adding load forecast error to the hourly average of load. The load forecast error is generated by using a multivariate stationary Markov Chain to reproduce the statistical characteristics including the standard deviation, mean value, and autocorrelation of current load forecast error. Table 5.5 shows the statistics for EIC and ERCOT load forecast errors.

Table 5.5. Statistics of Hour-Ahead EIC Load Forecast Error (the percentage values are based on peak load)

	Mean (%)	Standard Deviation (%)	Auto Correlation
MROE	-0.38	1.32	0.9287
MROW	-0.52	1.30	0.9362
NEWE	-0.45	1.26	0.9315
NYLI	-0.54	1.33	0.9286
NYUP	-0.56	1.25	0.9166
RECM	-0.49	1.33	0.9331
RFCE	-0.43	1.32	0.9342
RFCW	-0.48	1.39	0.9360
SPNO	-0.53	1.24	0.9242
SPSO	-0.62	1.31	0.9313
SRCE	-0.53	1.14	0.9145
SRDA	-0.38	1.23	0.9246
SRGW	-0.48	1.31	0.9301
SRVC	-0.46	1.27	0.9297
ERCOT	0.47	3.7	0.9723

6.0 Technology Choices for Balancing Services

To mitigate the additional intermittency and fast ramps at higher penetration of intermittent energy resources (i.e., wind power in our case) in the NWPP, the conventional solution is to build more peaking units such as combustion turbine units. However, the advancement of battery technology, smart grid concepts coupled with demand response options, and the anticipated need for carbon reduction, places new emphasis on exploring non-conventional resources. The importance of a broader set of technology options for providing the ancillary services requirements that traditionally have been provided by fast-starting and flexible CT cannot be understated.

The following technologies are considered in this study:

- CT, as the base case technology
- Sodium sulfur (Na-S) battery
- Lithium-ion (Li-ion) battery
- Vanadium reduction-oxidation (redox) flow battery
- CAES
- Flywheels
- PHES
- 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 Volume 2.

6.1 Definition of Technology Options

The set of technologies mentioned above can be applied individually or in combination with other technologies. Technology 'packages' of two technologies were investigated. These technology packages can be thought of as a portfolio of resources that, in most cases, will be dispersed throughout each of the NERC areas. Only in the cases of PH and CAES energy storage would a single location, or potentially multiple locations, be viable based on topology to support upper and lower reservoirs (for PH) or the geological cavities for storing air in the ground (for CAES). Retrofitting options for the existing "run the river" hydro plants to a pumped hydro station were not considered because of very site-specific specifications and environmental constraints. For most of technologies, the actual capacity will be widely dispersed. This is particularly the case for demand response. Table 6.1 shows the 16 single technology packages, which we will call "cases."

Explored were seven hybrid storage combinations comprised of two technologies (C10 through C16). The selection of the pairing was arbitrary and somewhat guided by intuition that a technology designed for a high power application is complementary and perhaps more cost-competitive when paired with a high energy capacity technology.

Table 6.1. Definition of Technology Cases

	Case	Technology	Comments
Individual Technologies	C1	Combustion turbine	Conventional technology considered as the reference case.
	C2	Na-S	Sodium sulfur battery only.
	C3	Li-ion	Lithium-ion battery only.
	C4	Flywheel	Flywheel only.
	C5	CAES with 2 mode changes	CAES with a 7-minute waiting period for mode changes (compression-generation and vice versa). Balancing services will be provided during compression mode at night (8 pm-8 am) and during generation mode during the day (8 am-8 pm). Na-S battery is assumed to make up operations during 7 minute waiting period.
	C6	Flow battery	Flow battery only.
	C7	PH with multiple mode changes	PH with a 4-minute waiting period for mode changes (pumping-generation and vice versa). This machine allows multiple mode changes during the day. Na-S battery is assumed to make up operations during 4 minute waiting period.
	C8	PH with 2 mode changes	Same as (C7), except only two mode changes. Balancing services will be provided during pumping mode at night (8 pm-8 am) and during generation mode during the day (8 am-8 pm). Na-S battery is assumed to make up operations during 4 minute waiting period.
	C9	DR (demand response)	Demand response only. This assumes that balancing services will be provided as a load. Only considered is PHEV charging at home and work. Resources are expressed in MW of DR capacity as well as in numbers of PHEV with demand response capability.
Technology Packages	C10	Na-S DR	Sodium sulfur battery and DR combined.
	C11	Li-ion DR	Lithium-ion battery and DR combined
	C12	CAES Flywheel	CAES with no constraints for mode changes with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.
	C13	PH with multiple mode chances Na-S	PH with no constraints for mode changes with Na-S battery. The balancing requirement is allocated to each technology according to minimum cost.
	C14	PH with 2 mode changes Na-S	PH with two mode changes per day (see C8) with Na-S battery. The balancing requirement is allocated to each technology according to minimum cost.
	C15	PH with multiple mode chances Flywheel	PH with no constraints for mode changes with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.
	C16	PH with 2 mode changes Flywheel	PH with two mode changes per day (see C8) with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.

7.0 Results: Projected Balancing Requirements

This section presents the results of the balancing analysis by sub-region for the whole nation.

7.1 Total Balancing Requirements for the US

The total balancing signals for every sub-region are obtained using the BPA's 99.5 percent probability bound and based on 1-year simulation results. The main factors that affect the balancing requirements are the wind adoption level, wind forecast accuracy, load forecast accuracy, peak demand level of every region, load intra-hour variations, and wind intra-hour variations in every region. The results indicate that the total balancing requirements span a spectrum of frequencies, from minute-to-minute variability (intra-hour balancing) to those indicating cycles over several hours (inter-hour balancing). This analysis focused on the intra-hour balancing market because the sharp ramp rates required in this market are of significant concern to grid operators. The intra-hour balancing requirements were decomposed from the total balancing requirements and are presented in Table 7.1. Compared to total balancing requirements, the power capacity requirements are significantly reduced in intra-hour balancing, but the ramp rate requirements are very well preserved. Total intra-hour balancing requirements are around 3 percent to 17 percent of peak load in every sub-region. One exceptional region is SRGW. It has a very high installed wind power capacity of 31 GW while it only has 5.8 GW of peak load.

Table 7.1. Intra-hour Balancing Requirements in US by Sub-Regions

	Power (MW)	Balancing Power Required as a Percentage of Average Demand (%)	Balancing Power Required as a Percentage of Peak Demand (%)	Ramp Rate (MW/min)
AZNM	1090 -1220	11	11	290
CAMX	1790 -2400	5	5	230
NWPP	1690 -2020	4	4	200
RMPA	670 -670	22	15	120
MROE	430 -490	9	5	220
MROW	4340 -3860	9	6	410
NEWE	1360 -1370	7	5	250
NYLI	520 -540	16	9	220
NYUP	1270 -1440	13	9	240
RFCE	2280 -2530	6	4	290
RFCM	580 -600	5	4	220
RFCW	3090 -3830	6	4	350
SPNO	2760 -2290	25	17	320
SPSO	2540 -2400	12	9	320
SRCE	1090 -1070	3	3	240
SRDA	800 -830	4	3	230
SRGW	3290 -3080	118	56	380
SRVC	1780 -1610	4	3	270
ERCOT	3840 -3930	7	5	510

Table 7.2 shows the intra-hour balancing requirements caused by wind uncertainty only. According to the last column, an intra-hour balancing capacity of approximately 6 percent to 17 percent of the installed wind capacity is needed.

Table 7.2. Balancing Requirements (Intra-hour) for NERC Sub-Regions caused by Wind Variability Only (without considering load variability)

	(MW)	As a % of average demand	As a % of peak demand	As a % of wind capacity
AZNM	170	1	0.5	12.8
CAMX	940	2.5	1.4	14.4
NWPP	1,070	2.1	1.5	11
RMPA	500	5.6	3.6	8
MROE	10	0.2	0.1	6.5
MROW	3070	6.1	4.4	7.8
NEWE	1,060	5.7	3.6	10.5
NYLI	420	12.0	7.0	16.9
NYUP	1080	9.9	6.5	9.9
RFCE	850	1.8	1.2	7.5
RFCM	360	3.1	2.3	12.1
RFCW	2250	3.7	2.6	12.0
SPNO	2470	22.0	15.3	10.8
SPSO	2240	10.9	7.5	10.9
SRCE	20	0.1	0.0	5.8
SRDA	20	0.1	0.1	9.0
SRGW	3360	117.4	57.5	10.8
SRVC	330	0.7	0.5	7.5
ERCOT	2030	3.8	2.7	8.5

Table 7.3 shows the intra-hour balancing requirements caused by load uncertainty only. Notice that the balancing requirements produced by load uncertainty can be larger than those produced by wind uncertainty for regions with high load and low wind adoption level.

Table 7.3. Balancing Requirements (Intra-hour) for NERC Sub-Regions caused by Load Variability Only (without considering wind variability)

	(MW)	*As a Percentage of Average Demand (%)*	*As a Percentage of Peak Demand (%)*	*As a Percentage of Installed Wind Capacity (%)*
AZNM	1130	6	3	83
CAMX	2810	7	4	43
NWPP	1770	4	2	18
RMPA	630	7	5	10
MROE	490	9	5	321
MROW	1970	4	3	5
NEWE	1100	6	4	11
NYLI	420	12	7	17
NYUP	680	6	4	6
RFCE	2110	5	3	19
RFCM	590	5	4	20
RFCW	2400	4	3	13
SPNO	610	6	4	3
SPSO	890	4	3	4
SRCE	1090	3	3	313
SRDA	830	4	3	375
SRGW	390	14	7	1
SRVC	1740	4	3	40
ERCOT	4140	8	5	17

7.2 Additional Projected Balancing Requirements for US

The additional projected balancing requirements to accommodate the additional wind capacity between now and 2020 and the small load growth are summarized in Table 7.4 . The additional intra-hour balancing requirements are driven primarily by the wind uncertainty. That is, a region with more hypothetical wind capacity has higher balancing requirements. The load uncertainties is only a minor component to the additional balancing services since only the uncertainty of the load growth can be considered here; and that is small (6 percent over the entire time horizon 2011-2020) compared to existing load. As can be seen in Table 7.4, the *additional* intra-hour balancing requirements are significant smaller compared to the *total* balancing requirements because of the large contribution of the uncertainty associated with the existing load compared to the uncertainty in the wind generation.

Table 7.4. Additional Intra-Hour and Total Intra-Hour Balancing Requirements for Every Sub-Region in US

	Additional Balancing Power Required (MW)	Total Balancing Power Required (MW)	Total Balancing Power Required as a Percentage of Peak Load (%)	Marginal Balancing Power Required as a Percentage Wind Capacity (%)	Existing Wind Capacity (MW)	Additional Wind Capacity (MW)	Total Wind Capacity in 2020 (MW)
AZNM	210	1,220	4	22	390	970	1,360
CAMX	530	2,400	4	13	2,430	4,110	6,540
NWPP	280	2,020	3	7	5,560	4,200	9,760
RMPA	510	670	5	10	1,170	5,160	6,330
Total WECC	**1,530**	**6,310**			**9,550**	**14,440**	**23,990**
MROE	20	490	5	13		150	150
MROW	2,750	4,340	6	8	4,470	34,760	39,230
NEWE	610	1,370	5	8	2,900	7,190	10,080
NYLI	420	540	9	17		2,480	2,480
NYUP	840	1,440	9	10	2,530	8,380	10,910
RFCE	880	2,530	4	9	980	10,310	11,290
RFCM	340	600	4	11		2,980	2,980
RFCW	2,280	3,830	4	14	2,470	16,320	18,780
SPNO	2,340	2,760	17	11	2,040	20,820	22,850
SPSO	2,090	2,540	9	11	2,290	18,350	20,640
SRCE	60	1,090	3	36	180	170	340
SRDA	40	830	3	18		220	220
SRGW	2,890	3,290	56	11	4,390	26,670	31,060
SRVC	360	1,780	3	9	210	4,160	4,370
Total EIC	**15,920**	**27,430**			**22,460**	**152,960**	**175,380**
ERCOT	1,120	3,930	5	9	10,950	12,860	23,810
Total US	**18,570**	**37,670**			**42,960**	**180,260**	**223,180**

This study indicates that the future total intra-hour balancing requirements to address both load and renewable variability are generally expected to range between 3 percent and 9 percent of the peak load in a given region. SPNO and SRGW are exceptional because they are wind zones with very little load. Furthermore, on the margin for every additional unit of wind capacity power, approximately 0.07 to 0.36 units of intra-hour balancing capacity need to be added.

These values most likely under-estimate the size of the balancing market and the additional generation or storage power needed because a simplifying assumption was made in the analysis that current individual BAs are consolidated to one single, large balancing area within each sub-region. This consolidating assumption takes advantages of load diversity and renewable generation diversity within a sub-region.

7.3 Market Size for Energy Storage for Balancing Services

The assessment estimated the size requirements for energy storage capacity to meet the total and additional intra-hour balancing requirements as summarized in Figure 9.2.

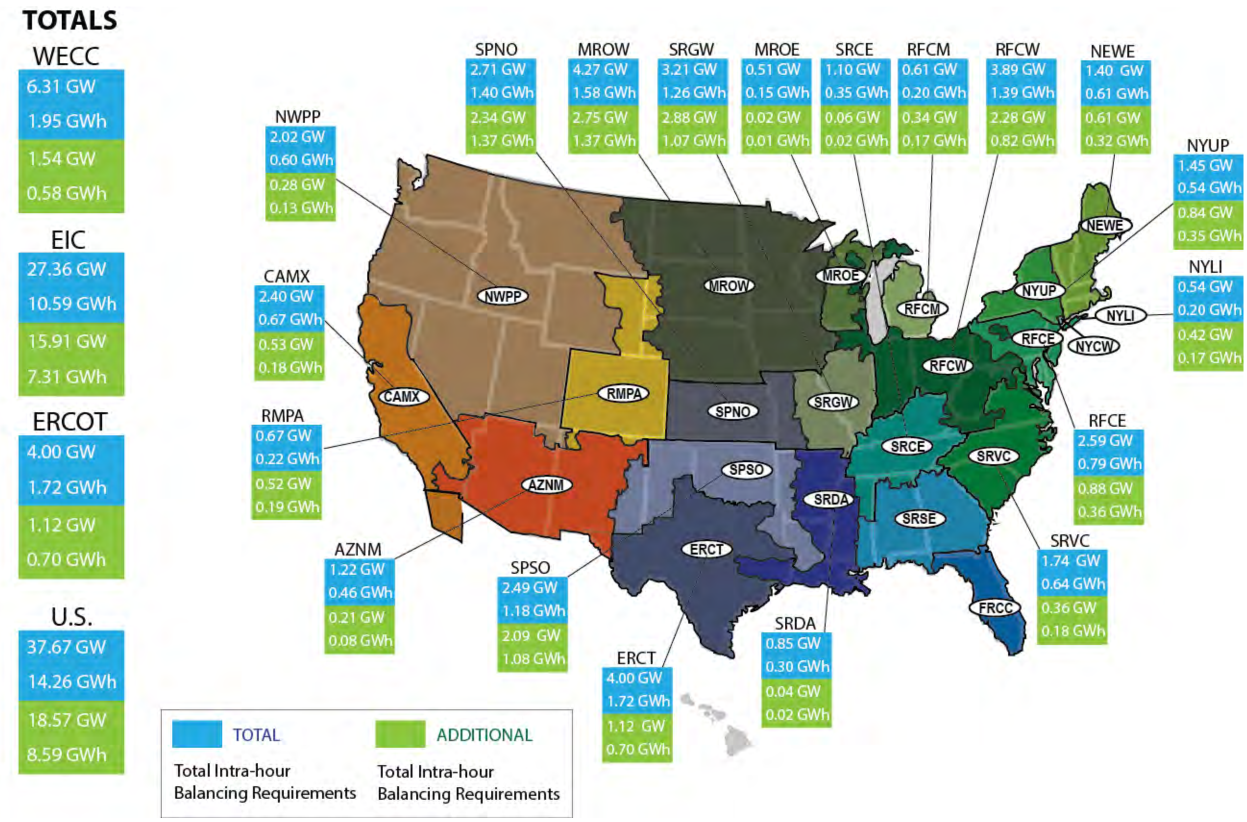


Figure 7.1. Size Requirements for Storage Technologies to Meet the Total and Additional Intra-Hour Balancing Services for a 2020 Grid with 20 percent RPS.

8.0 Arbitrage Opportunities for Energy Storage

8.1 Introduction and Methodology

Arbitrage is the practice of taking advantage of price differences between two market prices. In the context of electric energy markets, energy storage can be used to charge during low-price periods (i.e., buying electricity) in order to discharge the stored energy during periods of high prices (i.e., selling during high-priced periods). The economic reward is the price differential between buying and selling electrical energy, minus the cost of losses during the full charging/discharging cycle.

The revenue potential of arbitrage is illustrated in Figure 8.1a and Figure 8.1b . Figure 8.1a presents an illustrative locational marginal price (LMP) differential for hours throughout the year along a congested point in the grid. Note that the number of hours in a year was cut in half to account for the time required to charge energy storage devices assuming that there was a balance between charging and discharging throughout the year. This is a reasonable assumption for a storage plant with a total duration of about 10 hours at rated power capacity.

LMP differentials begin at high levels yielding the largest marginal revenues but would be expected to decline as more energy storage enters the arbitrage market. Figure 8.1b demonstrates how the marginal revenue generated for each additional hour of operation of a power plant, or in this case an energy storage device, would be expected to decline. As these energy storage devices are expanded in terms of capacity and production, marginal revenues per MWh would be expected to decline until marginal revenues and the marginal costs of introducing more capacity reach a point of equilibrium. At this point, no more capacity would enter the market because the marginal expansion in energy capacity would yield economic losses.

The figures demonstrate that the first block of installed energy storage capacity would supply a portion of the energy required during the highest value hours (Area A). At the height of the load duration curve when demand is greatest, the LMP differential would reach an apex and the revenue per hour of operating the energy storage device would be maximized. In this case, the presence of the first block of energy storage devices entering the market would meet some of the demand placed on the system during the highest peak hours of the year resulting in a reduction in the LMP differential available for other energy suppliers in the arbitrage market (Area B). In addition to capturing the high-value hours represented by Area A in the figures, building energy storage into the market would result in a shift in the LMP differential curve further reducing profits available to other market participants or to further expansion of energy storage capacity.

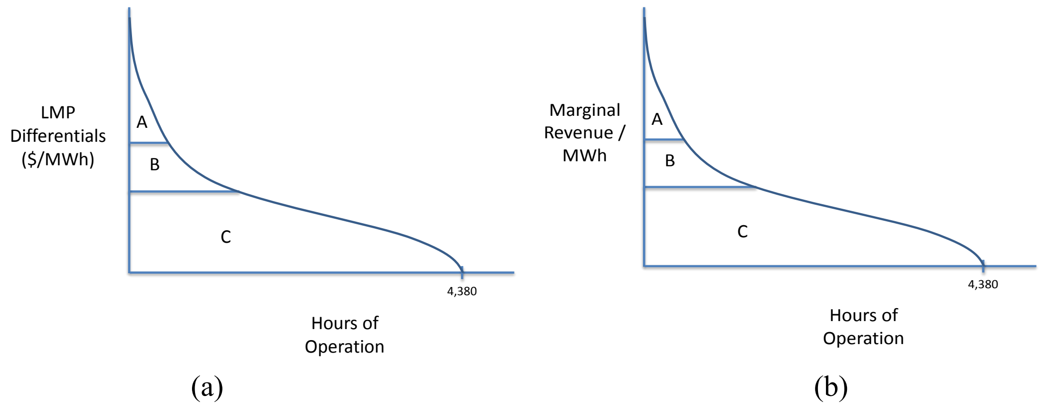


Figure 8.1. (a) LMP Differential per Hour of Operation ($/MWh) and (b) Marginal Revenue per Hour of Operation ($/MWh)

To generate arbitrage revenue, energy storage is cycled daily by charging during off-peak hours and discharging during peak hours of the day. Electro-chemical energy storage systems used for arbitrage store and discharge electrical energy at a specified power rating for many hours (4-10 hours or more). PH storage systems with a sufficiently large reservoir, however, could be used to store capacity over longer durations. For example, PH storage could be drawn down to a low state of charge by Friday evening. In turn, pumping could be initiated from Friday night through the weekend to be terminated in the early morning hours on Monday. In this instance, PH could then be used to supply energy during peak weekday hours. In some cases, it may be desirable to store electrical energy for longer periods. For instance, in the Pacific Northwest where there is significant hydro power capacity along the Columbia and Snake River systems, a rapid snow melt could result in energy production by dams that exceed the region's demand for electricity. In such a case it may be desirable to store the water or electricity for periods in the summer when the water resources are less ample. Such a storage system would be large in its capacity to store energy for weeks if not months. Typically, for longer duration applications in which significant amounts of energy must be stored, PH, CAES systems, and some electro-chemical storage systems (such as redox flow batteries) are used.

While these energy storage systems have been limited in terms of their overall application, their continued development has been supported through significant public and private investment. For example, the American Recovery and Reinvestment Act (ARRA) is currently funding grid-connected energy storage demonstrations at a federal funding level of approximately $185 million with additional industry cost-sharing of roughly $586 million.[11] Of the 16 demonstration projects initiated, eight projects demonstrate or explore storage with a cycle duration of 4 hours or more. The applications of the demonstration projects vary but all of them are capable or designed to perform energy arbitrage functions.

In addition to 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 sections of this report. Thus, this section focuses on the cost effectiveness of using energy storage as an arbitrage instrument to mitigate congestion-induced high

[11] Sandia National Laboratories ARRA Energy Storage Demonstrations Webpage. http://www.sandia.gov/ess/docs/ARRA_StorDemos_4-22-11.pdf. Last accessed on September 28, 2011.

electricity prices and/or to reduce potential low load conditions. The latter typically occur in cases where there is insufficient load (commonly at night) coincident with large electricity production attributable to growing wind generation capacity.

The exclusion of the balancing service value is made primarily based on the difficulty of valuing ancillary service in conjunction with energy arbitrage as a bundled service. To value a bundled storage product would require a coupled optimization in which the market values of ancillary services and energy markets in a given market (hour-ahead or day-ahead markets) must be solved subject to the important constraint of a finite stored energy and a maximum capacity. Due to its analytical complexity, this element has been left to future phases of this research program.

8.2 Arbitrage Analysis Framework

8.2.1 General discussion

To quantify the arbitrage value of energy storage, the research team applied an economic viability approach that compares the annual revenue requirements from the capital expenditure to the revenue potential from arbitrage. As indicated above, the arbitrage value was isolated and de-coupled from any other services that could potentially be bundled. Because of the complexity of the analysis to estimate the total value of bundled services with multiple payment streams, this analysis strictly focused on the arbitrage potential.

Economic viability of an energy arbitrage product or service is defined by a positive cash flow when the net revenue from performing energy arbitrage services exceeds the capital cost recovery requirements. The following equation defines the key parameters for the cash flow:

$$-((P\, d_o\, p_o) + \left((P\, \eta\, d_o\, p_p)\right) D \; > (P\, C_{Sto}\, d \; + P\, C_{PCS})\, \alpha \tag{8.1}$$

where
P = Power capacity of storage in [kW]
η = roundtrip efficiency of energy storage, dimensionless
d = duration of storage to maintain power output at rated capacity P in [h]
d_o = duration of storage operation per day at rated capacity P in [h/day]
D = number of days per year storage operates, dimensionless
p_o = off-peak price in [$/kWh]
p_p = on-peak price in [$/kWh]
C_{Sto} = incremental cost of storage device associated with the storage of electric energy in [$/kWh]
C_{PCS} = incremental cost of storage device associated with the power electronics in [$/kW]
α = annualization factor to annualize an investment, dimensionless

Assuming the energy storage system is charged to full capacity every day it operates, then d_o=d, and rearranging to solve for the necessary capital cost C_{Sto}, we can write the equation as follows:

$$p_o\left(-1 + \eta \frac{p_p}{p_o}\right) \frac{D}{\alpha} - \frac{C_{PSC}}{d} > \; C_{Sto} \tag{8.2}$$

Assuming that the incremental cost associated with power electronics for the power conditioning system is a known entity, then the necessary incremental cost for the storage component is a function of the off-peak power price p_o, the differential between peak and off-peak prices expressed as the ratio p_p/p_o, the roundtrip efficiency η, the number of days of operation D, and the annualization factor α.

Illustrated in Figure 8.2 is the dependency of the incremental cost C_{Sto} on the peak-to-off-peak prices differential and the efficiency η assuming that the storage device will be operating 5 days a week for 52 weeks. The annualization factor is consistent with the economic assumptions of discount rates and life cycles as calculated in the balancing services analysis (α=0.12). Furthermore, assumed is an incremental cost for the power electronics (power conditioning system) of C_{PCS}=\$150/kW consistent with earlier assumptions as shown in Volume 2, Table 3-1.

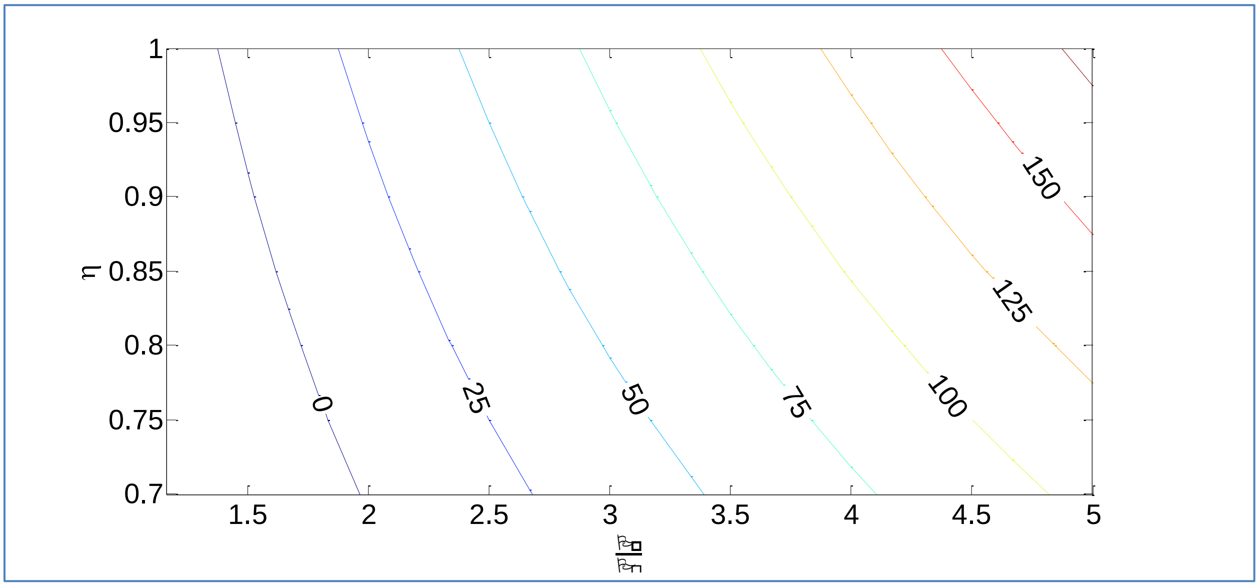


Figure 8.2. Dependency of Capital Cost for Storage Component C_{sto} in (\$/kWh) on Peak-Off Peak Ratio and Efficiency. Assumed: p_o = \$40/MWh, D = 260 days, α = 0.12.

Figure 8.2 clearly indicates the very low incremental cost for the storage component (that scales with kWh) that is necessary for a positive cash flow, the economic viability criterion. This indicates that for small p_p/p_o ratios of less than 1.5, (observed in competitive market conditions in CAISO for instance), the breakeven capital cost levels are negative meaning that the power conditioning system by itself is too expensive. This result unequivocally suggests that energy arbitrage by itself is unlikely to be a viable market niche for storage. Rather, it can be a value-enhancing component of other higher valued services.

If we assume that energy storage with sufficient energy capacity, say more than 6 hours, can contribute to the capacity requirements within a balancing authority, then we can assign a capacity value to this resource. Generally, the capacity value or the contribution to the capacity adequacy requirement is determined by its contribution to reduce the loss-of-load-probability. The value of such a resource can be found in active capacity markets such as the New York Independent System Operator (NYISO) installed capacity (ICAP) market. The value ranges from around \$100/kW-year to close to \$200/kW-year (NYISO 2010). If we assume a \$150/kW-year value that energy storage device with an energy capacity of more than 6 hours can provide, then the additional revenues from capacity payments would increase the target cost to higher values as seen in Figure 8.3 and Figure 8.4.

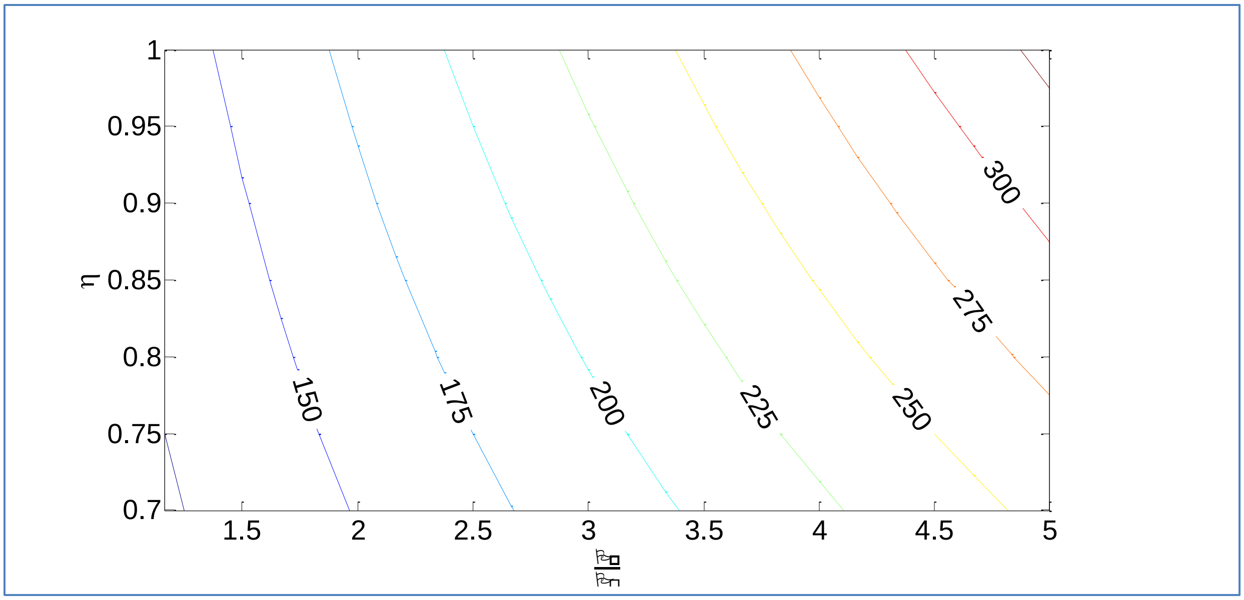


Figure 8.3. Dependency of Capital Cost for Storage Component C_{sto} in ($/kWh) on Peak-Off Peak Ratio and Efficiency. Assumed: p_o = $40/MWh, D = 260 days, α = 0.12, and capacity value of $150 per kW per year.

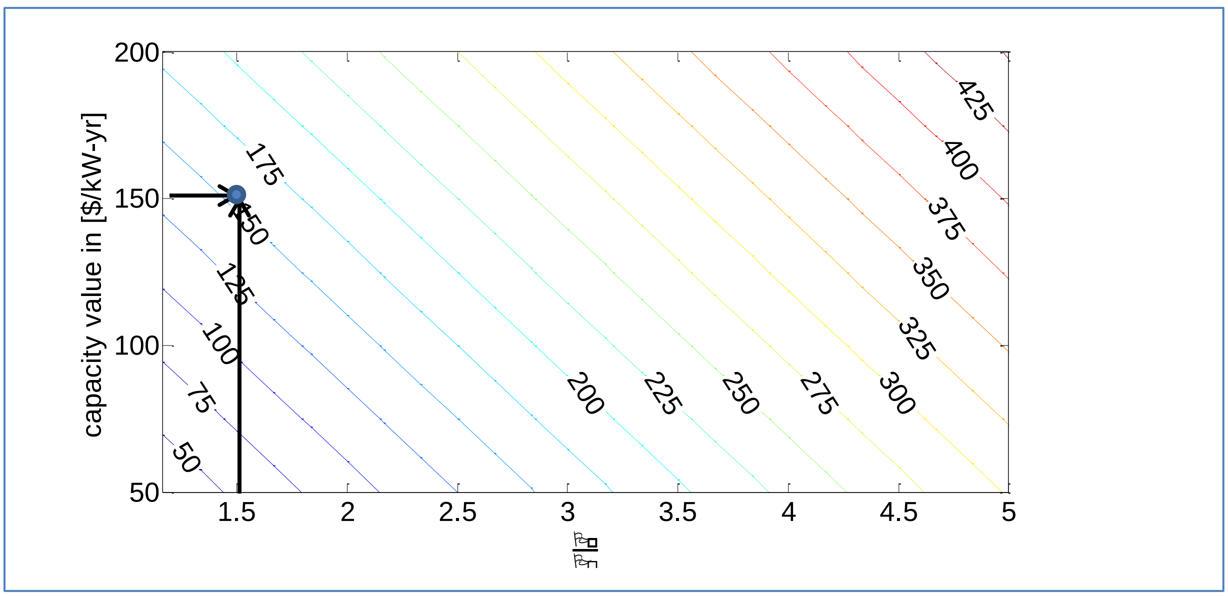


Figure 8.4. Dependency of Capital Cost for Storage Component C_{sto} in ($/kWh) on Peak-Off Peak Ratio and Capacity Value. Assumed: p_o = $40/MWh, D = 260 days, α = 0.12, and efficiency of η = 0.85.

With a capacity value of $150/kW-year and a peak to off-peak price differential of $p_{peak}/p_{off\text{-}peak}$ =1.5, the target cost of the storage must be about $150/kWh (see Figure 8.4). This is a challenging cost target for the energy storage devices.

8.2.1 Modeled Revenue Estimations

The revenue potential analysis is based on a production cost approach using PROMOD IV[12] 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 the zonal or nodal transmission level. In this analysis, a WECC system model developed by the vendor was used in its zonal mode with 22 utility zones for the WECC. A 2020 grid scenario is postulated with a generation capacity mix that was based on AEO 2011 reference case (DOE/EIA 2010b).

In support of the arbitrage analysis, several data forecasts were implemented in this model as described briefly below:

- Coal price forecast: The coal price forecast was done by Ventyx for each coal power plant. The prices include historical monthly prices through October 2010 followed by forecast annual prices to the year of study, 2020
- Natural gas price forecast: Monthly values are forecasted for the year of study
- Emission price forecast: NO_x and SO_2 forecasts reflect the Federal Clean Air Transportation Rule. Mercury price is not modeled. CO_2 price forecasts are included in the model
- Load forecast: Peak and energy load forecasts are based on the 2009 Federal Energy Regulatory Commission (FERC) 714 filings as well as more recent regional and ISO publications such as the NYISO Gold Book (NYISO, 2011) , ISO-NE CELT report (ISO-NE, 2011), ERCOT long-term reliability assessment (NERC, 2011), California Energy Commission and similar reports from Canadian sources
- Topology: The topology modeling is done at the BA level as reported in the 2009 FERC 714 filings. The new topology is designed to better align with ISO regions as well as state boundaries
- Hydro Energy: Historical average energy used to create the annual and monthly energy forecasts included 2009 actual data
- Load Shapes: The 8,760-hour load shapes have included hourly loads from 2003-2009
- Solar hourly shapes: The solar shapes specific to renewable basins are included in the database
- Zonal Transmission Expansion Plan: Zonal transmission expansion plans includes announced transmission projects and projected projects required to deliver renewable expansion to loads
- Wind hourly shapes: the wind hourly shapes are derived from NREL wind map data instead of wind data from PROMOD.

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

8.3 WECC

8.3.1 Assumptions

Our target was to build a system model that reflects the 20 percent RPS by the year 2020. The generation capacity based on AEO 2011 Reference Case projections for the year 2020 (EIA, 2010b). The load forecast in the database also uses very high growth assumptions. Thus, we adjusted the demand growth rate to 1.3 percent in CAMX and 0.65 percent for other areas in the system. In turn, we calculated the existing generation capacity (year 2010) and additional capacity to the year 2020 for the four WECC sub-regions after the generation adjustment.

With the base case determined above, we found that the system always has at least a 45 percent reserve margin during the entire year. A system with a 45 percent capacity margin, however, leaves little room for profit through arbitrage because energy storage will be competing with other traditional energy generation categories.

For the 2020 time horizon, it was assumed that some of the under-utilized capacity would be taking off-line for economic reasons. This would reduce the reserve margin from 45 percent to 30 percent. The affected plant units were primarily old single gas steam units and some combustion turbines. Additionally, some combined cycle units would also be decommissioned. The generation capacity after old steam natural gas units and CT are removed is shown in Table 8.1. We choose the efficiency of 75 percent for PH storage and 87 percent for the battery storage categories under consideration. The efficiency for battery storage is chosen to be higher in the arbitrage study compared with that in the previous sections (balancing services) because it is cycled at much lower rates. Simulation results for those cases are presented in the next section of this report.

Table 8.1. Existing and Additional Installed Capacity (MW) for AZNM, CAMX, NWPP, and RMPA for the Case of 30 percent Reserve Margin

	AZNM		CAMX		NWPP		RMPA	
Category	Existing (2010) [MW]	New Capacity [MW]	Existing (2010) [MW]	New Capacity [MW]	Existing (2010) [MW]	New Capacity [MW]	Existing (2010) [MW]	New Capacity [MW]
Coal	10,714	0	491	0	12,621	0	7,576	680
ST	1,597	0	12,906	50	800	0	239	0
CC	11,760	0	12,689	0	5,809	0	1,804	0
CT	2,875	0	4,613	0	1,731	0	2,034	0
Nuclear	3,875	0	4,550	0	1,146	0	0	0
Pumped Storage	216	0	3,190	0	314	0	563	0
Biomass	29	35	889	714	427	717	8	162
Geothermal	0	252	2,182	156	435	781	0	0
Hydro	2,923	0	7,635	0	23,968	0	912	0
Solar	138	1,768	322	293	0	76	10	298
Wind	394	967	2,632	4187	5,067	2,364	2,597	5,753
DG	886	0	4,801	0	900	0	400	0
Total	**35,407**	**3,022**	**56,900**	**5,399**	**53,217**	**3,937**	**16,142**	**6,894**

Simulation results reveal that there are several congested paths in the system. Several key congested paths, which experience numerous hours at their transfer limit for a month or more during the year, are shown in Figure 8.5 (red stars) and tabulated in Table 8.2. The most congested path is the interface between Utah and the Los Angeles Department of Water and Power (LADWP).

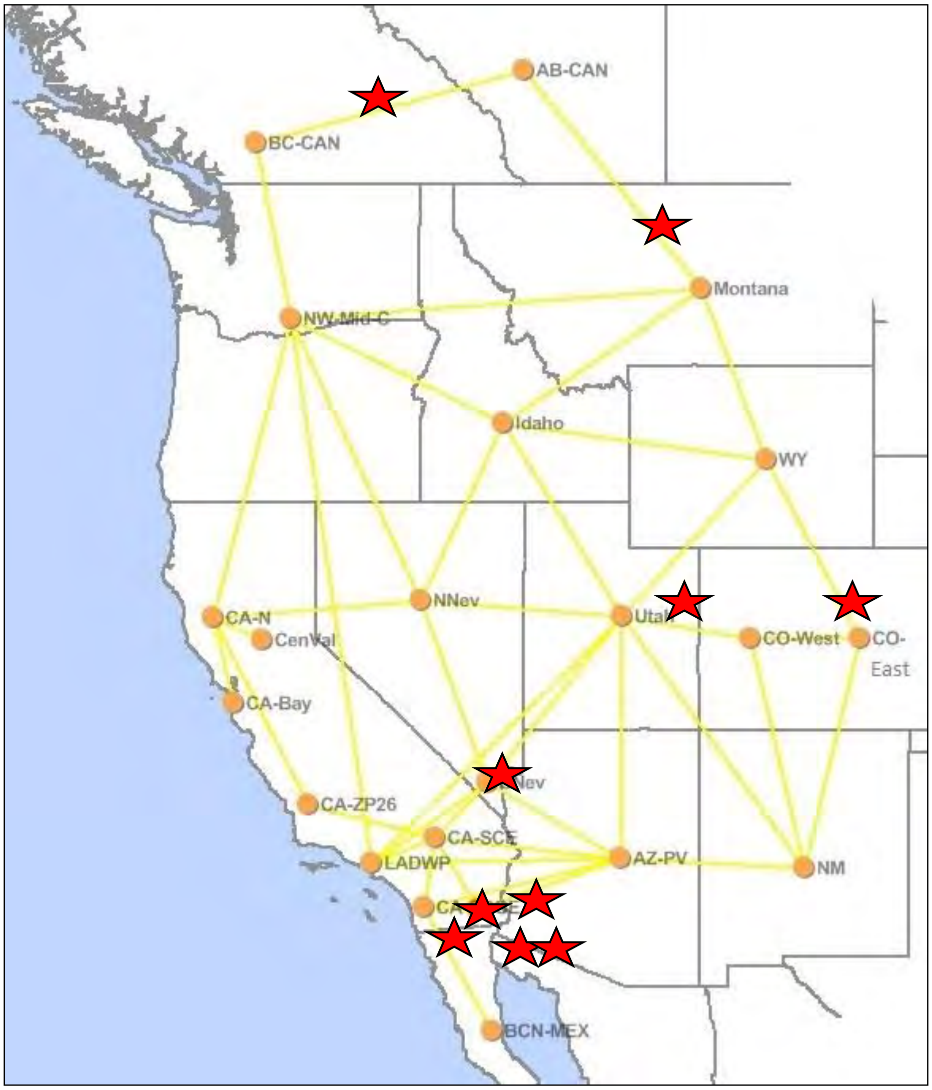


Figure 8.5. Key Congested Paths in WECC

Table 8.2. Number of Hours at 100 percent Transfer Limits

Interface	Without Storage [h]
Alberta-BC (from Alberta to BC-CAN)	2,363
Alberta-Montana (from AB-CAN to Montana)	2,600
Arizona-Southern California Edison (from AZ-PV to SCE)	4,527
Arizona-San Diego Gas &Electric (from AZ-PV to SDG&E)	4,071
Arizona-Imperial Irrigation District (from Arizona to IID)	751
Arizona-Imperial Irrigation District (from IID to AZ-PV)	1,104
Arizona-Los Angeles (Arizona to LADWP)	1,687
CO-East-Wyoming (from CO-E to WY)	906
Imperial Irrig. Distr.-SCE (from IID to SCE)	3,423
Imperial Irrig. Distr.-SDG&E (from IID to SDG&E)	3,760
UTAH-LADWP (from Utah to LADWP)	7,024
UTAH-Wyoming (From WY to Utah)	2,665

Energy storage sizes and locations are needed to determine how to mitigate those congested paths. Energy storage locations are assumed to be at the sink nodes of the paths, and sizes are determined using the assumptions outlined below.

Assume power flow on a path has n hours at its limit during the year. In this case, the average number of hours in a day that path is congested is equal to 24*n/8,784 (note that 2020 is a leap year that has 8,784 hours). To mitigate the path congestion in those hours, we propose storage with energy to supply an arbitrary fraction of 1/3 of the energy in that period, as shown in Figure 8.6. The apportioning of 1/3 of the peak energy was somewhat arbitrary, guided by the intent to reduce the congestion significantly. Hence, the storage size is (24*n/8784)*(F_{max}/3), where F_{max} is the path limit. We further assume that the storage energy (in MWh) determined as above has 10 hours of energy. The storage capacity (in MW) is therefore 1/10th of its energy. The same approach is applied to determine the size of storage required to alleviate all congested paths. The total storage size for the system is called x.

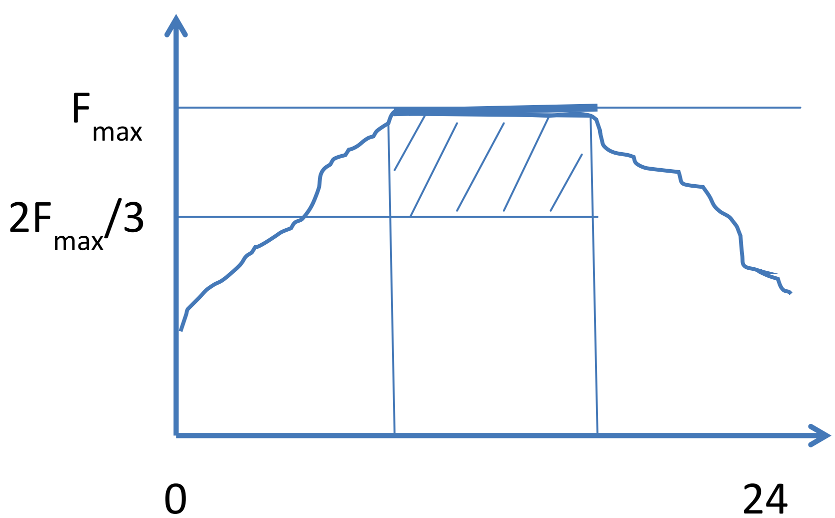


Figure 8.6. Determination of Storage Size

By applying the proposed approach, a total storage size needed is estimated as x = 48,560 MWh in which 42,710 MWh is located in CAMX and 5,850 MWh located in NWPP. We do not consider applying energy storage for the path Alberta-BC because it is in Canadian territory. To determine the optimal storage size implemented at the two regions above, storage with sizes of 0.05×, 0.1×, 0.2×, 0.25×, 0.5×, 0.75×, 1×, 1.25×, and 2× was applied. The storage size is optimal when it yields the highest system profit. The profit at each region is calculated as the difference between revenue obtained from selling energy to the system when discharging the storage and cost incurred from buying energy from the system to charge the storage.

$$Profit = \sum_{All\ hours}(G_i - L_i)LMP_i \tag{8.3}$$

where G_i is the energy generated by discharging the storage in hour i, L_i is the energy consumed by charging the storage in hour i, and LMP_i is the LMP in hour i at location where storage is installed.

The system profit is defined as the summation of profit from all regions.

8.3.2 Results

Table 8.3 presents the findings of the arbitrage analysis performed for the WECC for selected storage technologies. The revenue computed for each energy storage capacity includes the impact of the O&M costs for energy storage and a capital recovery factor built in for existing and forecast power plants. As shown, annual arbitrage revenues are estimated to range from $4.3-$99.1 million based on energy storage size, which ranges from 243-9,712 MW. Average annual revenue per MW falls from a high of $17,758 at 243 MW to $10,207 at 9,712 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, annual revenue continues to fall short for each technology under each storage size considered. Annualized costs are estimated to range from $49.3 million-$2.0 billion for pumped hydro, $110.6 million-$4.4 billion for Na-S, and $217.5.0 million-$8.7 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the WECC is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. Further, additional capacity payments are not sufficient to bridge the gap between arbitrage revenue and annual capital costs.

Detailed results for the WECC by sub-region are presented in Appendix A.

Table 8.3. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro **- WECC** ($Millions)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Only Arbitrage	Only Capacity	Pumped Hydro	Na-S	Li-Ion
243	4.3	36.4	49.3	110.6	217.5
486	8.6	72.8	98.6	221.3	435.0
971	16.7	145.7	197.1	442.6	869.9
1,214	20.5	182.1	246.4	553.2	1,087.4
2,428	37.9	364.2	492.8	1,106.4	2,174.8
3,642	52.3	546.3	739.3	1,659.7	3,262.1
4,856	66.0	728.4	985.7	2,212.9	4,349.5
6,070	75.2	910.5	1,232.1	2,766.1	5,436.9
7,284	83.5	1,092.6	1,478.5	3,319.3	6,524.3
8,498	92.0	1,274.7	1,724.9	3,872.5	7,611.7
9,712	99.1	1,456.8	1,971.3	4,425.8	8,699.0

8.4 ERCOT

The ERCOT base case with 20 percent RPS implemented will have a generation mix as shown in Table 8.4 and Table 8.5. We chose the efficiency of 87 percent for the energy storage under consideration. Simulation results for the base case are presented in the next section of this report.

Table 8.4. Existing Capacity (MW) for the ERCOT

Type	Capacity (MW)
Coal	19,039
ST	13,108
CC	31,646
CT	4,858
Nuclear	5,108
Biomass	77
Hydro	573
Solar	14
Wind	9,509
DG	1,304
DC Tie line to EIC	1,006

Table 8.5. Additional Installed Capacity (MW) for the ERCOT

Type	Capacity (MW)
PHES	352
Biomass	142
Wind	9,842

Simulation results reveal that there are two congested paths in the system. They are ERCOT-N to ERCOT-H and ERCOT-W to ERCOT-S, and the most congested path is the interface between ERCOT-N to ERCOT-H. The congested paths, which experience numerous hours at their transfer limit for a month or more during the year, are shown in Figure 8.7 (shown with red stars) and tabulated in Table 8.6. The storage install locations are proposed at ERCOT-H and ERCOT-S.

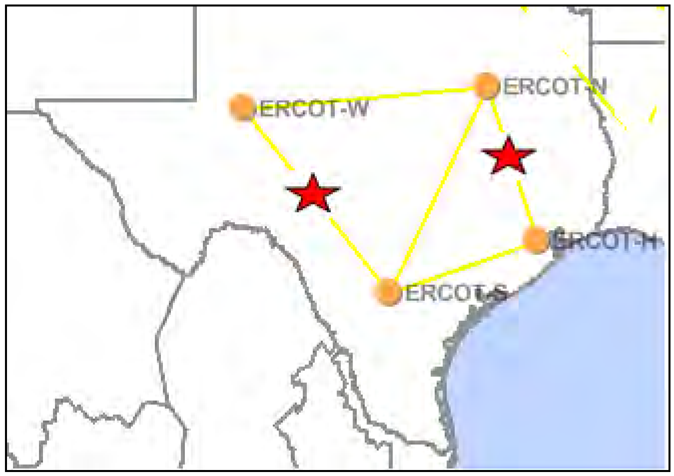


Figure 8.7. Transmission Path Across 4 Regions in Texas. (Congested paths are marked with red star)

Table 8.6. Number of Hours at 100 percent Transfer Limits

Interfaces	Hours at limit
ERCOT-N to ERCOT-H	2795
ERCOT-W to ERCOT-S	2116

Energy storage sizes and locations are needed to determine how to mitigate those congested paths. Energy storage locations are assumed to be at the sink node of the paths, and sizes are determined using the assumptions outlined in the previous section for the WECC.

8.4.1 Results

Using the approach outlined in the previous section, simulations were carried out for different energy storage sizes in the two studied regions of the ERCOT. The revenue computed for each energy storage capacity includes the impact of the O&M costs for energy storage and a capital recovery factor built in for existing and forecast power plants. The results of each simulation are presented in Table 8.7 and Figure 8.8. Revenues for the entire ERCOT grow from $84.7 million annually at 13463 MW of installed capacity to $2.79 billion at 53,840 MW.

Table 8.7. Annual Arbitrage Revenues by Energy Storage Capacity ($Thousands)

Size (MW)	Revenue (k$)
70.4	8,086
140.7	16,200
281.4	32,301
351.8	40,290
703.5	79,805
1055.3	118,468
1407.0	156,842
1758.8	193,287
2110.5	226,942
2462.3	259,957
2814.0	284,250

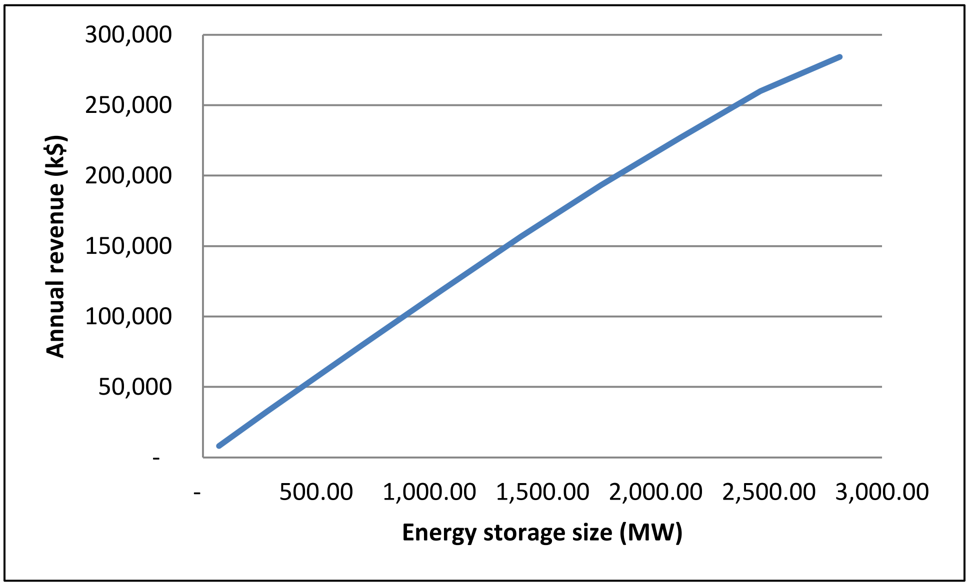


Figure 8.8. Revenue per year for Texas

Table 8.8 presents the findings of the arbitrage analysis performed for the ERCOT. As shown, annual arbitrage revenues are estimated to range from $8.1-$284.3 million based on energy storage size, which ranges from 70-2,814 MW. Average annual revenue per MW falls from a high of $114,943 at 70 MW to $101,013 at 2,814 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at all energy storage capacities. Annual profits are $4.4 million at 70 MW and $135.2 million at 2,814 MW of capacity. Annualized costs are estimated to range from $14.3-$571.2 million for pumped hydro, $32.1 million-$1.3 billion for Na-S, and $63.0 million-$2.5 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the ERCOT is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity payment is added to the analysis, the gap between arbitrage revenue and annual capital costs is closed but only for the PH case.

It should be pointed out that the revenue expectations for ERCOT are about 10 times those for the WECC. This is primarily determined by there being less generation in ERCOT compared to the WECC and a lesser degree of freedom to dispatch this supply optimally.

Table 8.8. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro – ERCOT (2020 dollars in Millions)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Only Arbitrage	Only Capacity	Pumped Hydro	Na-S	Li-Ion
70	8.1	10.6	14.3	32.1	63.0
141	16.2	21.1	28.6	64.1	126.0
281	32.3	42.2	57.1	128.2	252.0
352	40.3	52.8	71.4	160.3	315.1
704	79.8	105.5	142.8	320.6	630.1
1,055	118.5	158.3	214.2	480.9	945.2
1,407	156.8	211.1	285.6	641.2	1,260.2
1,759	193.3	263.8	357.0	801.5	1,575.3
2,111	226.9	316.6	428.4	961.8	1,890.4
2,462	260.0	369.3	499.8	1,122.0	2,205.4
2,814	284.3	422.1	571.2	1,282.3	2,520.5

8.5 EIC

Our target was to build a system model that reflects the 20 percent RPS by the year 2020. Because the database was built with some generation and expansion assumptions, we modified it by having generation capacity match AEO 2011 growth projections through the year 2020. The adjusted demand growth rate was 0.65 percent per year for the entire system. The generation capacity by type and regions were adjusted to agree with the AEO 2011 projections for the 2020 time horizon.

With the case determined as described above, we found that the existing transfer paths are not adequate to transfer power between sub-regions. Therefore, we upgraded the existing transfer paths using the approach as follows.

First, we assume all transfer paths have unlimited capacity by relaxing all path limits. Second, a simulation is carried out to determine the flow on each transfer path. Because the transfer path system has no limit, power is free to flow on any path. This results in a significant increase in flows for some paths while in other paths flows decrease. Next, the maximum flow for each individual transfer path during the whole year of simulation is determined. The transfer limits are unchanged for paths that have the maximum flow lower than their original limits. For paths whose maximum flow exceeds the original transfer limit, transmission reinforcements is necessary to meet load. Finally, we need to determine how much to increase the limits for those paths. The criteria that we used to determine the limits are:

- If the maximum path flow is greater than 20,000 MW, the initial new limit for that path is set to 35 percent of the maximum path flow
- If the maximum path flow is less than or equal to 20,000 MW, the initial new limit for that path is set to 25 percent of the maximum path flow

- If the initial new limit for a path is greater than its original limit, the final new limit is set to equal the initial new limit, otherwise, the final new limit is set to equal the original limit.

With these criteria applied, the path limit changes for the most impacted paths are shown in Table 8.9 and Figure 8.9. With these path limit increases, along with the 20 percent RPS implemented for the EIC, it is found that the model produces reasonable results in term of congestion when delivering power from areas with high renewable energy resources (such as the western region within the EIC) to high demand areas (such as the East Coast, especially New York).

Table 8.9. Existing and New Path Limits

Path	Fwd Limit (MW)	Back Limit (MW)	New Limit (MW)
Entergy to SPP - KSMO	3	11	15200
MISO - Minnesota to IESO (Ontario)	90	140	10000
MISO - Gateway to Entergy	33	25	1400
MISO - North Dakota to MISO - Manitoba	55	107	4000
MISO - WI-UPMI to MISO - Michigan	114	143	4700
NY-CDE (Cent North) to IESO (Ontario)	300	300	8200
MISO - Indiana to MISO - Michigan	294	294	7600
NE - West to NY-CDE (Cent North)	0	150	3500
PJM - AEP to PJM - South	322	516	11100
NE - West to Quebec	170	225	4300
MISO - Gateway to PJM - AEP	642	642	11500
PJM - APS to PJM MidAtlantic - East PA	176	176	3100
MISO - Gateway to MISO - Indiana	465	374	7900
TVA to Associated Electric	162	160	2500
MISO - Gateway to SPP - Central	209	209	3200
MISO - Manitoba to IESO (Ontario)	343	300	4000
NE - West to NY-K (Long Island)	330	330	3700
Associated Electric to Dakotas	222	222	2300
PJM - AEP to PJM - COMED	1724	1725	11800
SPP - Nebraska to SPP - KSMO	2075	1893	10600
Entergy to Southeastern	3050	2949	15500
NY-J (NY City) to NY-K (Long Island)	175	484	2300
FirstEnergy ATSI to PJM - APS	527	744	3500
IESO (Ontario) to MISO - Michigan	2260	1450	8900
TVA to Southeastern	2854	3741	13300
MISO - Gateway to TVA	4533	1177	14700
Florida to Southeastern	2100	3700	11800
PJM - APS to PJM MidAtlantic - SW	2592	2697	8400
NE - West to NY-GHI (Southeast)	600	800	2400
PJM - AEP to Carolinas	738	1181	3300
PJM MidAtlantic - E to PJM MidAtlantic - SW	2875	2875	7700
NY-CDE (Cent North) to PJM MidAtlantic - East PA	300	200	800
IESO (Ontario) to Quebec	2035	2795	7400
NY-K (Long Island) to PJM MidAtlantic - E	660	660	1700
NY-CDE (Cent North) to PJM MidAtlantic - West PA	200	800	2000
NY-CDE (Cent North) to NY-GHI (Southeast)	1700	1600	4100
NE - SWCT to NY-K (Long Island)	430	430	1000
Dakotas to Saskatchewan	165	215	500
MISO - Michigan to PJM - AEP	3337	2014	7600
PJM MidAtlantic - SW to PJM - South	2060	4046	9200

Path	Fwd Limit (MW)	Back Limit (MW)	New Limit (MW)
MISO - Iowa to SPP - Nebraska	1688	994	3700
MISO - Gateway to MISO - Iowa	4272	5254	11500
Entergy to SPP - Louisiana	226	232	500
NY-CDE (Cent North) to Quebec	1200	1500	3000

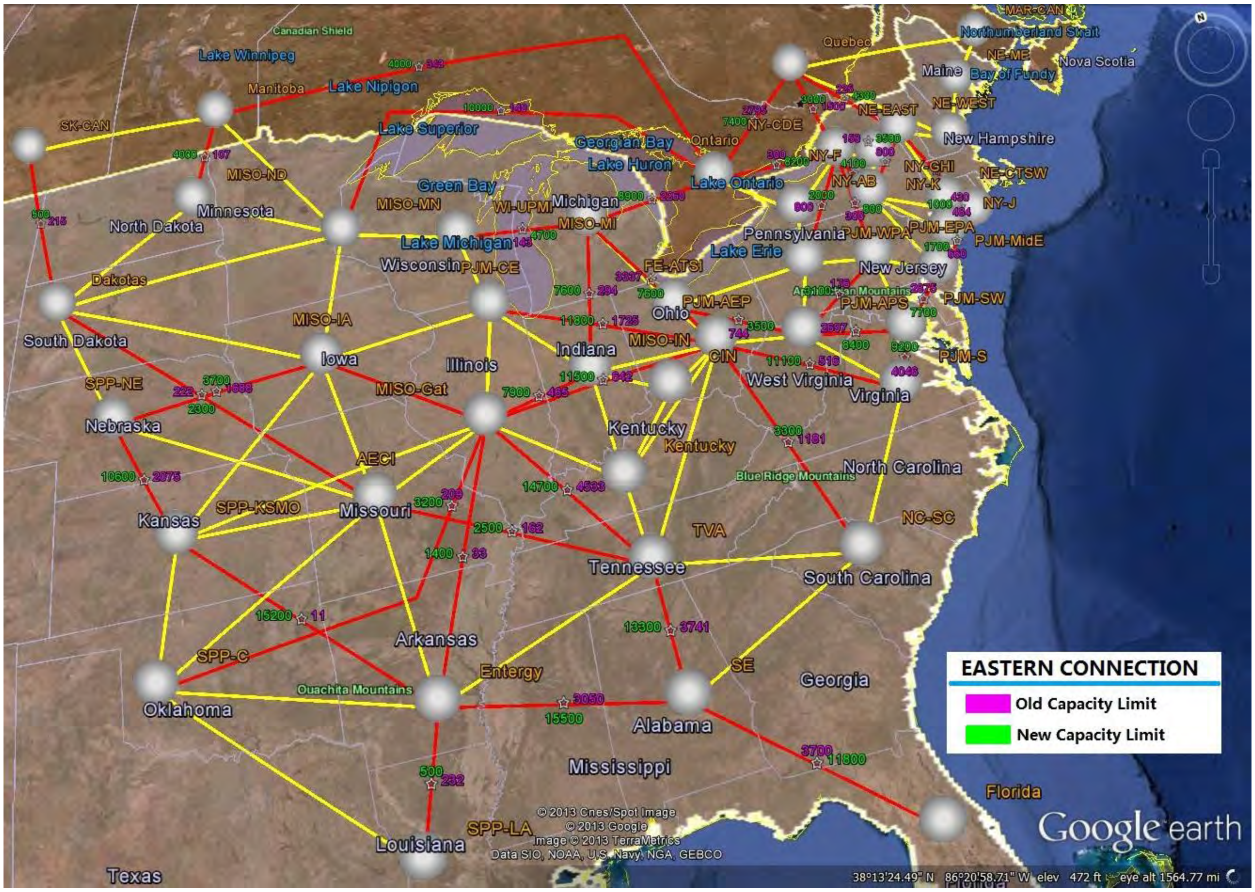


Figure 8.9.a EIC Path Flow Changes to Accommodate 20 percent RPS Provided primarily by Wind Energy

The final base case with new transfer limits and 20 percent RPS implemented would have a generation mix as shown in Table 8.10 and Table 8.11. We chose an efficiency of 87 percent to be representative for a generic energy storage system under consideration. Simulation results for the base case are presented in the next section of this report.

Table 8.10. Existing Installed Capacity (MW) for 17 Sub-Regions of the EIC

Region	Coal	ST	CC	CT	Nuclear	PS	Biomass	Hydro	Solar	Wind
FRCC	8,703	8,684	23,534	11,607	4,579		614	56	40	
MROE	8,969	100	1,925	3,234	1,175		45	2,709		1,015
MROW	19,341	483	4,868	8,807	4,557		433	736		7,809
NEWE	2,525	5,989	13,002	2,010	4,674	1,680	896	1,735		272
NYCW	62	4,341	2,633	1,864	343		10	17		
NYLI		2,730	787	2,212			121			
NYUP	2,310	3,626	6,063	335	5,107	1,413	224	4,697		1,357
RFCE	28,580	6,226	13,627	13,486	14,625	1,993	776	1,637	20	811
RFCM	9,865	2,366	4,906	3,551	1,944	1,979	231	137		159
RFCW	62,587	121	8,841	21,348	15,974	247	259	1,018	22	3,870
SRDA	8,637	13,126	13,998	3,003	5,437	59	21	761		107
SRGW	15,338	318	1,131	5,031	2,283	1,219	4	398		101
SRSE	24,396	281	15,819	13,622	5,771	1,675	86	4,545		
SRCE	15,505		5,291	6,704	7,342	1,825	1	5,432		29
SRVC	23,088	1,954	7,836	14,141	15,378	5,543	435	2,580	20	302
SPNO	8,532	1,348	1,412	4,639	1,184		4	16		1,479
SPSO	12,904	9,153	10,044	3,507		474	8	2,056		2,188
Total EIC	251,342	60,846	135,717	119,101	90,373	18,107	4,168	28,530	102	19,499

Table 8.11. Additional Installed Capacity (MW) for 17 Sub-Regions of the EIC

Region	PS	Biomass	Hydro	Solar	Wind
FRCC		152		175	
MROE		236			330
MROW	1,916	213	10		38,654
NEWE	5,742	235		14	7,204
NYCW		3,088			329
NYLI		94			2,480
NYUP	2,478	455			7,470
RFCE		992	32	1,489	11,002
RFCM		498			2,980
RFCW	492	1,622	56	242	23,244
SRDA	12,570	700			194
SRGW		739	10		14,621
SRSE	8,278	50			
SRCE		2	177		169
SRVC	12,548	1,402	4	13	4,170
SPNO		31			26,286
SPSO		367		8	18,758
Total EIC	44,024	10,724	289	1,766	157,891

Simulation results reveal that there are several congested paths in the system. The most congested path is the interface between the Carolinas to PJM-South. Several key congested paths, which experience numerous hours at their transfer limit for a month or more during the year, are shown in Figure 8.10 (shown with red stars) and tabulated in Table 8.12.

Figure 8.10. Key Congested Paths in EIC Indicated by Red Stars

Table 8.12. Number of Hours at 100 percent Transfer Limits

Interfaces	Hours at limit
Carolinas to PJM - South	5793
MISO - Indiana to Cincinnati	5148
PJM - AEP to PJM - South	5144
NY-CDE (Cent North) to NY-GHI (Southeast)	4550
NE - East to NE - West	4232
NE - West to NY-CDE (Cent North)	4112
Entergy to SPP - KSMO	4047
Entergy to SPP - Central	3984
NY-GHI (Southeast) to NY-J (NY City)	3738
Entergy to Southeastern	3351
PJM - AEP to Carolinas	3271
NE - East to Quebec	3097
Maritimes to Quebec	3025
MISO - Minnesota to MISO - North Dakota	2933
TVA to Carolinas	2278

Interfaces	Hours at limit
NE - West to Quebec	1912
PJM MidAtlantic - East PA to PJM MidAtlantic - West PA	1895
Associated Electric to Dakotas	1759
MISO - Iowa to SPP - KSMO	1608
NE - SWCT to NY-K (Long Island)	1542
NY-J (NY City) to NY-K (Long Island)	1541
NE - West to NY-F (Capital)	1505
MISO - Iowa to SPP - Nebraska	1486
Associated Electric to Entergy	1210
NY-J (NY City) to PJM MidAtlantic - E	1201
NY-CDE (Cent North) to Quebec	1137
Dakotas to SPP - Nebraska	1107
Dakotas to MISO - North Dakota	1078
MISO - Gateway to SPP - Central	1027
MISO - Gateway to Entergy	1024
Entergy to SPP - Louisiana	1021

Energy storage sizes and locations are needed to determine how to mitigate those congested paths. Energy storage locations are assumed to be at the sink nodes of the paths, and sizes are determined using the assumptions outlined in the previous section for the WECC.

8.5.1 Comparison to NREL's Eastern Wind Integration and Transmission Study (EWITS)

Because of the large transmission expansion requirements needed to integrate about 160 GW of wind deployment by 2020, we compared the results of this study with that of NREL's Eastern Wind Integration and Transmission Study (EWITS), scenario 1 (NREL 2011). This comparison is more qualitative in nature than quantitative for the following reasons: first, the zonal disaggregation of the production cost model (PROMOD) that NREL used was based on a higher level of aggregation (23 zones for the EIC) while this study used a zonal disaggregation of 44 zones. Thus, the transfer paths do not map cleanly from one system to the other. Second, both studies use the difference in path flows between the existing transfer limits and the unconstrained transmission capability to determine the necessary capacity increases for the appropriate paths. However, in this study, the transfer expansion was based on an adjusted maximum path flows of a few selected paths as opposed to establishing an average transmission reinforcement of a larger set of transfer paths as was performed in EWITS. The approach applied in this study yielded improved results with a fewer number of transfer reinforcements, however, at larger incremental transfer expansions.

Despite some of the differences in the zonal topology and the sizing evaluation, there exists a similar pattern for the transmission expansion and the associated power flows. In both studies, power transfers are from highly concentrated wind energy sources in the upper and central Midwest to load centers in the East. Significant transmission expansion must be deployed to facilitate these power transfers. In this study, the highly concentrated wind energy regions are the SPP and MISO. It is found that the transfer path system needs to be upgraded to adequately transfer wind energy to load centers in the East Coast and

Florida as shown in Figure 8.9. This finding is similar to the results from the EWITS. The heavy capacity increase in paths connecting SPP to Entergy, SE, and TVA agrees well with the EWITS. The heavy capacity increase in paths connecting the MISO to NYISO through PJM and IESO is also consistent with results from the EWITS. Qualitatively, the approach used in this study agrees, in general, with what was found in the EWITS in which paths need to be upgraded to transfer wind energy from highly concentrated wind regions (MISO and SPP) to load centers in other regions such as NYISO and FRCC.

Because of the fact that both EWITS and this study were performed using a zonal not nodal approach, the actual investment in the transmission overlay or transmission upgrades are difficult to estimate. The transfer capability is a measure of transfer from zone to zone and does not correlate with geographic distance. However, the investment needed to transfer electric energy from windy areas of the Midwest to eastern load centers will be significant. In this study, the capital cost of the transmission overlay that enables an wind power addition of about 160 GW is not considered in this study.

8.5.2 EIC Results

Using the approach outlined in the previous section, simulations were carried out for different energy storage sizes located in specific regions of the EIC. Only regions were considered that mitigated congestion along zonal transfers as shown in Figure 8.10. Storage was then placed on the destination side of the congested path. The profit computed for each energy storage system included the impact of its O&M costs and a recovery factor for its capital costs. Simulation results are presented for each region in Figure 8.11. The profit trajectories for growing energy storage capacity indicate an expected behavior. Profits grow up to a point, after which diminishing marginal revenues fall short of the marginal costs of adding more storage. That is, the most congested areas with the highest LMP differentials are targeted first and as energy storage expands into less congested areas with lower LMP differentials, profits fall and in some cases are eliminated entirely.

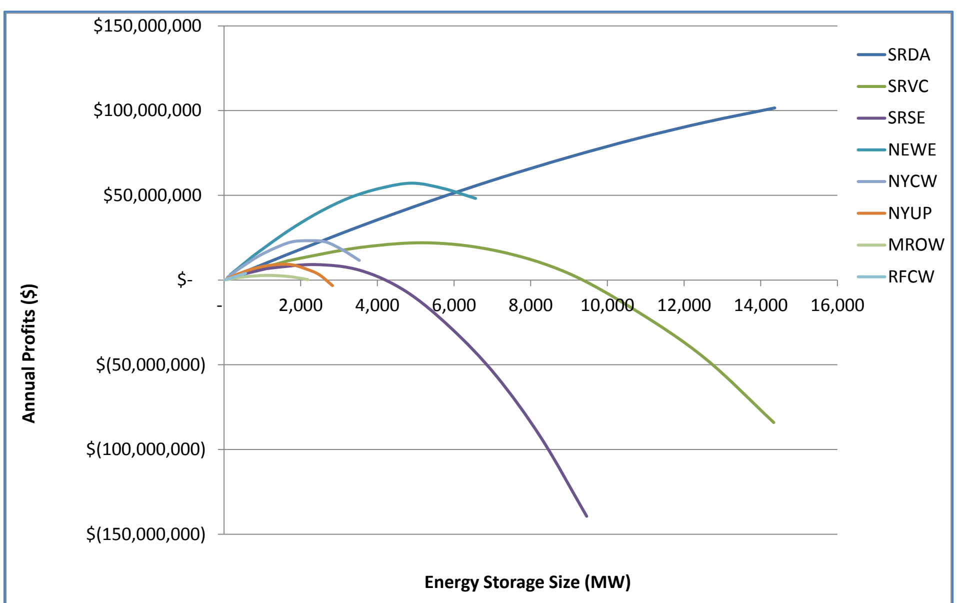


Figure 8.11. Arbitrage Profits per Year for EIC Zones

Table 8.13 presents the findings of the arbitrage analysis performed for the EIC. As shown, annual arbitrage revenues are estimated to range from $84.7 million-$2.8 billion based on energy storage size, which ranges from 1,346-53,840 MW. Average annual revenue per MW falls from a high of $62,936 at 1,346 MW to $51,844 at 53,840 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at energy storage capacities up to 47,110 MW. Annual profits range from $13.4 million at 1,346 MW to $155.7 million at 26,290 MW of capacity. Annualized costs are estimated to range from $273.2 million-$10.9 billion for pumped hydro, $613.4 million-$24.5 billion for Na-S, and $1.2 billion-$48.2 billion for Li-ion. These results support the conclusion that, at a 30 percent reserve margin, the EIC is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is bridged but only for pumped hydro storage. Positive net revenues could be realized up to 47,110 MW of energy capacity in the EIC; however, when energy storage capacities are set to profit maximizing points for each EIC sub-region, the EIC supports investment in 32,308 MW of pumped hydro investment for the provision of arbitrage and capacity reserve services.

Detailed results for the EIC by sub-region are presented in Appendix A.

Table 8.13. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro – EIC in 2020 (in Millions 2011 Dollars)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Only Arbitrage	Only Capacity	Pumped Hydro	Na-S	Li-Ion
1,346	84.7	201.9	273.2	613.4	1,205.6
2,692	169.0	403.8	546.4	1,226.7	2,411.2
5,384	336.5	807.6	1,092.8	2,453.5	4,822.4
6,730	419.5	1,009.5	1,366.1	3,066.9	6,028.1
13,460	825.3	2,019.0	2,732.1	6,133.7	12,056.1
20,190	1,214.8	3,028.5	4,098.2	9,200.6	18,084.2
26,920	1,582.0	4,038.0	5,464.2	12,267.4	24,112.2
33,650	1,922.9	5,047.5	6,830.3	15,334.3	30,140.3
40,380	2,239.8	6,057.0	8,196.3	18,401.2	36,168.4
47,110	2,529.5	7,066.5	9,562.4	21,468.0	42,196.4
53,840	2,791.3	8,076.0	10,928.4	24,534.9	48,224.5

8.6 Arbitrage Results for Total US

Using the approach outlined in the previous section, simulations were carried out for different energy storage sizes for the NWPP and CAMX in the WECC; the ERCOT; and the MROW, NEWE, NYCW, NYUP, RFCW, SRDA, SRSE, and SRVC sub-regions of the EIC. The results of these simulations, aggregated for the entire U.S., are presented in Table 8.14. Detailed results by sub-region are presented in Appendix A. The revenue computed for each energy storage capacity includes the impact of the O&M costs for energy storage and a capital recovery factor built in for existing and forecast power plants. As shown, arbitrage revenues for all regions examined in this assessment grow from $97.1 million annually at 1,659 MW of installed capacity to $3.2 billion at 66,366 MW. Of the 33,183 MW of installed energy storage in the 1× scenario, 4,856 MW (14.6 percent) is installed in the WECC, 1,407 MW (4.2 percent) in the ERCOT, and 26,920 MW (81.1 percent) is installed in the EIC.

Table 8.14. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro - U.S. Totals in 2020 (in Millions 2011 Dollars)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Only Arbitrage	Only Capacity	Pumped Hydro	Na-S	Li-Ion
1,659	97.1	248.9	336.8	756.1	1,486.1
3,318	193.8	497.7	673.5	1,512.1	2,972.2
6,637	385.5	995.5	1,347.1	3,024.3	5,944.4
8,296	480.4	1,244.4	1,683.9	3,780.4	7,430.5
16,592	943.0	2,488.7	3,367.7	7,560.7	14,861.0
24,887	1,385.6	3,733.1	5,051.6	11,341.1	22,291.5
33,183	1,804.8	4,977.5	6,735.5	15,121.5	29,722.0
41,479	2,191.4	6,221.8	8,419.4	18,901.9	37,152.5
49,775	2,550.2	7,466.2	10,103.2	22,682.2	44,583.0
58,070	2,881.4	8,710.5	11,787.1	26,462.6	52,013.5
66,366	3,174.7	9,954.9	13,471.0	30,243.0	59,444.0

While annual arbitrage revenue climbs as the capacity of energy storage increases, it does so at a declining rate. Table 8.17 and Figure 8.12 compare average and marginal revenue per MW per year for each of the energy storage capacities considered in this arbitrage analysis. Average revenue per MW is calculated by dividing total revenues obtained for a specific scenario by the corresponding storage size. Marginal revenue per MW is calculated by dividing the marginal revenues obtained by upsizing the storage capacity by the additional capacity added in the scenario. At 1,659 MW of energy storage, annual revenues are estimated at $97.1 million or $58.5 thousand per MW. At 66,366 MW of energy storage, annual revenues are estimated to grow to $3.2 billion but average and marginal revenue per MW falls to $47.8 thousand and $35.4 thousand, respectively. Note that the marginal revenue curve presented in Figure 8.12 is consistent the theoretical curve presented in Figure 8.1(b).

Table 8.15. Average and Marginal Arbitrage Revenues in U.S. (per MW per year)

Energy Storage Size (MW)	Average Revenue per MW per Year	Marginal Revenue per MW per Year
1,659	58,530	58,530
3,318	58,400	58,270
6,637	58,081	57,762
8,296	57,904	57,196
16,592	56,836	55,768
24,887	55,676	53,355
33,183	54,389	50,531
41,479	52,832	46,602
49,775	51,236	43,256
58,070	49,619	39,915
66,366	47,836	35,355

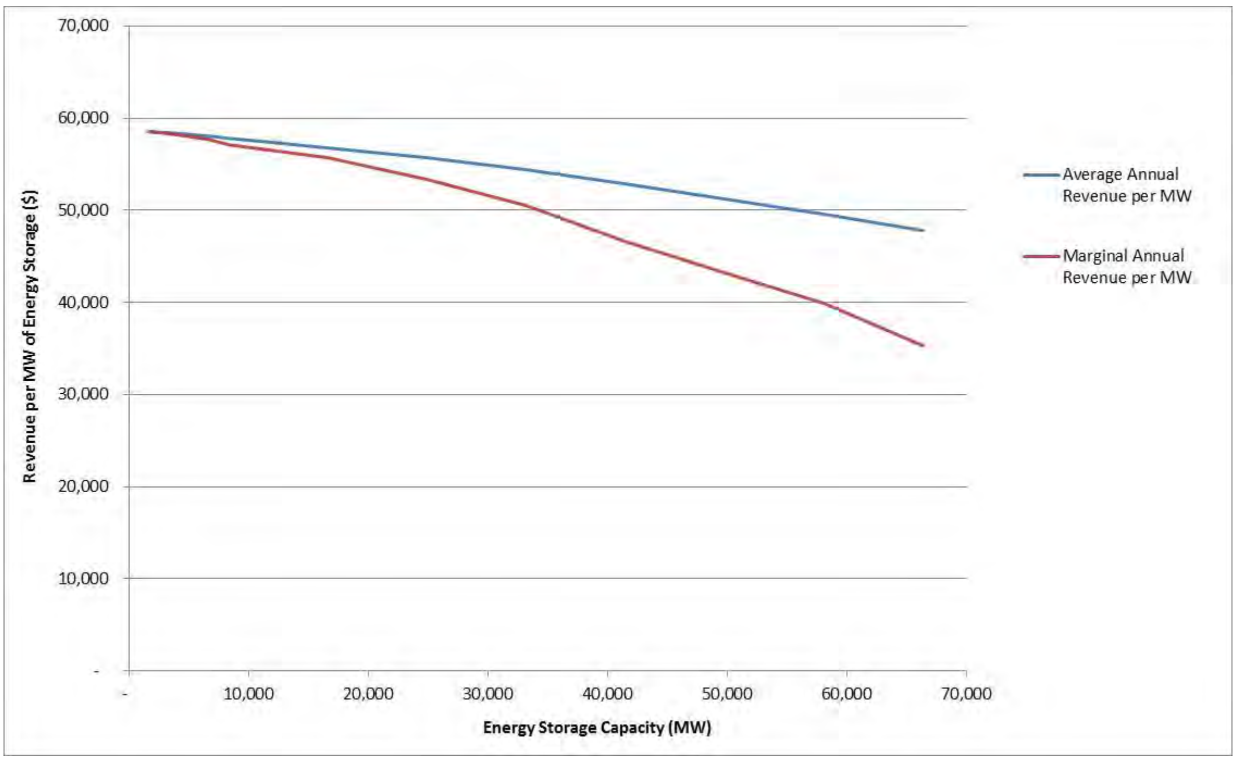


Figure 8.12. Average and Marginal Arbitrage Revenues per MW per Year

Adding a capacity value of $150/kW-year expands the values derived from energy storage significantly. For example, annual revenues generated by 33,183 MW of storage would expand from $1.8 billion to $6.8 billion. Annual revenues for 66,366 MW of energy storage would increase from $3.2 billion to $13.1 billion. Total revenue estimates demonstrate linearity as storage sizes expand because the vast majority of the revenues would be derived from capacity values, as opposed to arbitrage, which are measured in fixed terms ($/kW-year). Thus, as the energy storage devices are scaled up, revenues grow largely proportionally when both capacity values and arbitrage service values are considered together.

To determine the profitability of Na-S, Li-ion, and PH storage, the capital cost values presented in Table 3.2 in Volume 2 were applied to the power (MW) and energy requirements (MWh) established for each increment of energy storage capacity considered for the WECC, ERCOT, and EI. The energy to power ratio used in this assessment is 10.0. Thus, 1,659 MW of energy storage would have a corresponding energy capacity of 16,590 MWh. For PH storage, capital costs are estimated at $1,890 per MW and $10 per MWh. Na-S capital costs are estimated at $290 per MWh and $200 per MW for BOP and PCS costs. Li-ion capital costs are estimated at $510 per MWh and $200 per MW for BOP and PCS costs.

While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each storage size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at energy storage capacities up to 35,122 MW. When set to profit maximizing points in each sub-region, the results indicate that pumped hydro used to provide arbitrage and capacity services could generate $364.1 million in profits at 35,122 of installed capacity.

Table 8.16 presents the capacities and profit levels at which profits are maximized for PHES storage when both arbitrage and capacity reserve revenues are considered. As noted previously, no profits are realized in the WECC. ERCOT generates $135.2 million in annual profits at a capacity of 2,814 MW. An additional $228.9 million in annual profits are estimated for the EIC at 32,308 MW of installed capacity. In total, the results indicate that 35,122 MW of PHES could be installed profitably across the US when employed for arbitrage and capacity services, generating annual profits of $364.1 million.

Table 8.16. Pumped Hydro Capacity and Profit at Profit Maximizing Levels by Region

Region	Energy Storage Capacity at Profit Maximizing Point (MW)	Annualized Arbitrage and Capacity Reserve Profits ($)
NWPP	--	--
CAMX	--	--
ERCOT[13]	2,814	135,164,000
MROW	1,095	2,773,000
NEWE	4,922	57,176,000
NYCW	2,206	23,214,000
NYUP	1,415	9,204,000
RFCW[13]	562	3,948,000
SRDA[13]	14,366	101,566,000
SRSE	2,365	9,133,000
SRVC	5,378	21,932,000
Total	35,122	364,110,000

While the findings of this analysis suggest that profits from energy arbitrage and capacity value are in most cases insufficient to achieve capital cost recovery, it is important to note that there are several other services that could be supplied by energy storage technologies that were not included in this assessment.

[13] The ERCOT region and RFCW and SRDA sub-regions represent areas where profits were reached at maximum investment levels modeled. Thus, additional profits could potentially be achieved through more investment.

These services include load following, transmission and distribution upgrade deferral, power quality enhancements, and electricity service reliability. Thus, revenues from the energy storage technologies are not fully realized as a result of the limited focus of this analysis. Additional research is, therefore, necessary to examine the full revenue potential of energy storage used in electric utility applications.

8.6.1 Differences across Interconnections

The results were found to vary significantly by region. In the WECC, the annual arbitrage value ranged from a high of $17/kW to a low of $10/kW. In the ERCOT, the annual arbitrage range is $111/kW down to about $100/kW. Thus, annual arbitrage revenue per kW was estimated to be roughly 6-10 times higher in the ERCOT relative to the WECC, depending on the level of energy storage deployed. The energy storage revenue estimates for arbitrage in the EIC on a per kW bases are between $52 and $63/kW

Table 8.17. Arbitrage revenue expectations without capacity value

Arbitrage revenues $/kW	WECC	ERCOT	EIC
high	17	111	63
low	10	101	52

8.6.2 Final Observations on Arbitrage Results

The arbitrage analysis was performed using a production cost model with a zonal representation of the WECC, ERCOT, EIC. The zonal representation of a load zone assumes no congestion within the zone. In this analysis, congestion can only occur between zones by reaching inter-zonal transfer limits. It is likely that if a nodal representation of the transmission system were used that represents all major transmission lines with voltage ratings of 139 kV lines and above, more small niche markets of high congestions would have been identified. This would tend to raise the economic viability of energy arbitrage, however, the total market size (size of the storage to mitigate congestion) would most likely still be small.

9.0 Summary and Conclusions

This *National Assessment for Grid-Connected Energy Storage* estimated the total and additional or incremental balancing requirements for 22 NERC sub-regions for a projected 2020 grid scenario with a total of 223 GW of wind capacity to meet a hypothetical RPS requirements of 20 percent across 3 U.S. interconnections. The total balancing requirements were defined as the flexible grid assets necessary to accommodate all of the entire variability associated with renewable generation and load variabilities for a 2020 grid scenario. The additional balancing requirements define grid assets necessary to accommodate the additional variability in load growth and the presumed 180 GW of wind capacity additions in the WECC between 2011 and 2020. This study focused primarily on intra-hour balancing requirements, which are variations that oscillate within the hour.

9.1 Intra-Hour Balancing Requirements for 2020

Each sub-region was assumed to be a consolidated balancing area. The balancing-up requirement)[1] are presented in Table 9.1. for both the total and intra-hour requirements.

Table 9.1. Total and Intra-Hour Balancing Requirements for every NERC Region in WECC in 2020

	Additional Balancing Power Required (MW)	Total Balancing Power Required (MW)	Total Balancing Power Required as a Percentage of Peak Load (%)	Marginal Balancing Power Required as a Percentage Wind Capacity (%)	Existing Wind Capacity (MW)	Additional Wind Capacity (MW)	Total Wind Capacity in 2020 (MW)
AZNM	210	1,220	4	22	390	970	1,360
CAMX	530	2,400	4	13	2,430	4,110	6,540
NWPP	280	2,020	3	7	5,560	4,200	9,760
RMPA	510	670	5	10	1,170	5,160	6,330
Total WECC	**1,530**	**6,310**			**9,550**	**14,440**	**23,990**
MROE	20	490	5	13		150	150
MROW	2,750	4,340	6	8	4,470	34,760	39,230
NEWE	610	1,370	5	8	2,900	7,190	10,080
NYLI	420	540	9	17		2,480	2,480
NYUP	840	1,440	9	10	2,530	8,380	10,910
RFCE	880	2,530	4	9	980	10,310	11,290
RFCM	340	600	4	11		2,980	2,980
RFCW	2,280	3,830	4	14	2,470	16,320	18,780
SPNO	2,340	2,760	17	11	2,040	20,820	22,850
SPSO	2,090	2,540	9	11	2,290	18,350	20,640
SRCE	60	1,090	3	36	180	170	340
SRDA	40	830	3	18		220	220
SRGW	2,890	3,290	56	11	4,390	26,670	31,060
SRVC	360	1,780	3	9	210	4,160	4,370
Total EIC	**15,920**	**27,430**			**22,460**	**152,960**	**175,380**
ERCOT	1,120	3,930	5	9	10,950	12,860	23,810
Total US	**18,570**	**37,670**			**42,960**	**180,260**	**223,180**

[1] These estimates are based on BPA's customary 99.5% probability bound.

With the exception of the SRGW and SPNO regions, this study indicates that the future <u>total</u> intra-hour balancing requirements to address both load and renewable variability are expected to range generally between 3 percent and 9 percent of the <u>peak load</u> in a given region. In the regions SRGW and SPNO, where the native load is relatively small compared to the hypothetically placed new wind capacity, the percentage of balance requirements compared to peak load could be as high as 56 percent. Furthermore, on the margin for every additional unit of wind capacity power, approximately 0.07 to 0.36 units of intra-hour balancing need to be added.

These values most likely under-estimate the size of the balancing market and the additional generation or storage power needed. This may result from the simplifying assumption made in the analysis that the current individual BAs are consolidated to one single, large balancing area within each sub-region. This consolidating assumption embeds the possible advantages of load and renewable generation diversities within sub-regions.

9.2 Market Size for Energy Storage for Balancing Services

The *assessment* estimated the size requirements for energy storage capacity to meet the total and additional intra-hour balancing requirements as shown in Figure 9.1 for the three interconnections.

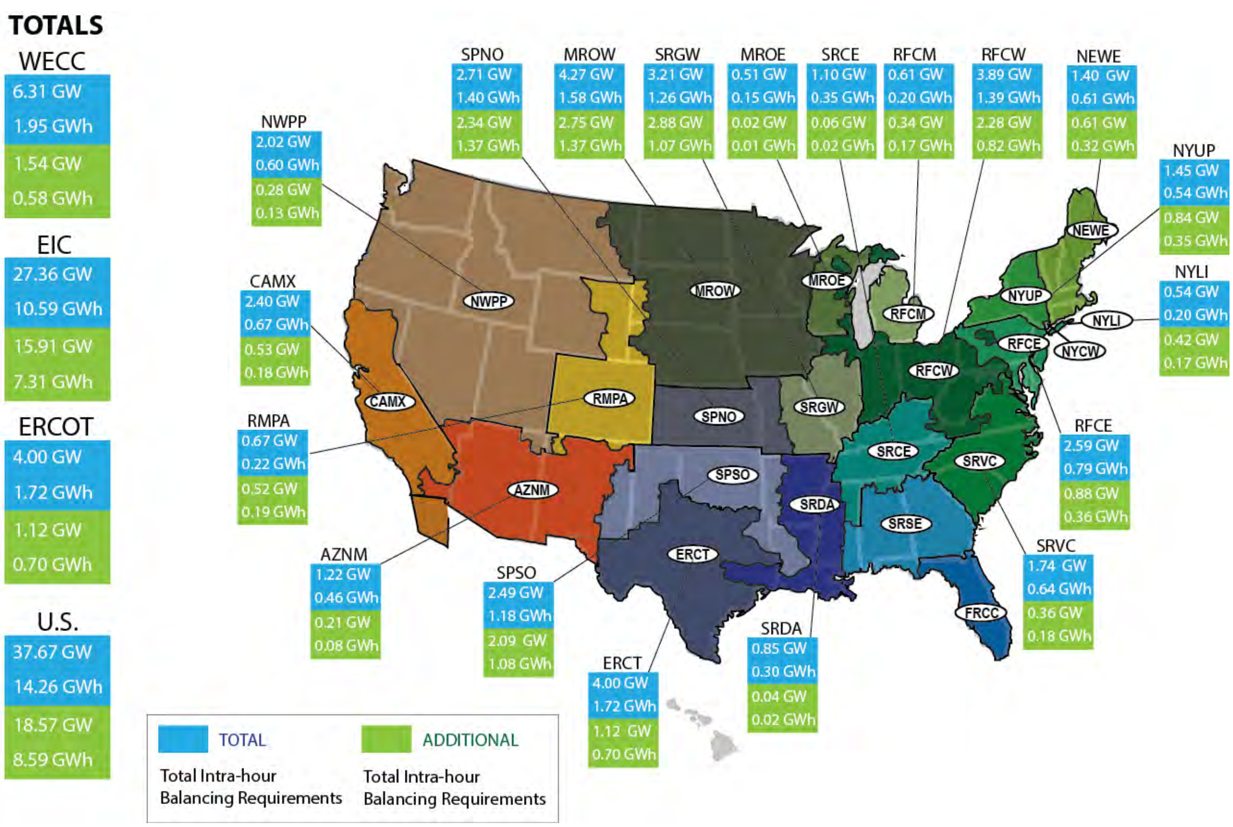


Figure 9.1. Market Size Estimates for Storage Technologies Necessary to Meet the Total and Additional Intra-Hour Balancing Services for a 2020 Grid with 20 percent RPS

9.3 Life-Cycle-Cost Analysis of Various Technology Options to Meet Future Balancing Requirements

A detailed LCC analysis was performed that sought the optimal cost combinations of generation and storage technologies to meet the total intra-hour balancing requirements over a 50-year lifetime. Our analysis evaluates nine cases of different technology options listed in Table 9.2.

Cost components considered include capital, O&M costs, as well as fuel prices and typical prices for criteria emissions such as NO_x and SO_x. The carbon dioxide (CO_2) emissions were valued at a cost of \$45/ton CO_2. It was assumed 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 and generation options for grid applications, and on choosing plausible and defensible cost performance characteristics of the technologies under consideration.

This study revealed several insights into the competitiveness of the nine technology cases shown in Table 9.2 as a result of optimizing their LCCs. First, the results of the economic analysis for all four WECC sub-regions indicate that of the nine cases examined in this report, Case 2, which employs Na-S batteries, is expected to be the most economical alternative in 2020. For the NWPP, the 50-year LCC for Case 2 using forecast 2020 prices is \$2.8 billion. The next least cost alternative is Case 4 (flywheels) at \$3.3 billion, followed by Case 3 (Li-ion batteries) at \$4.3 billion, and Case 6 (redox flow batteries) at \$6.2 million. While Na-S batteries (Case 2) appear to be the most cost-effective option for balancing in both 2011 and 2020, a critical assumption of this analysis is that Na-S batteries will be eventually be available with a stored energy to rated power ratio of ~1:1. Currently, this ratio is about seven, thus requiring a battery seven times the size selected in this study. This is the main reason Na-S batteries are not competitive with baseline CTs at present.

Table 9.2. Definition of Technology Cases

Case	Technology	Comments
C1	Combustion turbine	Conventional technology considered as the reference case.
C2	Na-S	Sodium sulfur battery only.
C3	Li-ion	Lithium-ion battery only.
C4	Flywheel	Flywheel only.
C5	CAES with 2 mode changes	CAES with a 7-minute waiting period for mode changes (compression-generation and vice versa). Balancing services will be provided during compression mode at night (8 pm-8 am) and during generation mode during the day (8 am-8 pm). Na-S battery is assumed to make up operations during 7 minute waiting period.
C6	Flow battery	Flow battery only.
C7	PH with multiple mode changes	PH with a 4-minute waiting period for mode changes (pumping-generation and vice versa). This machine allows multiple mode changes during the day. Na-S battery is assumed to make up operations during 4 minute waiting period.
C8	PH with 2 mode changes	Same as (C7), except only two mode changes. Balancing services will be provided during pumping mode at night (8 pm-8 am) and during generation mode during the day (8 am-8 pm). Na-S battery is assumed to make up operations during 4 minute waiting period.
C9	DR	Demand response only. This assumes that balancing services will be provided as a load. Only considered is PHEV charging at home and work. Resources are expressed in MW of DR capacity as well as in numbers of PHEV with demand response capability.

Flywheels (Case 4) appear the most cost-effective for both 2011 and 2020 if Na-S systems fail to reach the target energy to rated power ratio of approximately unity by 2020. In 2011, CAES (Case 5) and pumped hydro with multiple mode changes (Case 7), while costlier than flywheels (Case 4), are competitive with CTs (Case 1), while Li-ion systems (Case 3) are slightly more expensive than CTs (Case 1). In the 2020 scenario, all energy storage options are competitive with CTs (Case 1), except CAES (Case 5) and PH 2-mode (Case 8). Even at the high end of the capital cost estimates, in 2020, Li-ion (Case 3) and flywheels (Case 4) are expected to be cost-competitive with CTs (Case 1), while flow batteries (Case 6) are expected to be only barely more expensive.

In nearly all cases, the costs associated with other energy storage options are lower than those estimated for the combustion turbine case[1] (Case 1), particularly with respect to fuel and emissions costs. For the NWPP, costs for Case 1 (CT) are estimated at $7.1 billion, while the pumped hydro cases (Case 7 and Case 8), which vary based on the assumed number of mode changes per day, are estimated to cost between $6.8 and $13.2 billion. Under the current scenarios, capital costs drive the outcome of the analysis and the CT and pumped hydro technologies with their corresponding high capital costs are relatively expensive for the provision of balancing services alone[2]. The findings of this analysis suggest

[1] Natural gas used for combustion turbines is assumed to cost $4.94 per MMBTU in 2011dollars escalated at 3.2% over the 50-year analysis time horizon.
[2] Some of the existing hydro power plants could be retro-fitted into pumped hydro plants at lower capital cost than building a new pumped hydro plant.

that both options appear ill-suited for providing balancing services exclusively. For example, pumped hydro with a large reservoir is underutilized in this analysis. It could be providing other services as well.

Figure 9.2 presents the results of the LCC analysis and the effects of capital, O&M, emissions, and fuel costs on the total LCC for each case, as applied in the NWPP. Note that costs are also presented per MW to meet intra-hour balancing requirements for the NWPP. As noted in the figure, the bar chart uses 2020 cost assumptions while the results using 2011 price data are identified using the brackets added to the figure. For example, the LCC for the Na-S case (Case 2) is \$2.8 billion when using 2020 prices but rises to \$3.9 billion when using present 2011 prices.

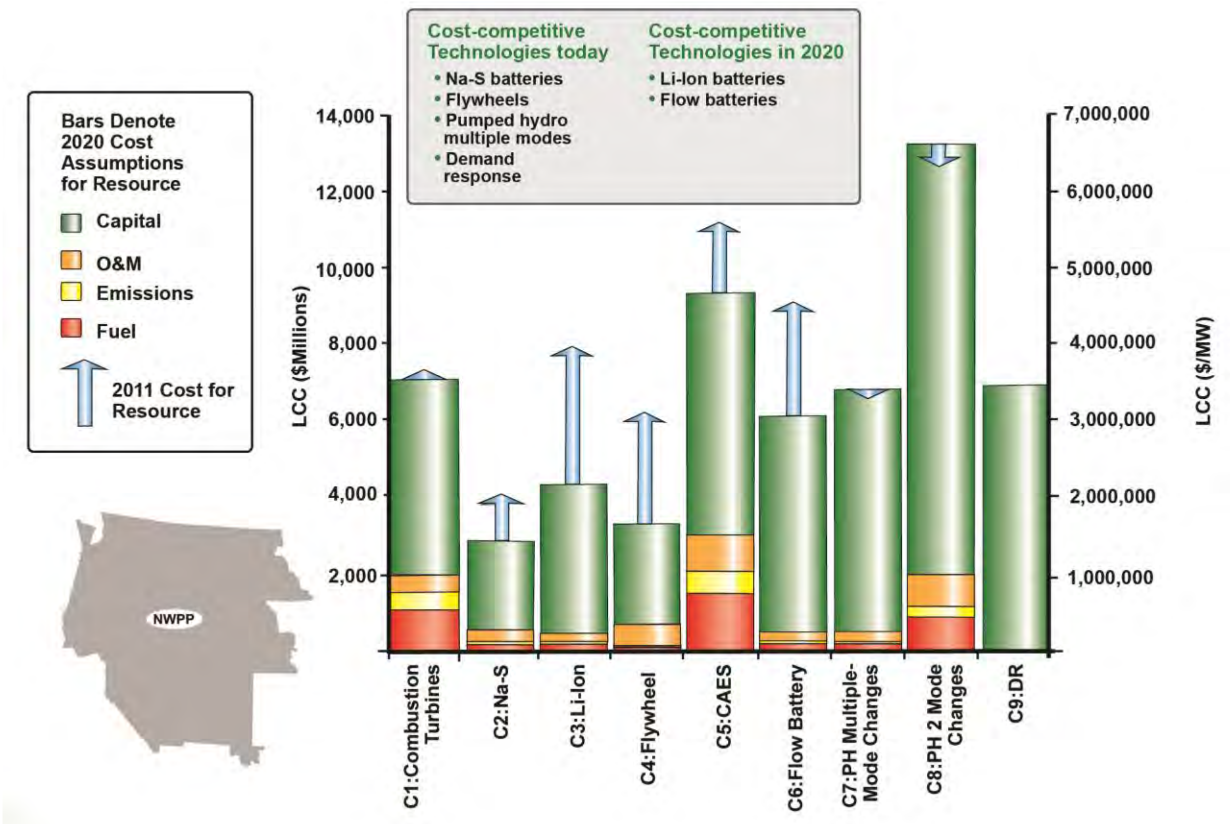


Figure 9.2. LCC Estimates for NWPP

The technical and cost uncertainty regarding energy storage technologies is evaluated in technology readiness levels (TRLs) and manufacturing readiness levels (MRLs). See section 2 in Volume 2. TRLs assigned to the energy storage technologies are as low as six for redox flow batteries and seven for Na-S batteries, Li-ion batteries, and flywheels. A TRL of six indicates that a prototype system has been verified while a TRL of seven indicates that an integrated pilot system has been demonstrated. Conversely, CTs are rated at a TRL of nine, which indicates that the system is proven and commercially deployed. The MRL for flywheels and redox flow batteries is about five indicating that the manufacturing process is under development. Na-S and Li-ion batteries received MRLs of six indicating that a critical manufacturing process for utility-scale systems has been prototyped. CTs received an MRL rating of 10 indicating that full rate production has been demonstrated and lean production practices are in place.

9.4 Hybrid Storage Systems

Additionally, this analysis investigated cases in which the balancing service was provided by combinations of two storage or generation technologies. The balancing signal was divided into “slow” and “fast” components. These balancing components are satisfied by two storage or generation technologies with different technical and economic characteristics. The LCC methodology was applied to different shares of the combination of technologies to determine the split with the highest cost effectiveness. The main finding is that technology shares comprised primarily of the lower-cost technology was always the most cost-effective. The least cost alternative represented the optimal technology choice. This suggests that the minute-by-minute time series for the balancing requirements did not reveal sufficiently sharp ramp behavior that exceeded the ramping behavior of the “slower” responding technologies. Thus, the minute-by-minute time resolution was not a differentiator between slow and fast-responding technologies. It is assumed that signals with shorter sampling frequency and sufficiently high ramping rates are necessary for fast-responding technologies to reveal their differentiating characteristics.

The combinations of Li-ion and DR technologies, and combinations of pumped hydro with multiple mode change and flywheels did indicate some distinct optimum of a two-technology solution. This result stems from the non-linearity in these two combination cases. For the Li-ion and DR combination case under the 2011 price scenario, the least cost technology share was 60 percent DR and 40 percent Li-ion in most regions as shown in Figure 9.3. There was a non-linearity originated by the availability of DR. For the pumped hydro with multiple mode changes plus flywheels combination case, the least cost technology share was 60 percent PH and 40 percent flywheel for the CAMX area, under the 2011 price scenario. The non-linearity in this case stemmed from the waiting period between PH mode changes. The non-linearity influences the technology share outcome when the costs of the two technologies are comparable.

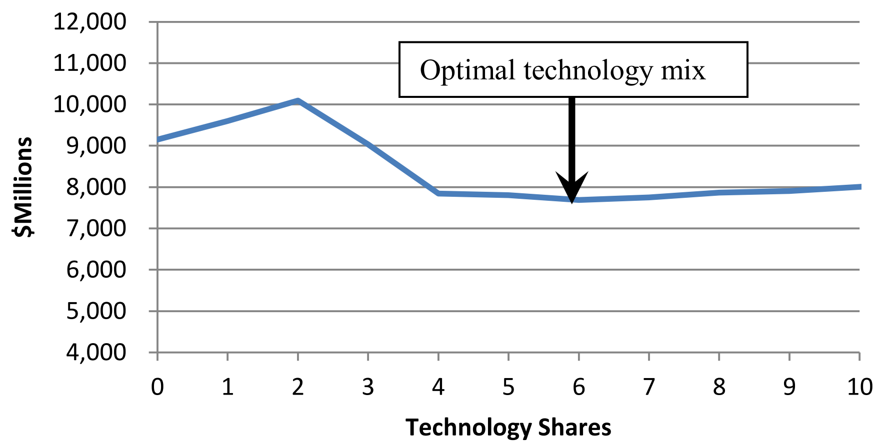


Figure 9.3. Total 50-Year LCCs for Li-Ion +DR Technology Shares for 2011Cost Assumptions. Optimal combination (technology share 6) only present in two cases under 2011 cost assumptions.

9.5 Energy Arbitrage Opportunities

The revenue potential of arbitrage was determined by identifying constraints in the system and determining the LMP differential for hours throughout the year along those congested paths. Simulations were then carried out for different energy storage sizes for the NWPP and CAMX in the WECC; the ERCOT; and the MROW, NEWE, NYCW, NYUP, RFCW, SRDA, SRSE, and SRVC in the EI. Arbitrage revenues for all regions grow from $97.1 million annually at 1,659 MW of installed capacity to $3.2 billion at 66,366 MW of energy storage nationwide considering that each region contributes different revenue streams to the national total with different storage sizes. Comparing the revenue projections with the cost indicates that arbitrage revenue expectations fall short of the revenue requirements necessary for cost recovery. This general finding applies to each scenario presented in this report. Thus, it would take either a significant increase in the peak- to off-peak LMP differential for extended periods of time or reductions in energy storage capital costs for energy arbitrage as designed in this analysis to break even. When capacity values are included in the assessment, pumped hydro generates profits. When set to profit maximizing points in each sub-region, the results indicate that pumped hydro used to provide arbitrage and capacity services could generate $364.1 million in profits at 35,122 MW of installed capacity.

These results vary significantly by region and are discussed in detail in 10.0Appendix A. In the WECC, the annual arbitrage value ranged from a high of $17/kW to a low of $10/kW. In the ERCOT, the energy $111/kW to about $100/kW. Thus, annual arbitrage revenue per kW was estimated to be roughly 6-10 times higher in the ERCOT relative to the WECC, depending on the level of energy storage deployed. The energy storage revenue estimates for arbitrage in the EIC on a per kW bases are between $52 and $63/kW (see Table 9.3).

Table 9.3. Arbitrage revenue expectations without capacity value

Arbitrage revenues $/kW	WECC	ERCOT	EIC
high	17	111	63
low	10	101	52

While the findings of this analysis indicate that profits from energy arbitrage are insufficient to achieve capital cost recovery and that only pumped hydro is profitable with capacity reserve revenues included in the analysis (up to 33,183 MW), it is important to note that there are several other services that could be supplied by energy storage technologies that were not included in this assessment. These services include load following, transmission and distribution upgrade deferral, grid stability management, power quality enhancements, and electricity service reliability. The valuation of these services and grid benefits, particularly when provided simultaneously, is complicated and/ or highly site-specific and, thus, beyond the scope of this assessment. Additional research is therefore necessary to examine the full revenue potential of energy storage used in multiple applications.

9.6 Overall Conclusions

Results provide crucial insights into the potential market size for energy storage from a national perspective. The following overall conclusions can be drawn from this analysis:

1. The total amount of installed power capacity for a 20 percent RPS scenario in the 3 U.S. interconnections would require a total intra-hour balancing capacity of approximately 37.67 GW. The total market size was estimated by sub-regions based on the potential for energy storage in the high-value balancing market. The energy capacity, if provided by energy storage, would be approximately 14.3 GWh, or storage that could provide power at rated capacity for about 27 minutes. The addition intra-hour balancing capacity that is required to accommodate the variability due to capacity additions from wind technology and load growth in the interval 2011-2020 was estimated to be 18.57 GW. If these additional balancing services were provided by new energy storage technology, the energy capacity would be about 8.6 GWh to provide electricity at rated power capacity for about 27 minutes.
2. The regional distribution of balancing requirements within the WECC is driven by load forecasting wind prediction errors. Because of the non-homogeneous distribution of the loads and wind across the WECC region, the balancing requirements increase with load and wind capacity. NWPP and California were the two major regions with significant intra-hour balancing requirements.
3. Various technologies compete for growing balancing market opportunities, not only energy storage, but also DR. The base case technology is a gas-fueled CT, which may be attractive particularly under the present low cost projections of gas prices in the next decades. The LCC analysis for intra-hour service indicated that Na-S, flywheel storage technologies, and DR under current cost estimates are already cost-competitive (lowest LCC). Li-ion will follow if our cost reduction assumptions made for the 2020 timeframe are realized.
4. LCC results are strictly applicable for intra-hour balancing services with an average cycle time of about 20-30 minutes. As the application requires longer cycle times with higher energy capacity, capital costs and production cost of conventional generators will be different, all affecting the LCC results and the relative cost competitiveness.
5. Energy arbitrage alone is insufficient to provide sufficient revenues to make new energy storage installations economically viable even in congested paths such as transfer into Southern California and interchange at the California-Oregon border. Although this result was based on the production cost modeling that estimates cost differential between peak and off-peak, not market price differentials, which tends to be higher than the cost differentials, the frequency and duration of transmission congestions were simply not sufficient to make energy storage technologies a viable business proposition as an energy product. When capacity values of $150/kW-year are included in the assessment, pumped hydro generates profits at energy storage capacities up to 35,122 MW. While the findings of this analysis indicate that profits from energy arbitrage are insufficient to achieve capital cost recovery and that only a limited amount of pumped hydropower is profitable, it is important to note that there are several other services that could be supplied by energy storage technologies that not included in this assessment. These services include load following, transmission and distribution upgrade deferral, grid stability management, power quality enhancements, and electricity service reliability. The valuation of these services and grid benefits, particularly when provided simultaneously, is immature or highly site-specific and, thus, beyond the scope of this assessment.
6. The hybrid energy storage system analysis did not show very compelling tradeoffs between slower cycling and faster cycling technologies. In all cases the time resolution used (minute-by-minute) did not show sufficiently sharp transients such that ramp limits affected use and selection of some technologies. As a consequence, all of the optimal cost pairings of two technologies were determined

solely on price, and, as such, the most prevalent results indicated a winner-take-all solution, in which the optimal pairing to technology suggested only one (namely the lower-cost) technology. This suggests that hybridizing storage technologies will only be meaningful if there is a wide spectrum of cycles expected with sharp transients with less than one-minute time resolution, which this analysis did not expose.

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Appendix A

Detailed Balancing Requirements and Storage Sizing by Zone

Appendix A

Detailed Balancing Requirements and Storage Sizing by Zone

The Appendix provides zonal details about the balancing requirements differentiated between energy and power requirements for each of the technologies analyzed. The cost and performance characteristics of each technologies are discussed in detail in Volume 2 of the National Assessment.

A.1 Southwest (AZNM)

The pattern of balancing signal determines the size of energy storage needed to provide the signal. Specifically, the magnitude of the signal determines the power capacity requirement of energy storage.

A.1.1 Balancing Requirements

Monthly and daily balancing signals of region AZNM are shown in Figure A.1 and Figure A.2, respectively. Long cycles across several days are included in the balancing signal. If only energy storage is used to meet this balancing signal, energy storage that has several days of energy capacity is needed. The long cycle energy storage is very expensive especially for emerging energy storage technologies such as batteries and flywheels. Furthermore, traditional generation resources should have sufficient ramp capability to meet these long cycles because they usually do not have steep slopes. Based on the whole year simulation, the balancing power requirements are 2740 MW of incremental (inc) capacity and 3554 MW of decremental (dec) capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August, especially the incremental capacity, are lower than the annual requirements.

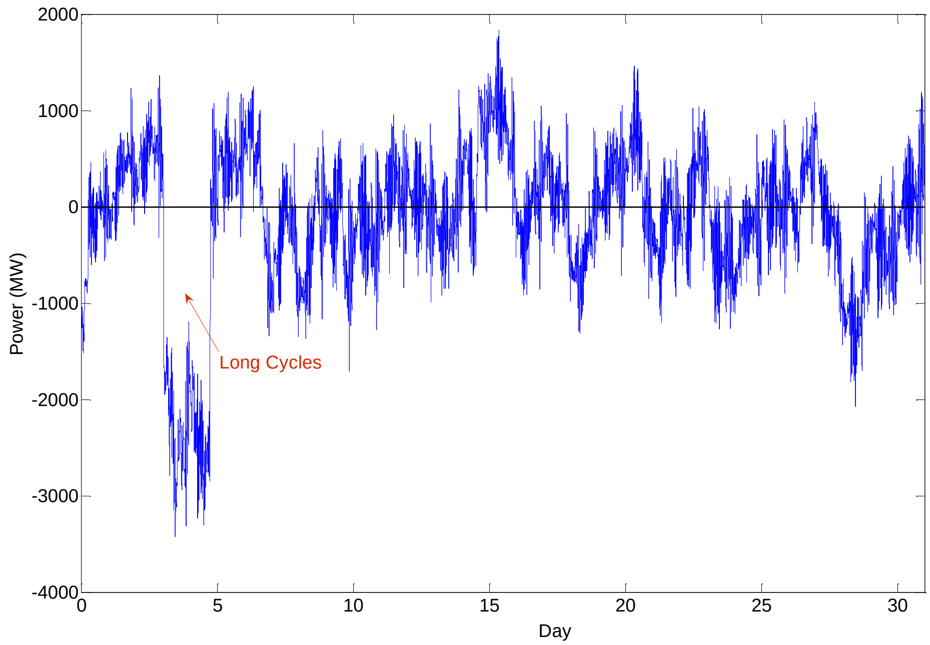

Figure A.1 One Month Li-Total Balancing Signal in August 2020 for AZNM

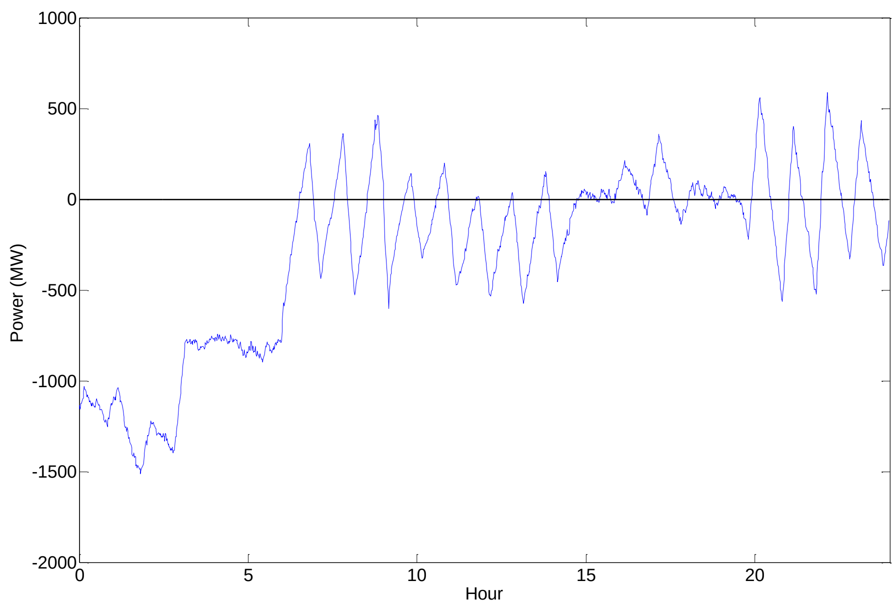

Figure A.2. One Typical Day Total Balancing Signal in August 2020 for AZNM

Figure A.3 shows monthly balancing signals caused by load and by wind separately for the region AZNM. For the southwest region, the balancing requirements are mainly caused by load uncertainty because wind resources in the southwest region are scarce and the peak load level is high. Figure A.4 presents the same balancing signals for one day.

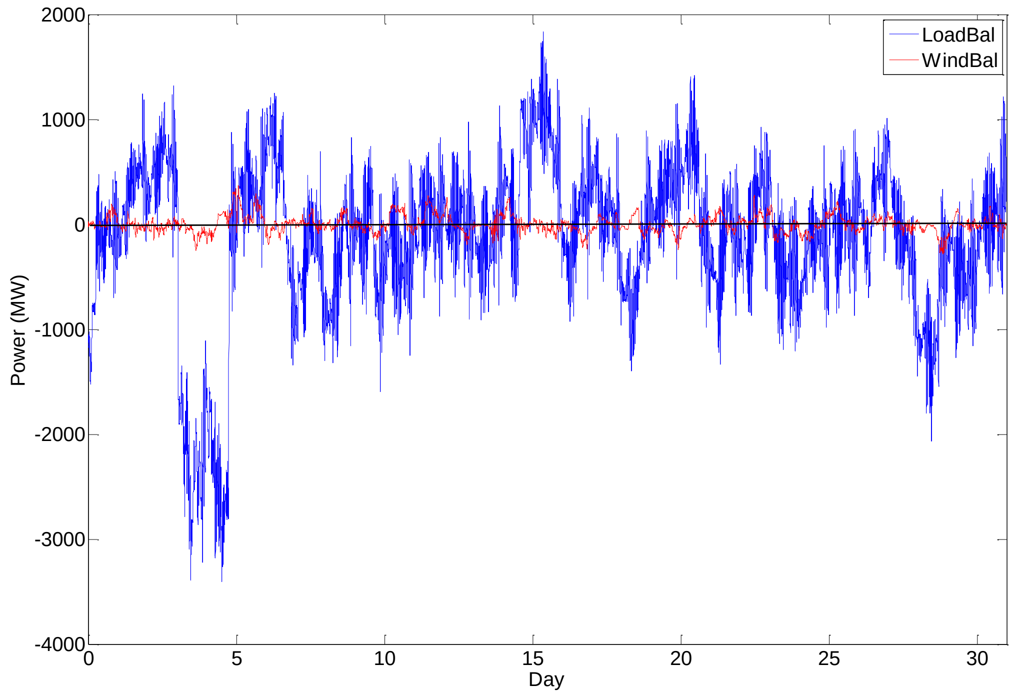

Figure A.3. One Month Balancing Requirements Caused by Load and Wind Respectively for AZNM

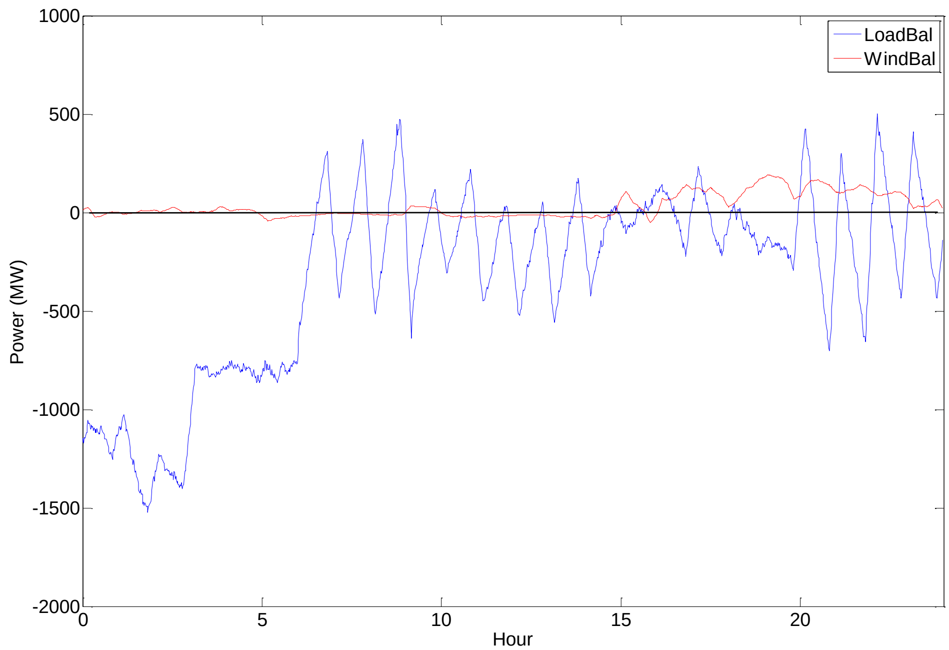

Figure A.4. One Typical Day Balancing Requirements Caused by Load and Wind Respectively for AZNM

A.1.2 Energy and Power Requirements

Extensive systems modeling was performed to estimate the power and energy capacity requirements to meet 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 Appendix B.

Table A.1 and Figure A.5 and Figure A.6 show the results of energy and power requirements for the scenarios in AZNM region. It should be noted that the capacity requirements or the minimal size of the battery is based on 100 percent DOD of the battery. This means that the size of the energy storage is fully utilized. The storage system will be cycled hypothetically 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 percent to improve the life of the battery. 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 changeover delay of the pumped hydropower and compressed air technologies.

The size of the alternative CT is set by the requirements of the generation increment, not by the sum of the increment and decrement. This is based on the notion that the existing CT capacity is operating at the zero balancing point already and would be able to provide some generation decrements by reducing its output. Then, only the increment in capacity would need to accounted for in the capital cost calculations. This is a very conservative assumption resulting in one-half of the capacity requirements as if one would size the CT to meet the entire amplitude of the balancing requirements from max increment to max decrement. This assumption is still justifiable considering that most CT may not solely be installed for providing balancing services but also participate in the energy markets. If one were to compare the CT technology against storage for its full capacity, then the CT technology must be upsized by the magnitude of the maximum decrement, which, in most cases, results in about doubling the size of the CT.

Table A.1. Power and Energy Requirements for Each Scenario for AZNM. Note: The energy capacity (GWh) for the batteries is specified at a DOD of 100 percent.

Case	Technology	GW	GWh
C01	Combustion turbine	1.20	-
C02	Na-S	1.22	0.46
C03	Li-ion	1.22	0.46
C04	Flywheel	1.21	0.42
C05	CAES	2.31	13.40
	Na-S	0.64	0.06
C06	Flow battery	1.23	0.48
C07	PH multiple modes	1.22	0.40
	4-min waiting period, Na-S	0.53	0.08
C08	PH 2 modes	2.31	13.47
	4-min waiting period, Na-S	0.51	0.03
C09	DR	4.33	-

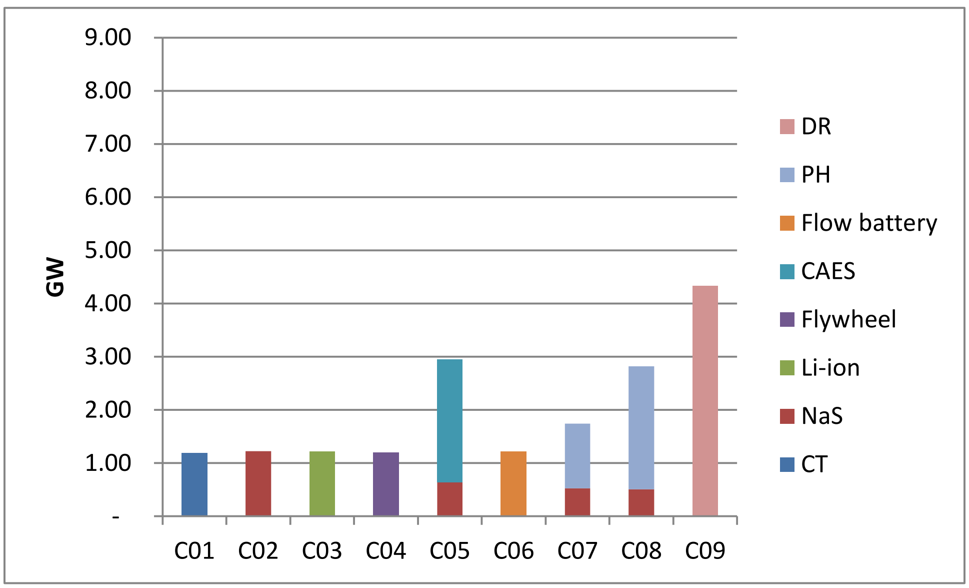

Figure A.5. Power Requirements for all the Technologies to Meet Balancing Signal for AZNM

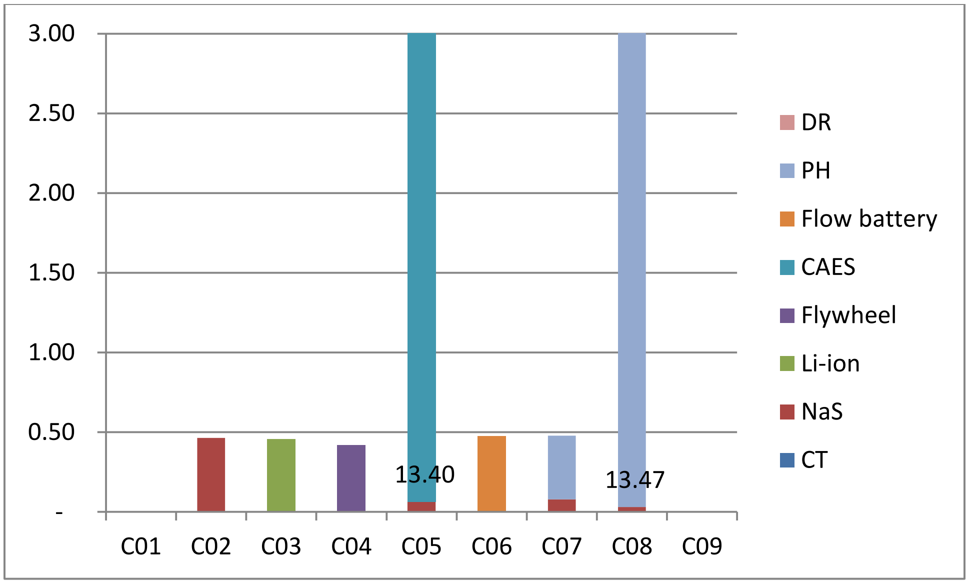

Figure A.6. Energy Requirements for Storage Technologies to Meet Balancing Signal for AZNM

Notice that there are differences in the sizes of storage (GW and GWh) required for the different cases of studies (see Table A.2). These differences are due to the efficiencies and operation strategies of the storage technologies. The GW and GWh difference in cases C2 to C4 and C6 are only due to difference in storage efficiency. The GW and GWh difference in case C7 is due to storage efficiency and due to the need of an additional storage technology (Na-S) to provide balancing during the 4-minute waiting period needed to change between PH charging and discharging modes (pumping and generation). The large GW and GWh difference in case C5 and C8 with respect to the rest of the cases is mainly because of the restriction in operation assumed; a restriction of only two mode changes (charging to discharging or discharging to charging) is assumed causing a large increase in size requirement (GW and GWh). Details of operational strategies for each technology can be found in Appendix B.

Table A.2 and Figure A.7 and Figure A.8 show the results of energy and power requirements for the scenarios in the AZNM region, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.2. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load Signal for AZNM. Note: The energy capacity (GWh) for the batteries is noted at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.21	-
C2	Na-S	0.21	0.08
C3	Li-ion	0.21	0.08
C4	Flywheel	0.21	0.07
C5	CAES	0.37	1.69
	Na-S	0.12	0.01
C6	Flow battery	0.21	0.08
C7	PH multiple modes	0.21	0.07
	4 min waiting period, Na-S	0.08	0.01
C8	PH 2 modes	0.37	1.70
	4 min waiting period, Na-S	0.07	0.00
C9	DR	0.75	-

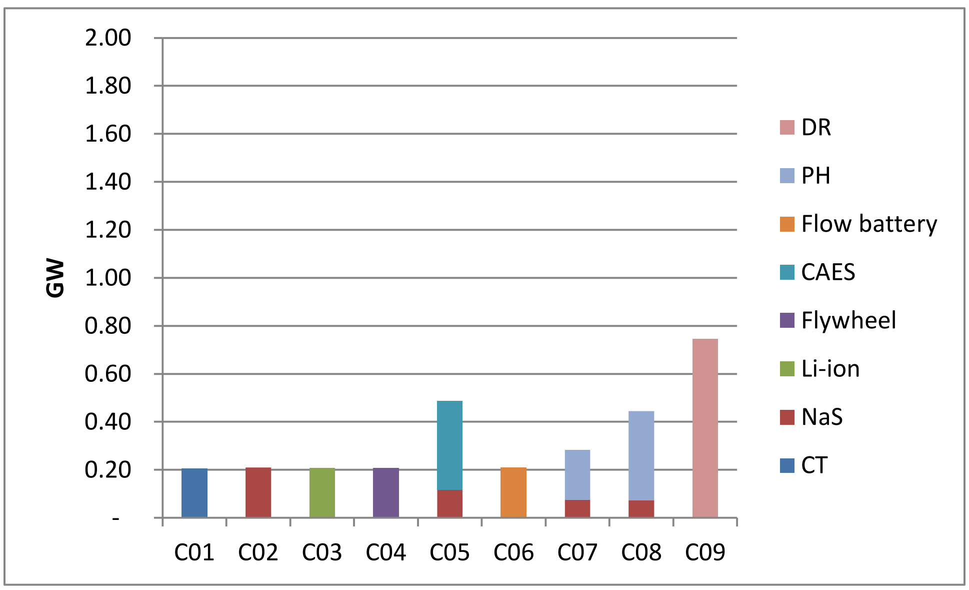

Figure A.7. Power Requirements for all the Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load Signal for AZNM

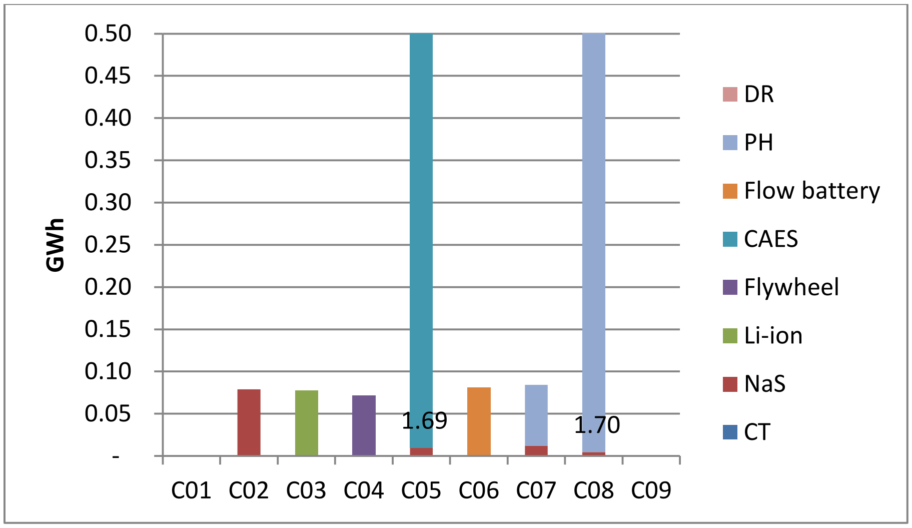

Figure A.8. Energy Requirements for Storage Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load Signal for AZNM

A.1.3 Life-Cycle Cost Analysis

The results of the economic analysis for the AZNM power area are presented in Table A.3and Figure A.9. These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Table A.3 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries, is the least cost alternative at $1.9 billion. Case 4, which consists of flywheels, represents the second least cost alternative with costs estimated at $2.0 billion or 9.6 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $4.2 billion. The CAES case (Case 5) is also more expensive with estimated costs of $5.9 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $8.0 billion. Total costs under Case 6, redox flow batteries, are estimated at $3.8 billion.

Table A.3. Economic Analysis Results – AZNM (in Million 2020 Dollars)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	3,185	783	290	309	**4,567**
2	1,495	119	200	47	**1,862**
3	2,431	107	196	42	**2,778**
4	1,609	51	361	20	**2,041**
5	3,891	999	586	395	**5,871**
6	3,437	138	170	55	**3,800**
7	3,832	104	181	41	**4,158**
8	7,172	266	451	105	**7,994**
9	4,154	-	-	-	**4,154**

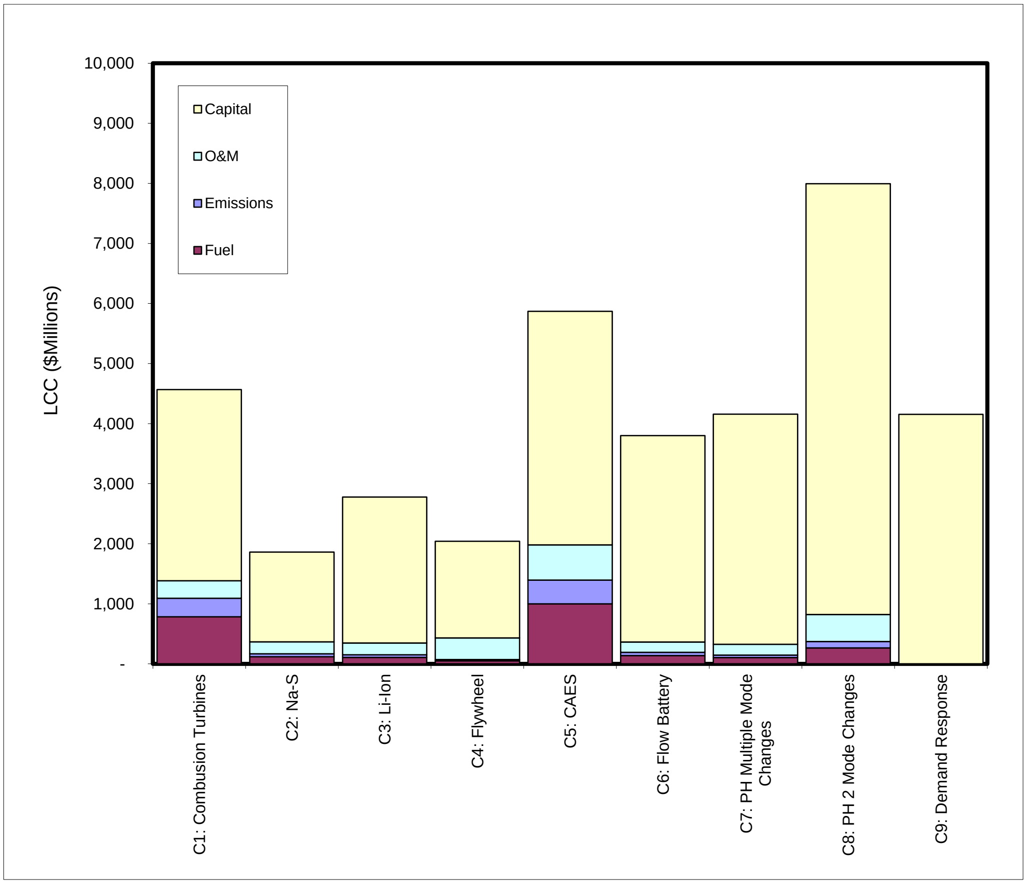

Figure A.9. Scenario LCC Estimates for AZNM

A.1.4 Arbitrage

Arbitrage analysis was not performed in the AZNM power area.

A.2 California (CAMX)

The pattern of balancing signal determines the size of energy storage needed to provide the signal. Specifically, the magnitude of the signal determines the power capacity requirement of energy storage.

A.2.1 Balancing Requirements

Figure A.10 and Figure A.11 show monthly and daily balancing signals for CAMX, respectively. Long cycles across several days are included in the balancing signal. If only energy storage is used to meet this balancing signal, energy storage that has several days of energy capacity is needed. The long cycle energy storage is very expensive especially for emerging energy storage technologies such as batteries and flywheels. Furthermore, traditional generation resources should have sufficient ramp capability to meet these long cycles because the long cycles usually do not have steep slope. Based on the whole year simulation, the balancing power requirements are 4126 MW of inc. capacity and 2922 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability of happening.

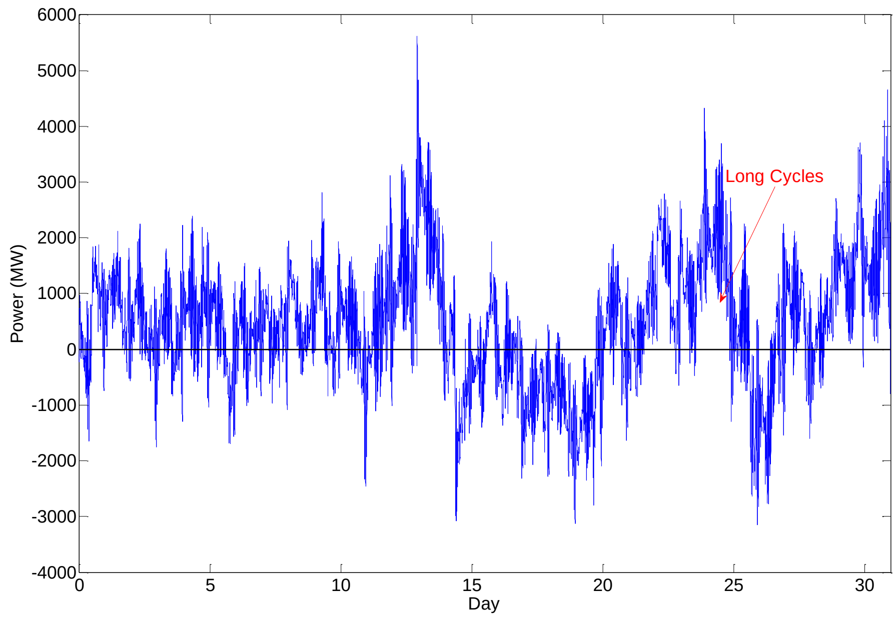

Figure A.10. One Month Total Balancing Signal in August 2020 for CAMX

Figure A.12 shows the balancing signal caused by wind and by load separately for the whole of August. Figure 8.11 shows the same information for a day in August. For the California region, the balancing requirements are mainly caused by load uncertainty because of the high peak demand in California in 2020. Most of time in August, balancing requirements caused by wind has the opposite sign to that of the balancing requirements caused by load. This indicates if wind production has an over-forecast which means actual wind power production is less than the wind forecast, load will have an under-forecast. Given load has positive correlation with temperature and wind has negative correlation with temperature in summer, the results are as we expected.

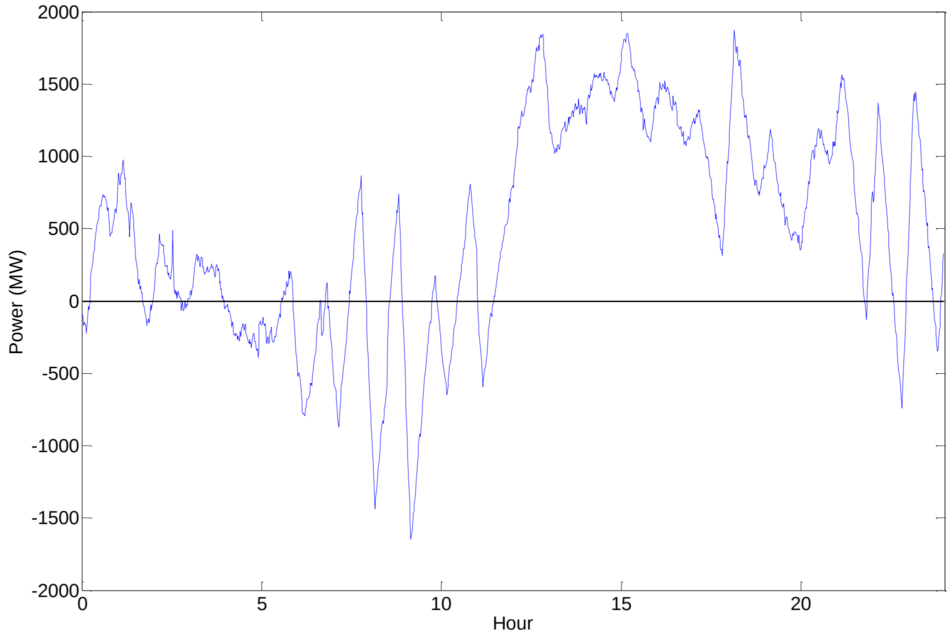

Figure A.11. One Typical Day Total Balancing Signal in August 2020 for CAMX

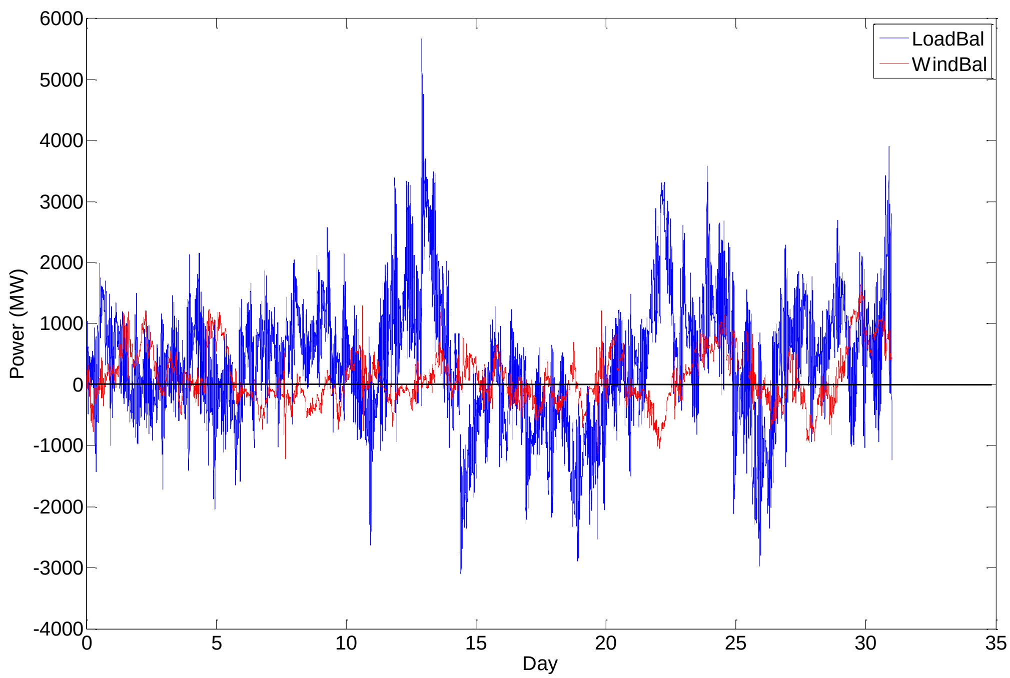

Figure A.12. One Month Balancing Requirements Caused by Load and Wind, Respectively for CAMX

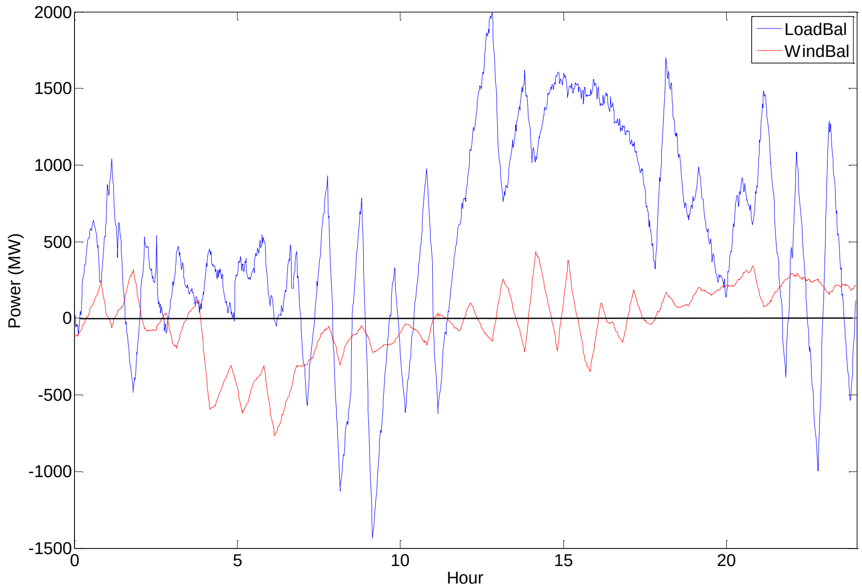

Figure A.13. One Typical Day Balancing Requirements Caused by Load and Wind, Respectively for CAMX

A.2.2 Energy and Power Requirements

Using the approach described above, Table A.4 and Figure A.14 and Figure A.15 show the results of energy and power requirements for in the California (CAMX) area, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

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 changeover delay of the pumped hydropower and compressed air technologies.

Table A.4. Power and Energy Requirements for Each Scenario for CAMX in 2020. Note: The energy capacity (GWh) for the batteries is nominally for a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.34	-
C2	Na-S	2.40	0.67
C3	Li-ion	2.39	0.66
C4	Flywheel	2.36	0.64
C5	CAES	4.17	23.84
	Na-S	0.90	0.10
C6	Flow battery	2.41	0.68
C7	PH multiple modes	2.39	0.59
	4-min waiting period, Na-S	0.89	0.15
C8	PH 2 modes	4.17	23.90
	4-min waiting period, Na-S	0.65	0.05
C9	DR	8.47	-

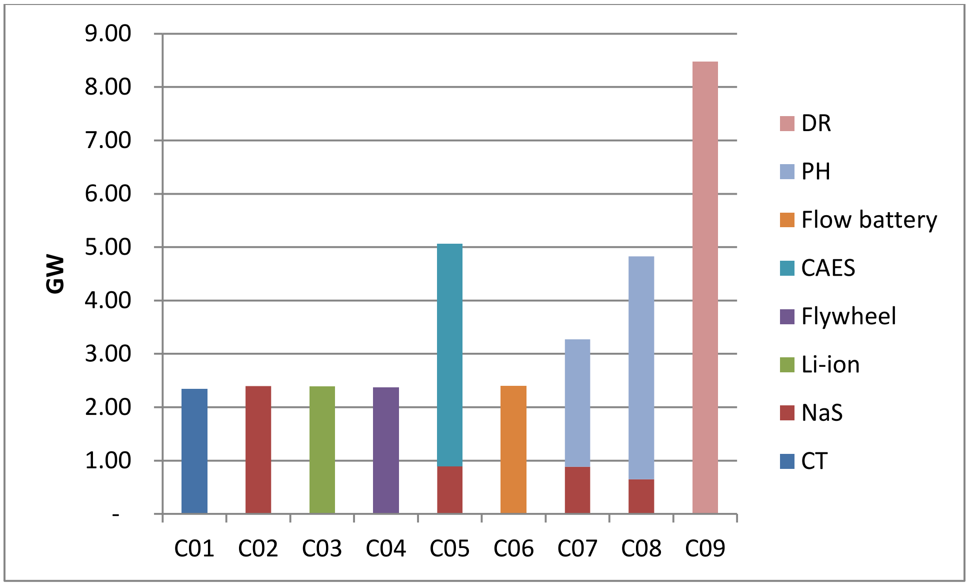

Figure A.14. Power Requirements for all Technologies to Meet CAMX Balancing Signal

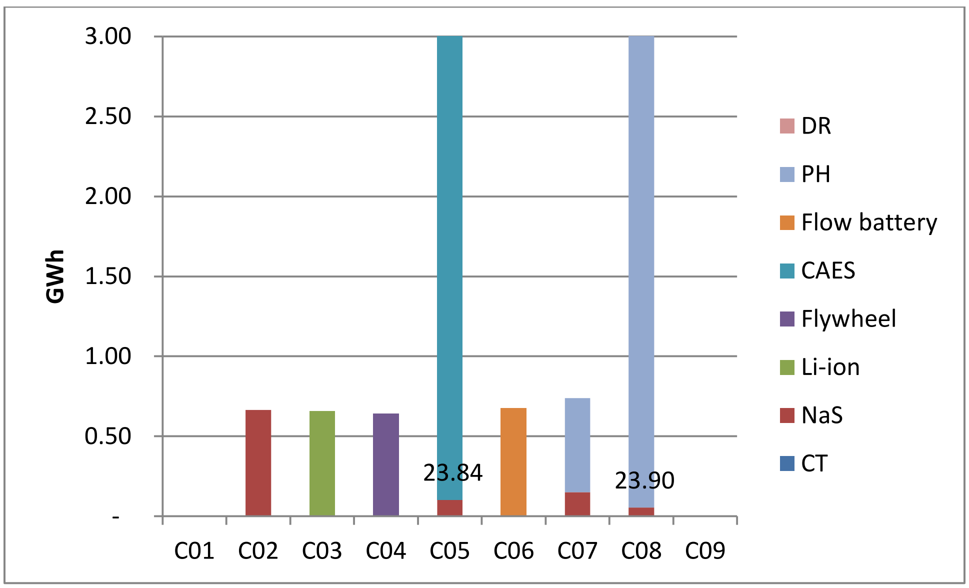

Figure A.15. Energy Requirements for Storage Technologies to Meet CAMX Balancing Signal

Table A.5. Power and Energy Requirements Resulting from 2011-2020 Additional Wind and Load Scenarios for CAMX. Note: The energy capacity (GWh) for the batteries is nominally for a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.53	-
C2	Na-S	0.53	0.18
C3	Li-ion	0.53	0.18
C4	Flywheel	0.53	0.17
C5	CAES	0.92	6.32
	Na-S	0.16	0.02
C6	Flow battery	0.52	0.19
C7	PH multiple modes	0.53	0.17
	4-min waiting period, Na-S	0.18	0.02
C8	PH 2 modes	0.92	6.35
	4-min waiting period, Na-S	0.10	0.01
C9	DR	1.53	-

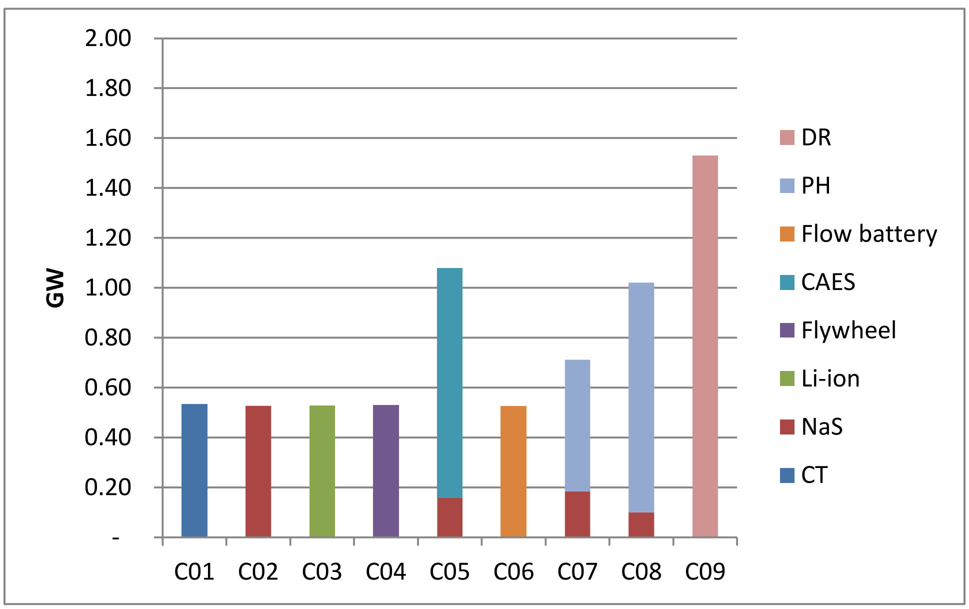

Figure A.16. Power Requirements for all the Technologies to Meet CAMX Balancing Signal Resulting from 2011-2020 Additional Wind Power and Load

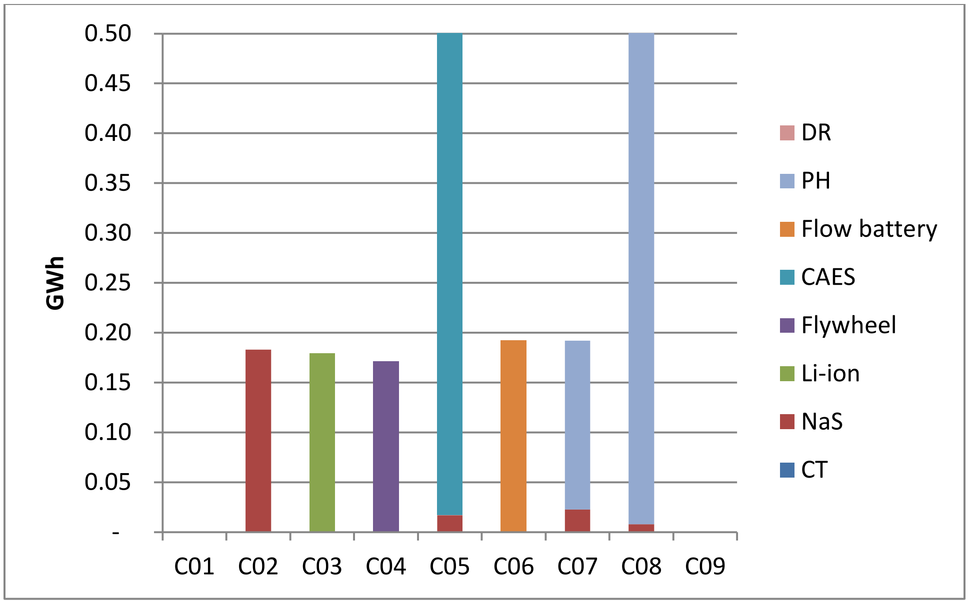

Figure A.17. Energy Requirements for Storage Technologies to Meet CAMX Balancing Signal Resulting from 2011-2020 Additional Wind Power and Load

A.2.3 Life-Cycle Cost Analysis

The results of the economic analysis for CAMX are presented in Table A.6 and Figure A.18. These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Table A.6 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Table A.6, Economic Analysis Results – California-Mexico Power Area in 2020 (in Million 2011 Dollars)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	5,971	1,391	552	550	**8,463**
2	2,827	214	373	85	**3,499**
3	4,533	193	366	76	**5,168**
4	3,108	91	704	36	**3,939**
5	6,912	1,781	1,042	704	**10,439**
6	6,667	248	330	98	**7,344**
7	7,456	187	339	74	**8,056**
8	12,838	462	794	183	**14,277**
9	8,120	-	-	-	**8,120**

Case 2, which employs Na-S batteries, is the least cost alternative at $3.5 billion. Case 4, which consists of flywheels, represents the second least cost alternative with costs estimated at $3.9 billion or 12.6 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $8.1 billion. The CAES case (Case 5) is also more expensive with estimated costs of $10.4 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $14.3 billion. Total costs under Case 6, redox flow batteries, are estimated at $7.3 billion.

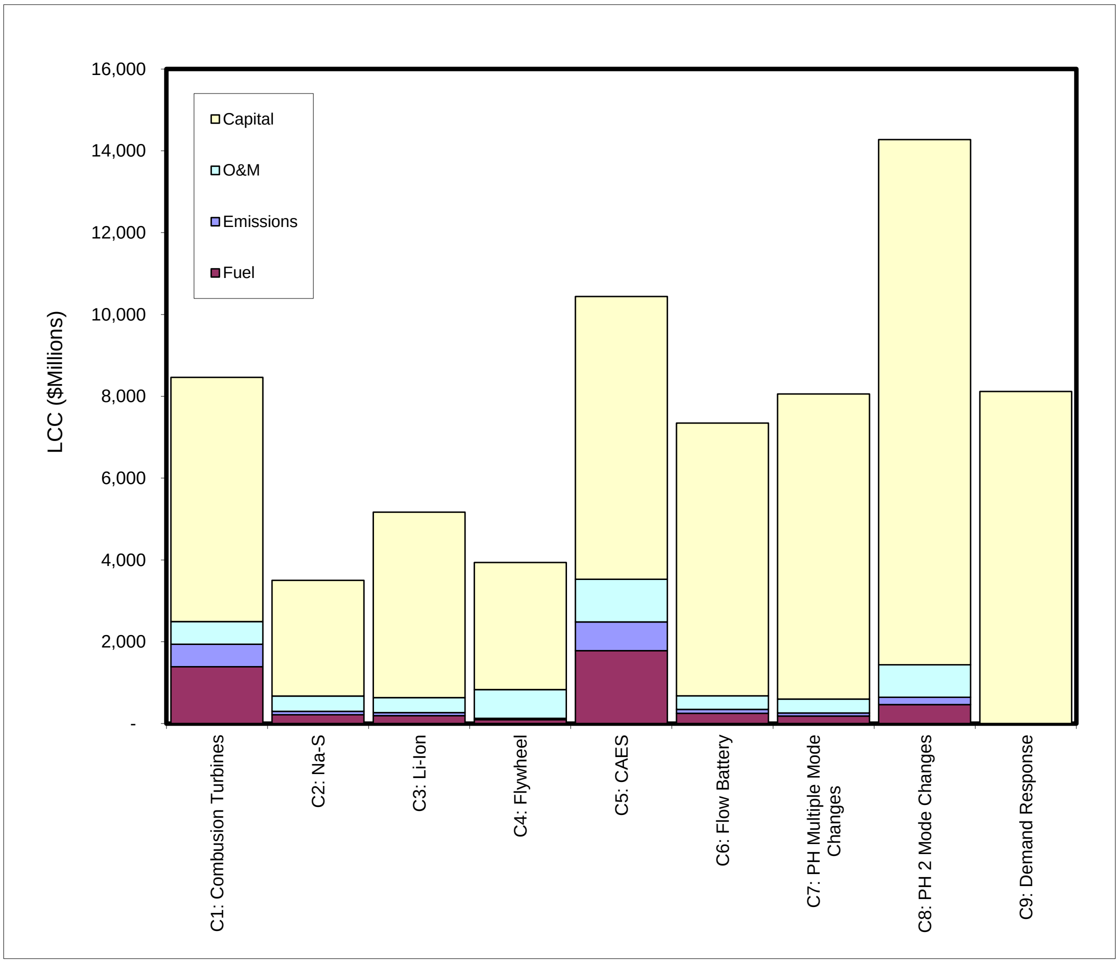

Figure A.18. Scenario LCC Estimates for California-Mexico Power Area (CAMX)

A.2.4 Arbitrage

Table A.7 presents the findings of the arbitrage analysis performed for the CAMX power area. As shown, annual revenues are estimated at $3.9-$87.3 million based on energy storage size, which ranges from 214-8,542 MW. While the simulation results reveal there are several congested paths in the system, with the most congested path being the interface between Utah and the LADWP, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. Annualized costs are estimated to range from $43.3 million-$1.7 billion for pumped hydro, $97.3 million-$3.9 billion for Na-S, and $191.3 million-$7.7 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the CAMX power area is not sufficiently congested for energy storage to become cost-effective when used to provide only arbitrage services.

Table A.7 CAMX Annualized Revenues and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydropower in 2011 Dollars

Storage Size		Annual Revenue	Annualized Costs		
MWh	MW		Pumped Hydro	Na-S	Li-Ion
2,136	214	$3,877,592	$43,346,379	$97,314,735	$191,276,735
4,271	427	$7,712,931	$86,692,758	$194,629,470	$382,553,470
8,542	854	$14,972,285	$173,385,516	$389,258,940	$765,106,940
10,678	1,068	$18,425,751	$216,731,895	$486,573,675	$956,383,675
21,355	2,136	$33,797,951	$433,463,790	$973,147,350	$1,912,767,350
32,033	3,203	$46,361,474	$650,195,685	$1,459,721,025	$2,869,151,025
42,710	4,271	$58,367,752	$866,927,580	$1,946,294,700	$3,825,534,700
53,388	5,339	$66,402,312	$1,083,659,475	$2,432,868,375	$4,781,918,375
85,420	8,542	$87,323,653	$1,733,855,160	$3,892,589,400	$7,651,069,400

A.3 Northwest Power Pool (NWPP)

A.3.1 Balancing Requirements

Figure 8.19 shows the balancing signal for NWPP for the whole month of August while Figure 8.20 displays the balancing signal for a day in August. Long cycles across several days are included in the balancing signal. If only energy storage is used to meet this balancing signal, energy storage that has several days of energy capacity is needed. The long cycle energy storage is very expensive especially for emerging energy storage technologies such as batteries and flywheels. Furthermore, traditional generation resources should have sufficient ramp capability to meet these long cycles because the long cycles usually do not have steep slope. Based on the whole year simulation, the balancing power requirements are 3431 MW of increased capacity and 2726 MW of decreased capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual increased capacity, but the spike has a probability of occurrence less than 0.5 percent.

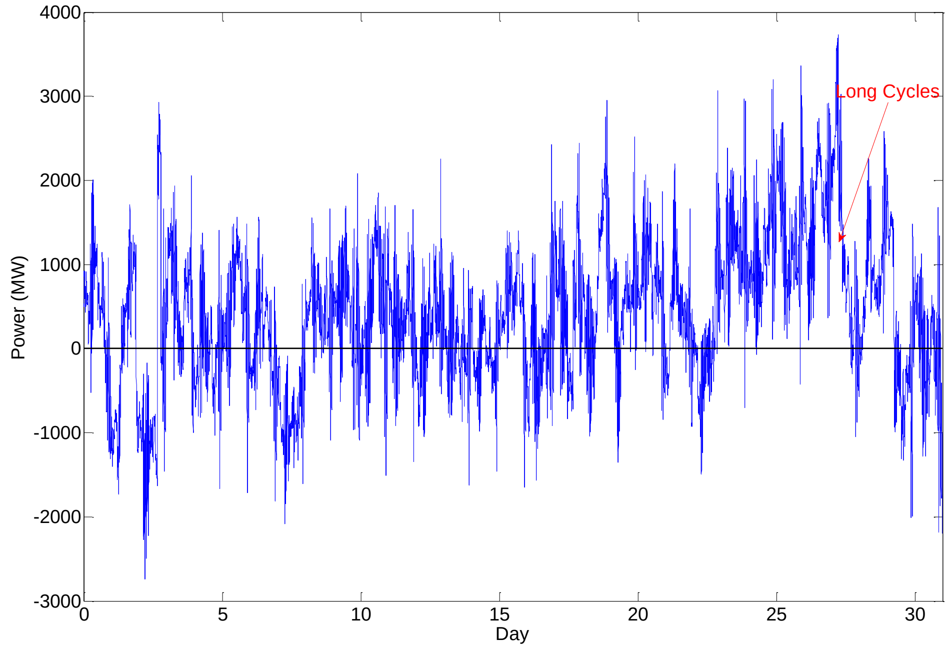

Figure A.19. One Month Total Balancing Signal in August 2020 for NWPP

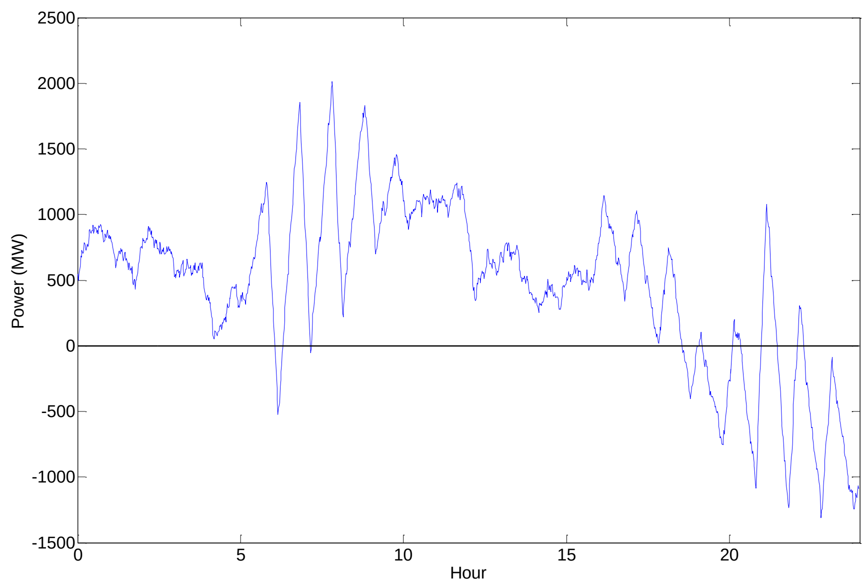

Figure A.20. One Typical Day Total Balancing Signal in August 2020 for NWPP

Figure A.21 shows the balancing signals caused by windpower and by load variations for the whole of August. On the third day, a significant load forecast error is observed. But because of the 99.5 percent criteria, the balancing signal spike falls into the range of 0.5 percent outliers. Therefore, in the summary table at the beginning of this section, the balancing requirements caused by load are still smaller than the balancing signal caused by wind for NWPP. Figure A.22 displays the balancing signals for one day in August.

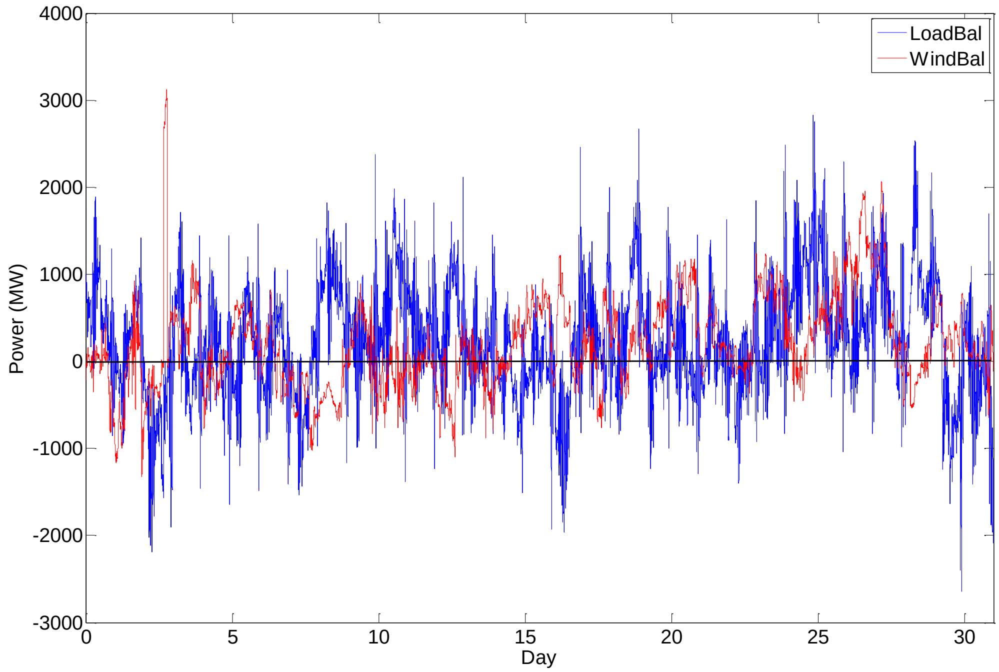

Figure A.21. One Month Balancing Requirements Caused by Load and Wind, Respectively for NWPP

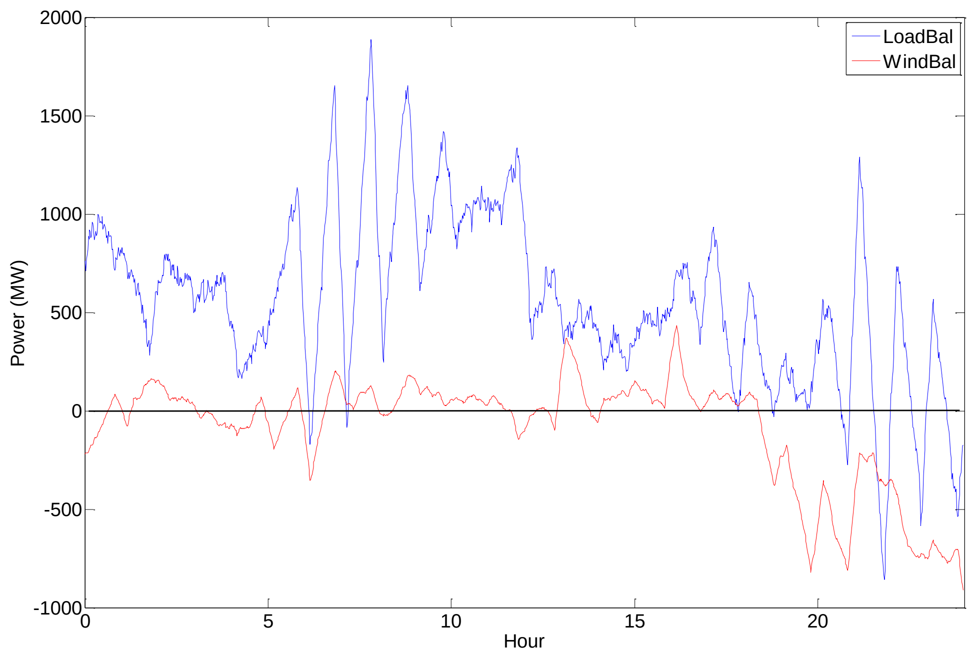

Figure A.22. One Typical Day Balancing Requirements Caused by Load and Wind, Respectively for NWPP

A.3.2 Energy and Power Requirements

Extensive systems modeling 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 Appendix B.

Table A.8, Figure A.23 and Figure A.24 show the results of energy and power requirements for the scenarios in the NWPP area. It should be noted that the capacity requirements or the minimal size of the battery is based on 100 percent 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 percent to improve the life of the battery. For instance, a battery with a DOD of 50 percent only uses its energy storage capability to 50 percent. 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 changeover delay of the pumped hydro and compressed air technologies.

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.

Notice that there are differences in the sizes of storage (GW and GWh) required for the different cases of studies (see Table A.8). These differences are due to the efficiencies and operation strategies of the storage technologies. The GW and GWh differences in cases C2 to C4 and C6 are only due to difference in storage efficiency. The GW and GWh difference in case C7 is due to storage efficiency and due to the need of an additional storage technology (Na-S) to provide balancing during the 4-minute waiting period needed to change between charging and discharging mode (pumping and generation). The large GW and GWh difference in case C5 and C8 with respect to the rest of the cases is mainly because of the restriction in operation assumed; a restriction of only two mode changes (charging to discharging or discharging to charging) is assumed causing a large increase in size requirement (GW and GWh). Details of operation strategies for each technology can be found in Appendix B.

Table A.8, Figure A.23 and Figure A.24 show energy and power requirements for the scenarios in the Northwest (NWPP) area, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.8. Power and Energy Requirements for Each Scenario for NWPP. Note: The energy capacity (GWh) for the batteries is specified for DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	1.99	-
C2	Na-S	2.02	0.60
C3	Li-ion	2.02	0.59
C4	Flywheel	2.00	0.56
C5	CAES 2 modes	3.71	22.09
	7 min waiting period, Na-S	1.24	0.11
C6	Flow battery	2.03	0.62
C7	PH multiple modes	2.01	0.58
	4 min waiting period, Na-S	0.87	0.14
C8	PH 2 modes	3.71	22.21
	4 min waiting period, Na-S	0.89	0.05
C9	DR	7.19	-

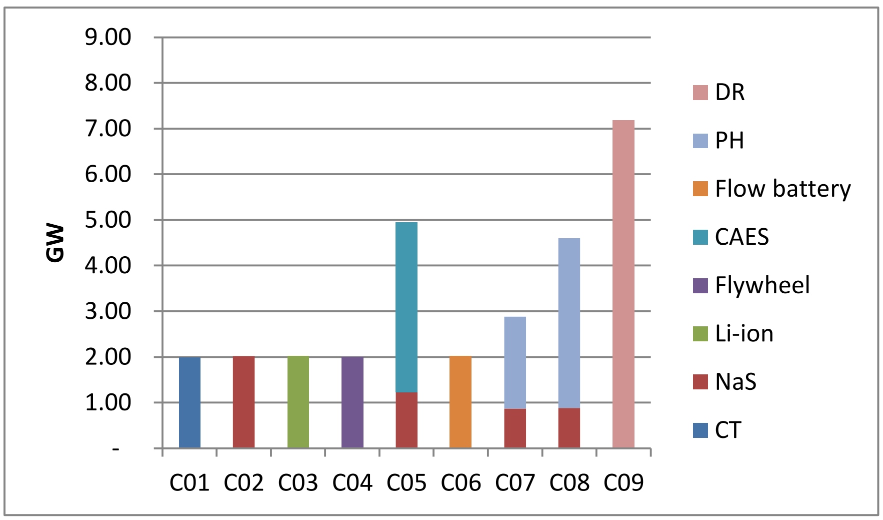

Figure A.23. Power Requirements for all the Technologies to Meet Balancing Signal for NWPP

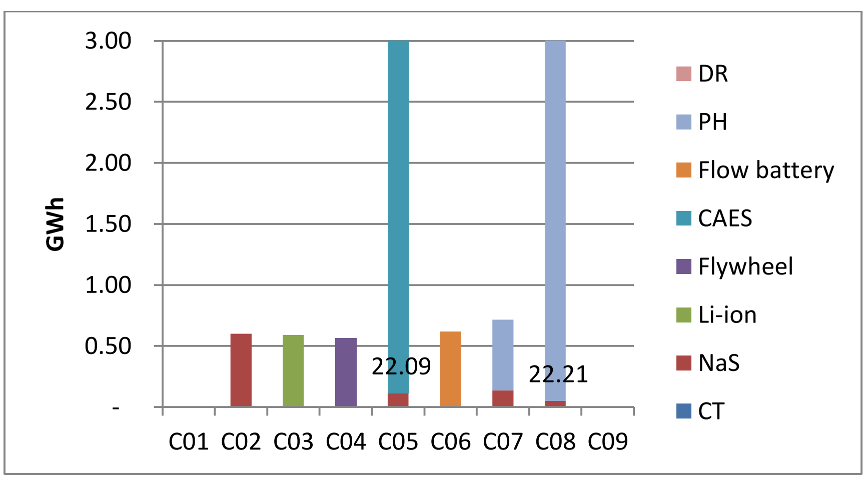

Figure A.24. Energy Requirements for Storage Technologies to Meet Balancing Signal

Table A.9. Power and Energy Requirements for Each Scenario resulting from the 2011-2020 Additional Wind and Load for NWPP. Note: The energy capacity (GWh) for the batteries is specified based on a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.28	-
C2	Na-S	0.28	0.13
C3	Li-ion	0.28	0.12
C4	Flywheel	0.28	0.11
C5	CAES	0.52	2.84
	Na-S	0.10	0.01
C6	Flow battery	0.28	0.13
C7	PH multiple modes	0.28	0.12
	4-min waiting period, Na-S	0.10	0.02
C8	PH 2 modes	0.52	2.86
	4-min waiting period, Na-S	0.07	0.01
C9	DR	1.01	-

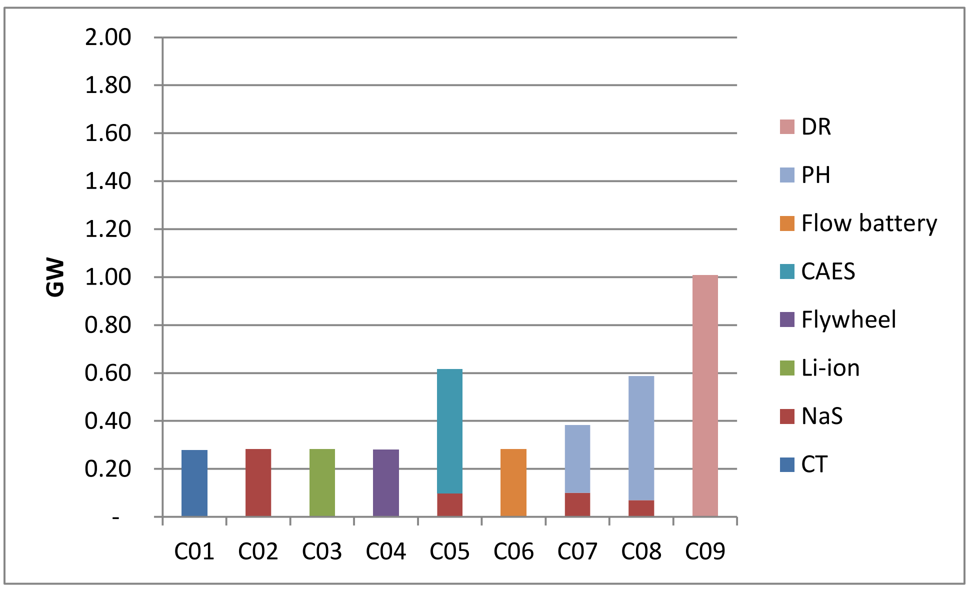

Figure A.25. Power Requirements for all the Technologies to Meet Balancing Signal for the 2011-2020 Additional Wind and Load for NWPP

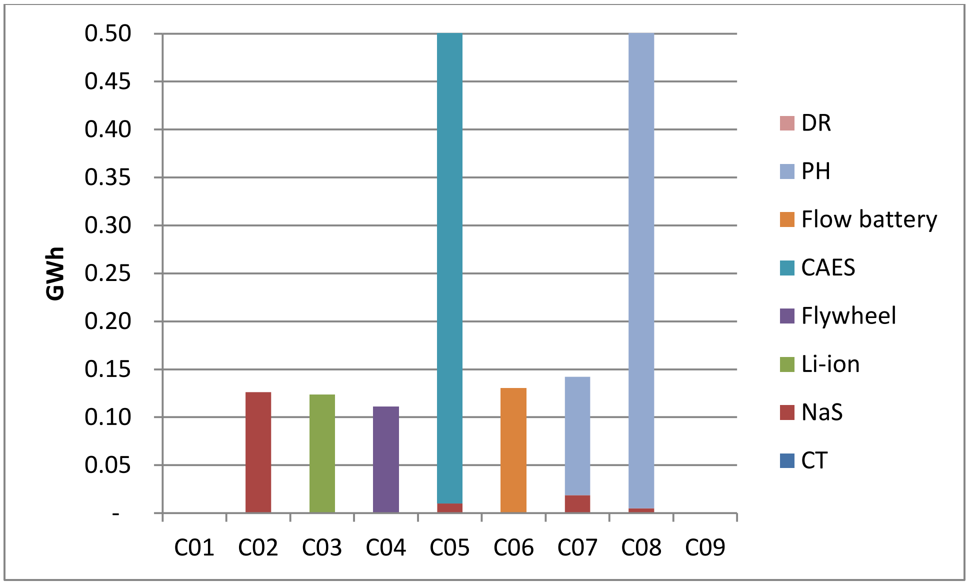

Figure A.26. Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting for the 2011-2020 Additional Wind and Load for NWPP

A.3.3 Life-Cycle Cost Analysis

The results of the economic analysis for the NWPP are presented in Table A.10 and Figure A.27. These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Table A.10 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2 discounted at 8.0 percent.

Table A.10 Economic Analysis Results for the NWPP (2011Dollars)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	5,175	1,067	454	422	**7,117**
2	2,316	164	304	65	**2,849**
3	3,884	147	277	58	**4,366**
4	2,635	70	592	28	**3,324**
5	6,332	1,478	903	584	**9,298**
6	5,629	190	272	75	**6,166**
7	6,334	144	281	57	**6,817**
8	11,550	646	776	255	**13,227**
9	6,891	-	-	-	**6,891**

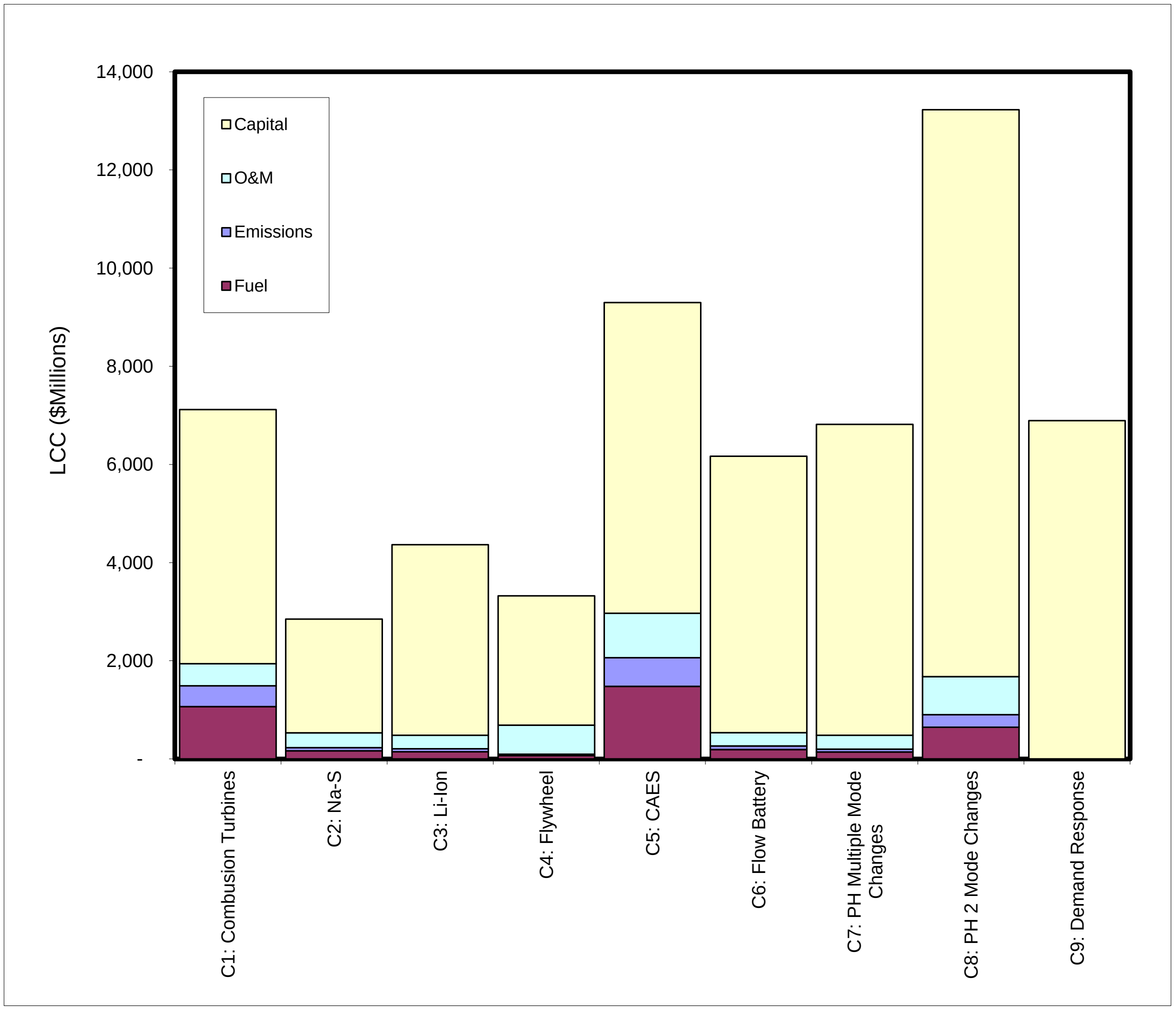

Figure A.27. Scenario LCC Estimates (NWPP)

Case 2, which employs Na-S batteries , is the least cost alternative at $2.8 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $3.3 billion or 16.7 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $6.9 billion. The CAES case (Case 5) is also more expensive with estimated costs of $9.3 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $13.2 billion. Total costs under Case 6, redox flow batteries , are estimated at $6.2 billion.

A.3.4 Arbitrage

Table A.**11** presents the findings of the arbitrage analysis performed for the NWPP. As shown, annual revenues are estimated to range from $0.4-$11.8 million based on energy storage size, which ranges from 29-1,170 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. Annualized costs are estimated to range from $5.9-$237.5 million for pumped hydro, $13.3-$533.2 million for Na-S, and $26.2 million-$1.0 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the NWPP is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services.

Table A.11. Annualized Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (NWPP)

Storage Size		Annual	Annualized Costs		
MWh	MW	Revenue	Pumped Hydro	Na-S	Li-Ion
293	29	$433,947	$5,937,165	$13,329,225	$26,199,225
585	59	$866,424	$11,874,330	$26,658,450	$52,398,450
1,170	117	$1,710,215	$23,748,660	$53,316,900	$104,796,900
1,463	146	$2,120,051	$29,685,825	$66,646,125	$130,996,125
2,925	293	$4,117,123	$59,371,650	$133,292,250	$261,992,250
4,388	439	$5,968,425	$89,057,475	$199,938,375	$392,988,375
5,850	585	$7,627,850	$118,743,300	$266,584,500	$523,984,500
7,313	731	$8,835,563	$148,429,125	$333,230,625	$654,980,625
11,700	1,170	$11,810,694	$237,486,600	$533,169,000	$1,047,969,000

A.4 Rocky Mountain Power Area (RMPA)

The pattern of balancing signal determines the size of energy storage needed to provide the signal. Specifically, the magnitude of the signal determines the power capacity requirement of energy storage.

A.4.1 Balancing Requirements

Figure 8.28 and Figure 8.29 show the balancing signal for the whole of August and one day in August, respectively. Long cycles across several days are included in the balancing signal. If only energy storage is used to meet this balancing signal, energy storage that has several days of energy capacity is needed. Long cycle energy storage is very expensive especially for emerging energy storage technologies such as batteries and flywheels. Furthermore, traditional generation resources should have sufficient ramp capability to meet these long cycles because the long cycles usually do not have steep slopes. Based on the whole year simulation, the balancing power requirements are 2149 MW of increased capacity and 1629 MW of decreased capacity, using the BPA’s customary 99.5 percent probability bound. The balancing requirements for August, especially the increased capacity, are lower than the annual requirements.

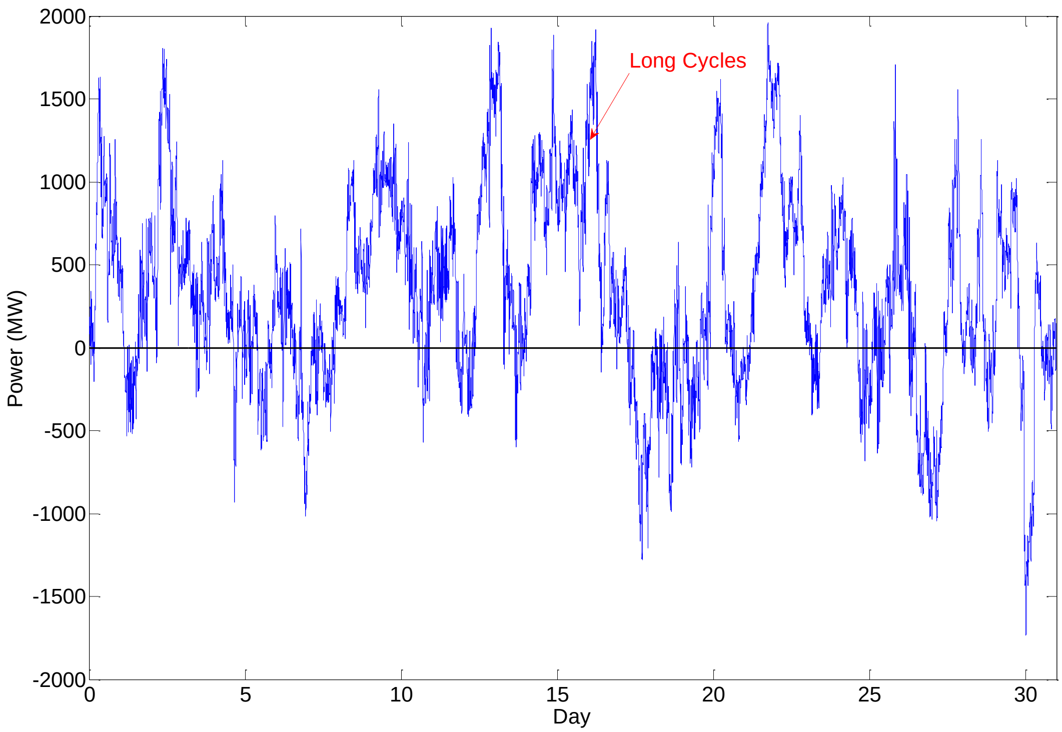

Figure A.28. One Month Total Balancing Signal of August 2020 for RMPP

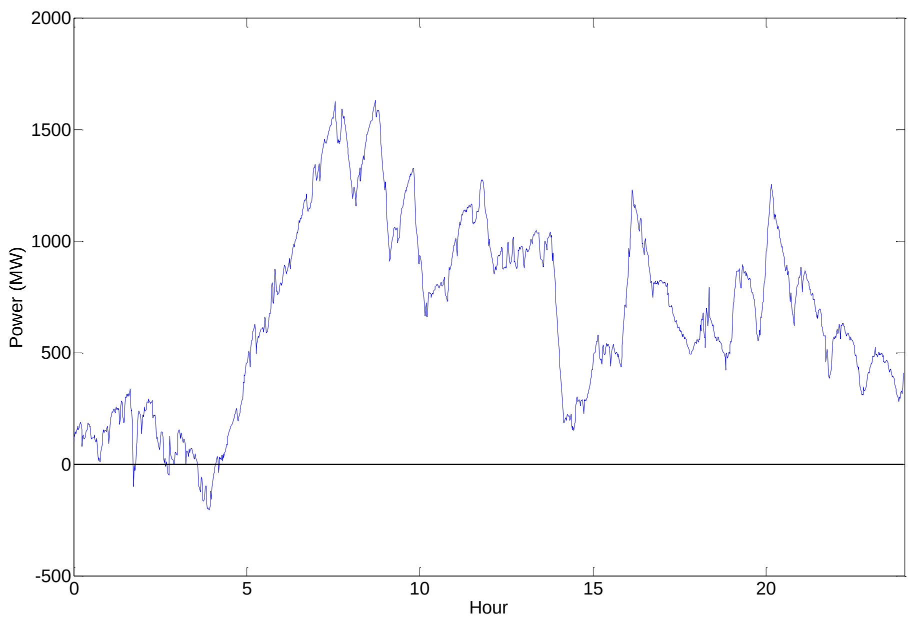

Figure A.29. One Typical Day Total Balancing Signal of August 2020 for RMPP

Figure 8.30 shows the balancing signals caused by wind uncertainty and caused by load uncertainty for the whole month of August. The balancing requirements are almost evenly caused by wind uncertainty and load uncertainty for RMPA. Figure 8.31 displays one day balancing signals caused by wind uncertainty and caused by load uncertainty.

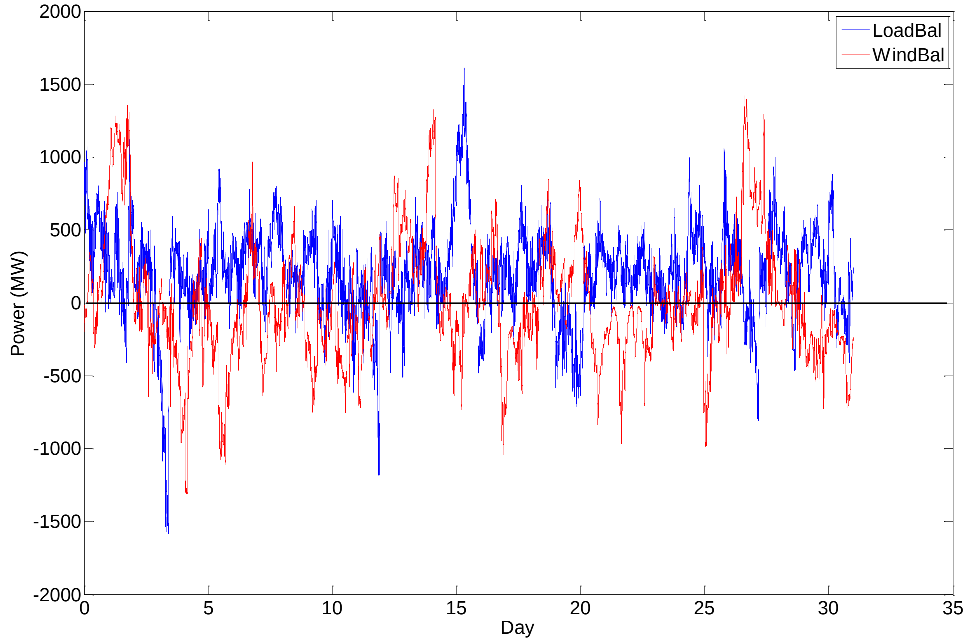

Figure A.30. One Month Balancing Requirements Caused by Load and Wind Respectively for RMPP

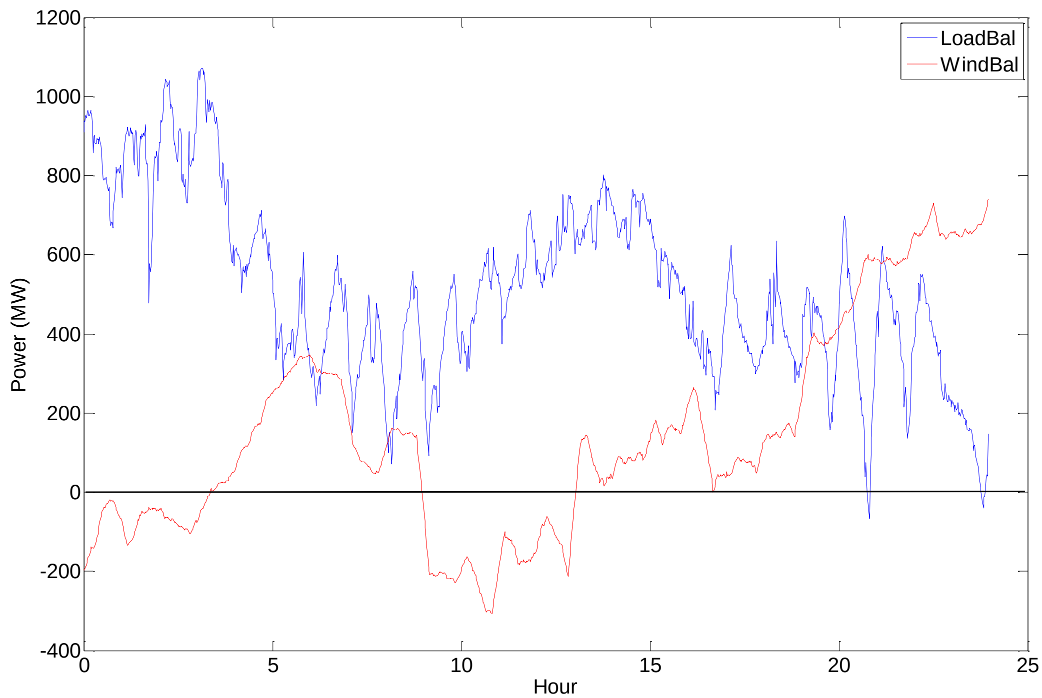

Figure A.31. One Typical Day Balancing Requirements Caused by Load and Wind Respectively for RMPP

A.4.2 Energy and Power Requirements

Extensive systems modeling 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 Appendix B.

Table A.12. Figure A.32 and Figure A.33 show the results of energy and power requirements for the scenarios in the RMPA. It should be noted that the capacity requirements or the minimal size of the battery is based on 100 percent DOD. This means that the size of the energy storage system is fully utilized and would be cycled from fully charged to fully discharged. As will be discussed, there are good economic reasons for upsizing the battery to allow a DOD of less than 100 percent to improve the life of the battery. For instance, a battery with a DOD of 50 percent only uses its energy storage capability to 50 percent. 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 changeover delay of the pumped hydro and compressed air technologies.

Table A.12. Power and Energy Requirements for Each Scenario for RMPP. Note: The energy capacity (GWh) for the batteries is specified for a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.68	-
C2	Na-S	0.67	0.22
C3	Li-ion	0.67	0.22
C4	Flywheel	0.68	0.22
C5	CAES	1.34	7.33
	Na-S	0.44	0.05
C6	Flow battery	0.67	0.22
C7	PH multiple modes	0.67	0.23
	4-min waiting period, Na-S	0.33	0.11
C8	PH 2 modes	1.34	7.37
	4-min waiting period, Na-S	0.36	0.03
C9	DR	2.37	-

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.

Notice that there are differences in the sizes of storage (GW and GWh) required for the different cases of studies (see Table A.12). These differences are due to the efficiencies and operation strategies of the storage technologies. The GW and GWh differences in cases C2 to C4 and C6 are only due to difference in storage efficiency. The GW and GWh difference in case C7 is due to storage efficiency and due to the need of an additional storage technology (Na-S) to provide balancing during the 4-minute waiting period needed to change between charging and discharging mode (pumping and generation). The large GW and GWh difference in case C5 and C8 with respect to the rest of the cases is mainly because of the restriction in operation assumed; a restriction of only two mode changes (charging to discharging or discharging to charging) is assumed causing a large increase in size requirement (GW and GWh). Details of operation strategies for each technology can be found in Appendix B.

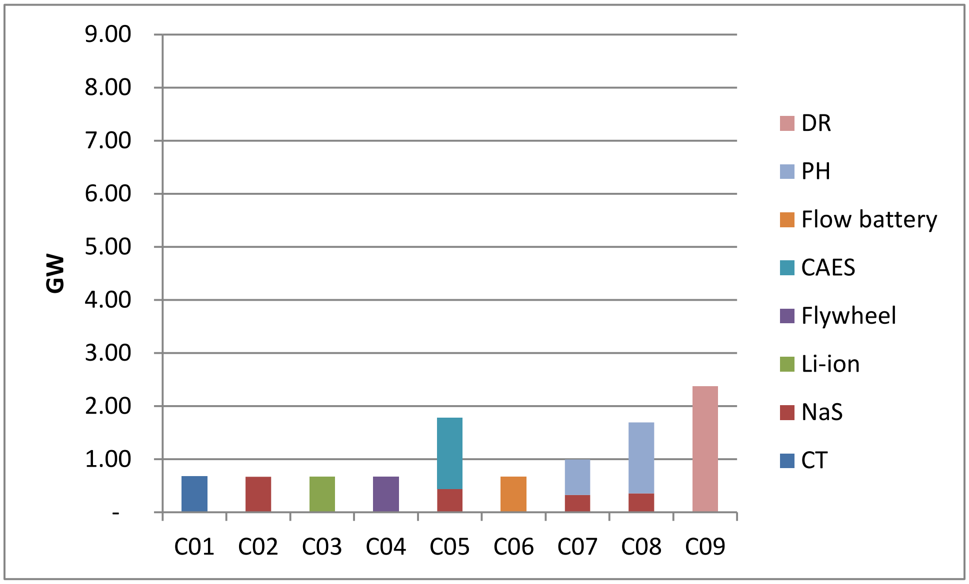

Figure A.32. Power Requirements for all the Technologies to Meet the Balancing Signal for RMPP

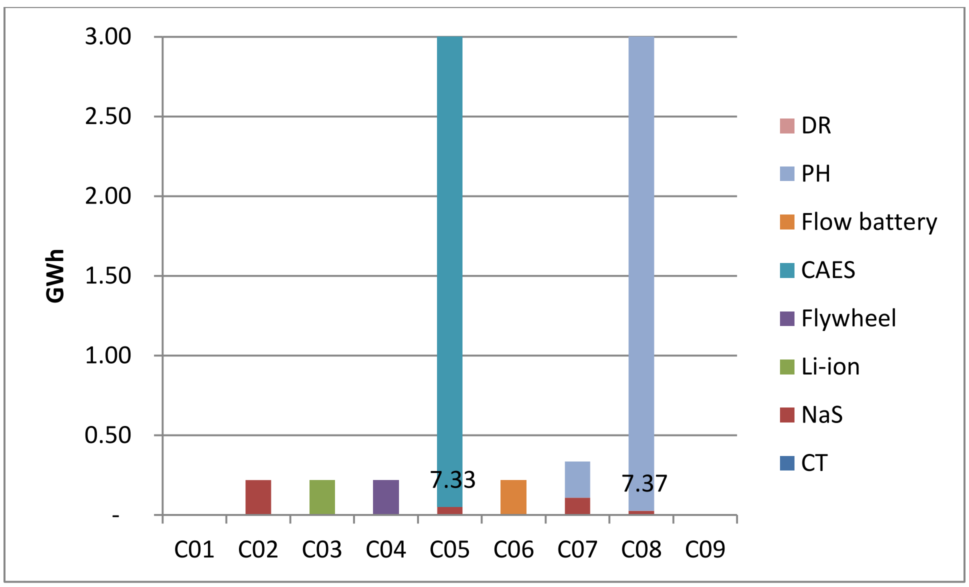

Figure A.33. Energy Requirements for Storage Technologies to Meet the Balancing Signal for RMPP

Table A.13, Figure A.34 and Figure A.35 show the results of energy and power requirements for the scenarios in the RMPA area, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for only additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.13. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for RMPP. Note: The energy capacity (GWh) for the batteries is specified for a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.52	-
C2	Na-S	0.51	0.19
C3	Li-ion	0.51	0.19
C4	Flywheel	0.51	0.18
C5	CAES	0.99	6.16
	Na-S	0.23	0.02
C6	Flow battery	0.51	0.19
C7	PH multiple modes	0.51	0.18
	4-min waiting period, Na-S	0.17	0.03
C8	PH 2 modes	0.99	6.19
	4-min waiting period, Na-S	0.18	0.01
C9	DR	1.73	-

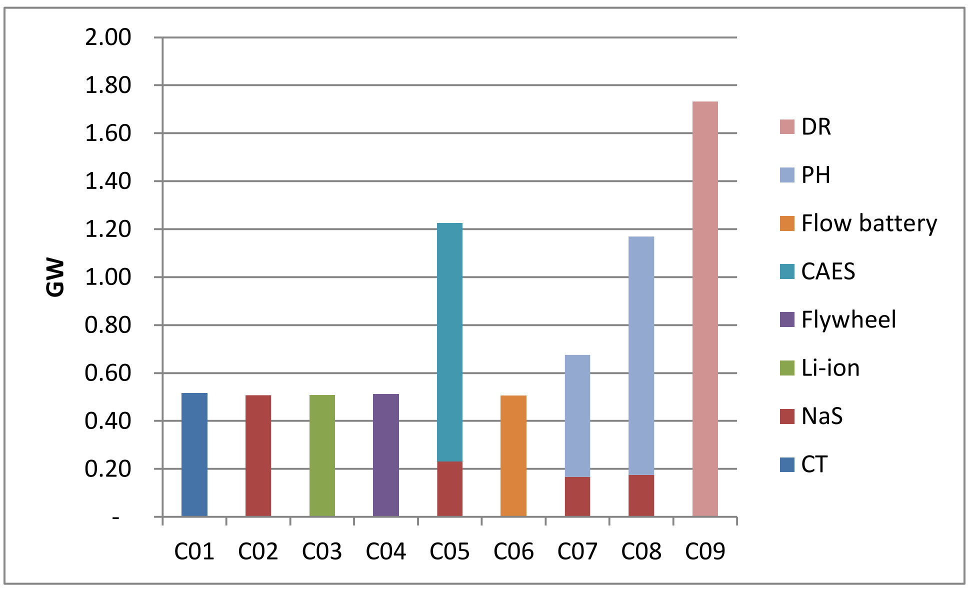

Figure A.34. Power Requirements for all the Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load for RMPP

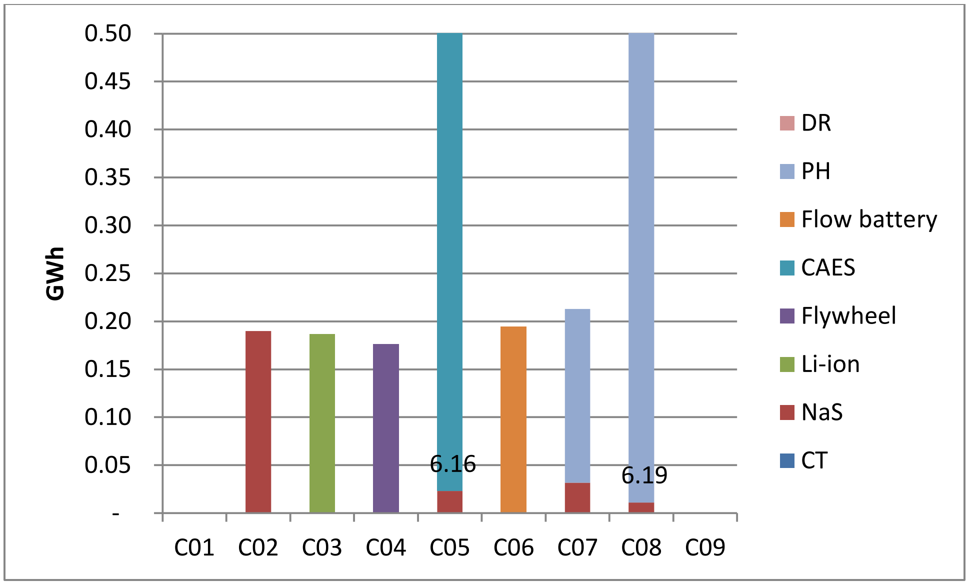

Figure A.35. Energy Requirements for Storage Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load for RMPP

A.4.3 Life-Cycle Cost Analysis

The results of the economic analysis for the RMPA are presented in Table A.14 and Figure A.36. These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Table A.14 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Table A.14. Economic Analysis Results – RMPA (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	1,990	380	156	150	**2,678**
2	766	57	98	22	**944**
3	1,233	51	97	20	**1,401**
4	899	24	201	10	**1,134**
5	2,290	508	318	201	**3,317**
6	1,873	66	91	26	**2,056**
7	2,176	51	101	20	**2,348**
8	4,183	139	251	55	**4,627**
9	2,277	-	-	-	**2,277**

Case 2, which employs Na-S batteries , is the least cost alternative at $0.9 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $1.1 billion or 20.1 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $2.3 billion. The CAES case (Case 5) is also more expensive with estimated costs of $3.3 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $4.6 billion. Total costs under Case 6, redox flow batteries , are estimated at $2.1 billion.

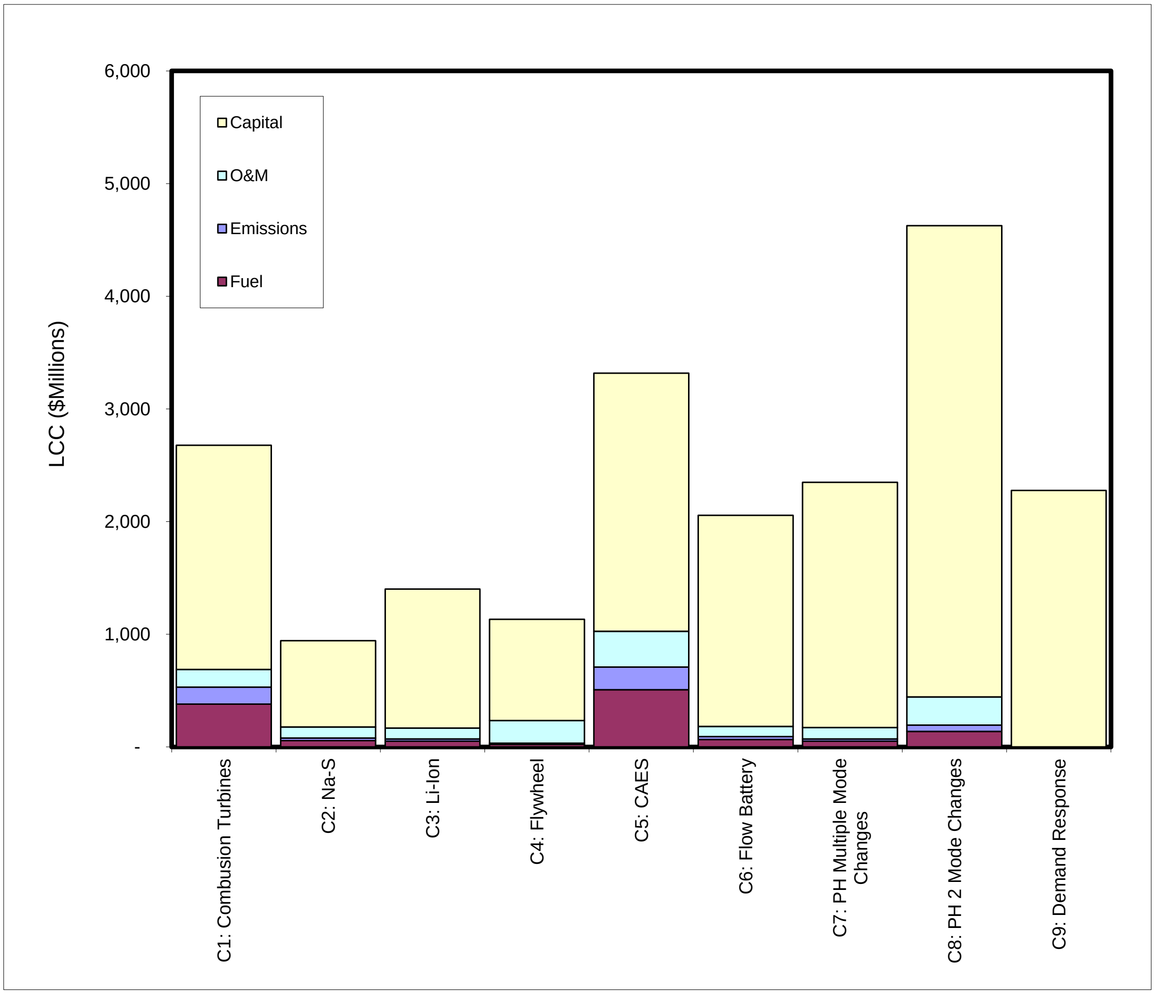

Figure A.36. Scenario LCC Estimates for RMPP

A.4.4 Arbitrage

Arbitrage analysis was not performed in the RMPA.

A.5 ERCOT

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.5.1 Balancing Requirements

Monthly and daily balancing signals of the ERCOT region are shown in Figure A.37 and Figure A.38, respectively. Long cycles across several days are included in the balancing signal. If energy storage alone is used to meet this balancing signal, several days of energy capacity is needed. Long cycle energy storage is very expensive especially for emerging energy storage technologies such as batteries and flywheels. Furthermore, traditional generation resources should have sufficient ramp capability to meet these long cycles because they typically do not have steep slopes. Based on the whole year simulation, balancing power requirements are 6879 MW of incremental (inc) capacity and 10996 MW of decremental (dec) capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August, especially the incremental capacity, are lower than the annual requirements.

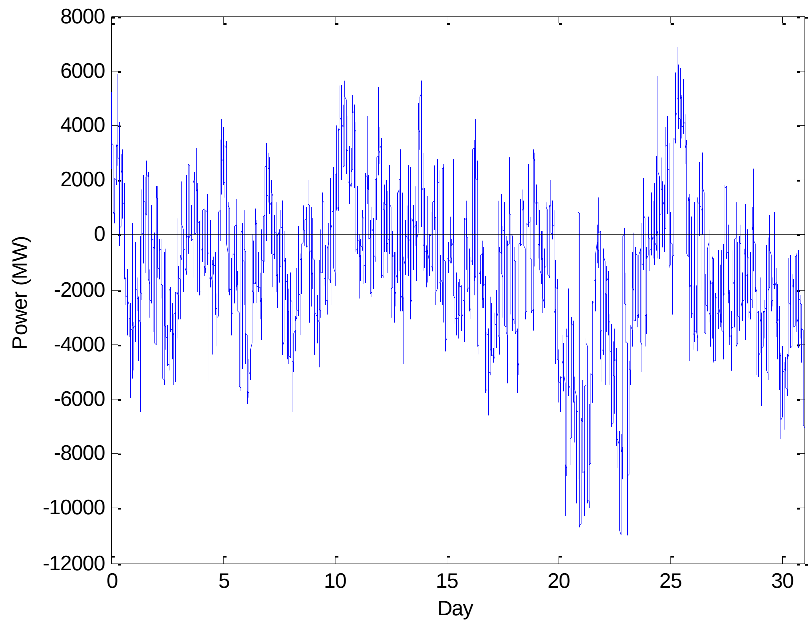

Figure A.37. One Month Total Balancing Signal in August 2020 for ERCOT

Figure A.39 shows the balancing signal caused by wind and by load separately for the whole of August. Figure A.**40** shows the same information for a day in August. For ERCOT, balancing requirements are caused by both load and wind uncertainty.

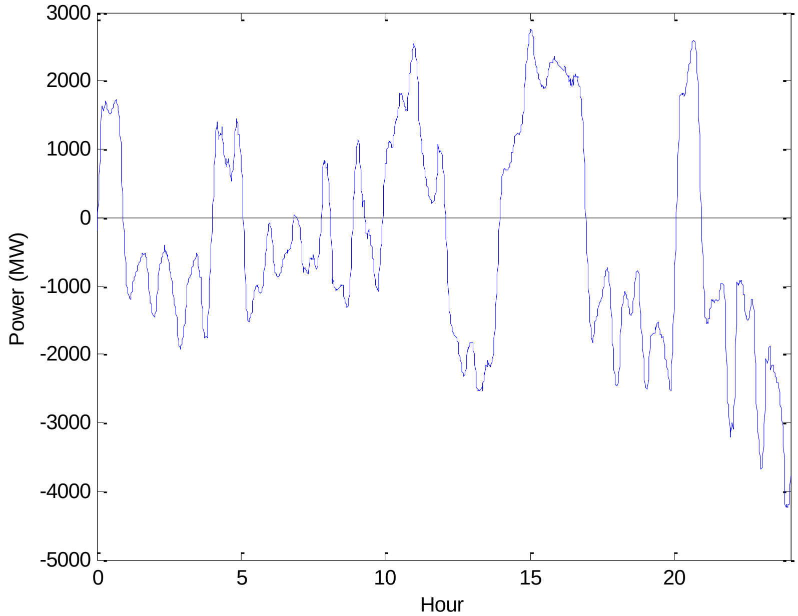

Figure A.38. One Typical Day Total Balancing Signal in August 2020 for ERCOT

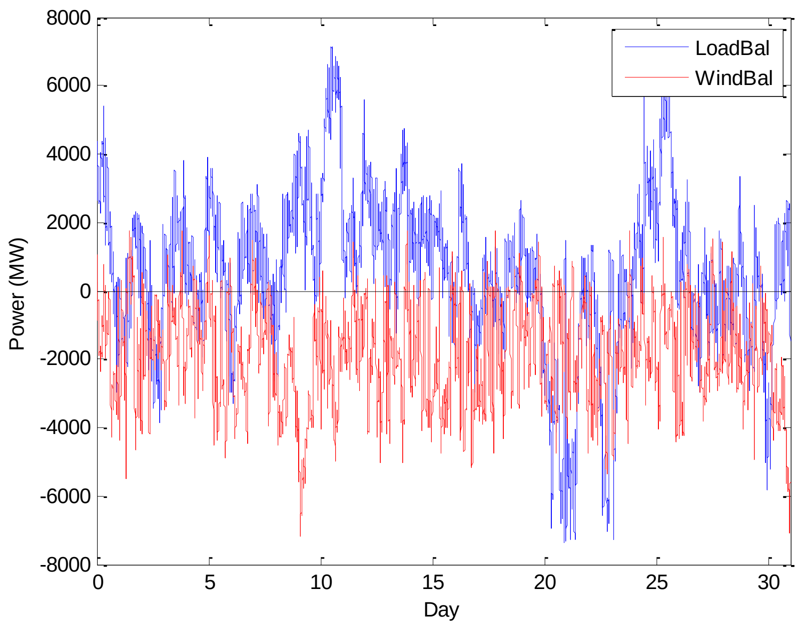

Figure A.39. One Month Balancing Requirements Caused by Load and Wind, Respectively, for ERCOT

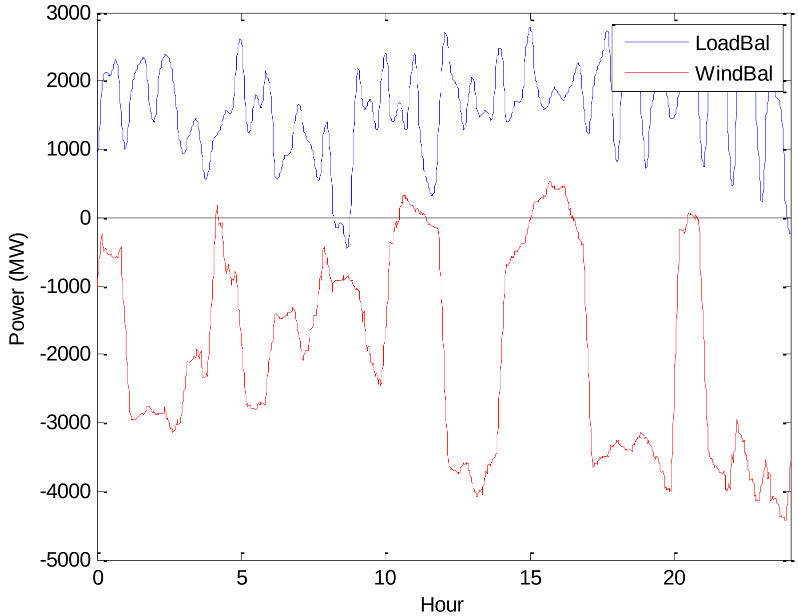

Figure A.40. One Typical Day Balancing Requirements Caused by Load and Wind, Respectively, for ERCOT

A.5.2 Energy and Power Requirements

Using the approach described above, Table A.15, Figure A.41 and Figure A.42 show the results of energy and power requirements for the ERCOT scenarios. It should be noted that the capacity requirements or the minimal size of the battery is based on nominal 100 percent DOD of the battery. As discussed previously, there are good economic reasons for upsizing the battery to a DOD of less than 100 percent to improve the life of the battery.

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 changeover delay of the pumped hydro and compressed air technologies.

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.

Notice that there are differences in the sizes of storage (GW and GWh) required for the different cases of studies (see Table A.15). These differences are due to the efficiencies and operation strategies of the storage technologies. The GW and GWh difference in cases C2 to C4 and C6 are only due to difference in storage efficiency. The GW and GWh difference in case C7 is due to storage efficiency and due to the need of an additional storage technology (Na-S) to provide balancing during the 4-minute waiting period needed to change between charging and discharging mode (pumping and generation). The large GW and GWh difference in case C5 and C8 with respect to the rest of the cases is mainly because of the restriction in operation assumed; a restriction of only two mode changes (charging to discharging or discharging to charging) is assumed causing a large increase in size requirement (GW and GWh). Details of operation strategies for each technology can be found in Appendix B.

Table A.15. Power and Energy Requirements for Each Scenario for ERCOT. Note: The energy capacity (GWh) for the batteries is specified for a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	3.93	-
C2	NaS	4.00	1.72
C3	Li-ion	3.99	1.71
C4	Flywheel	3.96	1.66
C5	CAES	6.63	45.88
	NaS	2.06	0.26
C6	Flow battery	4.01	1.75
C7	PH multiple modes	3.98	1.63
	4 min waiting period, NaS	1.85	0.32
C8	PH 2 modes	6.63	46.01
	4 min waiting period, NaS	2.06	0.16
C9	DR	14.19	-

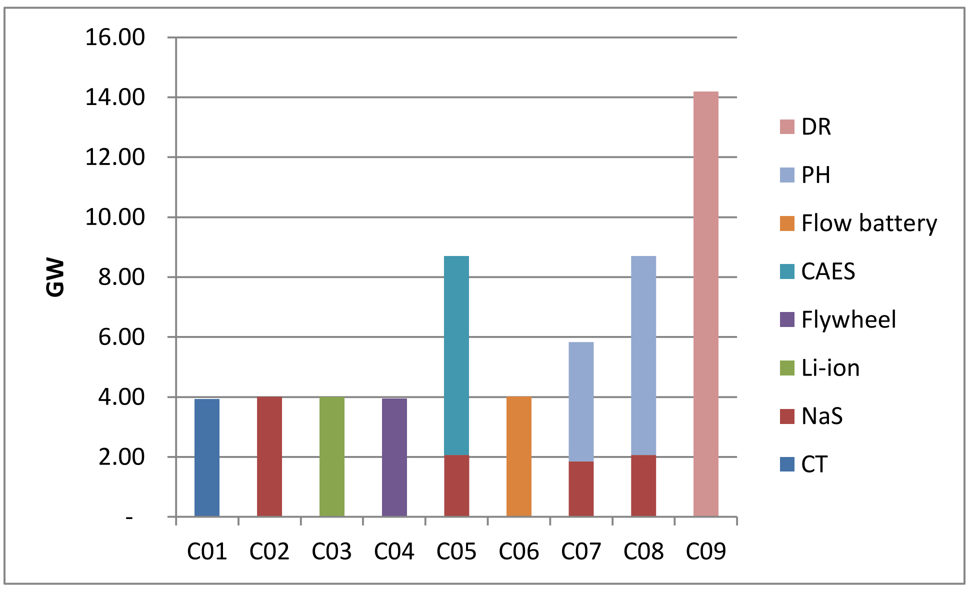

Figure A.41. Power Requirements for all the Technologies to Meet Balancing Signal for ERCOT

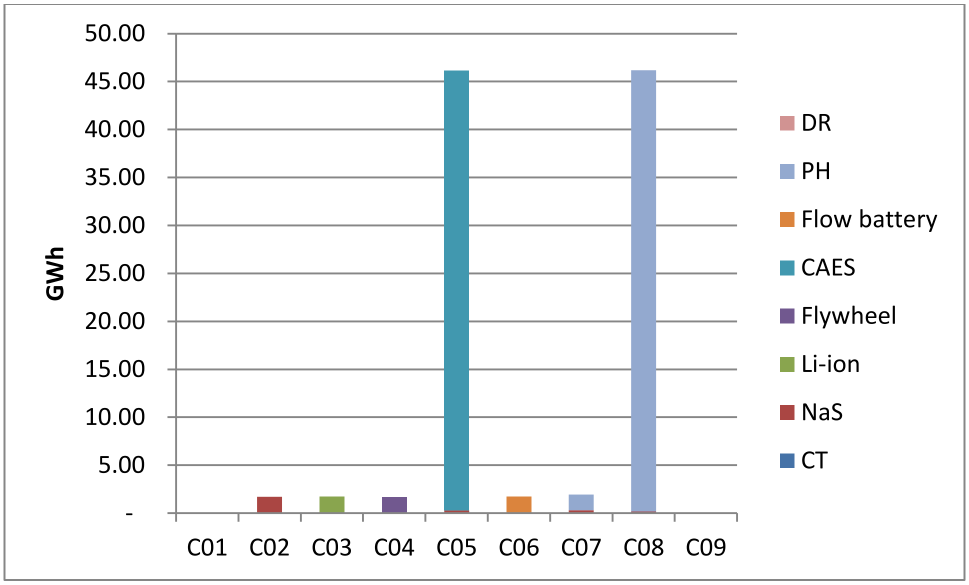

Figure A.42. Energy Requirements for Storage Technologies to Meet Balancing Signal for ERCOT

Table A.16, Figure A.43 and Figure A.44 show the results of energy and power requirements for the ERCOT scenarios,, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.16. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for ERCOT. Note: The energy capacity (GWh) for the batteries is specified for a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	1.12	-
C2	Na-S	1.15	0.70
C3	Li-ion	1.15	0.70
C4	Flywheel	1.13	0.67
C5	CAES	2.17	12.96
	Na-S	0.69	0.10
C6	Flow battery	1.15	0.71
C7	PH multiple modes	1.14	0.66
	4-min waiting period, Na-S	0.67	0.12
C8	PH 2 modes	2.17	13.04
	4-min waiting period, Na-S	0.57	0.05
C9	DR	4.06	-

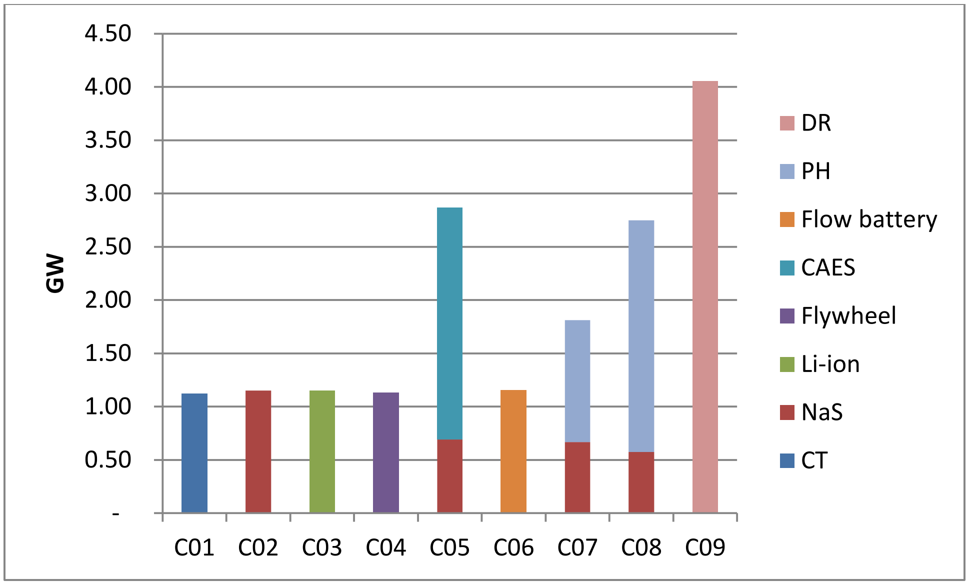

Figure A.43. Power Requirements for all the Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load for ERCOT

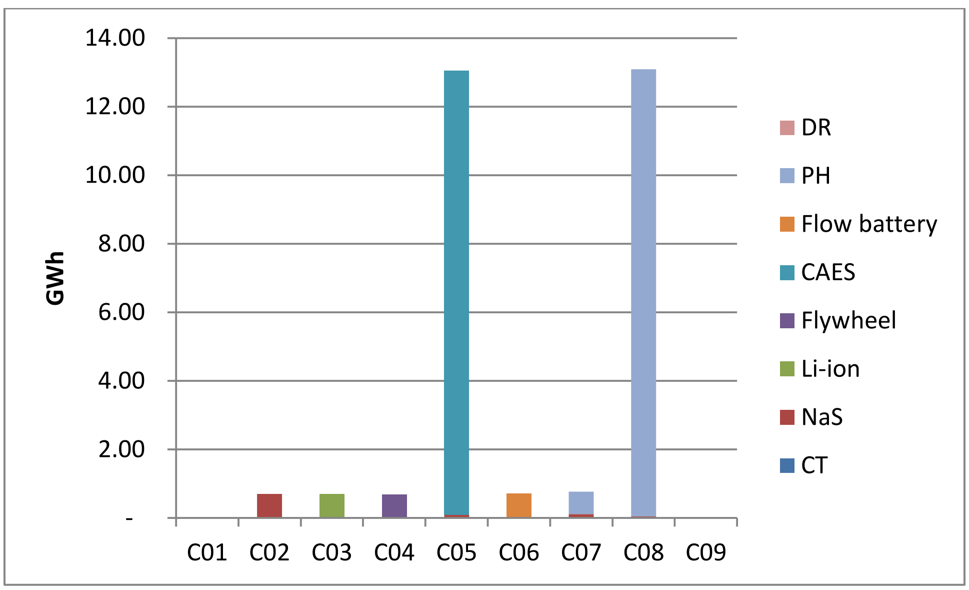

Figure A.44. Energy Requirements for Storage Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load for ERCOT

A.5.3 Life-Cycle Cost Analysis

The results of the economic analysis for the ERCOT power area are presented in Table A.17 and Figure A.45. These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Table A.17 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol.2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at \$5.7 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at \$6.7 billion or 17.4 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at \$13.6 billion. The CAES case (Case 5) is also more expensive with estimated costs of \$16.4 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at \$23.0 billion. Total costs under Case 6, redox flow batteries , are estimated at \$12.4 billion.

Table A.17. Economic Analysis Results – ERCOT (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	9,952	2,293	923	906	14,073
2	4,622	355	606	140	5,724
3	7,475	319	597	126	8,516
4	5,335	150	1,176	59	6,721
5	11,347	2,441	1,622	965	16,374
6	11,288	411	546	162	12,408
7	12,667	311	583	123	13,684
8	20,973	549	1,298	217	23,037
9	13,609	-	-	-	13,609

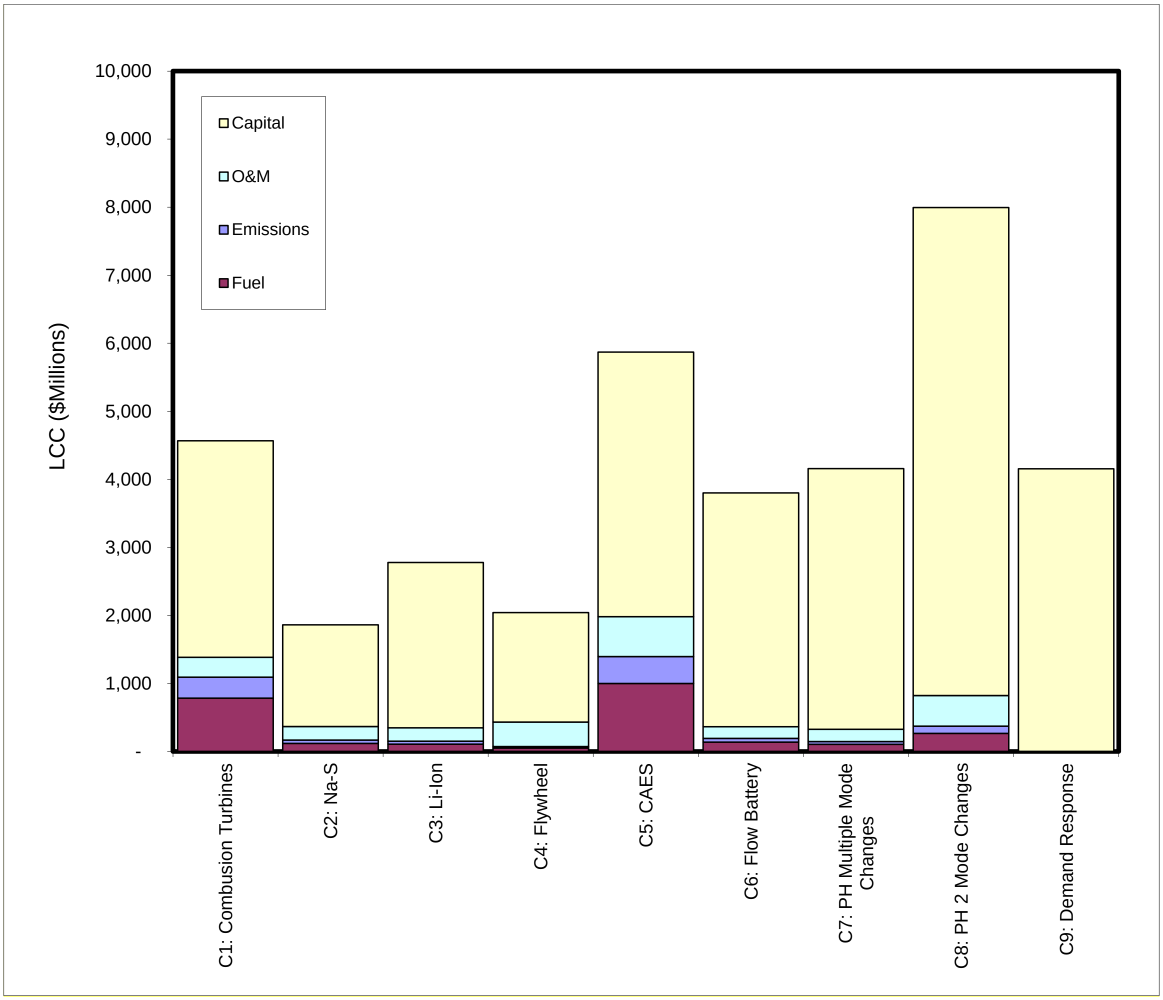

Figure A.45. Scenario LCC Estimates for ERCOT

A.5.4 Arbitrage

Table A.**18** presents the findings of the arbitrage analysis performed for the ERCOT. As shown, annual arbitrage revenues are estimated to range from $8.1-$284.3 million based on energy storage size, which ranges from 70-2,814 MW. Annual revenue per MW falls from a high of $114,943 at 70 MW to $101,013 at 2,814 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydropower generates profits at all energy storage capacities. Annual profits are $4.4 million at 70 MW and $135.2 million at 2,814 MW of capacity. Annualized costs are estimated to range from $14.3-$571.2 million for pumped hydro, $32.1 million-$1.3 billion for Na-S, and $63.0 million-$2.5 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the ERCOT is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is bridged but only withy pumped hydropower.

Table A.18. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (ERCOT)

Storage Size	Annual Revenue		Annualized Capital Costs		
(MW)	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
70	8,086,240	10,552,500	14,279,643	32,058,495	63,012,495
141	16,200,358	21,105,000	28,559,286	64,116,990	126,024,990
281	32,301,145	42,210,000	57,118,572	128,233,980	252,049,980
352	40,289,865	52,762,500	71,398,215	160,292,475	315,062,475
704	79,805,277	105,525,000	142,796,430	320,584,950	630,124,950
1,055	118,467,510	158,287,500	214,194,645	480,877,425	945,187,425
1,407	156,841,792	211,050,000	285,592,860	641,169,900	1,260,249,900
1,759	193,287,458	263,812,500	356,991,075	801,462,375	1,575,312,375
2,111	226,942,085	316,575,000	428,389,290	961,754,850	1,890,374,850
2,462	259,957,060	369,337,500	499,787,505	1,122,047,325	2,205,437,325
2,814	284,250,391	422,100,000	571,185,720	1,282,339,800	2,520,499,800

A.6 Florida

Balancing analysis was not carried out for this region because we assumed that no wind resource would be adopted in this region by the year 2020.

A.6.1 Arbitrage

Arbitrage analysis was not performed in this region.

A.7 MROE

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.7.1 Balancing Requirements

Monthly and daily balancing signals of region MROE are shown in Figure A.46 and Figure A.47, respectively Based on the whole year simulation, the balancing power requirements are 426.9 MW of incremental (inc) capacity and 662.5 MW of decremental (dec) capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August, especially the incremental capacity, are lower than the annual requirements.

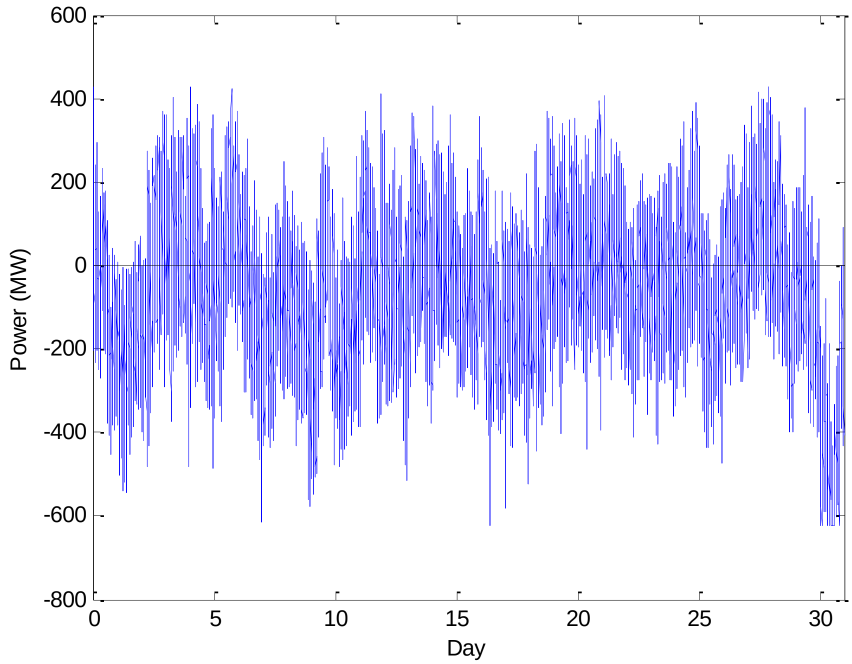

Figure A.46. One Month Total Balancing Signal in August 2020 for MROE

Figure A.48 shows the balancing signal caused by wind and by load separately for the whole of August. Figure A.49 shows the same information for a day in August. For the Midwest Reliability Council/East (MROE) region, the balancing requirements are mainly caused by load uncertainty because the wind resource in the MROE region is scarce and the peak load level is high.

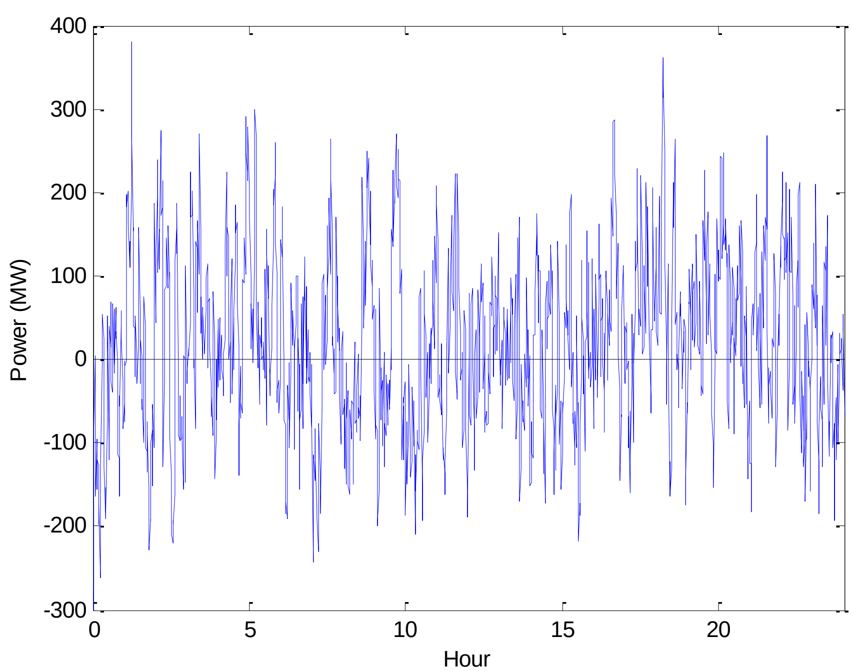

Figure A.47. One Typical Day Total Balancing Signal in August 2020 for MROE

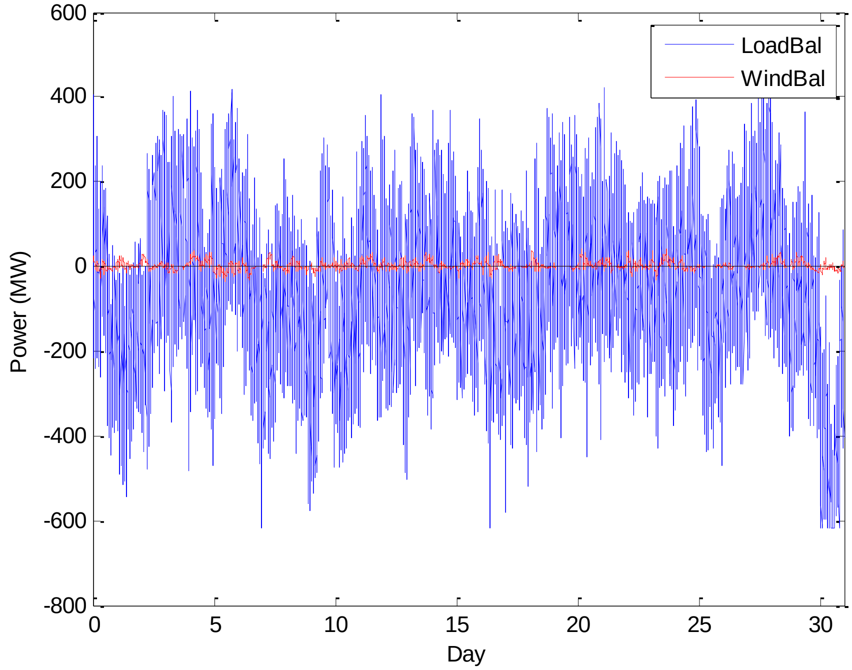

Figure A.48. One Month Balancing Requirements Caused by Load and Wind, Respectively for MROE

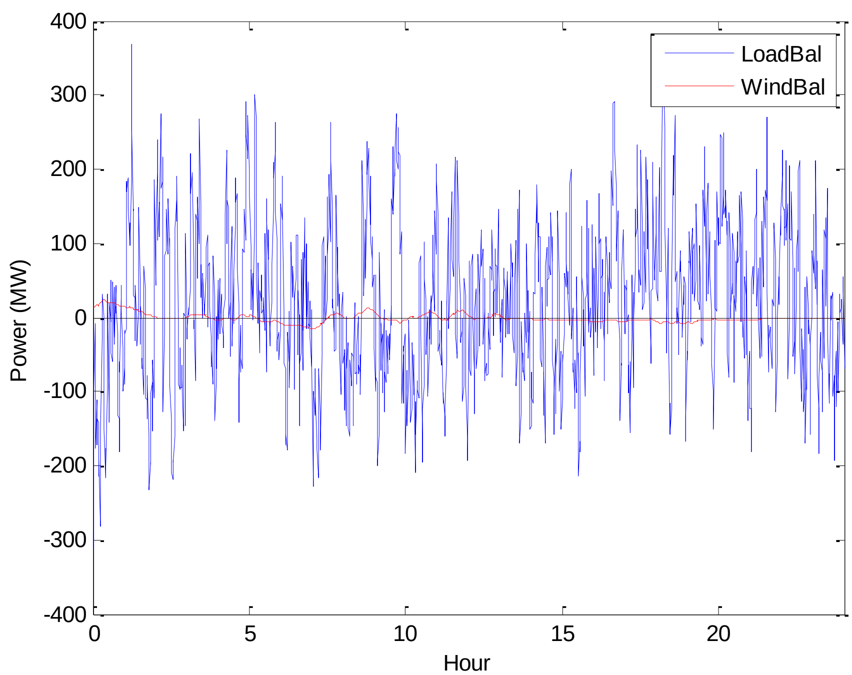

Figure A.49. One Typical Day Balancing Requirements Caused by Load and Wind Respectively for MROE

A.7.2 Energy and Power Requirements

Table A.19, Figure A.50 and Figure A.51 show the results of energy and power requirements for the scenarios in the MROE area.

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

Table A.19. Power and Energy Requirements for Each Scenario for MROE. Note: The energy capacity (GWh) for the batteries is nominally at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.49	-
C2	NaS	0.50	0.15
C3	Li-ion	0.50	0.14
C4	Flywheel	0.50	0.14
C5	CAES	0.91	5.61
	NaS	0.27	0.02
C6	Flow battery	0.50	0.15
C7	PH multiple modes	0.49	0.20
	4 min waiting period, NaS	0.46	0.19
C8	PH 2 modes	0.91	5.64
	4 min waiting period, NaS	0.25	0.01
C9	DR	1.78	-

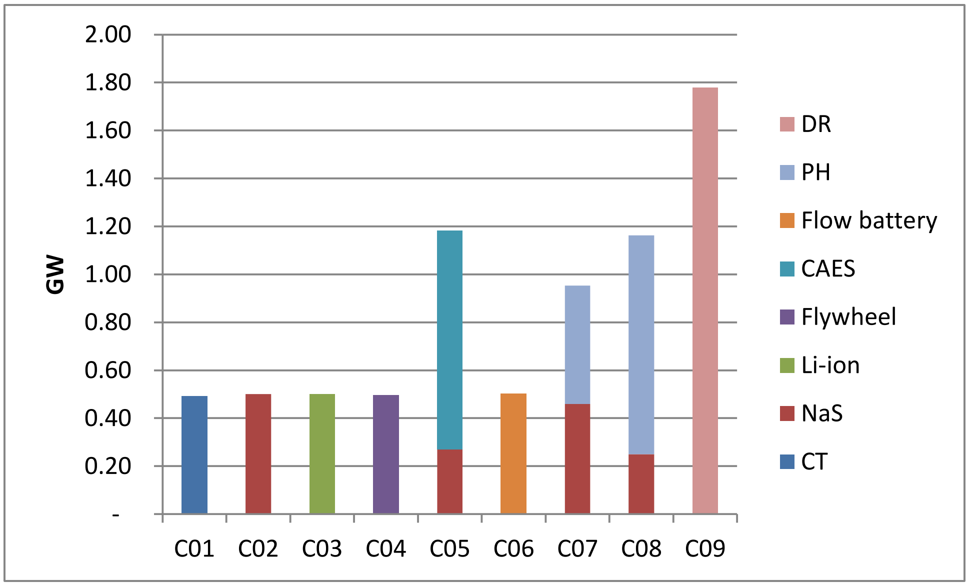

Figure A.50. Power Requirements for all the Technologies to Meet Balancing Signal for MROE

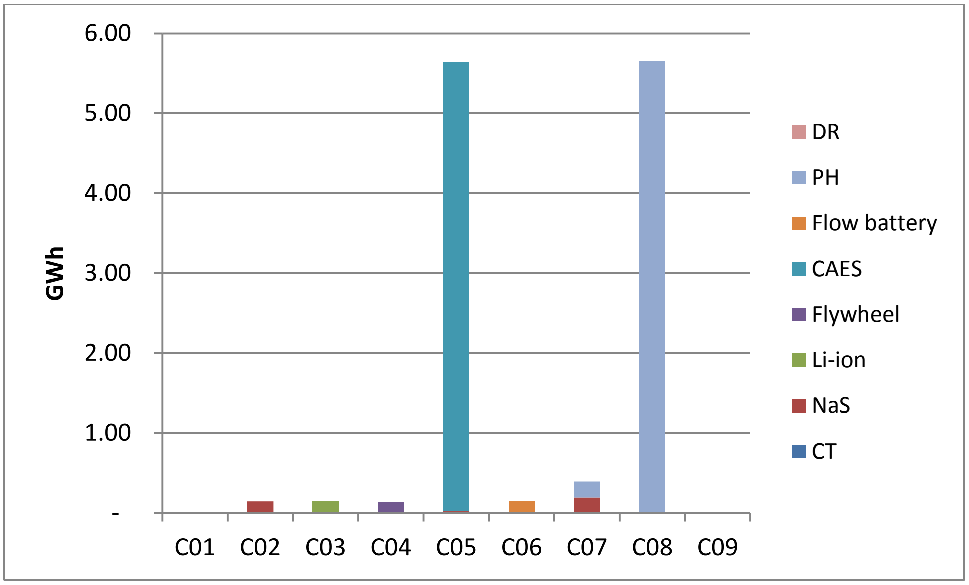

Figure A.51. Energy Requirements for Storage Technologies to Meet Balancing Signal for MROE

As explained previously there are differences in the sizes of storage (GW and GWh) required for the different cases. Table A.20, and Figure A.52 and Figure A.53 show the results of energy and power requirements for the future MROE scenarios, considering only the additional wind generation and load expected between 2011 and 2012. As before, these are the requirements for additional balancing assuming that the 2011 level of balancing is provided by existing resources.

Table A.20. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for MROE. Note: The energy capacity (GWh) for the batteries is specified for a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.02	-
C2	Na-S	0.02	0.01
C3	Li-ion	0.02	0.01
C4	Flywheel	0.02	0.01
C5	CAES	0.03	0.19
	Na-S	0.01	-
C6	Flow battery	0.02	0.01
C7	PH multiple modes	0.02	0.01
	4-min waiting period, Na-S	0.01	-
C8	PH 2 modes	0.03	0.19
	4-min waiting period, Na-S	0.01	-
C9	DR	0.06	-

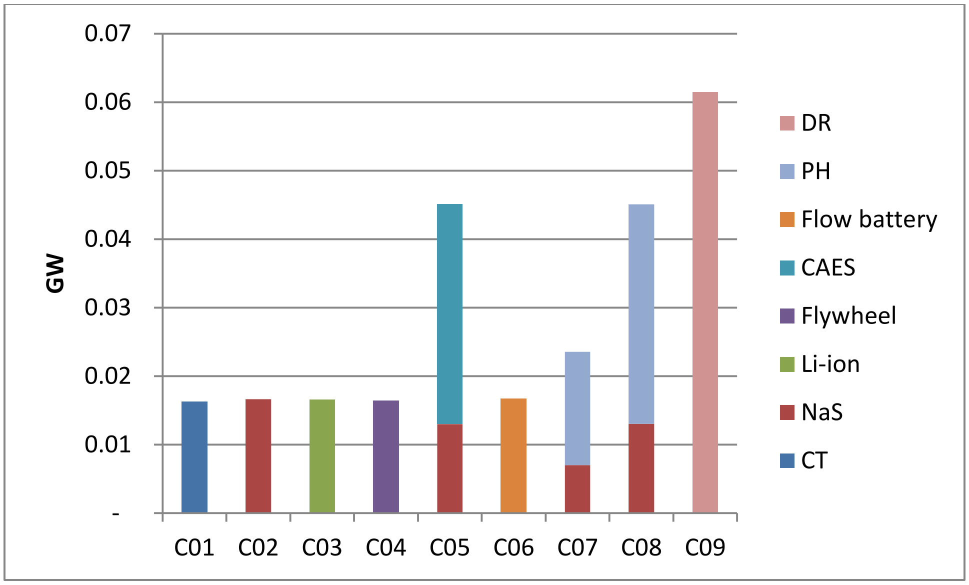

Figure A.52. Power Requirements for all the Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for MROE

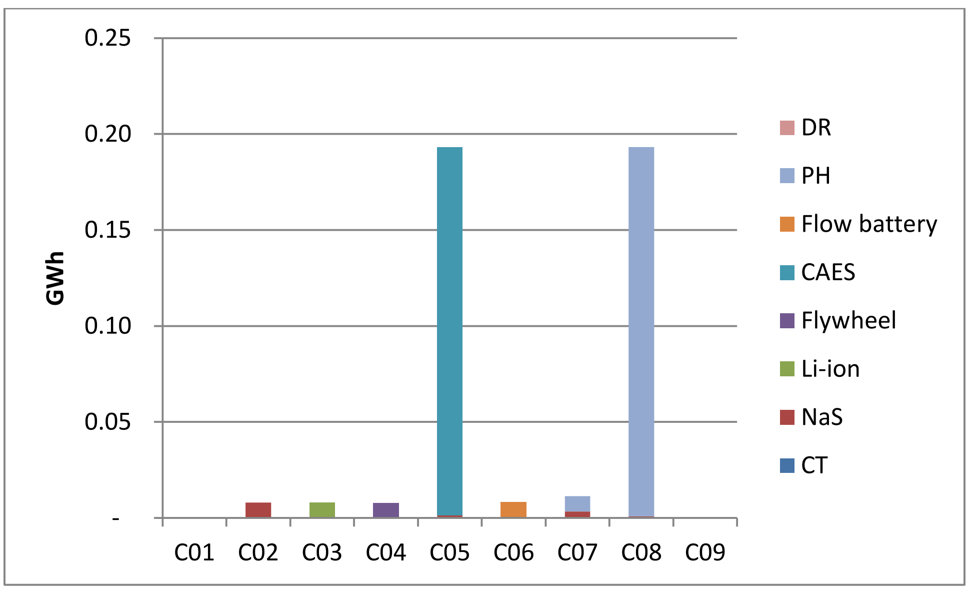

Figure A.53. Energy Requirements for Storage Technologies to Meet MROE Balancing Signal Resulting from 2011-2020 Additional Wind and Load Scenarios

A.7.3 Life-Cycle Cost Analysis

The results of the economic analysis for the MROE area are presented in Table A.21 and Figure A.54. The values presented in Table A.21 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $0.9 billion followed by Case 4, which consists of flywheels , at $1.5 billion. The costs associated with the DR-only case (Case 9) are nearly twice as expensive as those estimated for the two aforementioned cases, registering at $4.2 billion. The CAES case (Case 5) is also more expensive with estimated costs of $2.7 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $3.1 billion. Total costs under Case 6, redox flow batteries , are estimated at $2.2 billion.

Table A.21. Economic Analysis Results – MROE (2020 Dollars)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	1,623	318	118	126	2,184
2	724	47	75	19	864
3	1,468	42	74	17	1,601
4	1,322	20	148	8	1,498
5	1,845	454	248	180	2,727
6	2,085	54	72	21	2,233
7	1,923	47	102	18	2,090
8	2,711	124	197	49	3,081
9	1,705	-	-	-	1,705

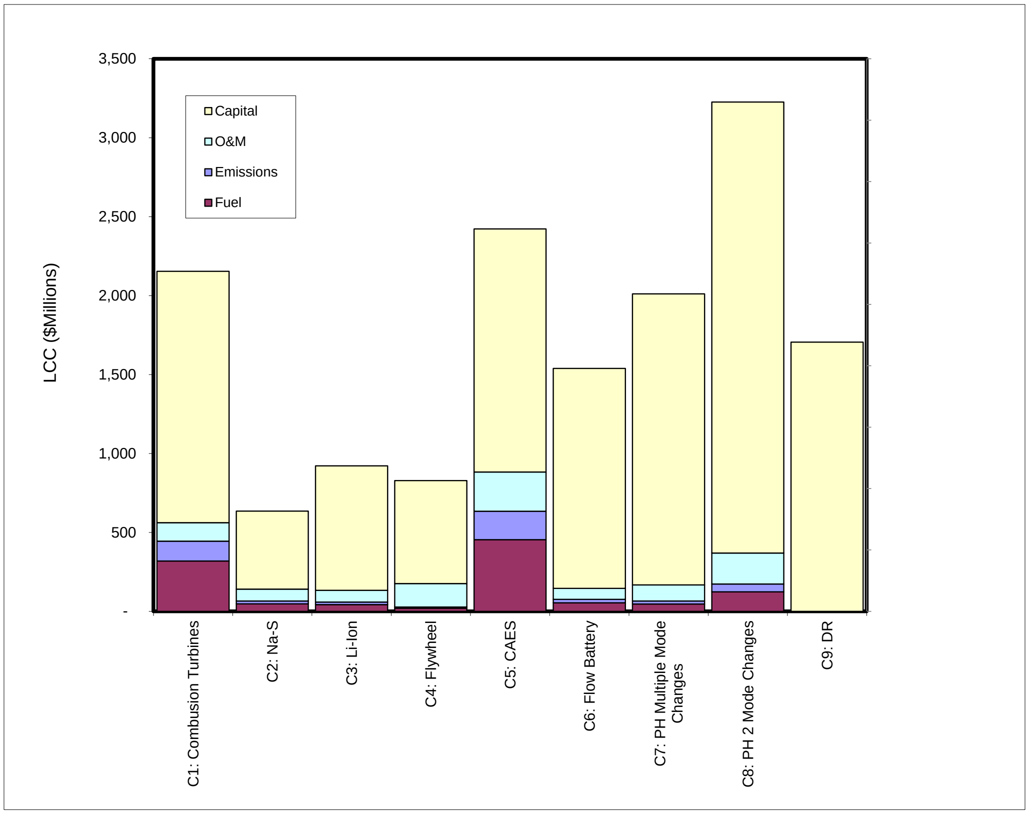

Figure A.54. LCC Scenario Estimates for MROE

A.7.4 Arbitrage

Arbitrage analysis was not performed for the MROE.

A.8 MROW

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.8.1 Balancing Requirements

Monthly and daily balancing signals of the MROW area are shown in Figure A.55 and Figure A.56, respectively. Based on the whole year simulation, balancing power requirements are 7286 MW of incremental (inc) capacity and 6766.6 MW of decremental (dec) capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August, especially the incremental capacity, are lower than the annual requirements.

Figure A.57 shows monthly balancing signals caused by load and wind variations in the MROW region. In this region, the balancing requirements are caused more by wind uncertainty than by load because the wind resource here is abundant. Figure A.58 presents MROW balancing signals for one day.

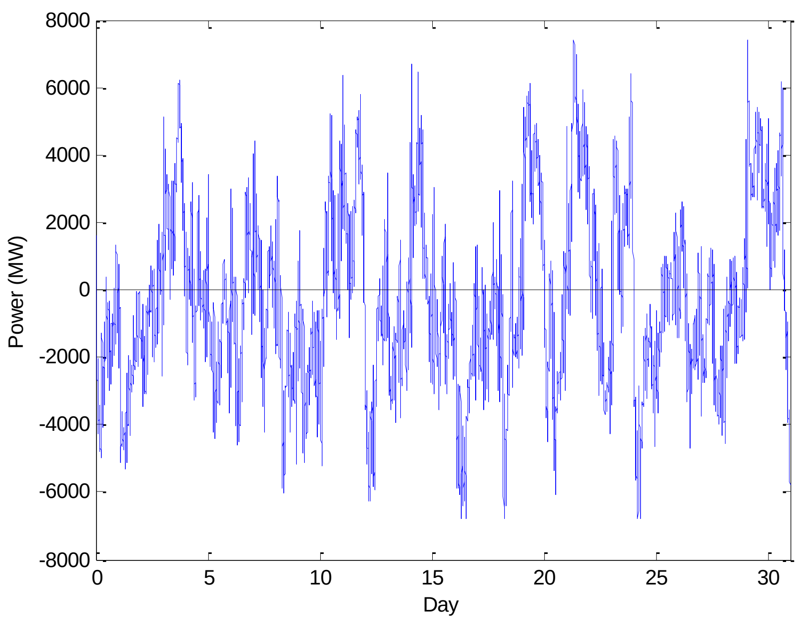

Figure A.55. One Month Total MROW Balancing Signal in August 2020

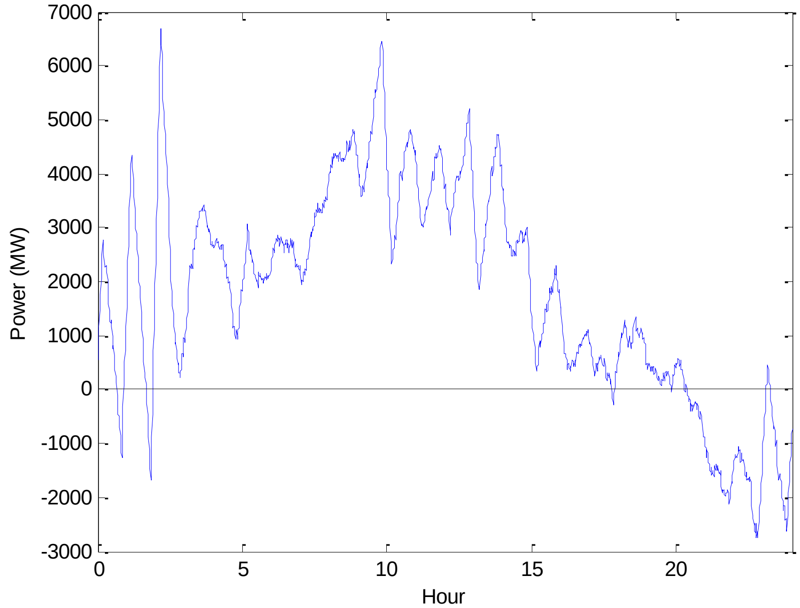

Figure A.56. One Typical Day Total MROW Balancing Signal in August 2020

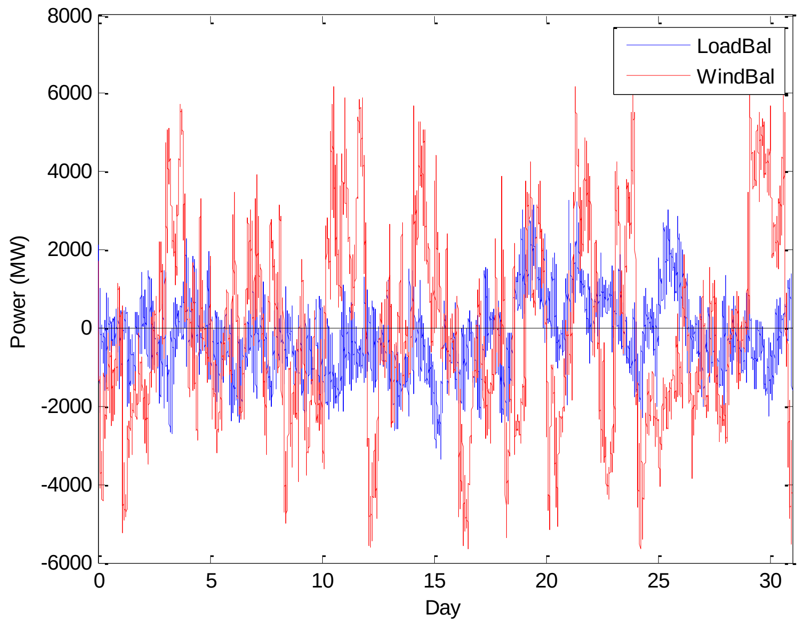

Figure A.57. One Month Balancing Requirements Caused by Load and Wind Respectively for MROW

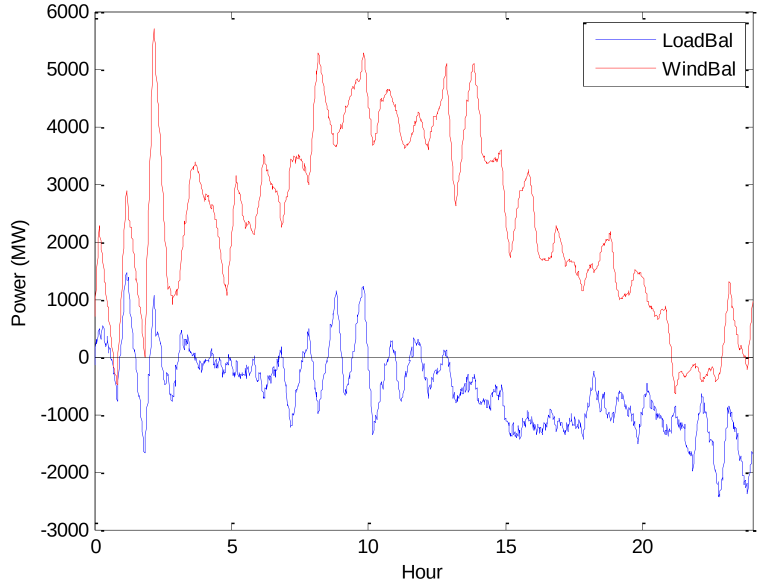

Figure A.58. Typical Day Balancing Requirements Caused by Load and Wind Respectively for MROW

A.8.2 Energy and Power Requirements

Table A.22, Figure A.59 and Figure A.60 show the results of energy and power requirements for future MROW scenarios.

As noted above, here are differences in the sizes of storage (GW and GWh) required for the different cases. Table A.22, Figure A.59 and Figure A.60 show energy and power requirements for the MROW scenarios in the considering only the additional wind generation and load expected between 2011 and 2012. As before, these are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.22. Power and Energy Requirements for Each Scenario for MROW. Note: The energy capacity (GWh) of the batteries is nominally for at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	4.34	-
C2	NaS	4.27	1.58
C3	Li-ion	4.28	1.54
C4	Flywheel	4.31	1.46
C5	CAES	8.20	42.60
	NaS	1.67	0.19
C6	Flow battery	4.26	1.63
C7	PH multiple modes	4.29	1.44
	4 min waiting period, NaS	1.71	0.29
C8	PH 2 modes	8.20	42.76
	4 min waiting period, NaS	1.23	0.10
C9	DR	13.95	-

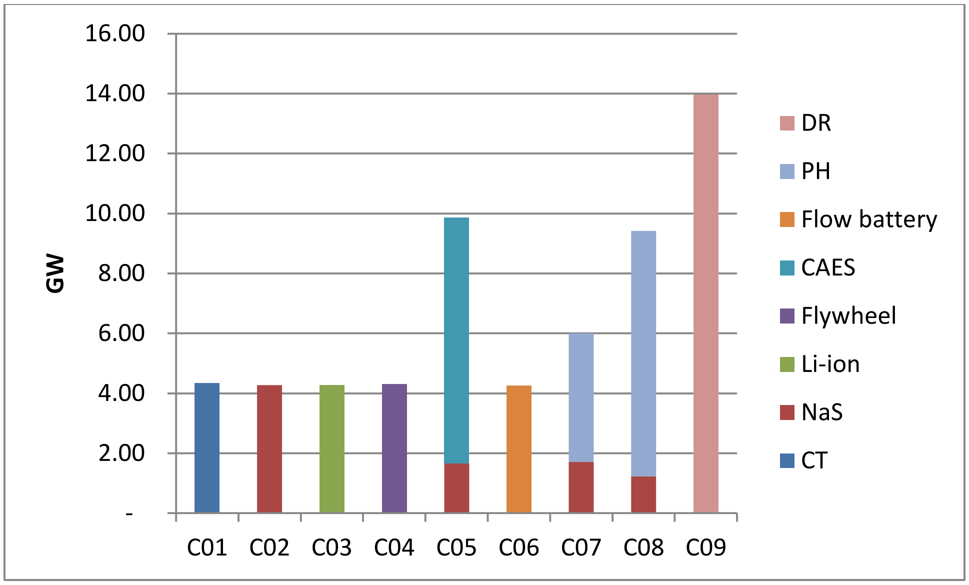

Figure A.59. Power Requirements for all the Technologies to Meet Balancing Signal for MROW

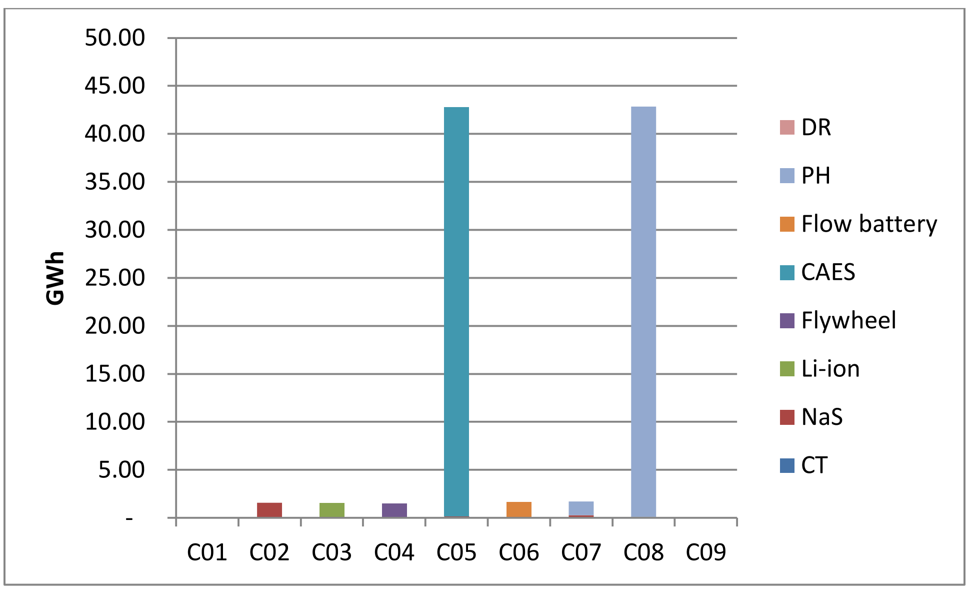

Figure A.60. Energy Requirements for Storage Technologies to Meet Balancing Signal for MROW

Table A.23. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for MROW. Note: The energy capacity (GWh) for the batteries is specified for at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.75	-
C2	Na-S	2.72	1.37
C3	Li-ion	2.72	1.35
C4	Flywheel	2.74	1.25
C5	CAES	5.00	27.58
	Na-S	1.33	0.17
C6	Flow battery	2.71	1.41
C7	PH multiple modes	2.72	1.27
	4-min waiting period, Na-S	1.12	0.17
C8	PH 2 modes	5.00	27.69
	4-min waiting period, Na-S	1.05	0.09
C9	DR	8.31	0.00

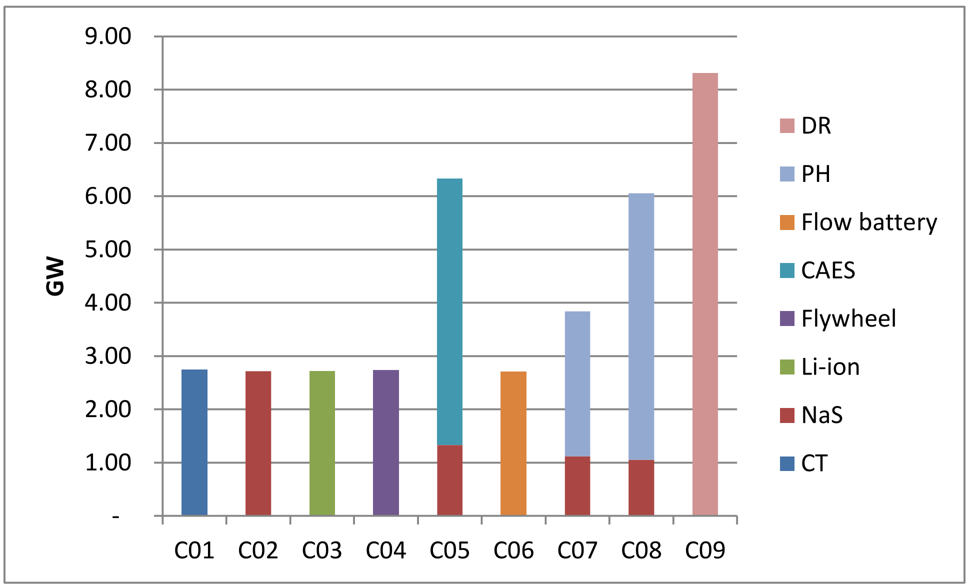

Figure A.61. Power Requirements for all the Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for MROW

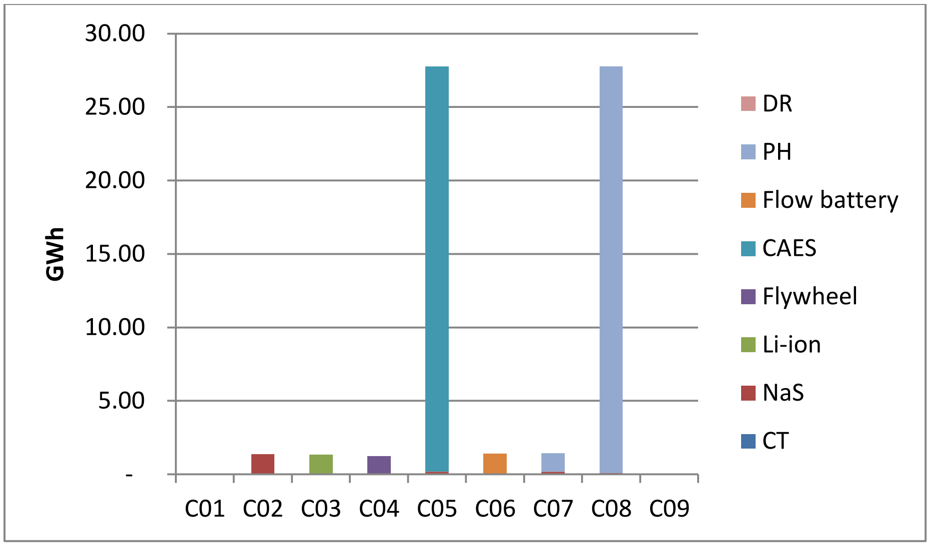

Figure A.62. Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for MROW

A.8.3 Life-Cycle Cost Analysis

The results of the economic analysis for the MROW power area are presented in Table A.24 and Figure A.63. These results represent the base or reference case for the nine technologies defined in Section 5.1. The values presented in Table A.24 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $5.6 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $7.,2 billion or 24.4 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the Case 2, registering at $13.4 billion. The CAES case (Case 5) is also more expensive with estimated costs of $19.0 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $27.6 billion. Total costs under Case 6, redox flow batteries , are estimated at $13.0 billion.

Table A.24. Economic Analysis Results – MROW (2020 Dollars)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	11,146	2,171	972	858	15,147
2	4,701	336	623	133	5,793
3	7,779	302	576	119	8,776
4	5,733	143	1,273	56	7,205
5	13,510	2,655	1,807	1,050	19,022
6	11,919	390	570	154	13,032
7	13,432	295	587	117	14,431
8	25,129	773	1,436	305	27,643
9	13,380	-	-	-	13,380

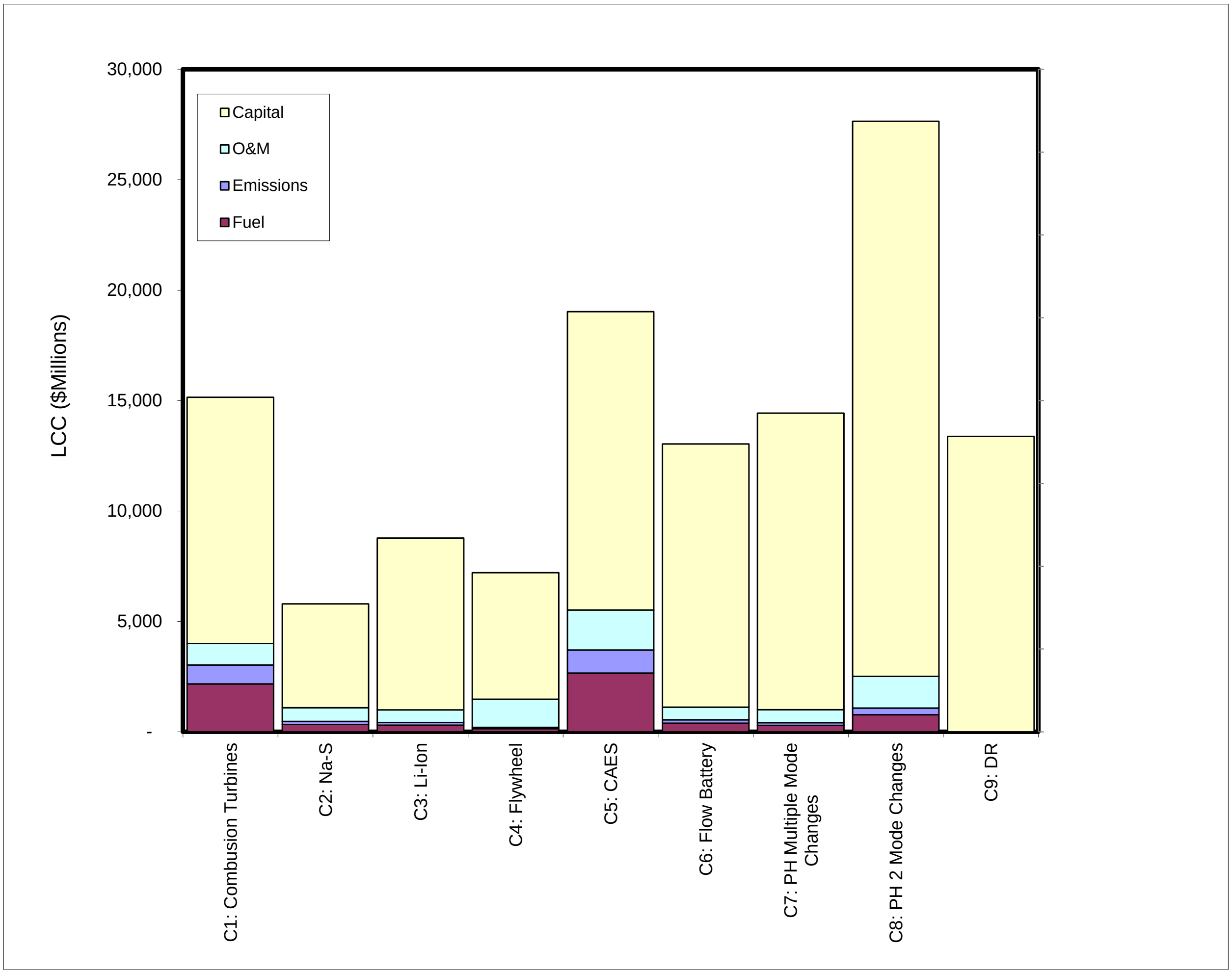

Figure A.63. LCC Scenario Estimates for MROW

A.8.4 Arbitrage

Table A.25 presents the findings of the arbitrage analysis performed for the MROW. As shown, annual arbitrage revenues are estimated to range from $3.1-$116.3 million based on energy storage size, which ranges from 55-2,190 MW. Annual revenue per MW falls from a high of $57,209 at 110 MW to $53,093 at 2,190 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at all energy storage capacities. Annual profits range from a low of $231,425 at 55 MW to a high of $2.8 million at 1,095 MW of capacity. Annualized costs are estimated to range from $11.1-$444.5 million for pumped hydro, $24.9-$998.0 million for Na-S, and $49.0 million-$2.0 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the MROW is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is reduced but only overcome by pumped hydropower.

Table A.25. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (MROW)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
55	3,132,080	8,212,500	11,113,155	24,949,575	49,039,575
110	6,264,404	16,425,000	22,226,310	49,899,150	98,079,150
219	12,481,110	32,850,000	44,452,620	99,798,300	196,158,300
274	15,596,565	41,062,500	55,565,775	124,747,875	245,197,875
548	30,933,312	82,125,000	111,131,550	249,495,750	490,395,750
821	45,973,859	123,187,500	166,697,325	374,243,625	735,593,625
1,095	60,786,868	164,250,000	222,263,100	498,991,500	980,791,500
1,369	75,129,651	205,312,500	277,828,875	623,739,375	1,225,989,375
1,643	89,208,010	246,375,000	333,394,650	748,487,250	1,471,187,250
1,916	102,895,440	287,437,500	388,960,425	873,235,125	1,716,385,125
2,190	116,272,773	328,500,000	444,526,200	997,983,000	1,961,583,000

A.9 NEWE

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.9.1 Balancing Requirements

Figure A.64 and Figure A.65 show monthly and daily balancing signals for NEWE, respectively. Based on the whole year simulation, the balancing power requirements are 2371.9 MW of inc. capacity and 2043.3 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability of happening.

Figure A.66 shows balancing signals caused by load and by wind separately for the region NEWE for one month. These balancing requirements are caused by both wind and load uncertainty in the NEWE in 2020. Figure A.67 presents the same balancing signals for one day.

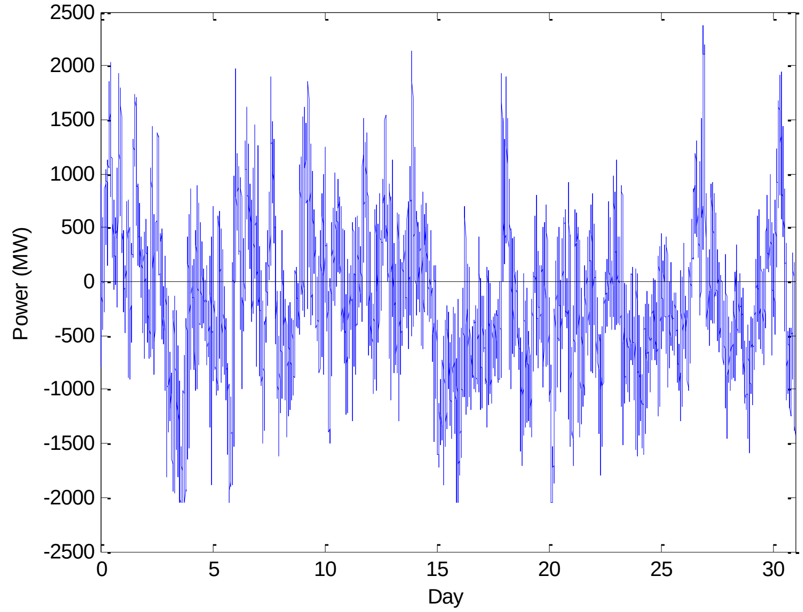

Figure A.64. One Month Total NEWE Total Balancing Signal in August 2020

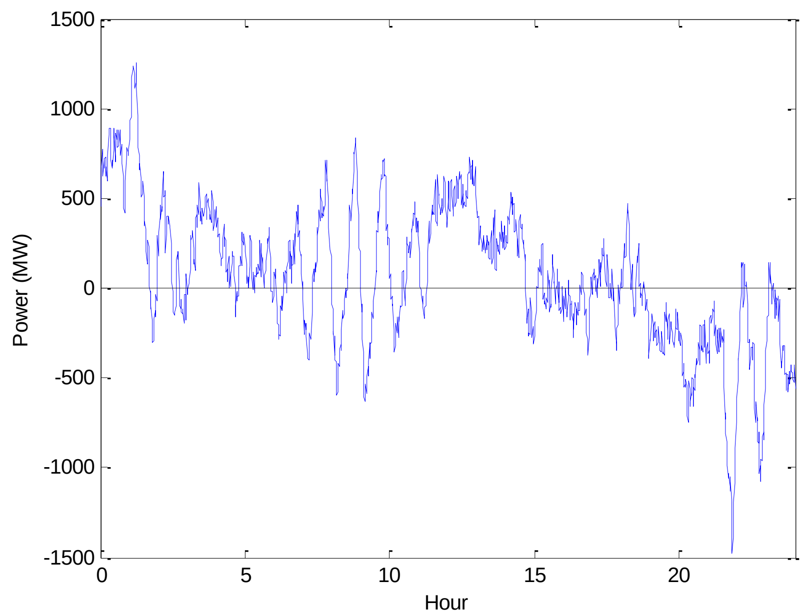

Figure A.65. One Typical Day Total NEWE Balancing Signal in August 2020

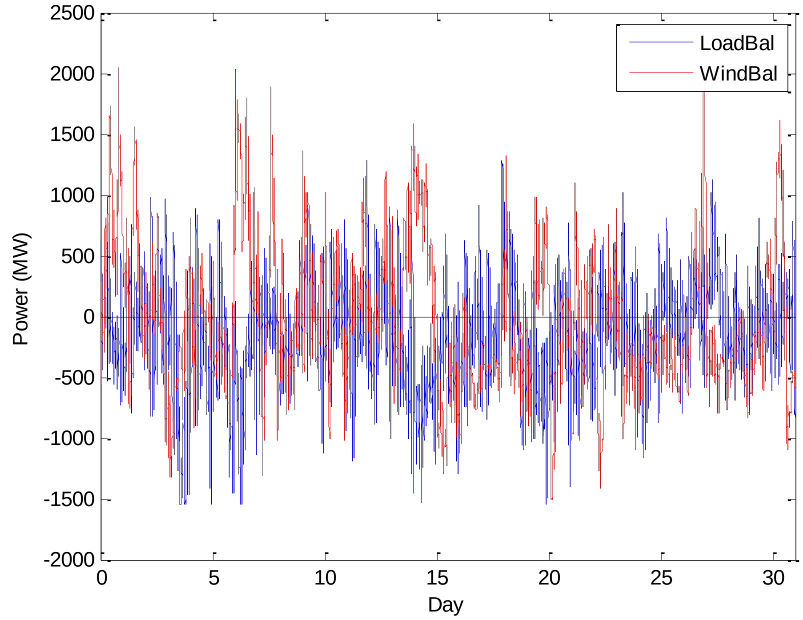

Figure A.66. One Month Balancing Requirements Caused by Load and Wind Respectively for NEWE

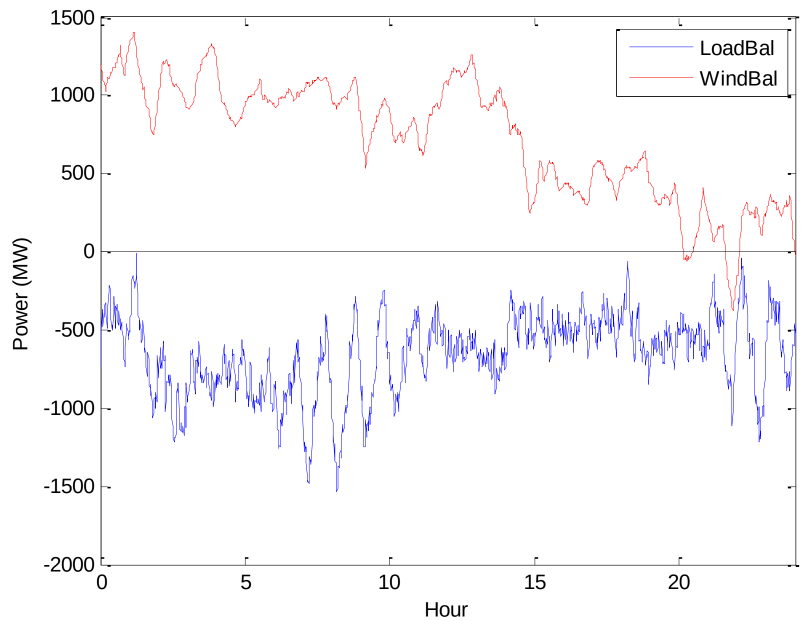

Figure A.67. Typical Day Balancing Requirements Caused by Load and Wind Respectively for NEWE

A.9.2 Energy and Power Requirements

Table A.**26**, Figure A.68 and Figure A.69 show the results of energy and power requirements for the scenarios in the Northeast Power Coordinating Council (NEWE) area.

There are differences in the sizes of storage (GW and GWh) required for the different cases of studies (see Table A.**26**). The GW and GWh difference in cases C2 to C4 and C6 are only due to difference in storage efficiency. The GW and GWh difference in case C7 is due to storage efficiency and due to the need of an additional storage technology (Na-S) to provide balancing during the 4-minute waiting period needed to change between charging and discharging mode (pumping and generation). The large GW and GWh difference in case C5 and C8 with respect to the rest of the cases is mainly because of the restriction in operation assumed; a restriction of only two mode changes (charging to discharging or discharging to charging) is assumed causing a large increase in size requirement (GW and GWh). Details of operation strategies for each technology can be found in Appendix B.

Table A.26. Power and Energy Requirements for Each Scenario for NEWE. Note: The energy capacity (GWh) for the batteries is specified at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	1.37	-
C2	NaS	1.40	0.61
C3	Li-ion	1.39	0.60
C4	Flywheel	1.38	0.55
C5	CAES	2.61	15.28
	NaS	0.70	0.07
C6	Flow battery	1.40	0.63
C7	PH multiple modes	1.39	0.67
	4 min waiting period, NaS	0.71	0.19
C8	PH 2 modes	2.61	15.34
	4 min waiting period, NaS	0.52	0.03
C9	DR	4.94	-

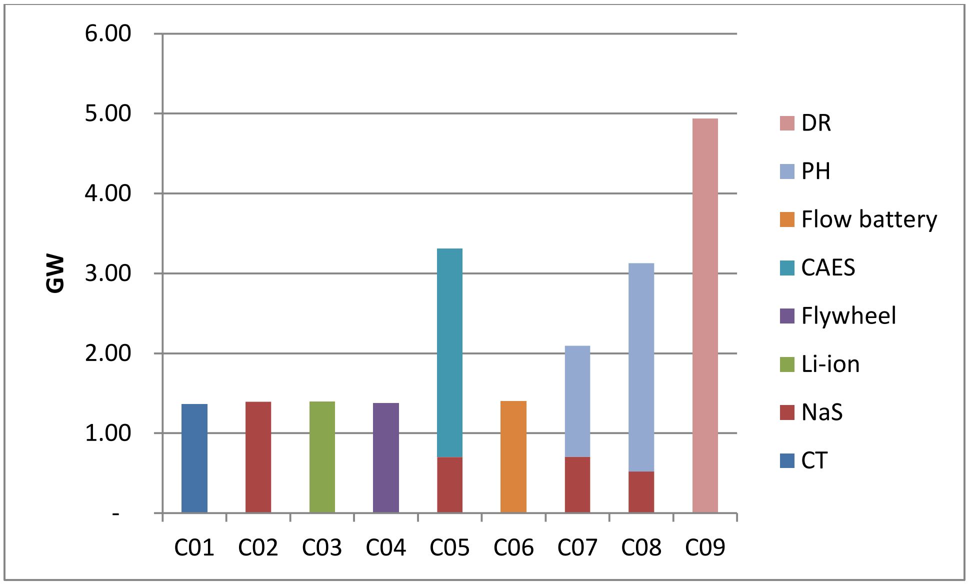

Figure A.68. Power Requirements for all the Technologies to Meet Balancing Signal for NEWE

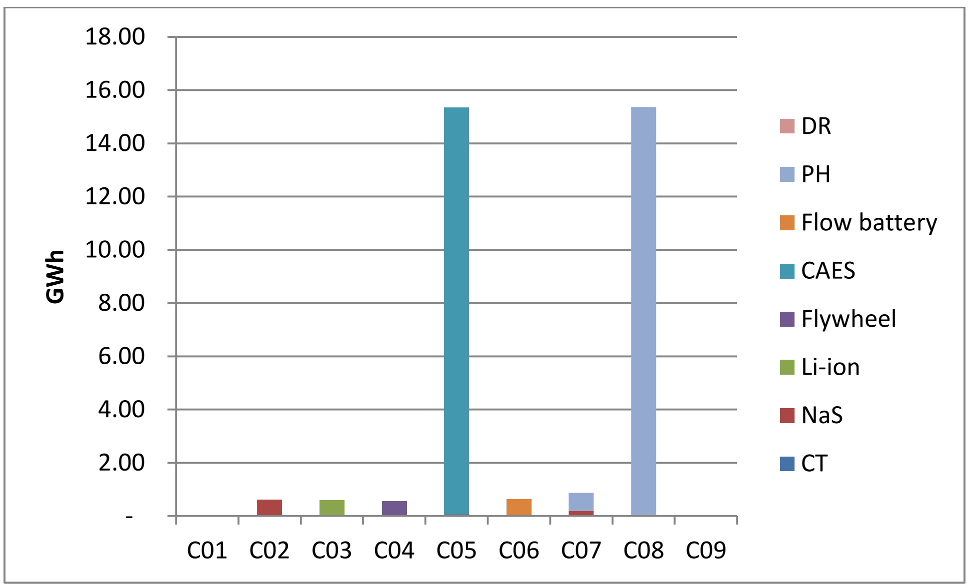

Figure A.69. Energy Requirements for Storage Technologies to Meet Balancing Signal for NEWE

Table A.27, Figure A.70 and Figure A.71 show the results of energy and power requirements for the scenarios in the NEWE area, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.27. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for NEWE. Note: The energy capacity (GWh) for the batteries is specified at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.61	-
C2	Na-S	0.62	0.32
C3	Li-ion	0.62	0.31
C4	Flywheel	0.61	0.29
C5	CAES	1.11	6.74
	Na-S	0.33	0.03
C6	Flow battery	0.62	0.33
C7	PH multiple modes	0.62	0.28
	4-min waiting period, Na-S	0.22	0.05
C8	PH 2 modes	1.11	6.76
	4-min waiting period, Na-S	0.33	0.02
C9	DR	2.21	-

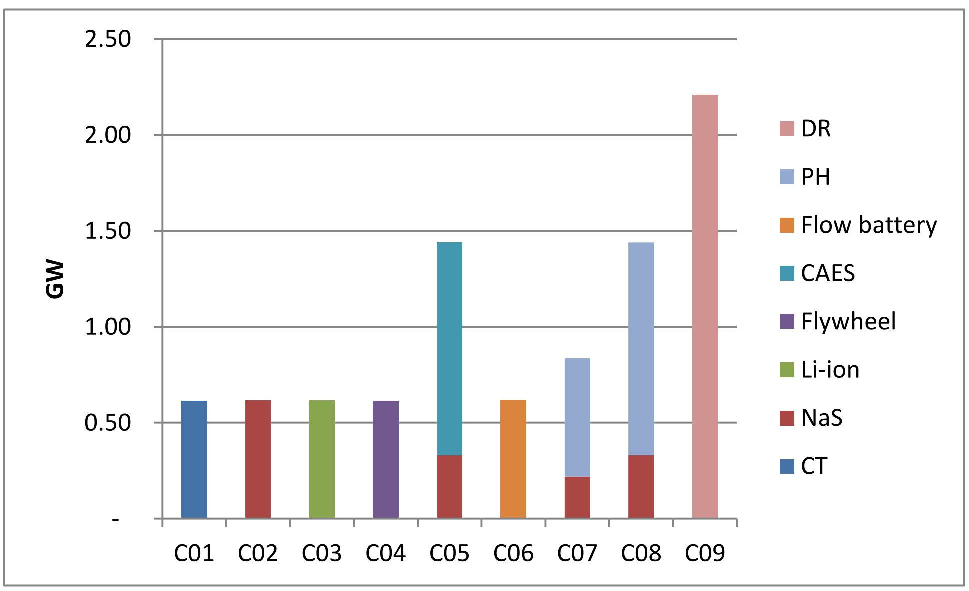

Figure A.70. Power Requirements for all the Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for NEWE

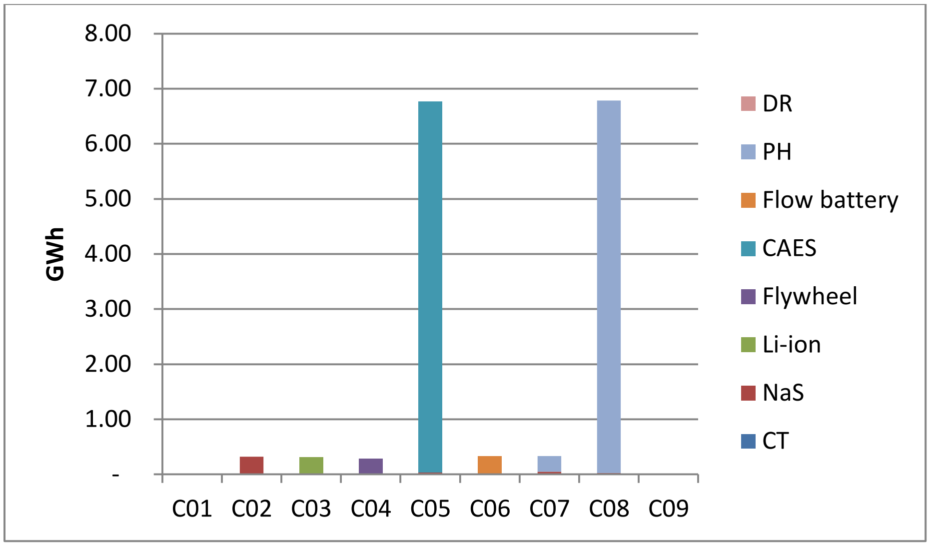

Figure A.71. Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for NEWE

A.9.3 Life-Cycle Cost Analysis

The results of the economic analysis for the NEWE power area are presented in Table A.28 and . These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Figure A.72 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $2.2 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $2.3 billion or 8.8 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $4.7 billion. The CAES case (Case 5) is also more expensive with estimated costs of $6.7 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $9.1 billion. Total costs under Case 6, redox flow batteries , are estimated at $4.4 billion.

Table A.28. Economic Analysis Results – NEWE (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	3,583	872	329	345	5,128
2	1,731	133	236	53	2,153
3	2,877	120	217	47	3,261
4	1,852	56	412	22	2,342
5	4,371	1,164	671	460	6,665
6	3,946	154	194	61	4,356
7	4,519	121	220	48	4,908
8	8,066	329	527	130	9,052
9	4,733	-	-	-	4,733

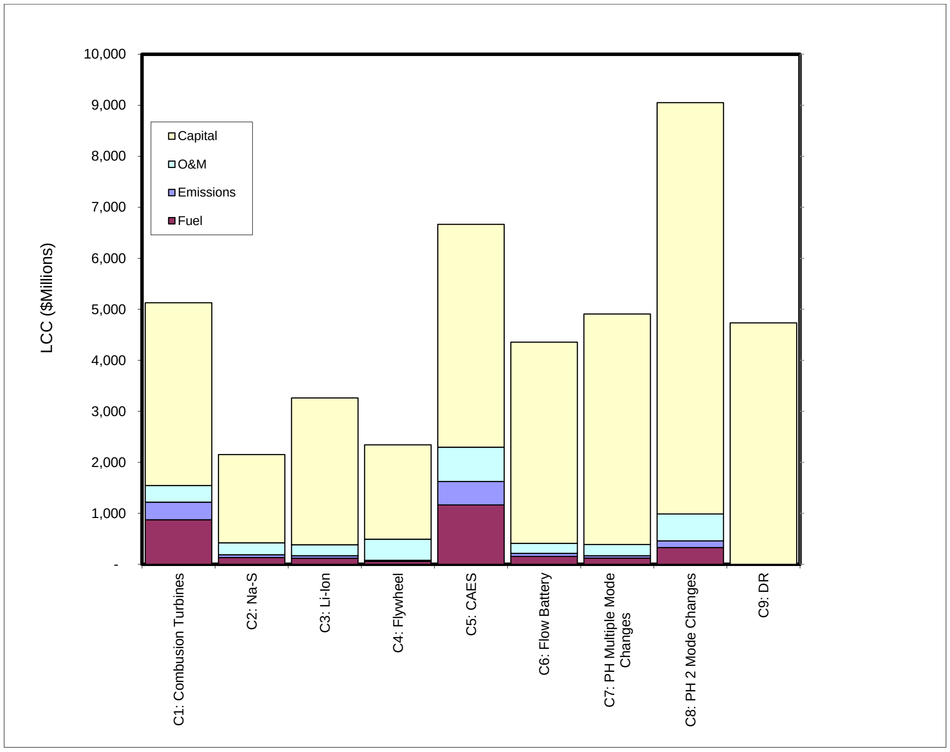

Figure A.72. LCC Estimates for NEWE

A.9.4 Arbitrage

Table A.**29** presents the findings of the arbitrage analysis performed for the NEWE. As shown, annual arbitrage revenues are estimated to range from $11.9-$395.8 million based on energy storage size, which ranges from 164-6,562 MW. Annual revenue per MW falls from a high of $72,370 at 164 MW to $60,321 at 6,562 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydropower generates profits at all energy storage capacities. Annual profits range from a low of $3.2 million at 164 MW to a high of $57.2 million at 4,922 MW of capacity. Annualized costs are estimated to range from $33.3 million -$1.3 billion for pumped hydro, $74.8 million-$3.0 billion for Na-S, and $146.9 million-$5.9 billion for Li-ion. This result supports the conclusion that with a 30 percent reserve margin, the NEWE is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is overcome but only with pumped hydropower.

Table A.29. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (NEWE)

Storage Size	Annual Revenue		Annualized Capital Costs		
(MW)	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
164	11,872,331	24,607,500	33,298,869	74,757,585	146,939,585
328	23,577,111	49,215,000	66,597,738	149,515,170	293,879,170
656	47,013,270	98,430,000	133,195,476	299,030,340	587,758,340
820	58,675,388	123,037,500	166,494,345	373,787,925	734,697,925
1,641	115,406,043	246,075,000	332,988,690	747,575,850	1,469,395,850
2,461	170,151,069	369,112,500	499,483,035	1,121,363,775	2,204,093,775
3,281	222,461,433	492,150,000	665,977,380	1,495,151,700	2,938,791,700
4,101	271,588,481	615,187,500	832,471,725	1,868,939,625	3,673,489,625
4,922	317,917,551	738,225,000	998,966,070	2,242,727,550	4,408,187,550
5,742	358,118,121	861,262,500	1,165,460,415	2,616,515,475	5,142,885,475
6,562	395,825,297	984,300,000	1,331,954,760	2,990,303,400	5,877,583,400

A.10 NYCW

A.10.1 Balancing Requirements

No balancing analysis was performed for this region because we assumed that no wind resource would be adopted in this region by 2020.

A.10.2 Life-Cycle Cost Analysis

No costs were estimated for this region.

A.10.3 Arbitrage

Table 8.18 presents the findings of the arbitrage analysis performed for the NYCW. As shown, annual arbitrage revenues are estimated to range from $6.2-$198.6 million based on energy storage size, which ranges from 88-3,530 MW. Annual revenue per MW falls from a high of $70,371 at 88 MW to $56,268 at 3,530 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at all energy storage capacities. Annual profits range from a low of $1.5 million at 88 MW to a high of $23.2 million at 2,206 MW of capacity. Annualized costs are estimated to range from $17.9-$716.5 million for pumped hydro, $40.2 million-$1.6 billion for Na-S, and $79.0 million-$3.2 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the NYCW is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is bridged but only for pumped hydro.

Table A.30. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (NYCW)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
88	6,210,218	13,237,500	17,912,985	40,215,525	79,045,525
177	12,407,569	26,475,000	35,825,970	80,431,050	158,091,050
353	24,712,609	52,950,000	71,651,940	160,862,100	316,182,100
441	30,771,421	66,187,500	89,564,925	201,077,625	395,227,625
883	60,622,309	132,375,000	179,129,850	402,155,250	790,455,250
1,324	88,953,825	198,562,500	268,694,775	603,232,875	1,185,682,875
1,765	116,037,958	264,750,000	358,259,700	804,310,500	1,580,910,500
2,206	140,101,275	330,937,500	447,824,625	1,005,388,125	1,976,138,125
2,648	162,778,077	397,125,000	537,389,550	1,206,465,750	2,371,365,750
3,089	181,483,046	463,312,500	626,954,475	1,407,543,375	2,766,593,375
3,530	198,625,891	529,500,000	716,519,400	1,608,621,000	3,161,821,000

A.11 NYLI

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.11.1 Balancing Requirements

Figure A.73 and Figure A.74 show monthly and daily balancing signals for NYLI, respectively. Long cycles across several days are included in the balancing signal. Based on the whole year simulation, the balancing power requirements are 653.7 MW of inc. capacity and 671.1 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability of happening.

Figure A.75 shows balancing signals caused by load and by wind separately for the NYLI region for one month The 2020 balancing requirements are caused by both of wind and load uncertainty. Figure A.76 presents the same balancing signals for one day.

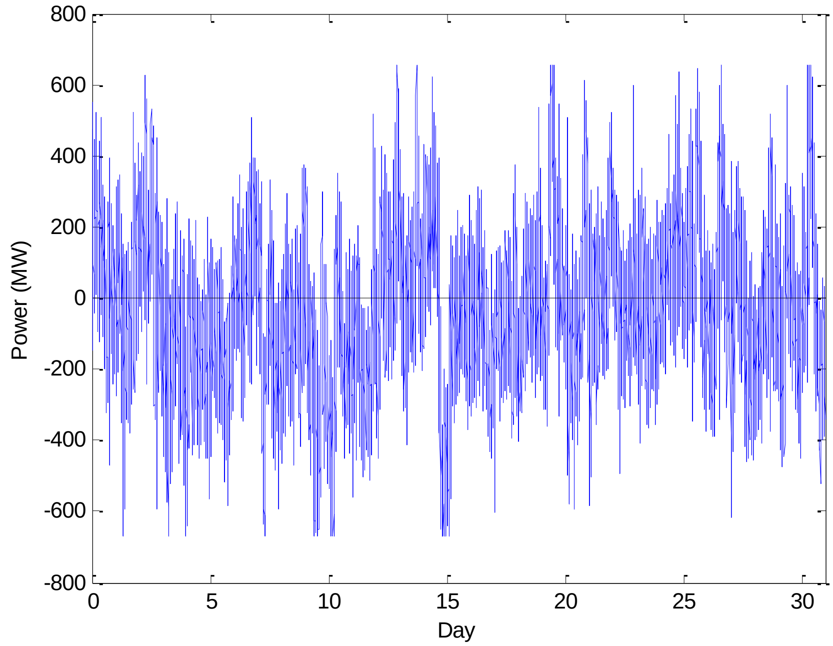

Figure A.73. NYLI One Month Total Balancing Signal in August 2020

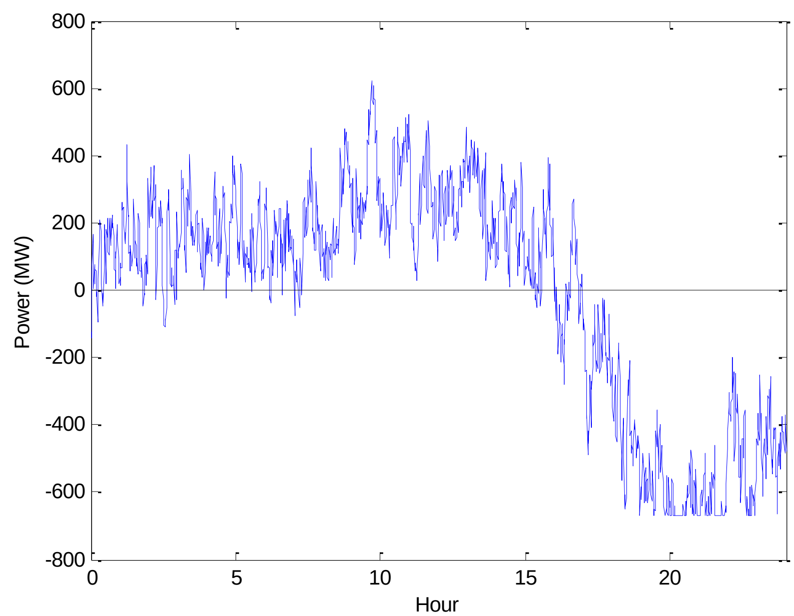

Figure A.74. One Typical Day NYLI Total Balancing Signal in August 2020

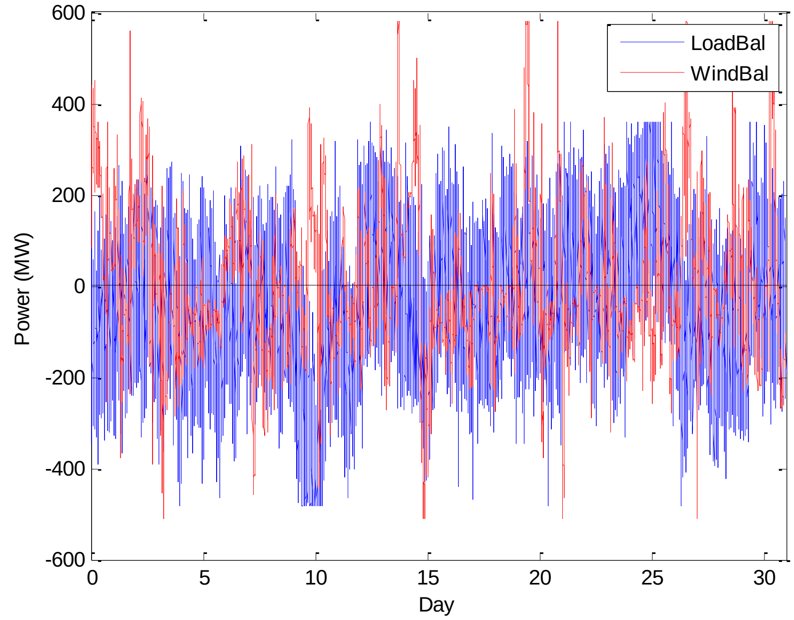

Figure A.75. One Month Balancing Requirements Caused by Load and Wind Respectively for NYLI

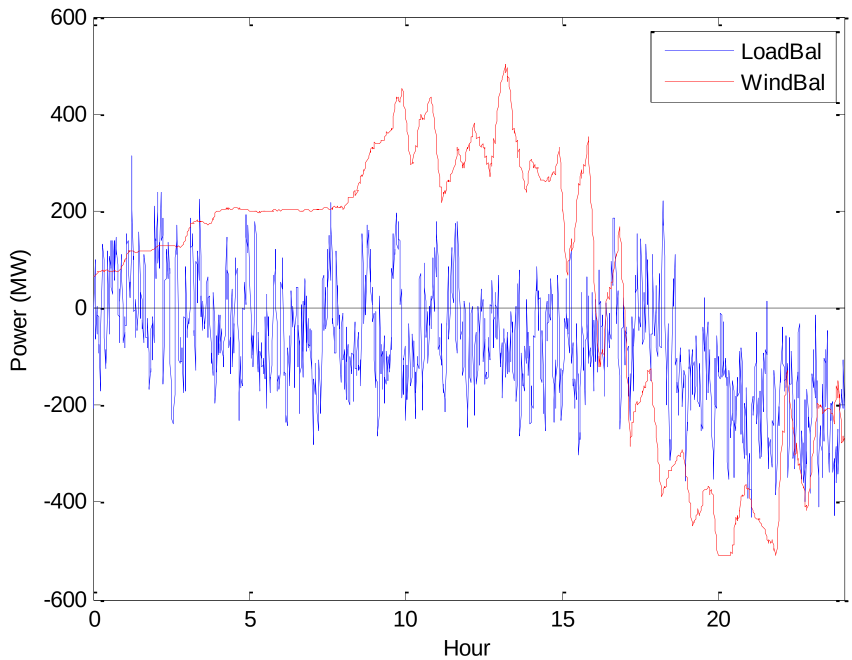

Figure A.76. NYLI Typical Day Balancing Requirements Caused by Load and Wind Respectively

A.11.2 Energy and Power Requirements

Table A.31, Figure A.77 and Figure A.78 show energy and power requirements for the scenarios in the Northeast Power Coordinating Council/Long Island (NYLI) area.

Table A.31. Power and Energy Requirements for Each Scenario for NYLI. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.54	-
C2	NaS	0.54	0.20
C3	Li-ion	0.54	0.20
C4	Flywheel	0.54	0.20
C5	CAES	1.01	5.83
	NaS	0.33	0.02
C6	Flow battery	0.55	0.20
C7	PH multiple modes	0.54	0.25
	4 min waiting period, NaS	0.44	0.22
C8	PH 2 modes	1.01	5.86
	4 min waiting period, NaS	0.22	0.01
C9	DR	1.94	-

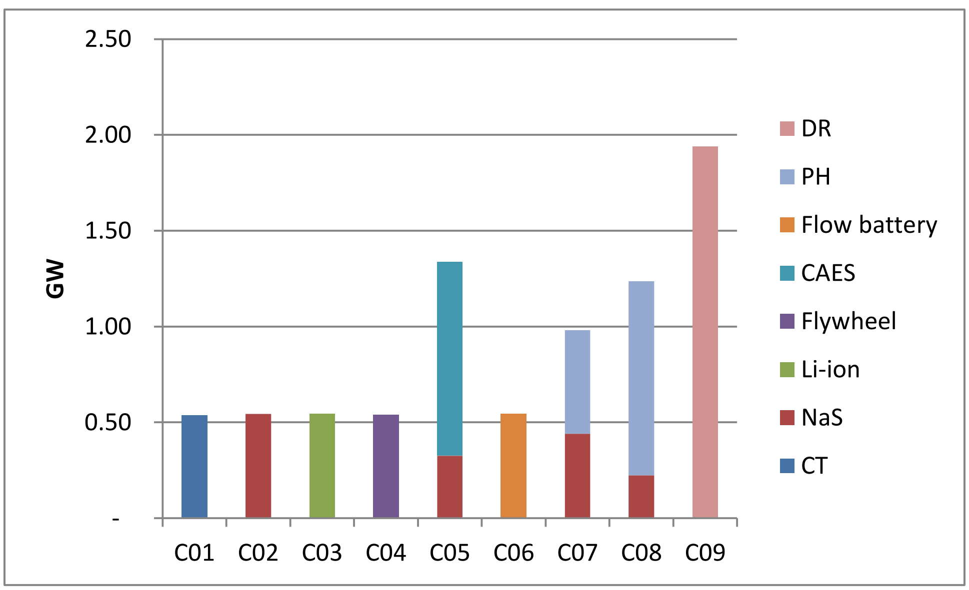

Figure A.77. Power Requirements for all the Technologies to Meet Balancing Signal for NYLI

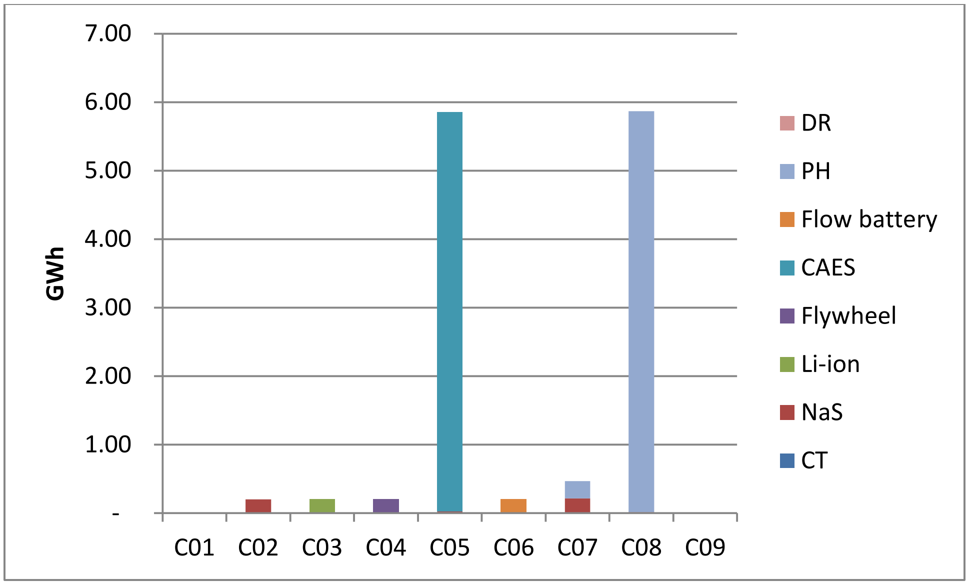

Figure A.78. Energy Requirements for Storage Technologies to Meet Balancing Signal for NYLI

Table A.**32**, Figure A.79 and Figure A.80 show energy and power requirements for the scenarios in the NYLI area, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.32. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for NYLI. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.42	-
C2	Na-S	0.42	0.17
C3	Li-ion	0.42	0.17
C4	Flywheel	0.42	0.18
C5	CAES	0.79	4.71
	Na-S	0.18	0.02
C6	Flow battery	0.42	0.18
C7	PH multiple modes	0.42	0.17
	4-min waiting period, Na-S	0.25	0.04
C8	PH 2 modes	0.79	4.73
	4-min waiting period, Na-S	0.14	0.01
C9	DR	1.46	-

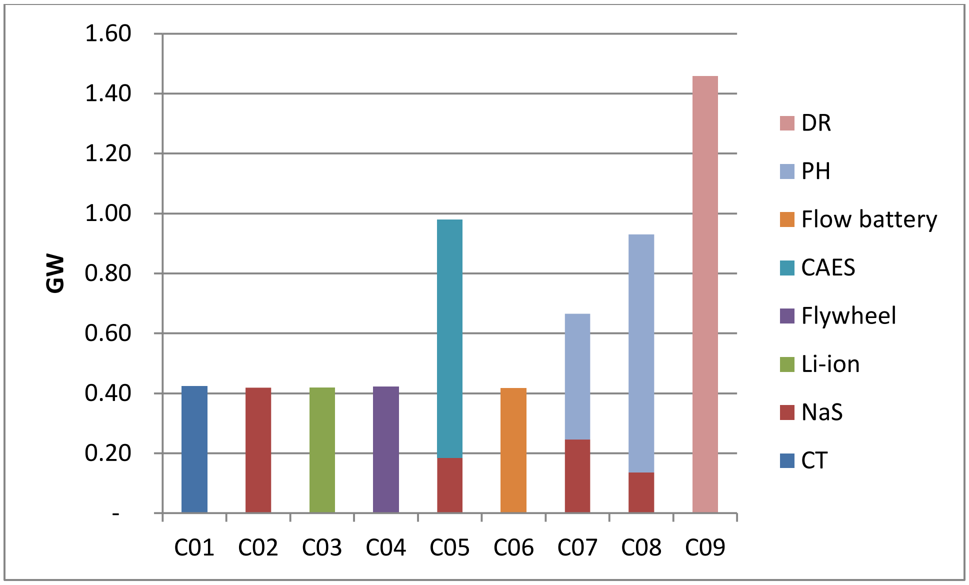

Figure A.79. Power Requirements for all the Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load for NYLI

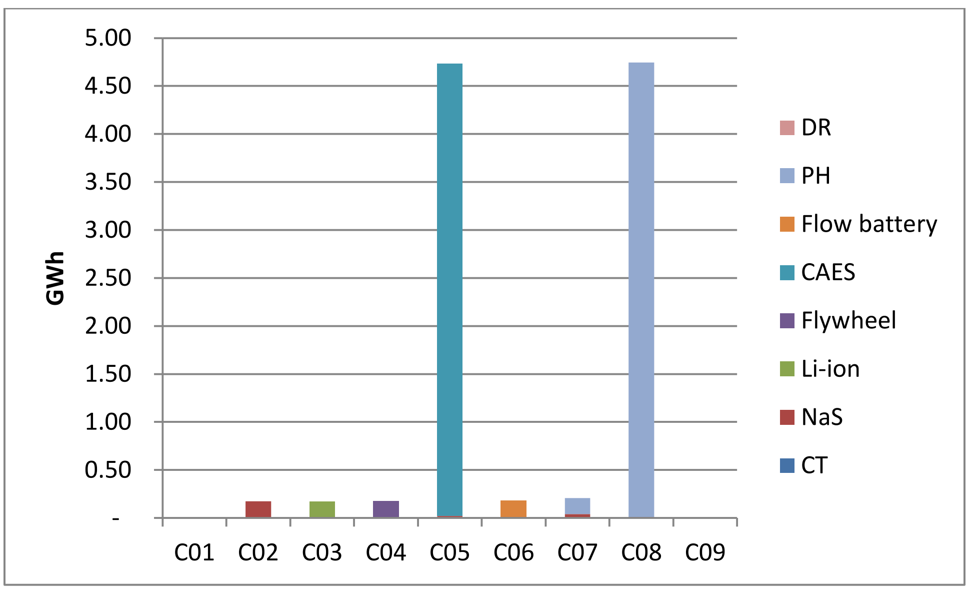

Figure A.80. Energy Requirements for Storage Technologies to Meet Balancing Signal due to 2011-2020 Additional Wind and Load for NYLI

A.11.3 Life-Cycle Cost Analysis

The results of the economic analysis for the NYLI power area are presented in Table A.33 and Figure A.81. These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Table A.33 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $0.7 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $0.9 billion or 23.8 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $1.8 billion. The CAES case (Case 5) is also more expensive with estimated costs of $2.7 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $3.5 billion. Total costs under Case 6, redox flow batteries , are estimated at $1.7 billion.

Table A.33 Economic Analysis Results – NYLI (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	1,592	354	129	140	2,216
2	582	53	83	21	739
3	928	47	82	19	1,076
4	723	22	161	9	915
5	1,713	484	273	191	2,661
6	1,527	61	76	24	1,688
7	1,972	52	110	21	2,155
8	3,138	112	211	44	3,504
9	1,861	-	-	-	1,861

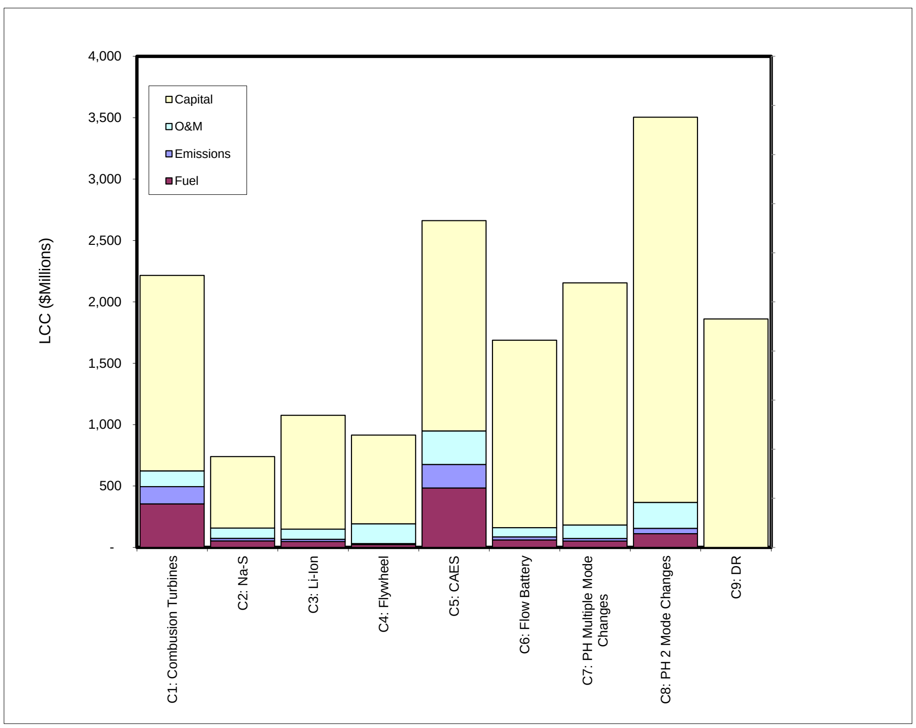

Figure A.81. LCC Estimates for NYLI

A.11.4 Arbitrage

Arbitrage analysis was not performed for the NYLI because the economic value was estimated to be low.

A.12 NYUP

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.12.1 Balancing Requirements

Figure A.82 and Figure A.83 show monthly and daily balancing signals for NYUP, respectively. Based on the whole year simulation, the balancing power requirements are 2507 MW of inc. capacity and 1591 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability of happening.

Figure A.84 shows one-month balancing signals caused by load and by wind separately for the NYUP region. In 2020, balancing requirements are caused mostly by windpower uncertainty. Figure A.85 presents the same balancing signals for a typical day.

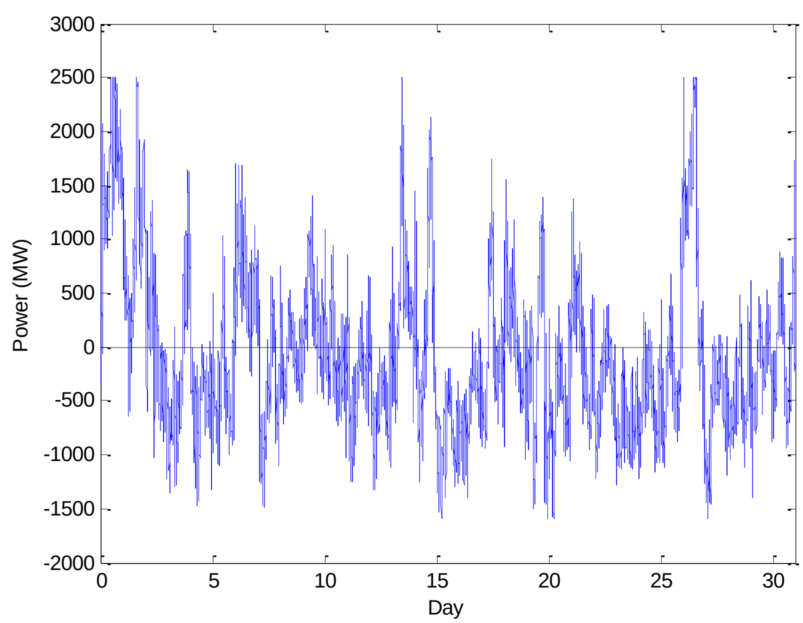

Figure A.82. One Month Total Balancing Signal in August 2020 for NYUP

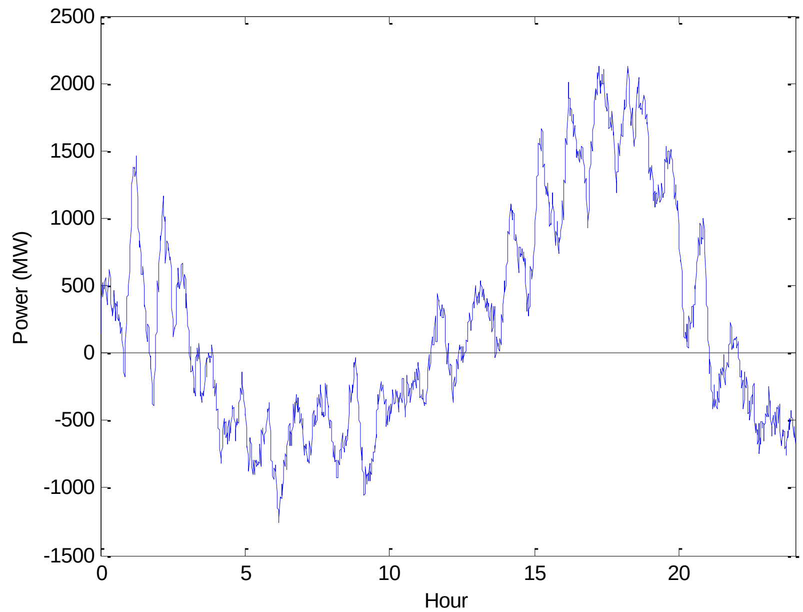

Figure A.83. NYUP Typical Day Total Balancing Signal in August 2020

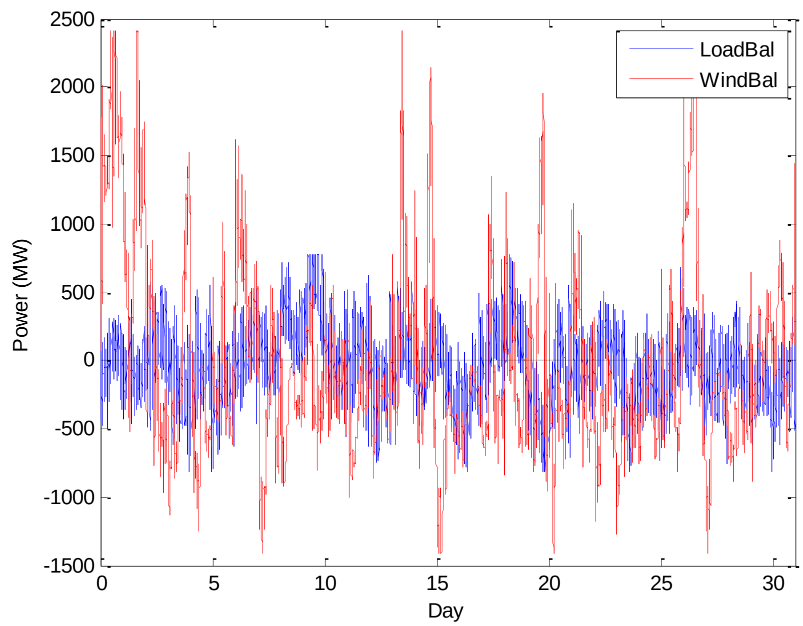

Figure A.84. One Month Balancing Requirements Caused by Load and Wind Respectively for NYUP

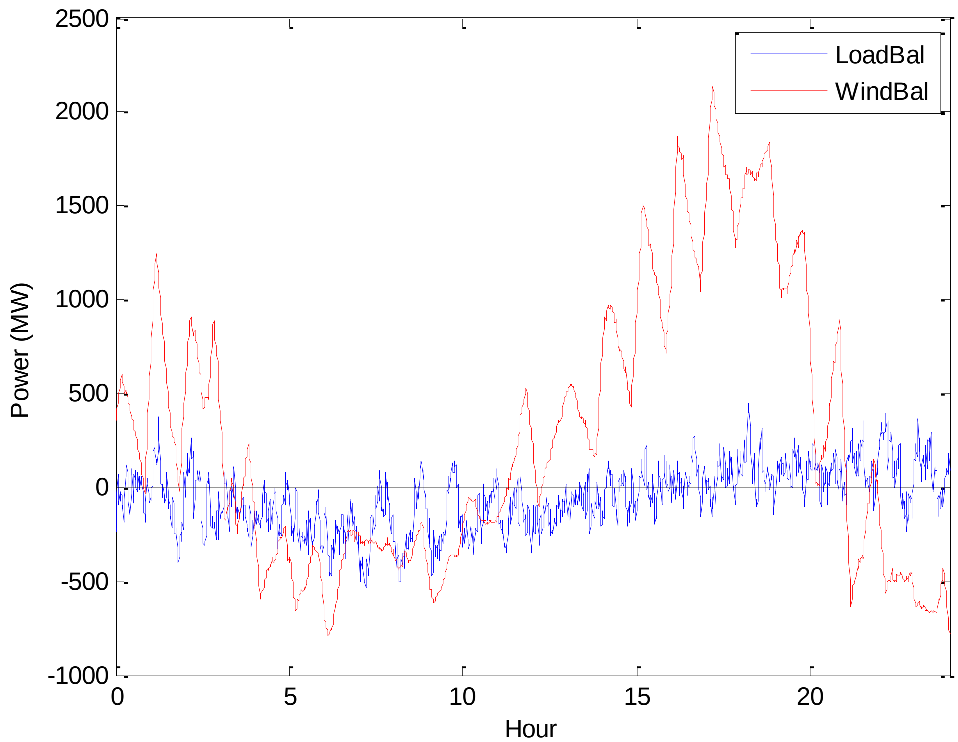

Figure A.85. Typical Day Balancing Requirements Caused by Load and Wind Respectively for NYUP

A.12.2 Energy and Power Requirements

Table A.34, Figure A.86 and Figure A.87 show energy and power requirements for the scenarios in the Northeast Power Coordinating Council/Upstate New York (NYUP) area.

Table A.34. Power and Energy Requirements for Each Scenario for NYUP. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	1.44	-
C2	NaS	1.45	0.54
C3	Li-ion	1.45	0.53
C4	Flywheel	1.44	0.50
C5	CAES	2.52	13.81
	NaS	0.69	0.05
C6	Flow battery	1.46	0.55
C7	PH multiple modes	1.45	0.51
	4 min waiting period, NaS	0.73	0.28
C8	PH 2 modes	2.52	13.83
	4 min waiting period, NaS	0.41	0.02
C9	DR	5.19	-

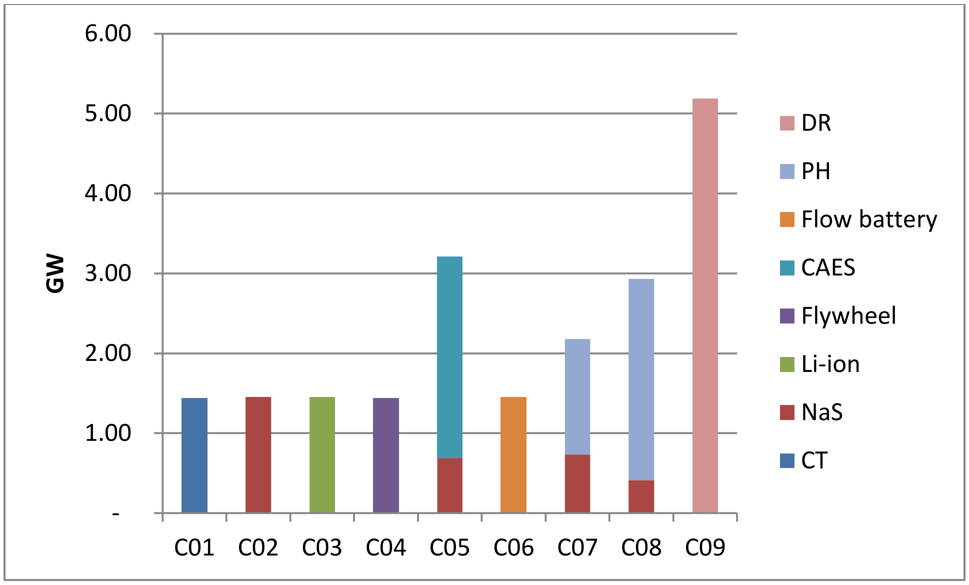

Figure A.86. Power Requirements for all the Technologies to Meet Balancing Signal for NYUP

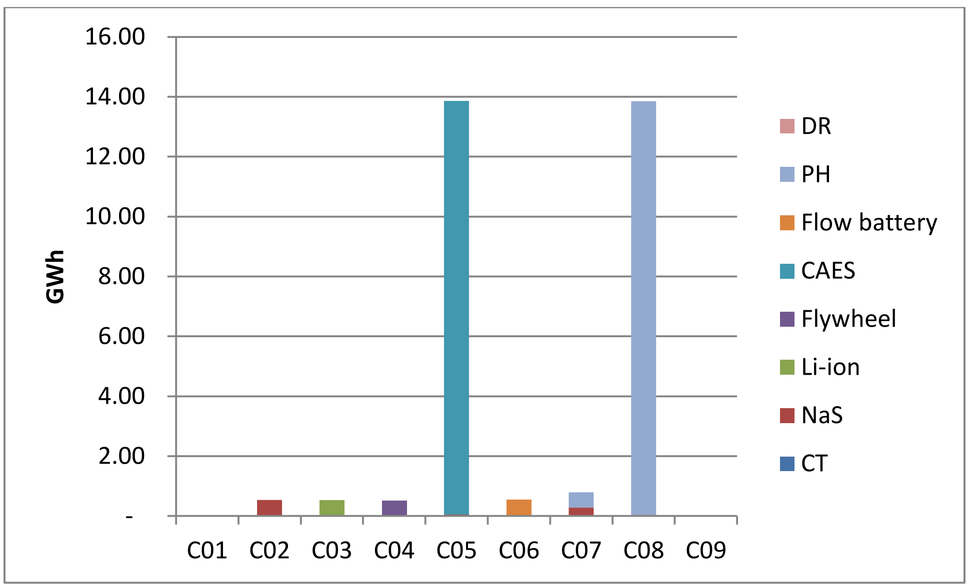

Figure A.87. Energy Requirements for Storage Technologies to Meet Balancing Signal for NYUP

Table A.35, Figure A.88 and Figure A.89 show energy and power requirements for the scenarios in the NYUP area, considering only the additional wind generation and load expected between 2011 and 2012. These are the requirements for additional balancing assuming that the 2011 level of balancing is still provided by existing resources.

Table A.35. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for NYUP. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.84	-
C2	Na-S	0.85	0.35
C3	Li-ion	0.85	0.34
C4	Flywheel	0.85	0.33
C5	CAES	1.53	7.67
	Na-S	0.36	0.03
C6	Flow battery	0.86	0.35
C7	PH multiple modes	0.85	0.32
	4-min waiting period, Na-S	0.29	0.05
C8	PH 2 modes	1.53	7.70
	4-min waiting period, Na-S	0.20	0.02
C9	DR	3.04	-

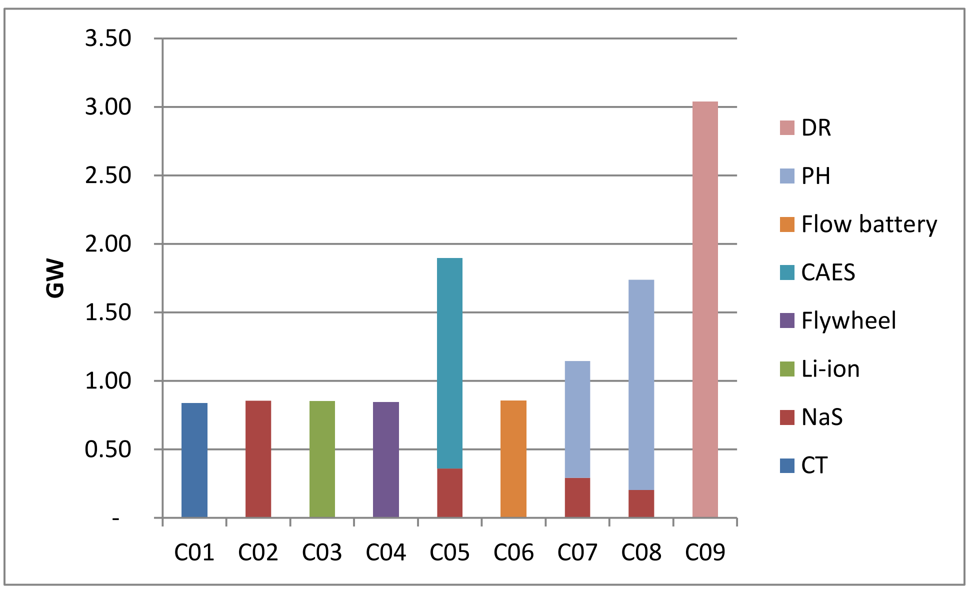

Figure A.88. NYUP Power Requirements for all Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load

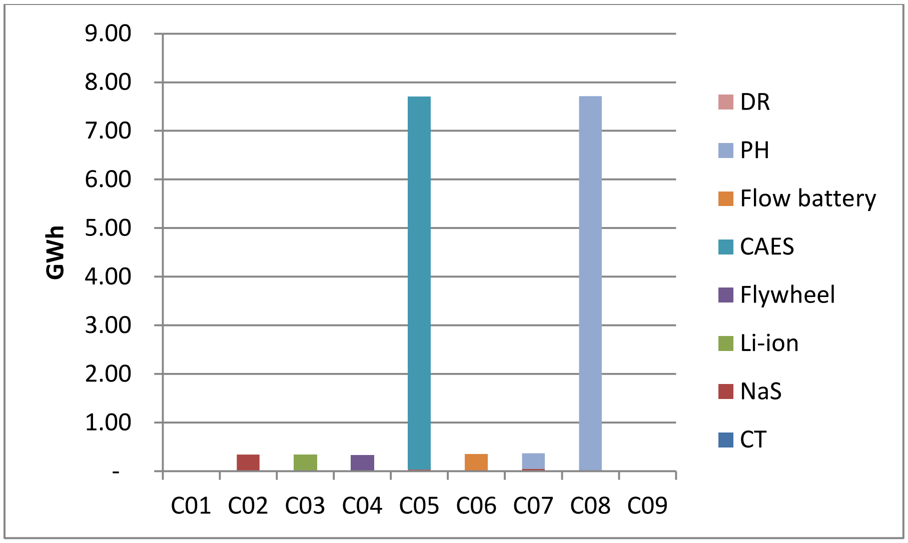

Figure A.89. NYUP Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load

A.12.3 Life-Cycle Cost Analysis

The results of the economic analysis for the NYUP power area are presented in Table A.36 and Figure A.90 The values presented in Table A.36 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $1.8 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $2.4 billion or 35.2 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $5.0 billion. The CAES case (Case 5) is also more expensive with estimated costs of $6.1 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $8.5 billion. Total costs under Case 6, redox flow batteries , are estimated at $4.4 billion.

Table A.36 Economic Analysis Results – NYUP (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	3,583	667	314	264	4,827
2	1,450	101	188	40	1,779
3	2,320	91	185	36	2,632
4	1,922	43	424	17	2,406
5	4,213	936	592	370	6,110
6	4,070	117	190	46	4,424
7	4,734	94	211	37	5,077
8	7,734	231	465	91	8,521
9	4,978	-	-	-	4,978

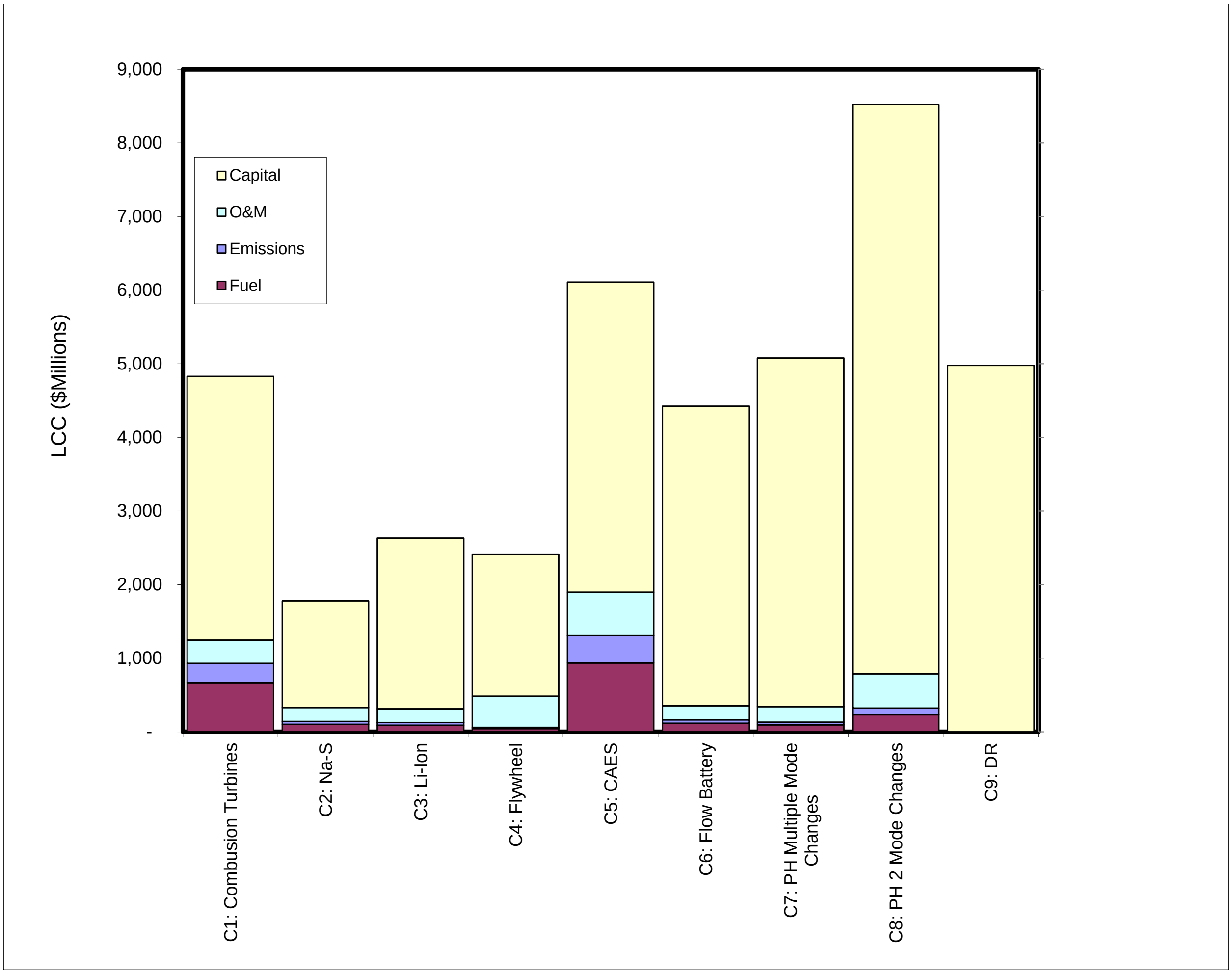

Figure A.90. LCC Estimates for NYUP

A.12.4 Arbitrage

Table A.37 presents the findings of the arbitrage analysis performed for the NYUP. As shown, annual arbitrage revenues are estimated to range from $4.5-$146.7 million based on energy storage size, which ranges from 71-2,830 MW. Annual revenue per MW falls from a high of $63,289 at 71 MW to $51,824 at 2,830 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, PH generates profits at all energy storage capacities with the exception of 2,830 MW where annual losses of $3.3 million are registered. From 71 MW to 2,476 MW, annual profits range from a low of $0.7 million at 71 MW to a high of $9.2 million at 1,415 MW of capacity. Annualized costs are estimated to range from $14.4-$574.4 million for pumped hydro, $32.2 million-$1.3 billion for Na-S, and $63.4 million-$2.5 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the NYUP is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is overcome with pumped hydropower at storage capacities up to 2,476 MW.

Table A.37. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (NYUP)

Storage Size	Annual Revenue		Annualized Capital Costs		
(MW)	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
71	4,477,723	10,612,500	14,360,835	32,240,775	63,370,775
142	8,938,065	21,225,000	28,721,670	64,481,550	126,741,550
283	17,836,470	42,450,000	57,443,340	128,963,100	253,483,100
354	22,222,716	53,062,500	71,804,175	161,203,875	316,853,875
708	43,783,385	106,125,000	143,608,350	322,407,750	633,707,750
1,061	64,452,765	159,187,500	215,412,525	483,611,625	950,561,625
1,415	84,170,795	212,250,000	287,216,700	644,815,500	1,267,415,500
1,769	102,742,209	265,312,500	359,020,875	806,019,375	1,584,269,375
2,123	119,124,503	318,375,000	430,825,050	967,223,250	1,901,123,250
2,476	134,465,335	371,437,500	502,629,225	1,128,427,125	2,217,977,125
2,830	146,661,202	424,500,000	574,433,400	1,289,631,000	2,534,831,000

A.13 RFCE

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.13.1 Balancing Requirements

Figure A.91 and Figure A.92 show monthly and daily balancing signals for RFCE, respectively. Based on the whole year simulation, the balancing power requirements are 3192 MW of inc. capacity and 3447MW of dec. capacity, using the BPA’s customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability of happening.

Figure A.93 shows balancing signals caused by load and by wind separately in the region RFCE for one month. In this region, the balancing requirements are caused mostly by load uncertainty in 2020. Figure A.94 presents the same balancing signals for a typical day.

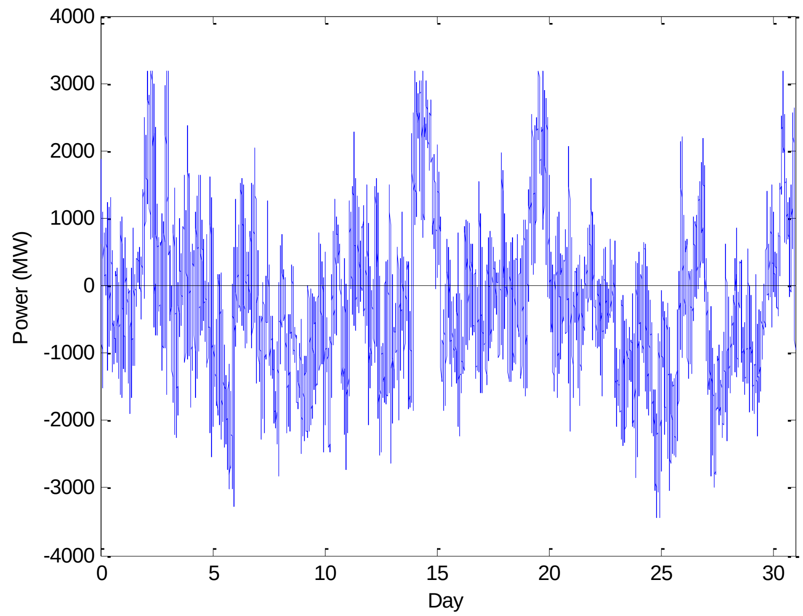

Figure A.91. One Month Total Balancing Signal in August 2020 for RFCE

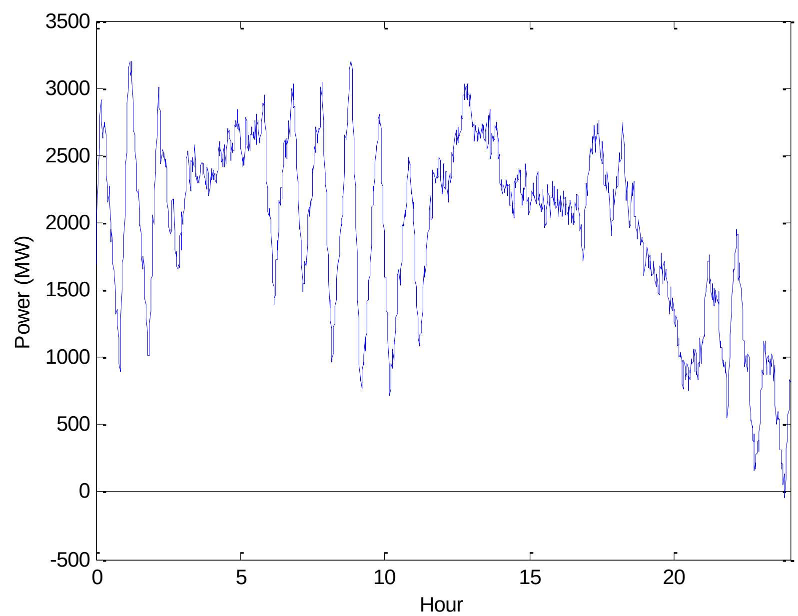

Figure A.92. Typical Day Total Balancing Signal in August 2020 for RFCE

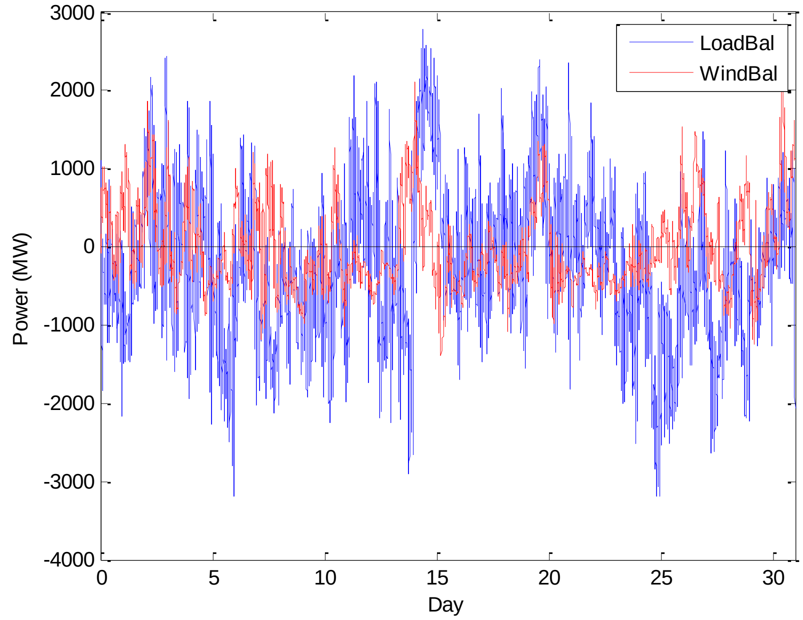

Figure A.93. One Month Balancing Requirements Caused by Load and Wind Respectively for RFCE

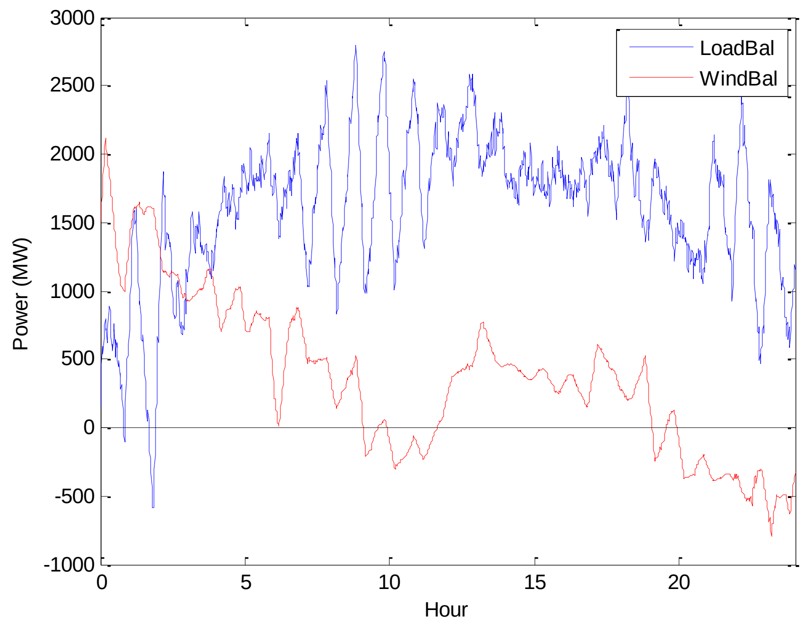

Figure A.94. RFCE Typical Day Balancing Requirements Caused by Load and Wind Respectively

A.13.2 Energy and Power Requirements

Table A.38, Figure A.95 and Figure A.96 show energy and power requirements for the scenarios in the Reliability First Corporation/East (RFCE) area

Table A.38. Power and Energy Requirements for Each Scenario for RFCE. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.53	-
C2	NaS	2.59	0.79
C3	Li-ion	2.58	0.79
C4	Flywheel	2.55	0.77
C5	CAES	4.81	27.85
	NaS	1.15	0.07
C6	Flow battery	2.60	0.80
C7	PH multiple modes	2.58	0.75
	4 min waiting period, NaS	1.16	0.24
C8	PH 2 modes	4.81	27.95
	4 min waiting period, NaS	0.65	0.03
C9	DR	9.15	-

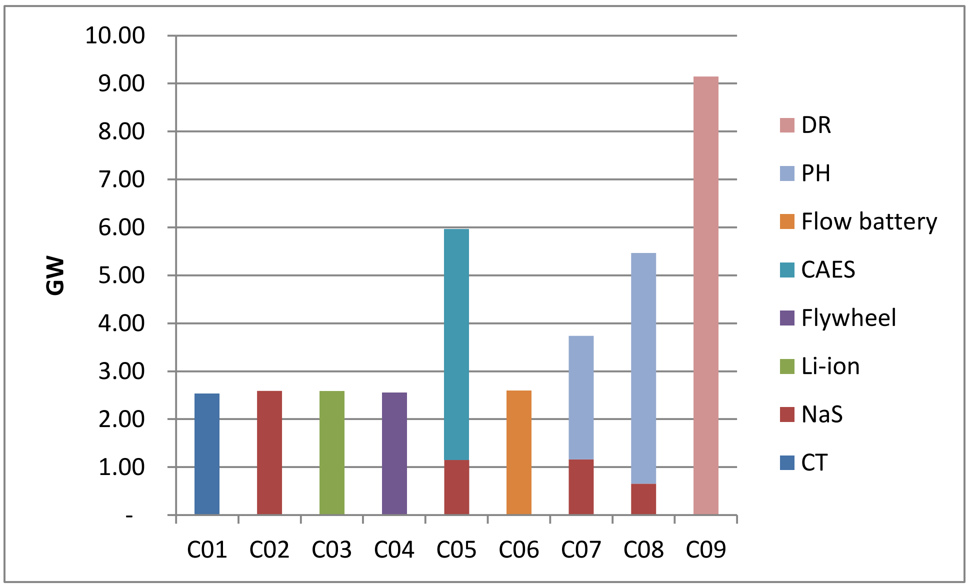

Figure A.95. RFCE Power Requirements for all the Technologies to Meet Balancing Signal

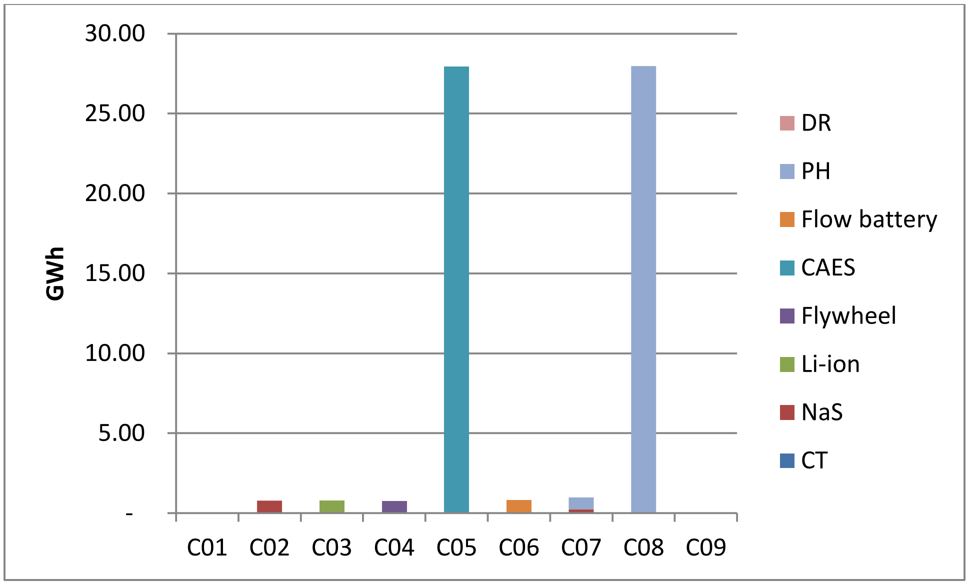

Figure A.96. RFCE Energy Requirements for Storage Technologies to Meet Balancing Signal

Table A.39, Figure A.97 and Figure A.98 show the energy and power requirements for the RFCE scenarios considering the additional wind generation and load expected between 2011 and 2012.

Table A.39. Power and Energy Requirements for Each RFCE Scenario resulting from 2011-2020 Additional Wind and Load. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.88	-
C2	Na-S	0.85	0.36
C3	Li-ion	0.86	0.36
C4	Flywheel	0.87	0.33
C5	CAES	1.66	9.01
	Na-S	0.45	0.05
C6	Flow battery	0.85	0.37
C7	PH multiple modes	0.86	0.35
	4-min waiting period, Na-S	0.43	0.13
C8	PH 2 modes	1.66	9.05
	4-min waiting period, Na-S	0.33	0.02
C9	DR	2.82	-

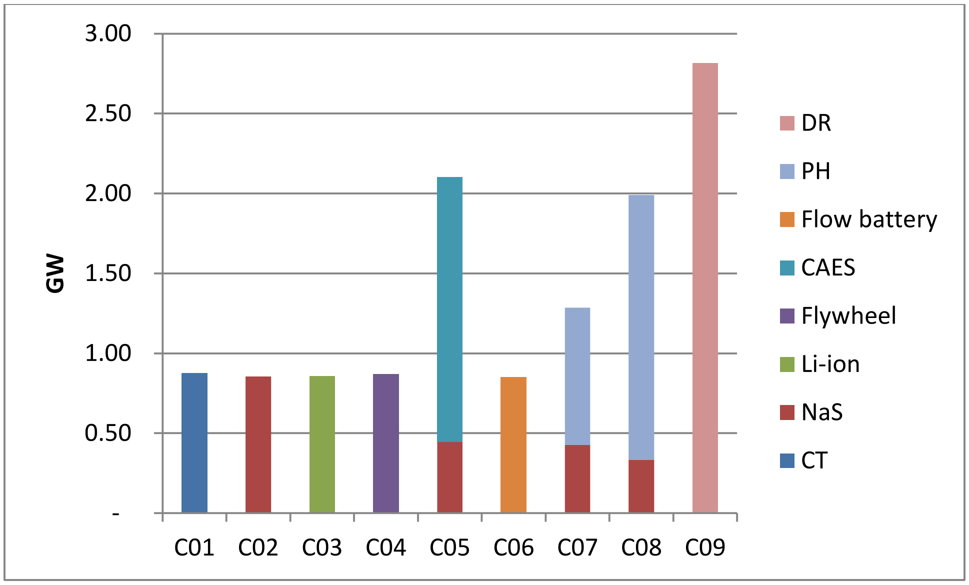

Figure A.97. Power Requirements for all the Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for RFCE

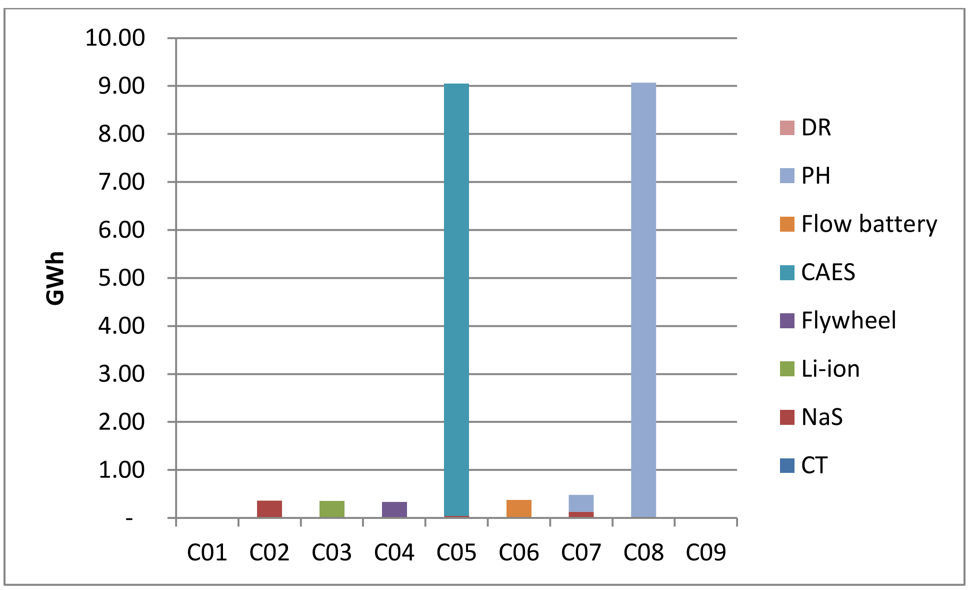

Figure A.98. Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for RFCE

A.13.3 Life-Cycle Cost Analysis

The results of the economic analysis for the RFCE power area are presented in Table A.40 and Figure A.99. These results represent the base or reference case for the nine technologies defined in Section 6.1. The values presented in Table A.40 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $3.7 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $4.3 billion or 15.4 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $8.8 billion. The CAES case (Case 5) is also more expensive with estimated costs of $11.7 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $16.3 billion. Total costs under Case 6, redox flow batteries , are estimated at $7.9 billion.

Table A.40. Economic Analysis Results – RFCE (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	6,369	1,442	589	570	8,969
2	3,009	222	377	88	3,696
3	4,882	199	371	79	5,531
4	3,375	94	760	37	4,266
5	7,979	1,817	1,137	718	11,652
6	7,224	257	355	102	7,938
7	8,174	196	375	78	8,823
8	14,759	505	881	200	16,344

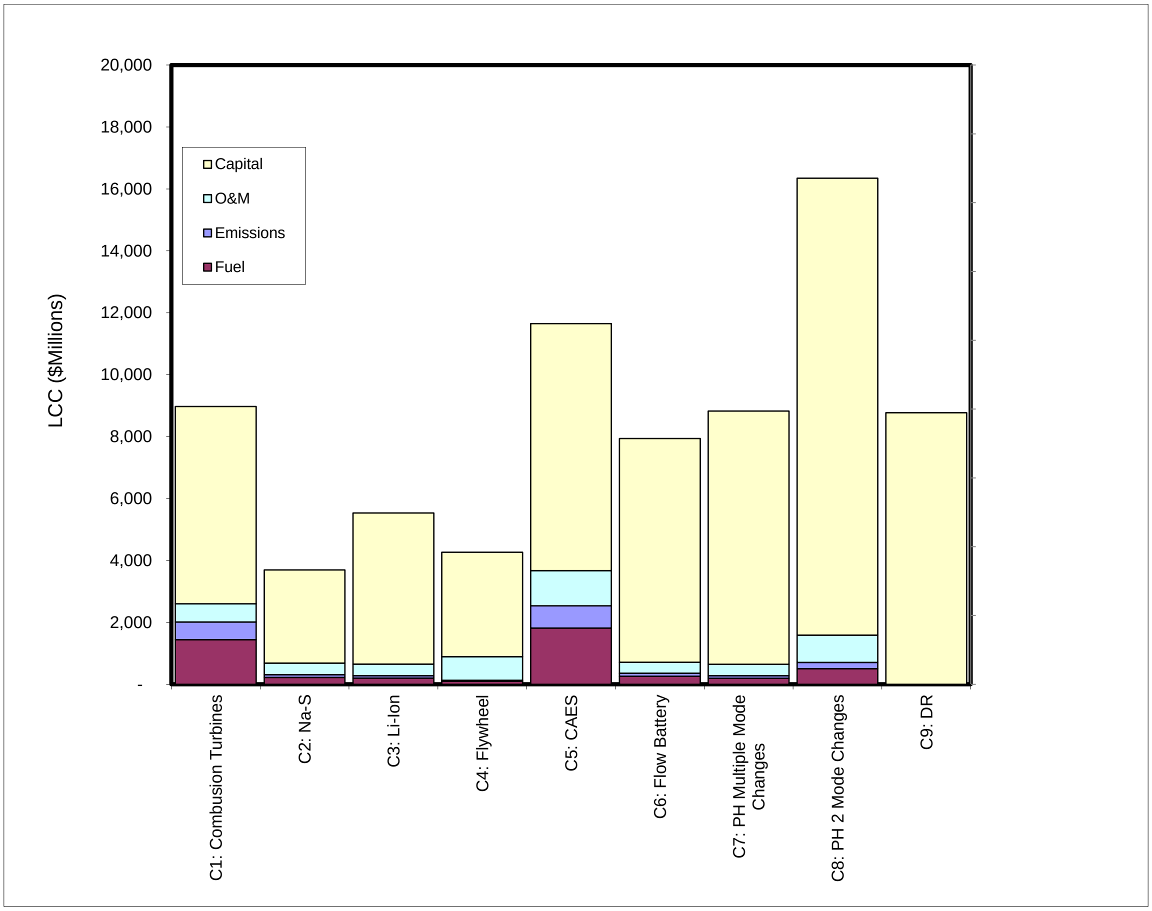

Figure A.99. LCC Estimates for RFCE

A.13.4 Arbitrage

Arbitrage analysis was not performed for the RFCE area because of expected low-economic value estimation.

A.14 RFCM

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.14.1 Balancing Requirements

Figure A.100 and Figure A.101 show monthly and daily balancing signals for RFCM, respectively. Based on the whole year simulation, the balancing power requirements are 912.7 MW of inc. capacity and 885 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability of happening.

Figure A.102 shows one-month balancing signals caused by load and by wind separately for the RFCM region. In 2020, these balancing requirements are caused mostly by load uncertainty. Figure A.103 presents the same balancing signals for a typical day.

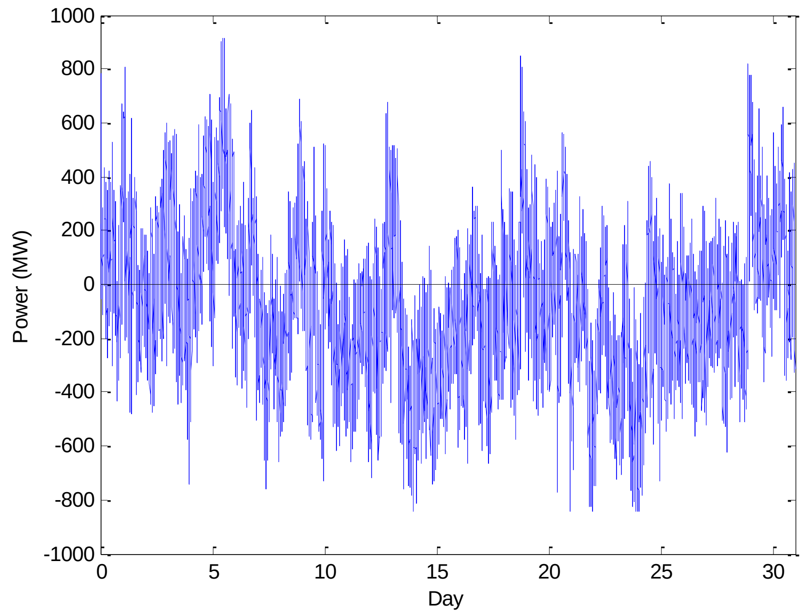

Figure A.100. One Month Total Balancing Signal of August 2020 for RFCM

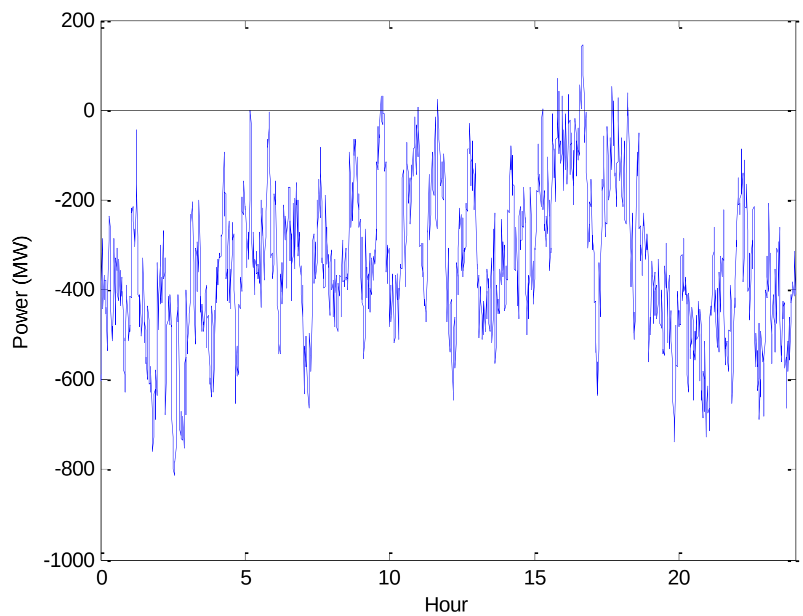

Figure A.101. Typical Day Total Balancing Signal in August 2020 for RFCM

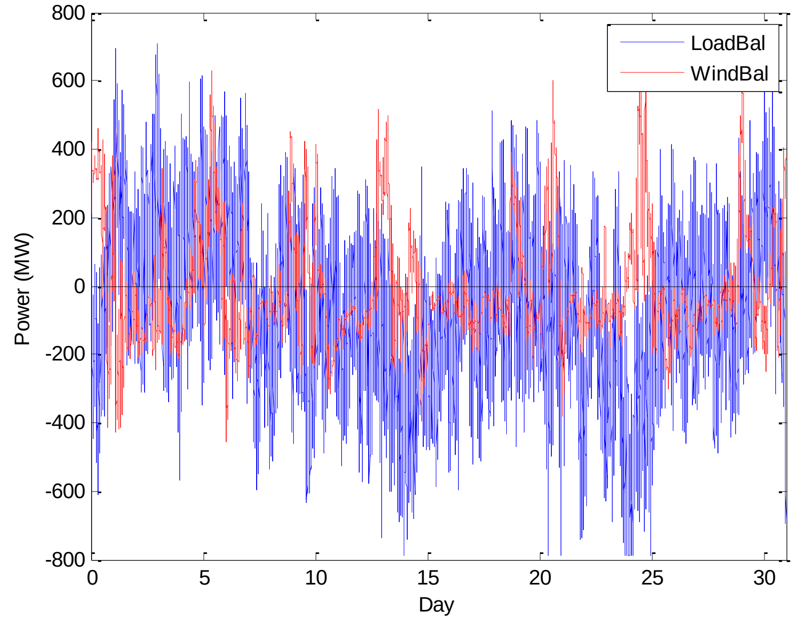

Figure A.102. One Month Balancing Requirements Caused by Load and Wind Respectively for RFCM

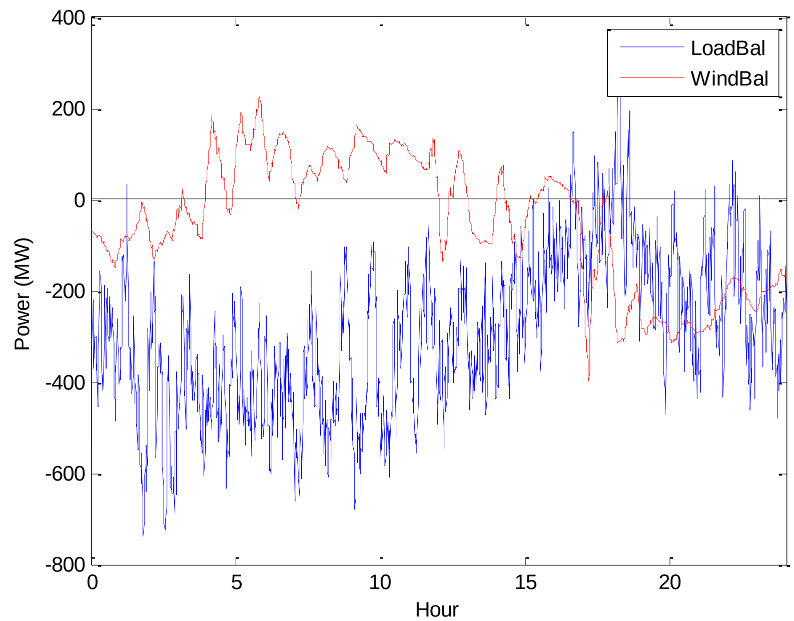

Figure A.103. Typical Day Balancing Requirements Caused by Load and Wind Respectively for RFCM

A.14.2 Energy and Power Requirements

Table A.41, Figure A.104 and Figure A.105 show energy and power requirements for the scenarios in the RFCM area.

Table A.41. Power and Energy Requirements for Each Scenario for RFCM. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.60	-
C2	NaS	0.61	0.20
C3	Li-ion	0.61	0.20
C4	Flywheel	0.61	0.19
C5	CAES	1.17	6.93
	NaS	0.35	0.03
C6	Flow battery	0.62	0.21
C7	PH multiple modes	0.61	0.29
	4 min waiting period, NaS	0.48	0.24
C8	PH 2 modes	1.17	6.97
	4 min waiting period, NaS	0.25	0.01
C9	DR	2.18	-

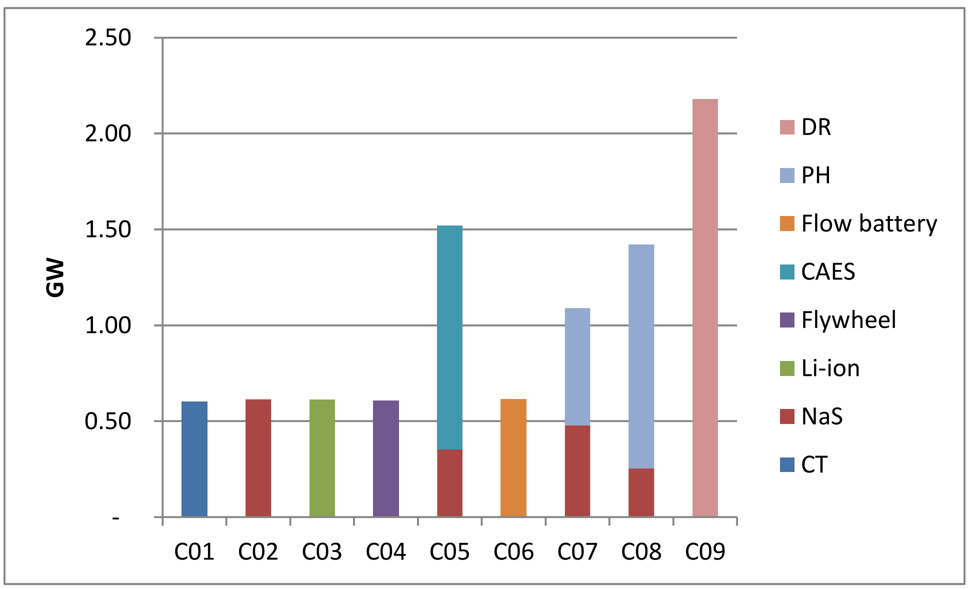

Figure A.104. Power Requirements for all the Technologies to Meet Balancing Signal for RFCM

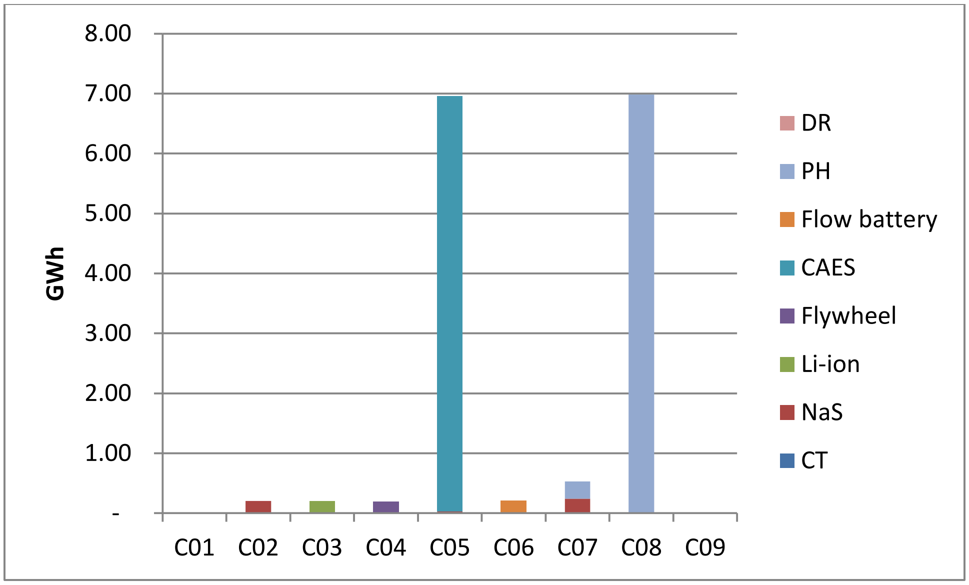

Figure A.105. Energy Requirements for Storage Technologies to Meet Balancing Signal for RFCM

Table A.42, Figure A.106 and Figure A.107 show energy and power requirements of the RFCM scenarios considering the additional wind generation and load expected between 2011 and 2012 assuming that the 2011 level of balancing is still provided by existing resources.

Table A.42. Power and Energy Requirements for Each Scenario resulting from 2011-2020 Additional Wind and Load for RFCM. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.34	-
C2	Na-S	0.34	0.17
C3	Li-ion	0.34	0.17
C4	Flywheel	0.34	0.15
C5	CAES	0.61	3.47
	Na-S	0.20	0.02
C6	Flow battery	0.34	0.18
C7	PH multiple modes	0.34	0.16
	4-min waiting period, Na-S	0.17	0.03
C8	PH 2 modes	0.61	3.49
	4-min waiting period, Na-S	0.11	0.01
C9	DR	1.23	-

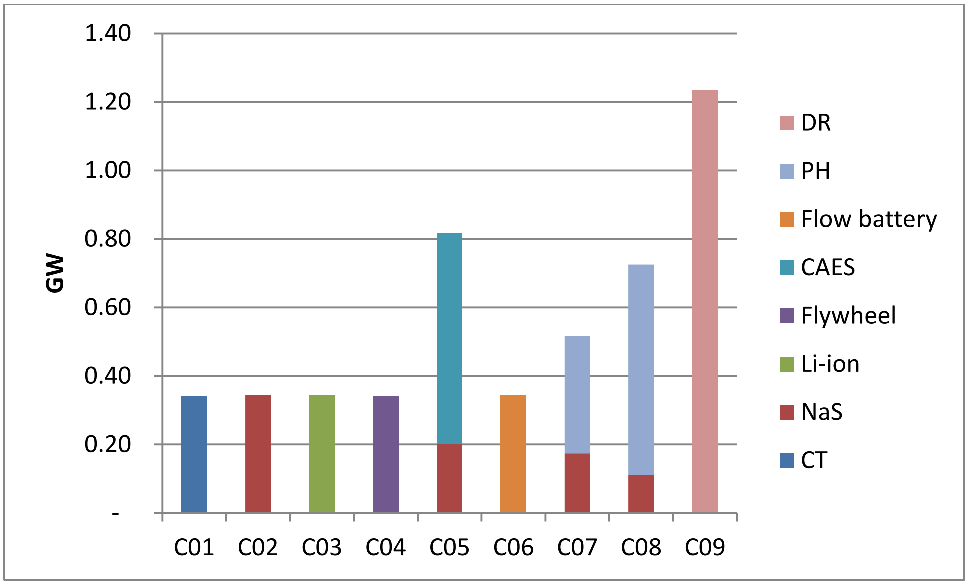

Figure A.106. Power Requirements for all the Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for RFCM

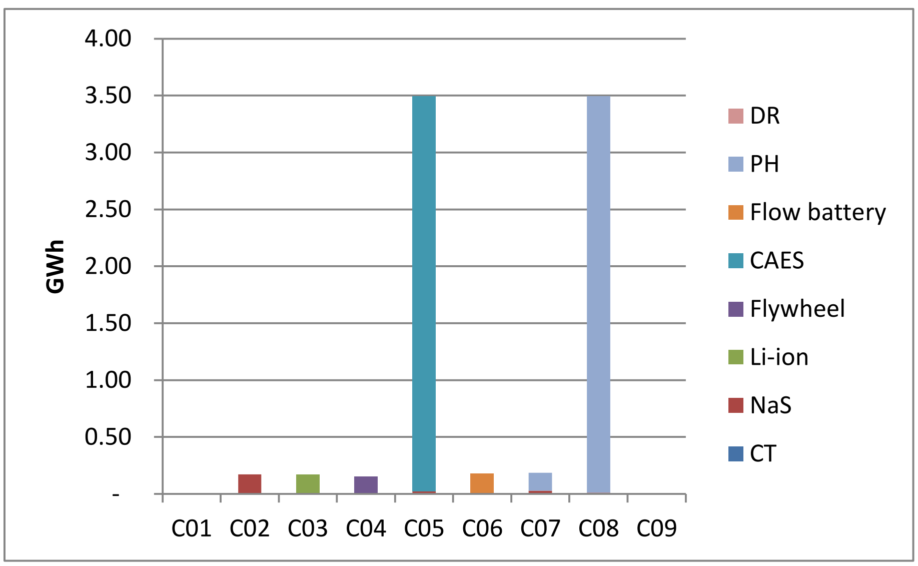

Figure A.107. Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for RFCM

A.14.3 Life-Cycle Cost Analysis

The results of the economic analysis for the RFCM power area are presented in Table A.43 and Figure A.108. The values presented in Table A.43 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at \$0.9 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at \$1.0 billion or 12.3 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at \$2.1 billion. The CAES case (Case 5) is also more expensive with estimated costs of \$3.1 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at \$4.1 billion. Total costs under Case 6, redox flow batteries , are estimated at \$1.9 billion.

Table A.43. Economic Analysis Results – RFCM (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	1,592	422	149	167	2,330
2	724	63	100	25	912
3	1,156	57	98	22	1,333
4	804	27	182	11	1,024
5	1,970	572	318	226	3,086
6	1,718	73	86	29	1,907
7	2,201	61	121	24	2,407
8	3,621	144	245	57	4,067
9	2,089	-	-	-	2,089

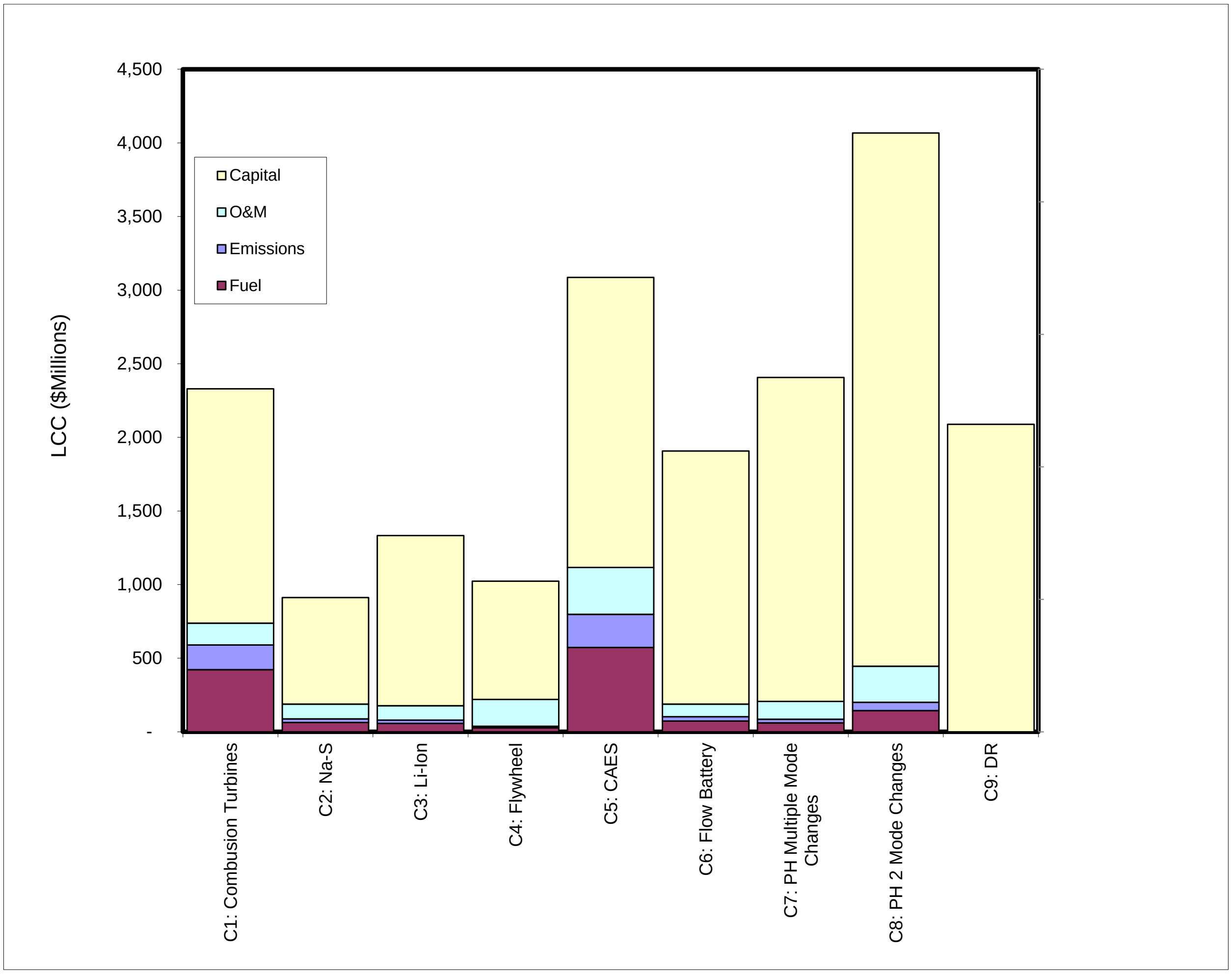

Figure A.108. LCC Estimates for RFCM

A.14.4 Arbitrage

Arbitrage analysis was not performed for the RFCM because of the expected low economic value estimation.

A.15 RFCW

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.15.1 Balancing Requirements

Figure A.109 and Figure A.110 show monthly and daily balancing signals for Reliability First Corporation/West (RFCW), respectively Based on the whole year simulation, the balancing power requirements are 5147 MW of inc. capacity and 5555MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability to happen.

Figure A.111 shows balancing signals caused by load and caused by wind separately for the region RFCW for one month. For the RFCW, the balancing requirements are almost evenly caused by load uncertainty and wind uncertainty in 2020. Figure A.112 presents the same balancing signals for one day.

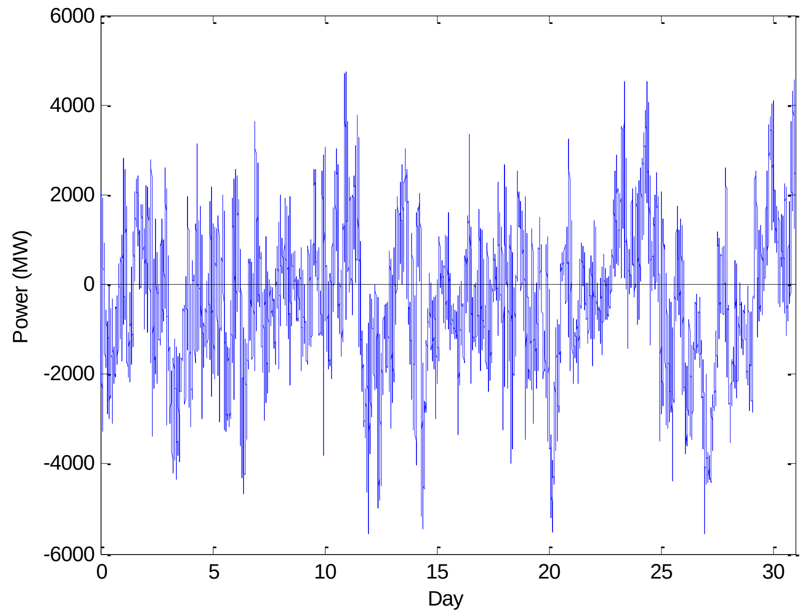

Figure A.109. One Month Total Balancing Signal of August 2020 for RFCW

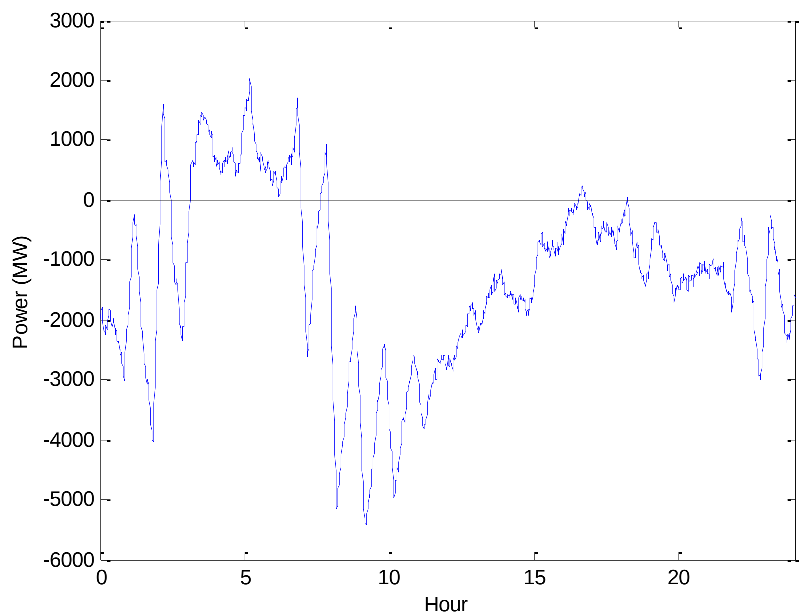

Figure A.110. Typical Day Total Balancing Signal of August 2020 for RFCW

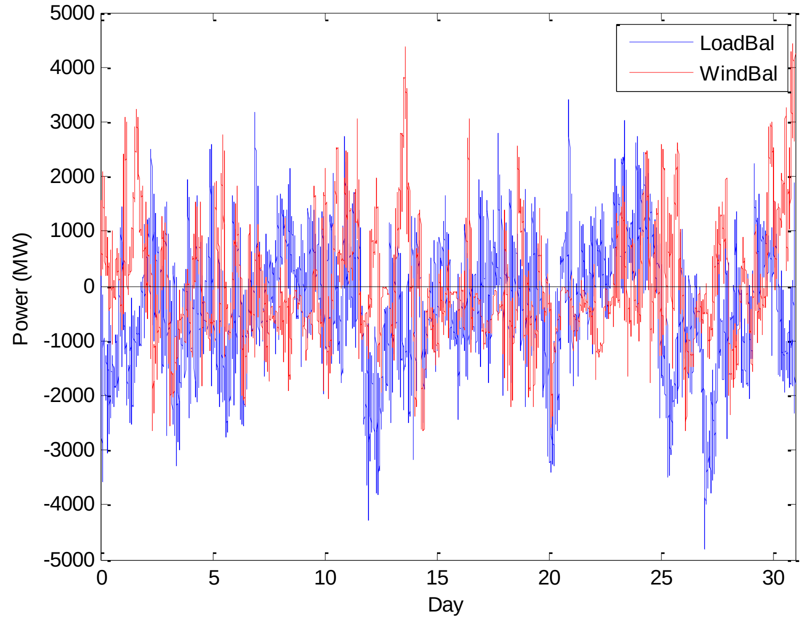

Figure A.111. One Month Balancing Requirements Caused by Load and Wind Respectively for RFCW

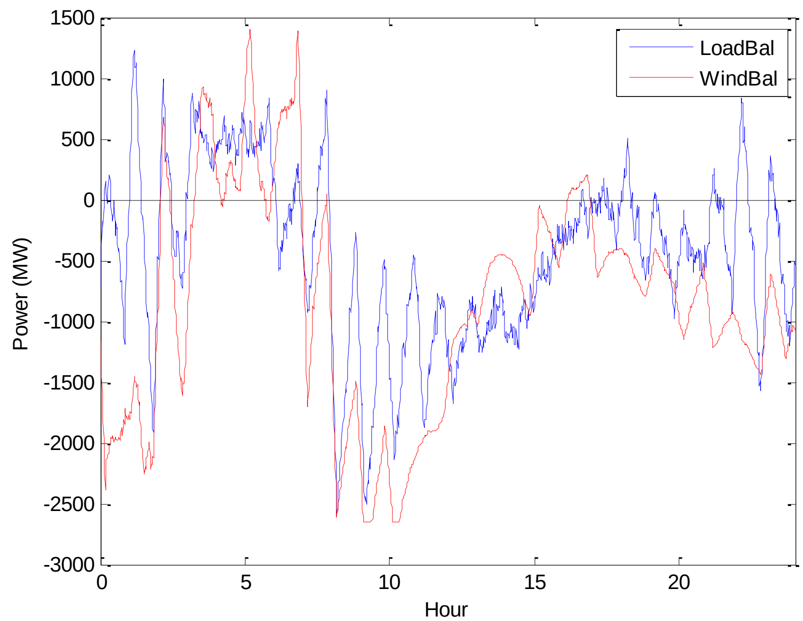

Figure A.112. Typical Day Balancing Requirements Caused by Load and Wind Respectively for RFCW

A.15.2 Energy and Power Requirements

Table A.44, Figure A.113 and Figure A.114 show energy and power requirements for the scenarios in the Reliability First Corporation/West (RFCW) area.

Table A.44. Power and Energy Requirements for Each Scenario for RFCW. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	3.83	-
C2	NaS	3.88	1.39
C3	Li-ion	3.87	1.36
C4	Flywheel	3.85	1.28
C5	CAES	6.43	42.43
	NaS	2.05	0.15
C6	Flow battery	3.89	1.43
C7	PH multiple modes	3.87	1.24
	4 min waiting period, NaS	1.55	0.30
C8	PH 2 modes	6.43	42.59
	4 min waiting period, NaS	1.25	0.07
C9	DR	13.85	-

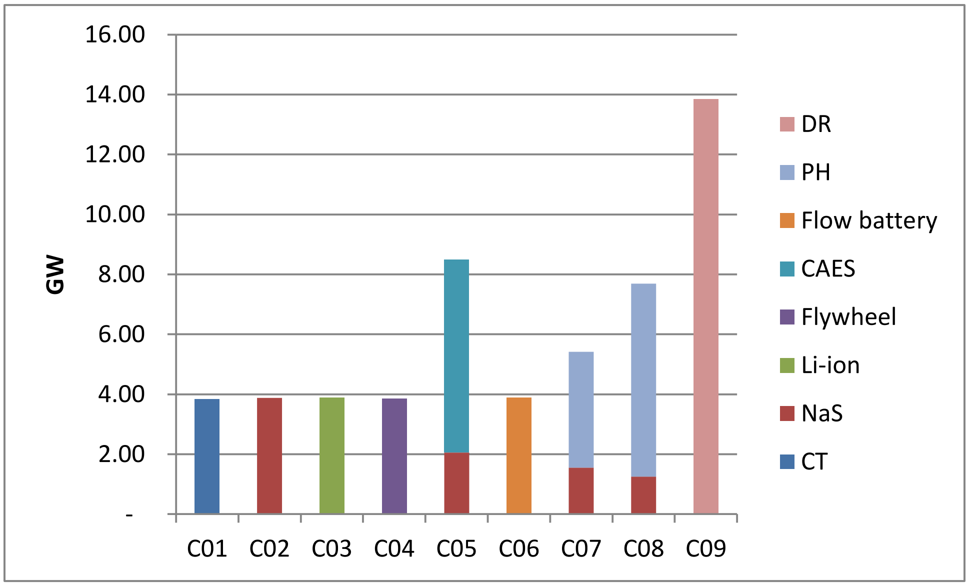

Figure A.113. Power Requirements for all the Technologies to Meet Balancing Signal for RFCW

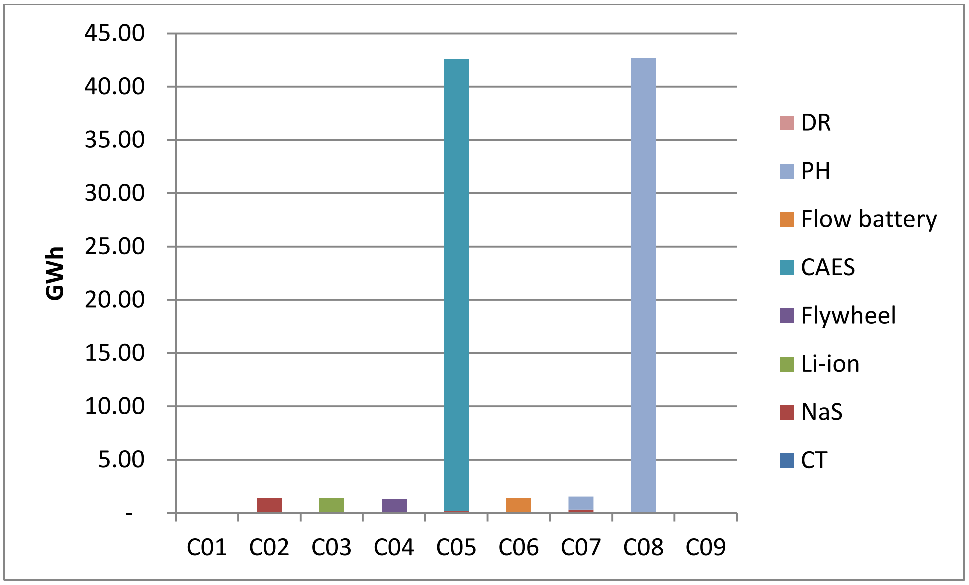

Figure A.114. Energy Requirements for Storage Technologies to Meet Balancing Signal for RFCW

Table A.45, Figure A.115 and Figure A.116 show energy and power requirements for the scenarios in the RFCW area, considering only the additional wind generation and load expected between 2011 and 2012 and assuming that the 2011 level of balancing is still provided by existing resources.

Table A.45. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for RFCW. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.28	0.00
C2	Na-S	2.30	0.82
C3	Li-ion	2.30	0.80
C4	Flywheel	2.29	0.79
C5	CAES	3.81	23.16
	Na-S	1.03	0.10
C6	Flow battery	2.30	0.86
C7	PH multiple modes	2.29	0.75
	4-min waiting period, Na-S	0.82	0.13
C8	PH 2 modes	3.81	23.24
	4-min waiting period, Na-S	0.77	0.06
C9	DR	8.23	0.00

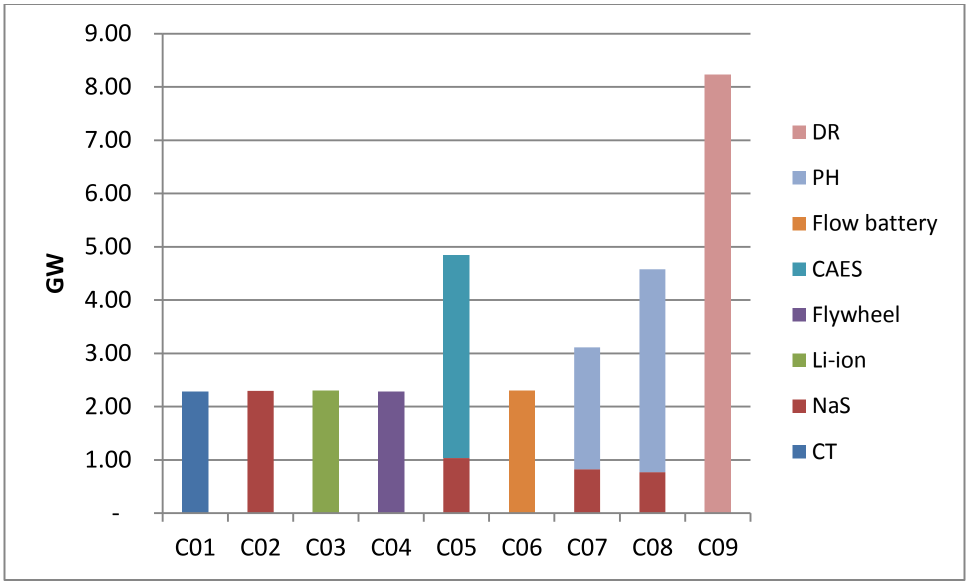

Figure A.115. Power Requirements for all the Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for RFCW

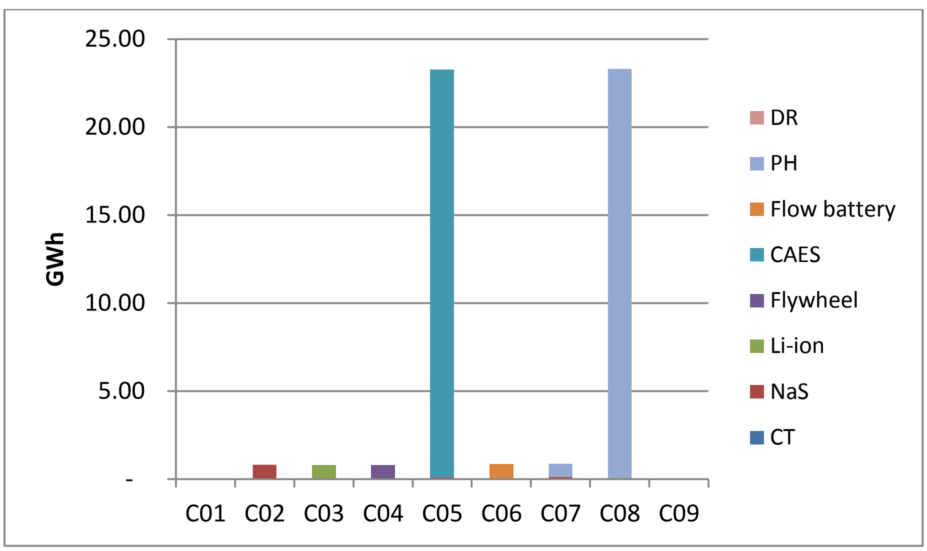

Figure A.116. Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Wind and Load for RFCW

A.15.3 Life-Cycle Cost Analysis

The results of the economic analysis for the RFCW power area are presented in Table A.46 and Figure A.117. The values presented in Table A.46 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $5.2 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $6.4 billion or

24.7 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $13.3 billion. The CAES case (Case 5) is also more expensive with estimated costs of $16.4 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $22.3 billion. Total costs under Case 6, redox flow batteries , are estimated at $11.9 billion.

Table A.46. Economic Analysis Results – RFCW (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	9,554	1,949	862	770	13,135
2	4,177	302	558	119	5,157
3	6,925	271	515	107	7,819
4	5,113	128	1,137	51	6,429
5	10,926	2,782	1,631	1,100	16,438
6	10,862	350	519	138	11,869
7	12,128	265	529	105	13,027
8	19,968	732	1,270	289	22,260
9	13,280	-	-	-	13,280

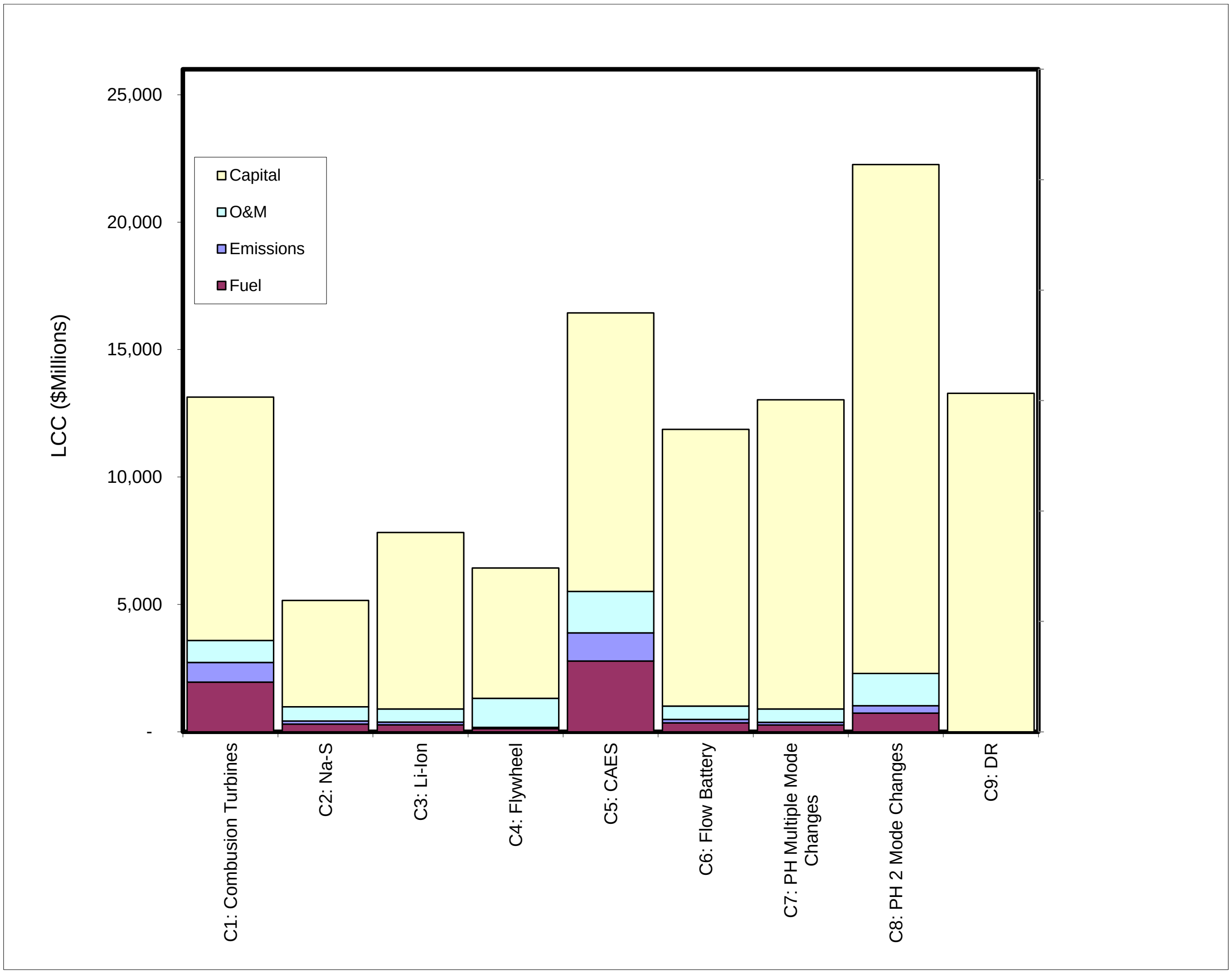

Figure A.117. LCC Estimates for RFCW

A.15.4 Arbitrage

Table A.47 presents the findings of the arbitrage analysis performed for the RFCW. As shown, annual arbitrage revenues are estimated to range from $0.8-$33.7 million based on energy storage size, which ranges from 14-562 MW. Annual revenue per MW is consistently in the $59.7-$60.2 million range across all energy storage sizes. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at all energy storage capacities. Annual profits range from a low of $95,276 at 14 MW to a high of $3.9 million at 562 MW of capacity. Annualized costs are estimated to range from $2.9-$114.1 million for pumped hydro, $6.4-$256.1 million for Na-S, and $12.6-$503.4 million for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the RFCW is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is reduced but only overcome by pumped hydropower.

Table A.47. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (RFCW)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
14	839,645	2,107,500	2,851,869	6,402,585	12,584,585
28	1,680,925	4,215,000	5,703,738	12,805,170	25,169,170
56	3,362,180	8,430,000	11,407,476	25,610,340	50,338,340
70	4,202,921	10,537,500	14,259,345	32,012,925	62,922,925
141	8,456,347	21,075,000	28,518,690	64,025,850	125,845,850
211	12,660,366	31,612,500	42,778,035	96,038,775	188,768,775
281	16,866,102	42,150,000	57,037,380	128,051,700	251,691,700
351	21,068,489	52,687,500	71,296,725	160,064,625	314,614,625
422	25,319,539	63,225,000	85,556,070	192,077,550	377,537,550
492	29,520,383	73,762,500	99,815,415	224,090,475	440,460,475
562	33,722,986	84,300,000	114,074,760	256,103,400	503,383,400

A.16 SRDA

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.16.1 Balancing Requirements

Figure A.118 and Figure A.119 show monthly and daily balancing signals for SRDA, respectively Based on the whole year simulation, the balancing power requirements are 1325MW of inc. capacity and 1613 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability to happen.

Figure A.120 shows balancing signals caused by load and by wind separately for the SRDA region for one month. These balancing requirements are mainly caused by SRDA load uncertainty in 2020. Figure A.121 presents the same balancing signals for a typical day.

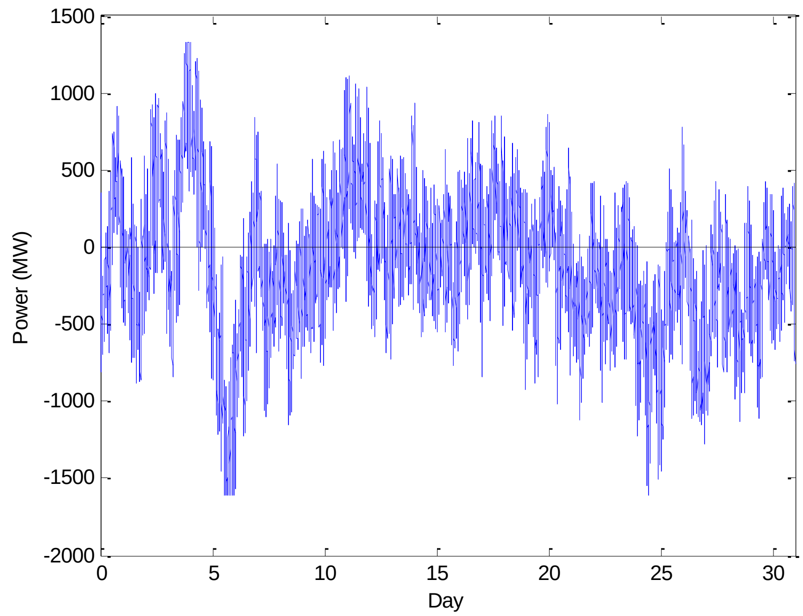

Figure A.118. One Month Total Balancing Signal in August 2020 for SRDA

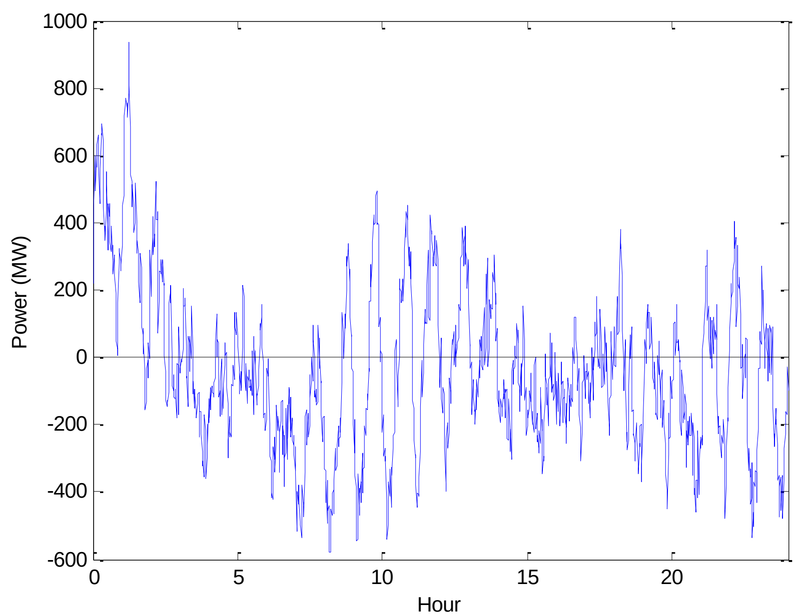

Figure A.119. Typical Day Total Balancing Signal of August 2020 for SRDA

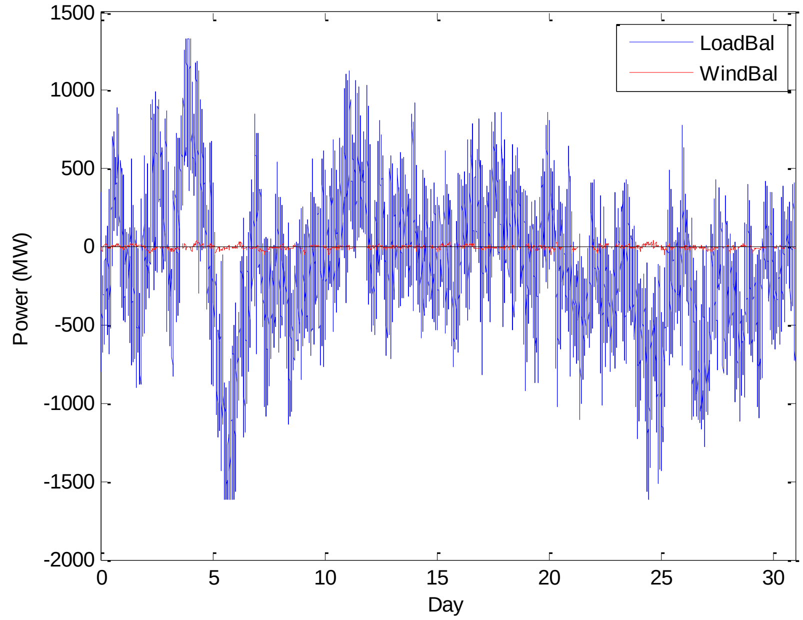

Figure A.120. One Month Balancing Requirements Caused by Load and Wind Respectively for SRDA

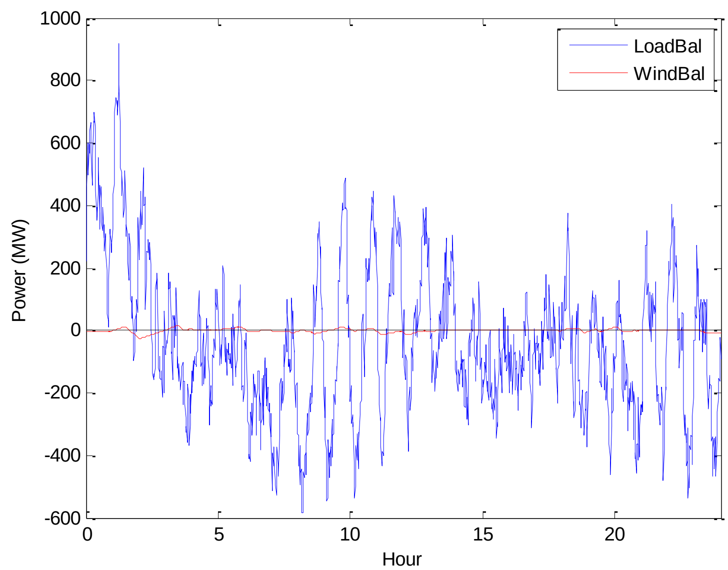

Figure A.121. One Typical Day Balancing Requirements Caused by Load and Wind Respectively for SRDA

A.16.2 Energy and Power Requirements

Table A.48, Figure A.122 and Figure A.123 show the results of energy and power requirements for the scenarios in the SERC Reliability Corporation/Delta (SRDA) area.

Table A.48. Power and Energy Requirements for Each Scenario for SRDA. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.83	-
C2	NaS	0.85	0.30
C3	Li-ion	0.85	0.30
C4	Flywheel	0.84	0.30
C5	CAES	1.54	9.01
	NaS	0.48	0.04
C6	Flow battery	0.86	0.30
C7	PH multiple modes	0.85	0.34
	4 min waiting period, NaS	0.63	0.22
C8	PH 2 modes	1.54	9.06
	4 min waiting period, NaS	0.43	0.02
C9	DR	3.01	-

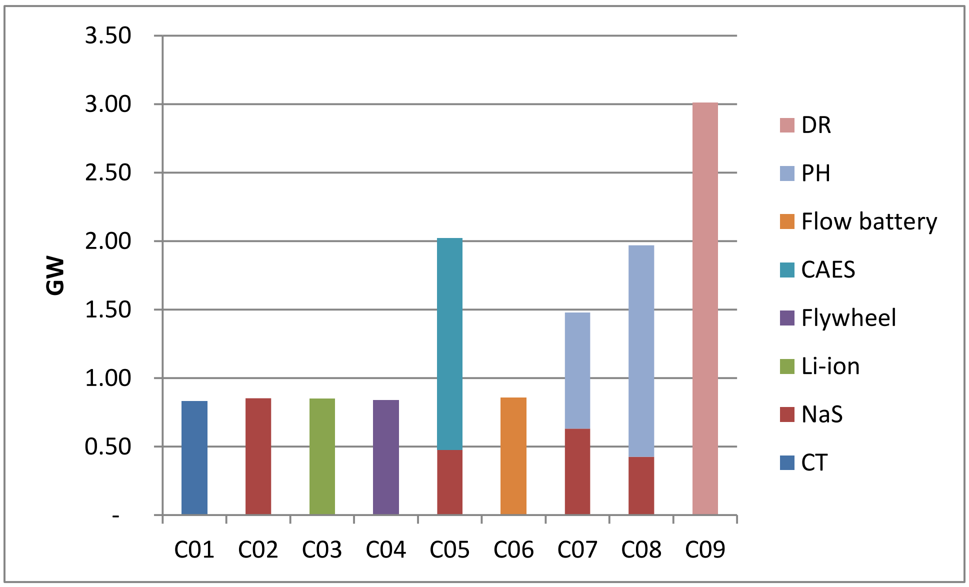

Figure A.122. Power Requirements for all the Technologies to Meet Balancing Signal for SRDA

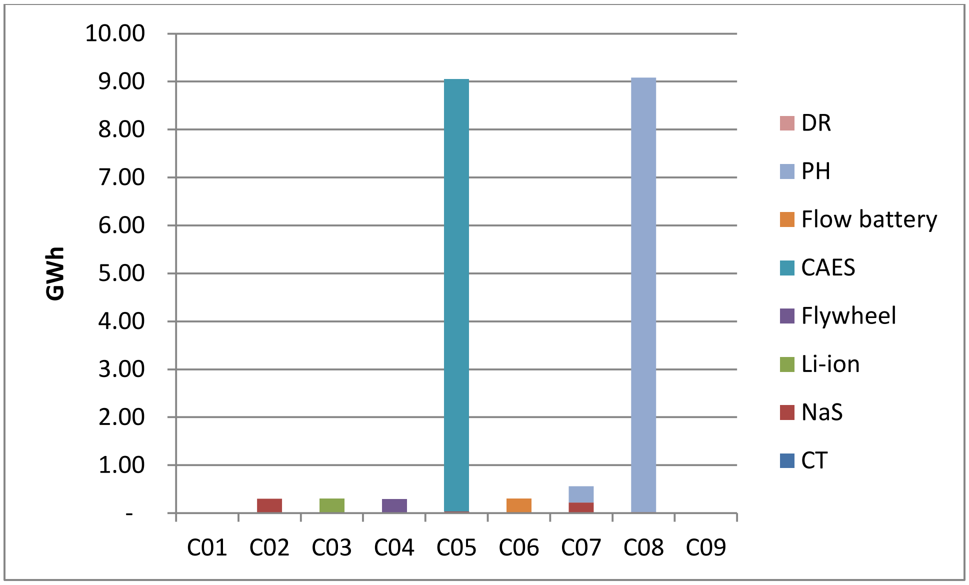

Figure A.123. Energy Requirements for Storage Technologies to Meet Balancing Signal for SRDA

Table A.49, Figure A.124 and Figure A.125 show energy and power requirements for the SRDA scenarios considering only the additional wind generation and load expected between 2011 and 2012. These estimates assume that the 2011 level of balancing is still provided by existing resources.

Table A.49. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for SRDA. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.04	-
C2	Na-S	0.04	0.02
C3	Li-ion	0.04	0.02
C4	Flywheel	0.04	0.02
C5	CAES	0.08	0.46
	Na-S	0.02	-
C6	Flow battery	0.04	0.02
C7	PH multiple modes	0.04	0.02
	4-min waiting period, Na-S	0.02	0.01
C8	PH 2 modes	0.08	0.46
	4-min waiting period, Na-S	0.02	-
C9	DR	0.14	-

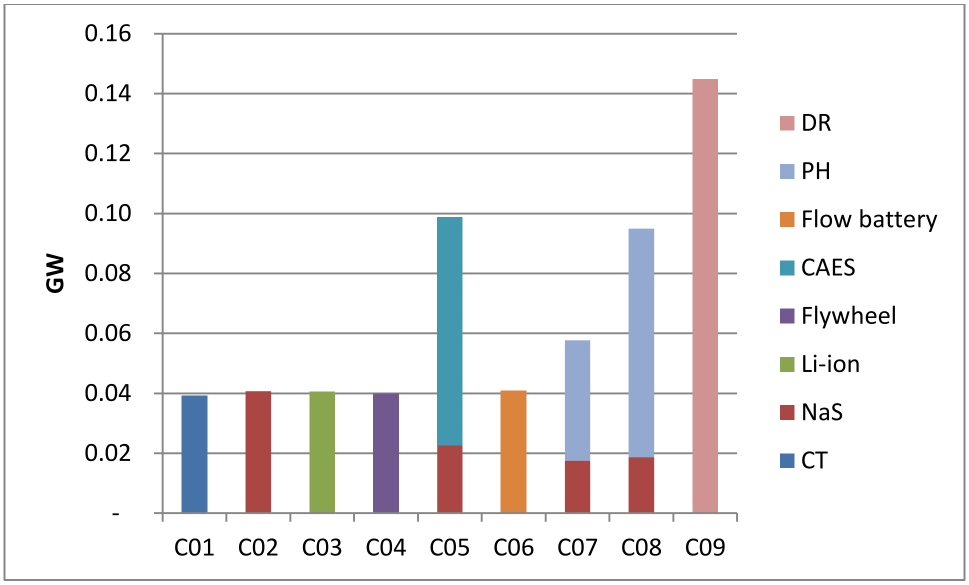

Figure A.124. Power Requirements for all the Technologies to Meet SRDA Balancing Signal Resulting from 2011-2020 Additional Windpower and Load

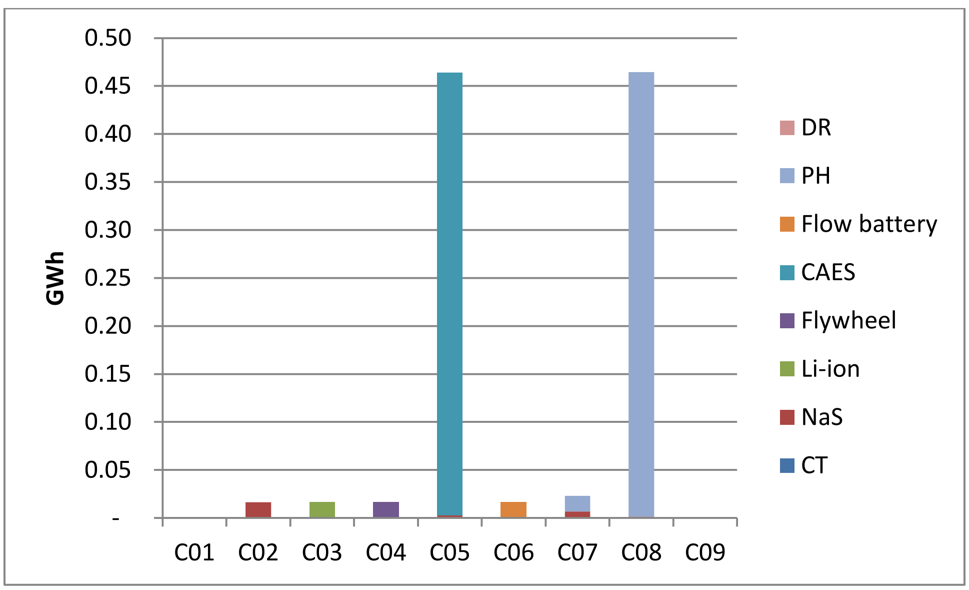

Figure A.125. Energy Requirements for Storage Technologies to Meet SRDA Balancing Signal Resulting from 2011-2020 Additional Windpower and Load

A.16.3 Life-Cycle Cost Analysis

The results of the economic analysis for the SRDA power area are presented in Table A.50 and Figure A.126. The values presented in Table A.50 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 4, which consists of flywheels , is the least cost alternative at $1.44 billion. Case 2, which employs Na-S batteries , represents the second least cost alternative with costs estimated at $1.46 billion or 3.1 percent higher than those estimated for Case 4. The costs associated with the DR-only case (Case 9) are nearly twice as expensive as those estimated for the two aforementioned cases, registering at $2.9 billion. The CAES case (Case 5) is also more expensive with estimated costs of $4.2 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $5.5 billion. Total costs under Case 6, redox flow batteries , are estimated at $2.7 billion.

Table A.50. Economic Analysis Results – SRDA (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	2,388	670	217	265	3,540
2	1,151	102	164	40	1,457
3	1,974	91	162	36	2,263
4	1,120	43	255	17	1,435
5	2,610	843	451	333	4,237
6	2,386	118	124	46	2,674
7	2,920	94	161	37	3,212
8	4,820	206	352	81	5,459
9	2,887	-	-	-	2,887

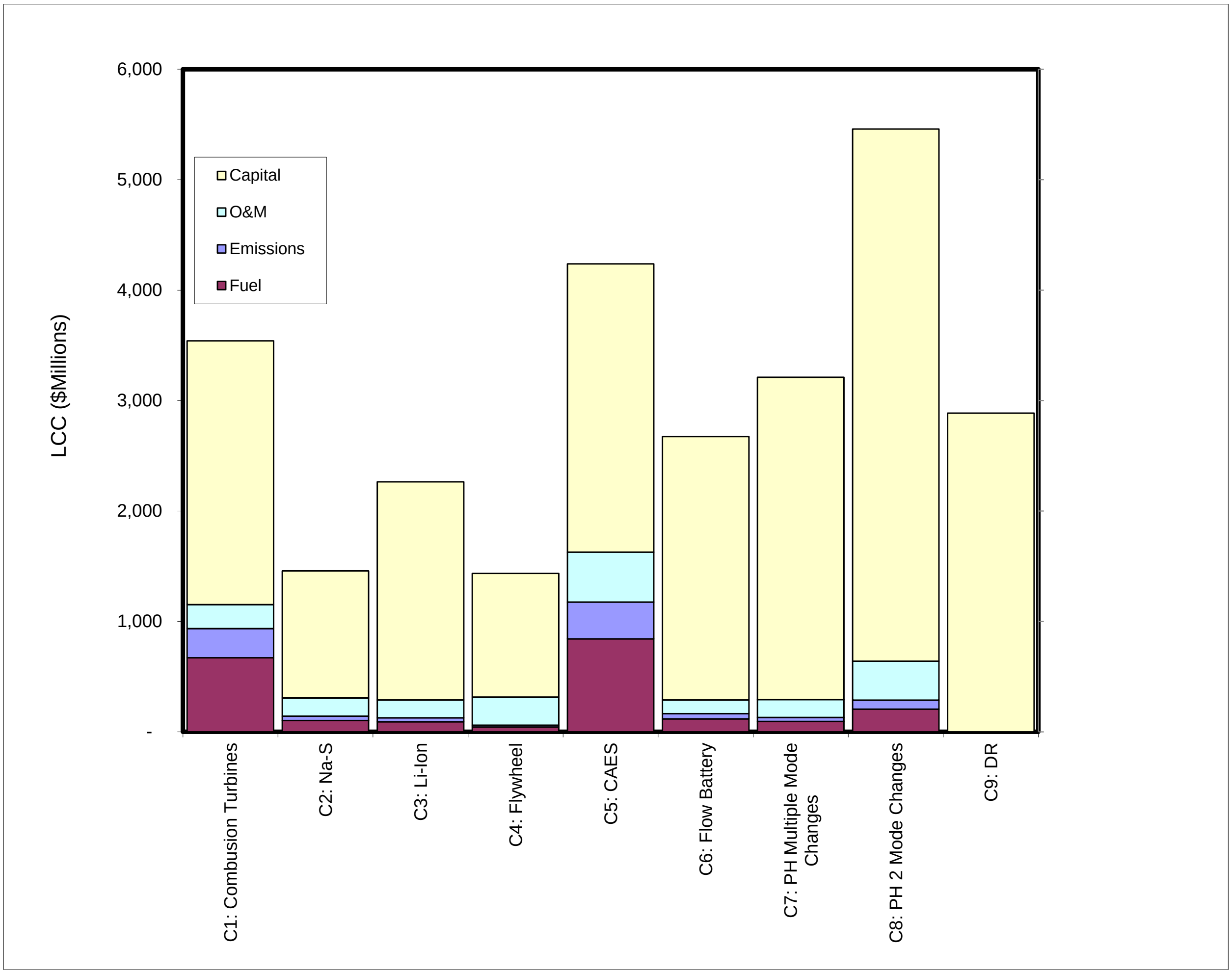

Figure A.126. LCC Estimates for SRDA

A.16.4 Arbitrage

Table A.51 presents the findings of the arbitrage analysis performed for the SRDA. As shown, annual arbitrage revenues are estimated to range from $22.3-$862.7 million based on energy storage size, which ranges from 359-14,366 MW. Annual revenue per MW ranges from a high of $62,100 at 359 MW to a low of $60,050 at 14,366 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at all energy storage capacities. Annual profits range from a low of $3.3 million at 359 MW to a high of $101.6 million at 14,366 MW of capacity. Annualized costs are estimated to range from $72.9 million - $2.9 billion for pumped hydro, $163.6 million-$6.5 billion for Na-S, and $321.7 million-$12.9 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the SRDA is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is reduced but only overcome with pumped hydropower.

Table A.51. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydropower (SRDA)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
359	22,303,241	53,872,500	72,900,267	163,664,655	321,690,655
718	44,599,833	107,745,000	145,800,534	327,329,310	643,381,310
1,437	89,214,440	215,490,000	291,601,068	654,658,620	1,286,762,620
1,796	111,503,377	269,362,500	364,501,335	818,323,275	1,608,453,275
3,592	222,376,935	538,725,000	729,002,670	1,636,646,550	3,216,906,550
5,387	332,106,119	808,087,500	1,093,504,005	2,454,969,825	4,825,359,825
7,183	440,692,593	1,077,450,000	1,458,005,340	3,273,293,100	6,433,813,100
8,979	548,099,909	1,346,812,500	1,822,506,675	4,091,616,375	8,042,266,375
10,775	654,326,042	1,616,175,000	2,187,008,010	4,909,939,650	9,650,719,650
12,570	759,177,488	1,885,537,500	2,551,509,345	5,728,262,925	11,259,172,925
14,366	862,677,135	2,154,900,000	2,916,010,680	6,546,586,200	12,867,626,200

A.17 SRGW

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.17.1 Balancing Requirements

Figure A.127 and Figure A.128 show monthly and daily balancing signals for SRGW, respectively Based on the whole year simulation, the balancing power requirements are 7114MW of inc. capacity and 4760 MW of dec. capacity, using the BPA’s customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability to happen.

Figure A.129 shows balancing signals caused by load and caused by wind separately for the region SRGW for one month. Balancing requirements are mainly caused by SRGW windpower uncertainty in 2020. Figure A.130 presents the same balancing signals for one day.

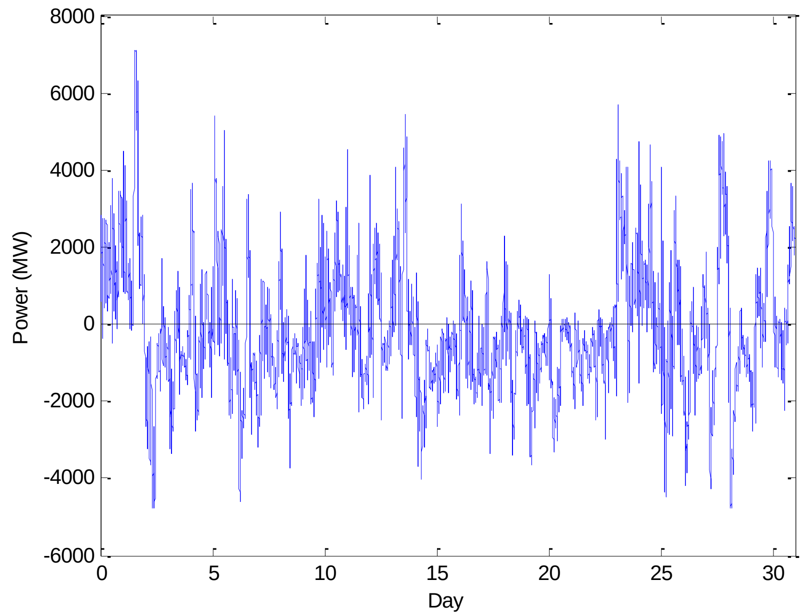

Figure A.127. One Month Total SRGW Balancing Signal in August 2020

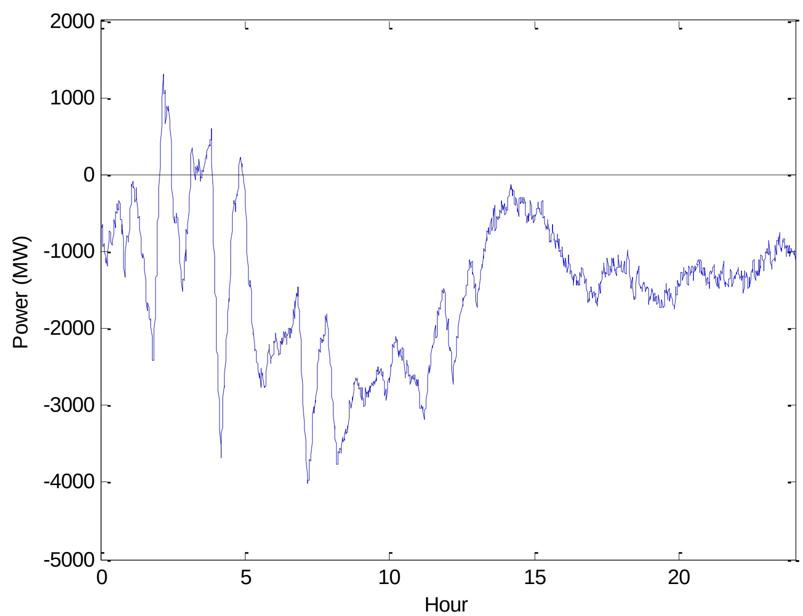

Figure A.128. Typical Day SRGW Balancing Signal in August 2020

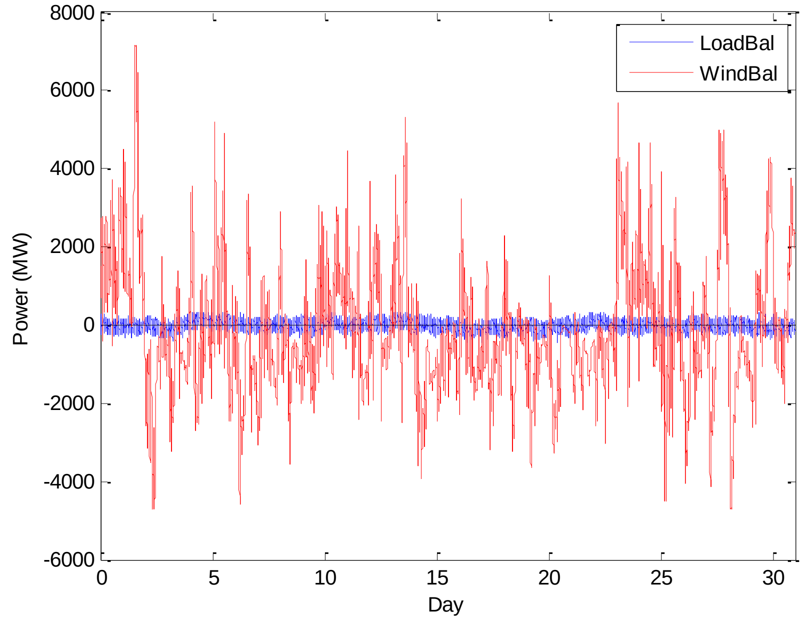

Figure A.129. One Month Balancing Requirements Caused by Load and Wind Respectively for SRGW

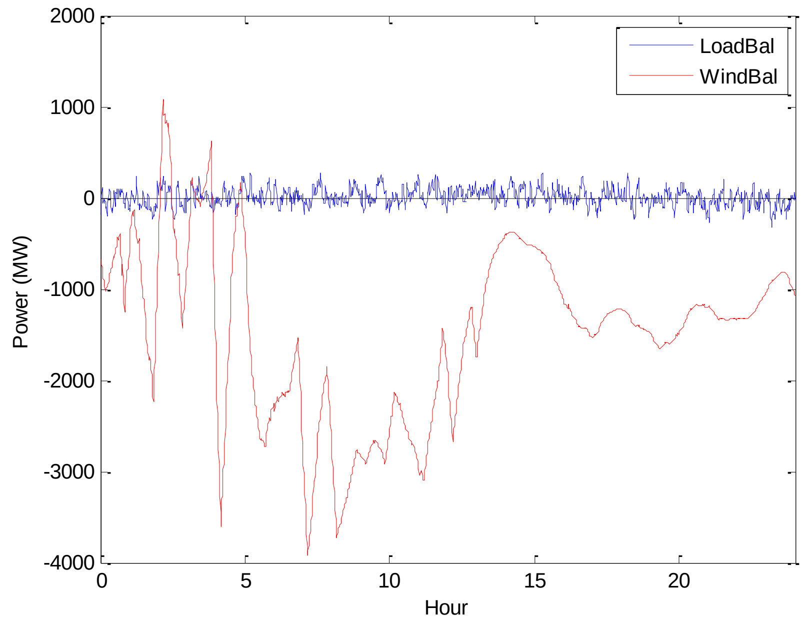

Figure A.130. Typical Day Balancing Requirements Caused by Load and Wind Respectively for SRGW

A.17.2 Energy and Power Requirements

Table A.52, Figure A.131 and Figure A.132 show the results of energy and power requirements for the scenarios in the SERC Reliability Corporation/Gateway (SRGW) area.

Table A.52. Power and Energy Requirements for Each Scenario for SRGW. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	3.29	-
C2	NaS	3.21	1.26
C3	Li-ion	3.21	1.24
C4	Flywheel	3.25	1.15
C5	CAES	6.24	39.07
	NaS	1.48	0.15
C6	Flow battery	3.20	1.30
C7	PH multiple modes	3.22	1.17
	4 min waiting period, NaS	1.62	0.24
C8	PH 2 modes	6.24	39.26
	4 min waiting period, NaS	1.13	0.07
C9	DR	11.15	-

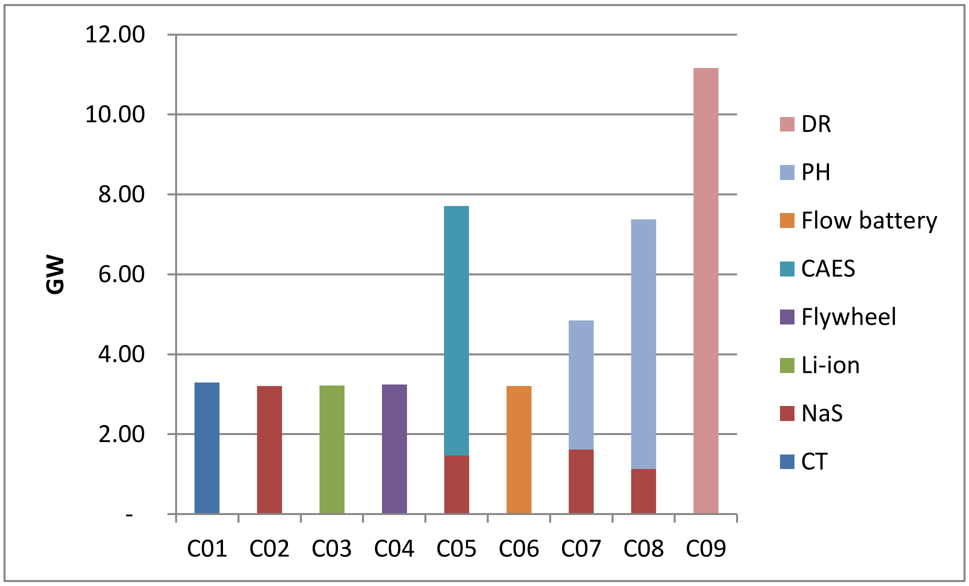

Figure A.131. Power Requirements for all the Technologies to Meet Balancing Signal for SRGW

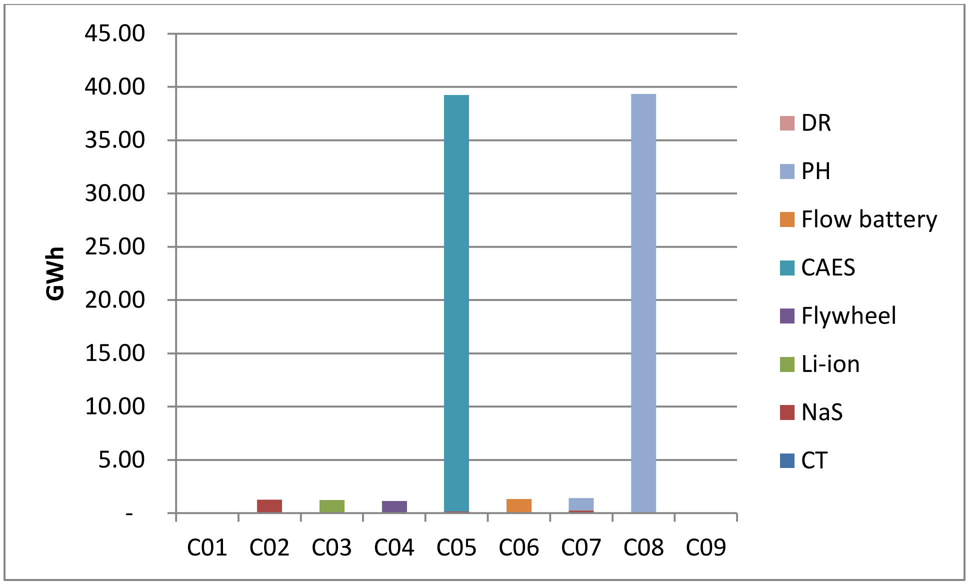

Figure A.132. Energy Requirements for Storage Technologies to Meet Balancing Signal for SRGW

Table A.53, Figure A.133 and Figure A.134 show estimated energy and power requirements for the scenarios in the Midwest Reliability Council/East (SRGW) area, considering only the additional windpower generation and load expected between 2011 and 2012. These requirements for only additional balancing assume that the 2011 level of balancing is still provided by existing resources.

Table A.53. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for SRGW. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.89	-
C2	Na-S	2.82	1.07
C3	Li-ion	2.82	1.05
C4	Flywheel	2.85	0.97
C5	CAES	5.56	34.32
	Na-S	1.20	0.13
C6	Flow battery	2.81	1.10
C7	PH multiple modes	2.83	1.00
	4-min waiting period, Na-S	1.29	0.15
C8	PH 2 modes	5.56	34.48
	4-min waiting period, Na-S	0.92	0.06
C9	DR	9.72	-

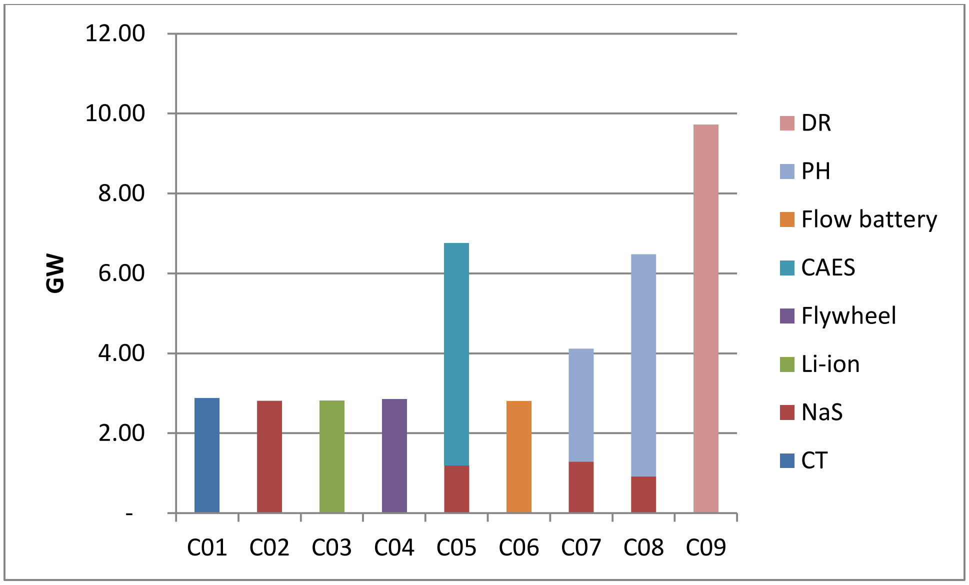

Figure A.133. SRGW Power Requirements for all the Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Windpower and Load

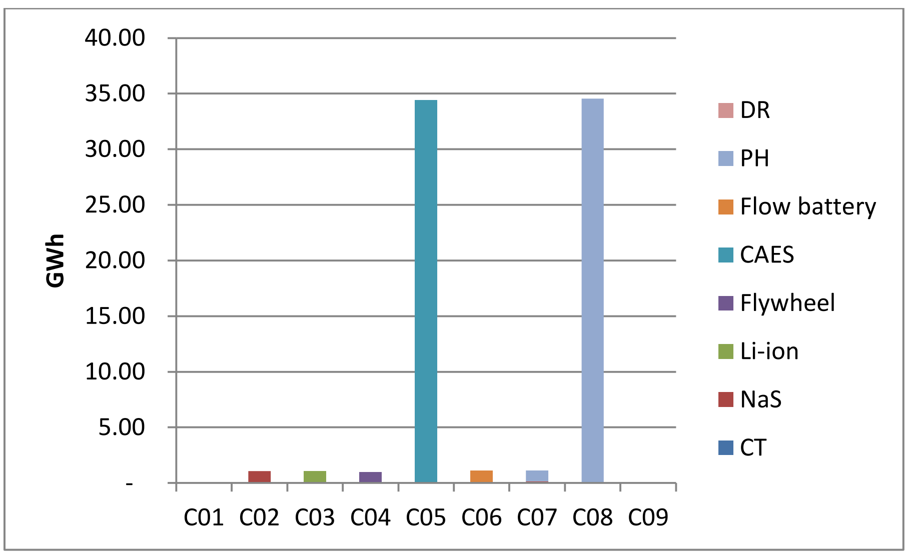

Figure A.134. SRGW Energy Requirements for Storage Technologies to Meet Balancing Signal Resulting from 2011-2020 Additional Windpower and Load

A.17.3 Life-Cycle Cost Analysis

The results of the economic analysis for the SRGW power area are presented in Table A.54 and Figure A.135 The values presented in Table A.54 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $4.3 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $5.4 billion or

25.0 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are nearly twice as expensive as those estimated for Case 4, registering at $10.7 billion. The CAES case (Case 5) is also more expensive with estimated costs of $15.1 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $21.2 billion. Total costs under Case 6, redox flow batteries , are estimated at $9.8 billion.

Table A.54. Economic Analysis Results – SRGW (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	8,359	1,549	724	612	11,245
2	3,566	239	440	95	4,341
3	5,741	215	433	85	6,473
4	4,328	101	958	40	5,427
5	10,403	2,333	1,457	922	15,115
6	8,962	277	429	110	9,777
7	10,264	212	451	84	11,012
8	19,306	584	1,117	231	21,237
9	10,696	-	-	-	10,696

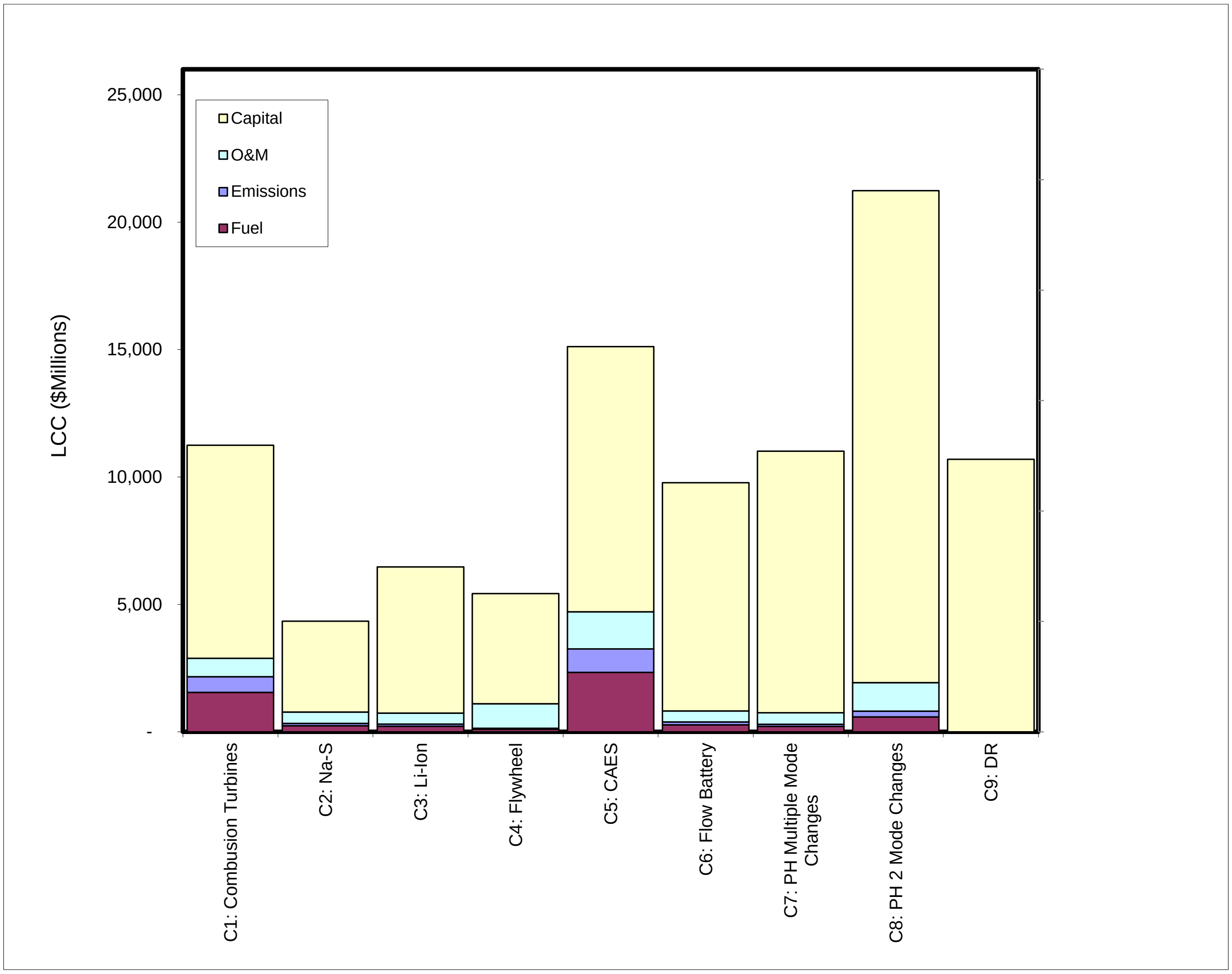

Figure A.135. LCC Estimates for SRGW

A.17.4 Arbitrage

Arbitrage analysis was not performed for the SRGW because of the low economic value expectations.

A.18 SRSE

A.18.1 Balancing Requirements

No balancing analysis was performed for the region because we assumed that no wind resource would be adopted in the region by 2020.

A.18.2 Life-Cycle Cost Analysis

No costs were estimated for this region.

A.18.3 Arbitrage

Table A.55 presents the findings of the arbitrage analysis performed for the SRSE. As shown, annual arbitrage revenues are estimated to range from $14.2-$361.8 million based on energy storage size, which ranges from 237-9,460 MW. Annual revenue per MW falls from a high of $60,152 at 237 MW to $38,246 at 9,460 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at energy storage capacities up to 3,548 MW. From 236 MW to 3,548 MW, annual profits range from a low of $1.7 million at 237 MW to a high of $9.1 million at 2,365 MW of capacity. Annualized costs are estimated to range from $48.0 million-$1.9 billion for pumped hydro, $107.8 million-$4.3 billion for Na-S, and $211.8 million-$8.5 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the SRSE is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is bridged but only for pumped hydro at storage sizes up to 3,548 MW.

Table A.55. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydropower (SRSE)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
237	14,225,906	35,475,000	48,004,770	107,773,050	211,833,050
473	28,326,199	70,950,000	96,009,540	215,546,100	423,666,100
946	55,998,286	141,900,000	192,019,080	431,092,200	847,332,200
1,183	69,612,979	177,375,000	240,023,850	538,865,250	1,059,165,250
2,365	134,431,000	354,750,000	480,047,700	1,077,730,500	2,118,330,500
3,548	193,687,227	532,125,000	720,071,550	1,616,595,750	3,177,495,750
4,730	244,126,132	709,500,000	960,095,400	2,155,461,000	4,236,661,000
5,913	285,111,592	886,875,000	1,200,119,250	2,694,326,250	5,295,826,250
7,095	319,538,478	1,064,250,000	1,440,143,100	3,233,191,500	6,354,991,500
8,278	345,219,214	1,241,625,000	1,680,166,950	3,772,056,750	7,414,156,750
9,460	361,810,384	1,419,000,000	1,920,190,800	4,310,922,000	8,473,322,000

A.19 SRCE

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.19.1 Balancing Requirements

Figure A.136 and Figure A.137show monthly and daily balancing signals for SRCE, respectively. Based on the whole year simulation, the balancing power requirements are 1164 MW of inc. capacity and 2093MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability to happen.

Figure A.138 shows balancing signals caused by load and by wind separately for the SRCE region in one month. The balancing requirements are mainly caused by load uncertainty in 2020. Figure A.139 presents the same balancing signals for a day.

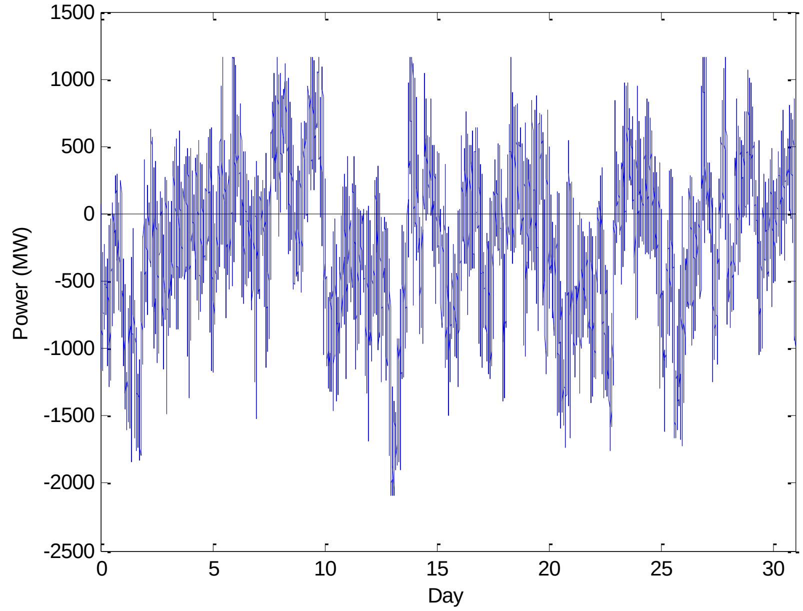

Figure A.136. One Month Total SRCE Balancing Signal in August 2020

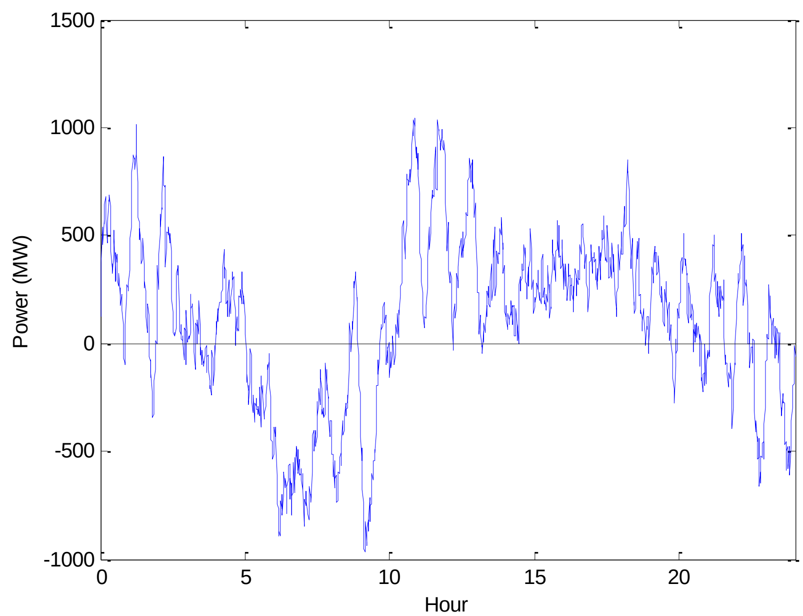

Figure A.137. Typical Day Total SRCE Balancing Signal in August 2020

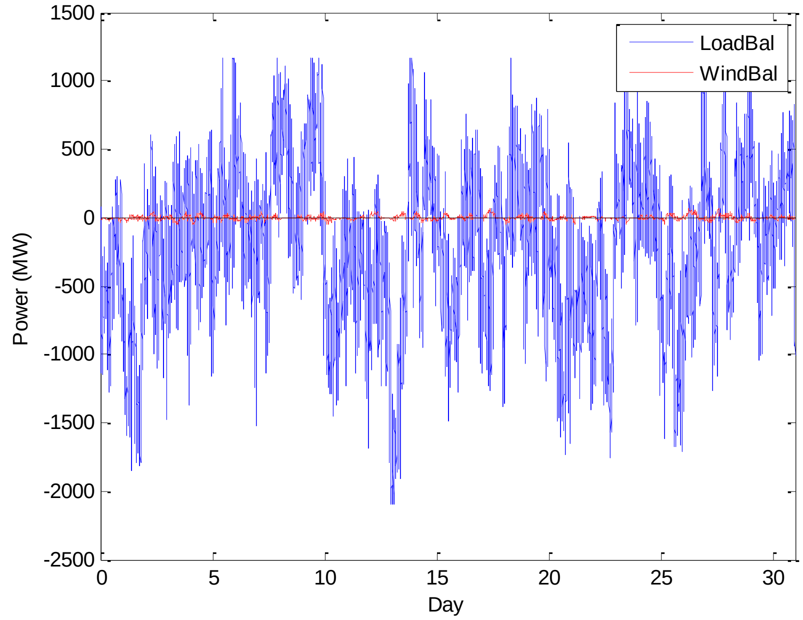

Figure A.138. One Month Balancing Requirements Caused by Load and Wind Respectively for SRCE

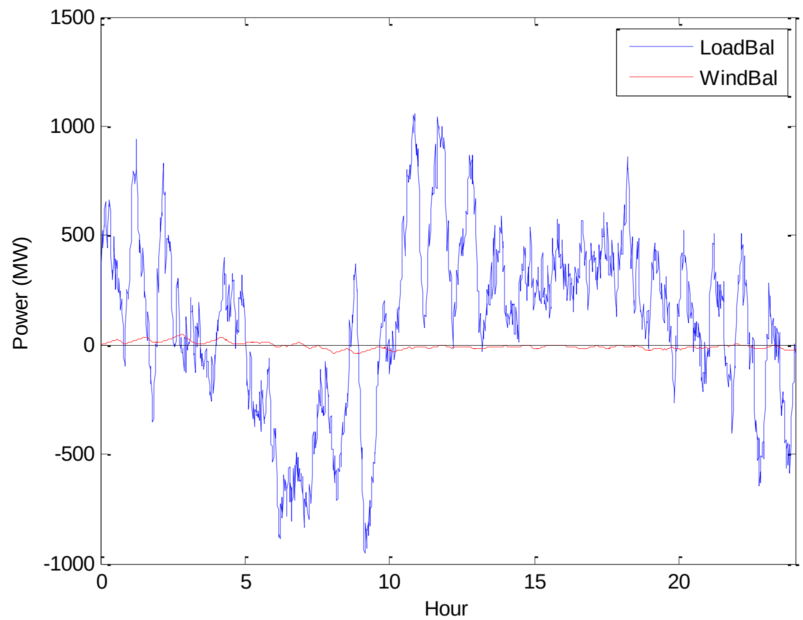

Figure A.139. Typical Day Balancing Requirements Caused by Load and Wind Respectively for SRCE

A.19.2 Energy and Power Requirements

Table A.56, Figure A.140 and Figure A.141 show the results of energy and power requirements for the scenarios in the SERC area.

Table A.56. Power and Energy Requirements for Each Scenario for SRCE. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	1.09	-
C2	NaS	1.10	0.35
C3	Li-ion	1.10	0.35
C4	Flywheel	1.09	0.33
C5	CAES	2.07	11.66
	NaS	0.54	0.05
C6	Flow battery	1.10	0.36
C7	PH multiple modes	1.09	0.35
	4 min waiting period, NaS	0.68	0.24
C8	PH 2 modes	2.07	11.71
	4 min waiting period, NaS	0.41	0.02
C9	DR	3.89	-

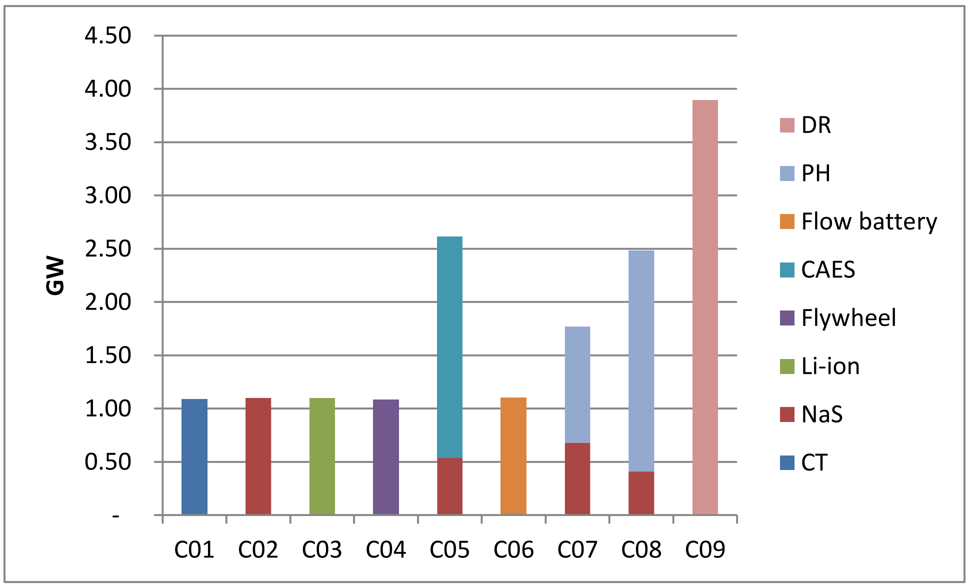

Figure A.140. Power Requirements for all the Technologies to Meet Balancing Signal for SRCE

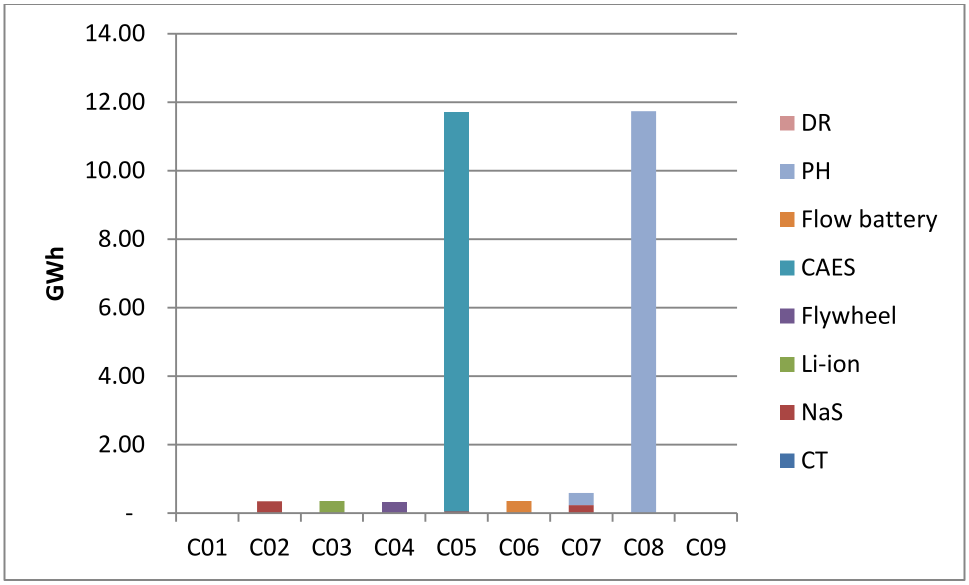

Figure A.141. Energy Requirements for Storage Technologies to Meet Balancing Signal for SRCE

Table A.57, Figure A.142Figure A.143 show estimates of energy and power requirements for the SERC scenarios considering the additional windpower generation and load expected between 2011 and 2012. These are the requirements assume that the 2011 level of balancing is still provided by existing resources.

Table A.57. Power and Energy Requirements for Each Scenario due to 2011-2020 Additional Wind and Load for SRCE. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.06	-
C2	Na-S	0.06	0.02
C3	Li-ion	0.06	0.02
C4	Flywheel	0.06	0.02
C5	CAES	0.11	0.69
	Na-S	0.04	-
C6	Flow battery	0.06	0.02
C7	PH multiple modes	0.06	0.02
	4-min waiting period, Na-S	0.03	0.01
C8	PH 2 modes	0.11	0.69
	4-min waiting period, Na-S	0.03	-
C9	DR	0.21	-

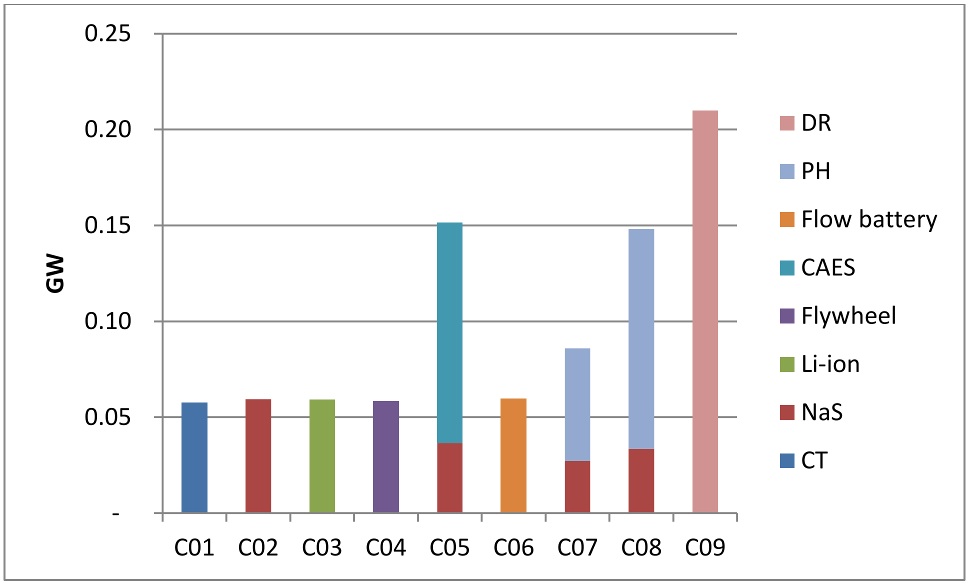

Figure A.142. SRCE Power Requirements for all the Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Windpower and Load

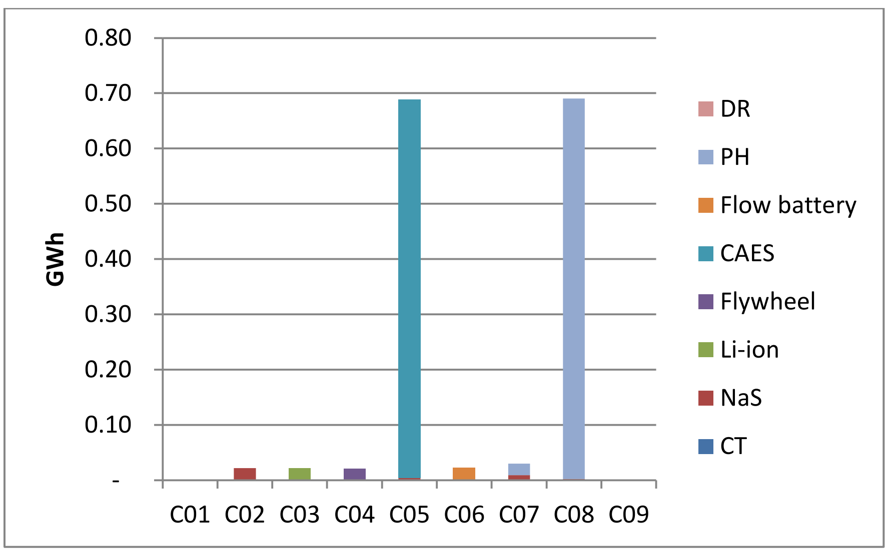

Figure A.143. SRCE Energy Requirements for Storage Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Windpower and Load

A.19.3 Life-Cycle Cost Analysis

The results of the economic analysis for the SRCE power area are presented in Table A.58 and Figure A.144. The values presented in Table A.58 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $1.78 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $1.83 billion or

3.1 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are more than twice as expensive as those estimated for the two aforementioned cases, registering at $3.7 billion. The CAES case (Case 5) is also more expensive with estimated costs of $5.4 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $7.2 billion. Total costs under Case 6, redox flow batteries , are estimated at $3.4 billion.

Table A.58. Economic Analysis Results – SRCE (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	2,786	797	275	315	4,173
2	1,411	121	198	48	1,779
3	2,323	109	195	43	2,669
4	1,434	51	327	20	1,833
5	3,465	1,010	560	399	5,434
6	3,068	140	158	56	3,422
7	3,633	110	192	44	3,979
8	6,406	260	437	103	7,206
9	3,732	-	-	-	3,732

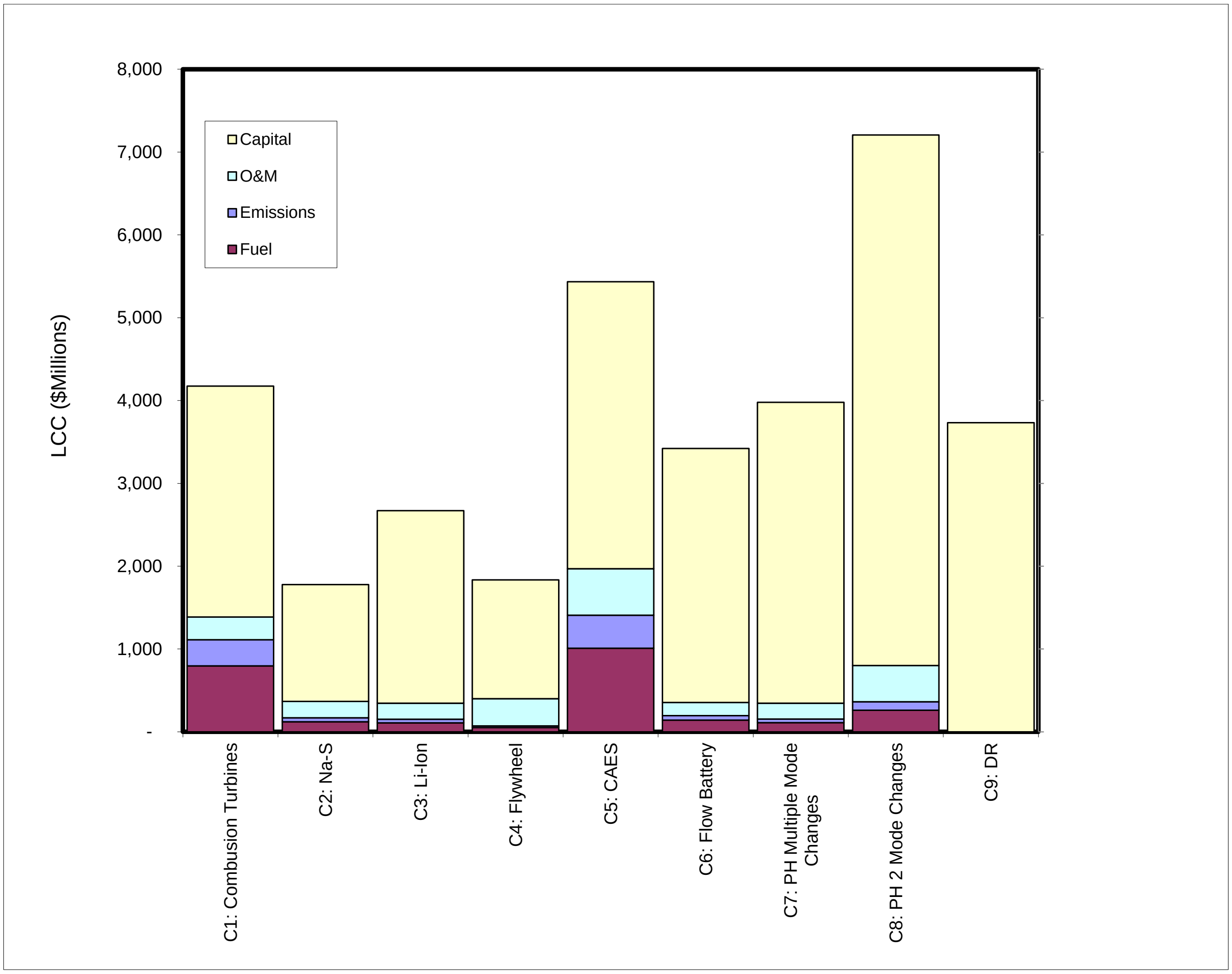

Figure A.144. LCC Estimates for SRCE

A.19.4 Arbitrage

Arbitrage analysis was not performed for the SRCE because of the expected low-economic value.

A.20 SRVC

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.20.1 Balancing Requirements

Figure A.145 and Figure A.146 show monthly and daily balancing signals for SRVC, respectively. Based on the whole year simulation, the balancing power requirements are 2532 MW of inc. capacity and 3898 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability to happen.

Figure A.147 shows balancing signals caused by load and by wind separately for the SRVC region for one month. , Balancing requirements are mainly caused by load uncertainty in 2020. Figure A.148 presents the same balancing signals for one day.

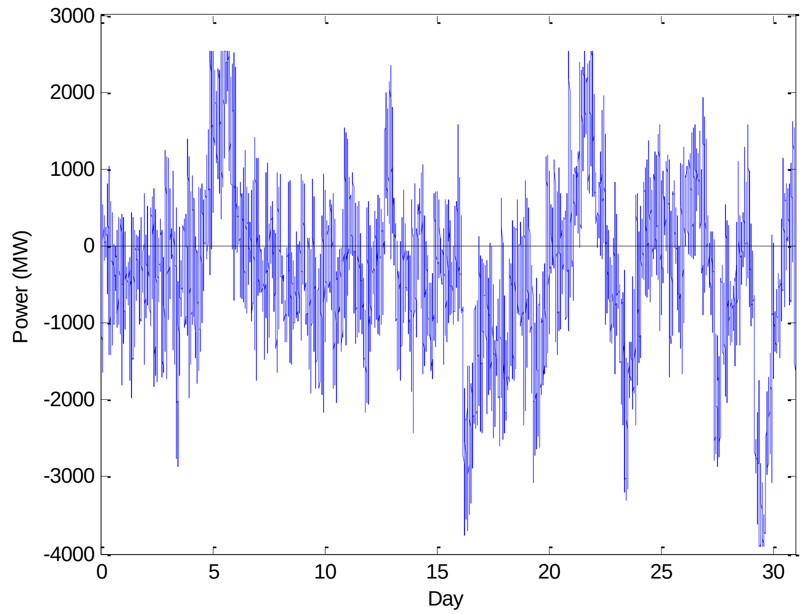

Figure A.145. One Month Total SRVC Balancing Signal in August 2020

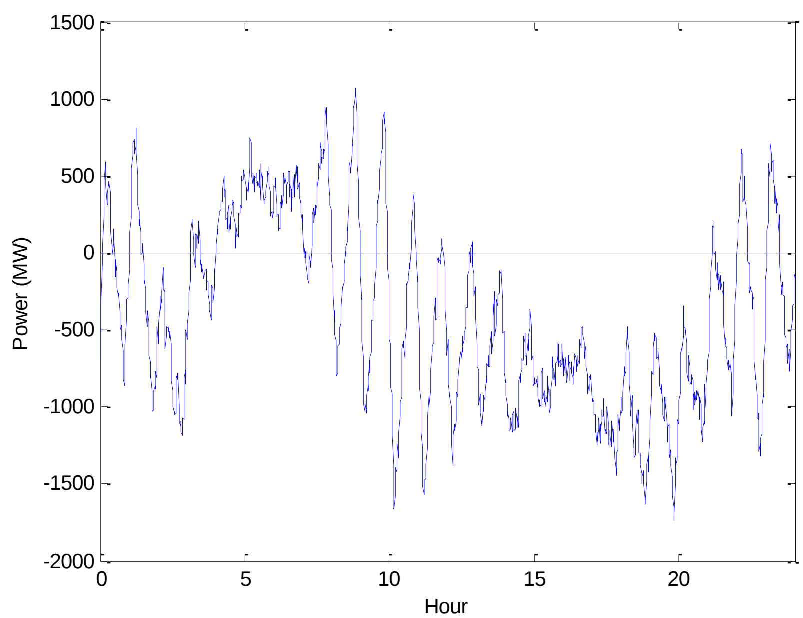

Figure A.146. One Typical Day Total SRVC Balancing Signal in August 2020

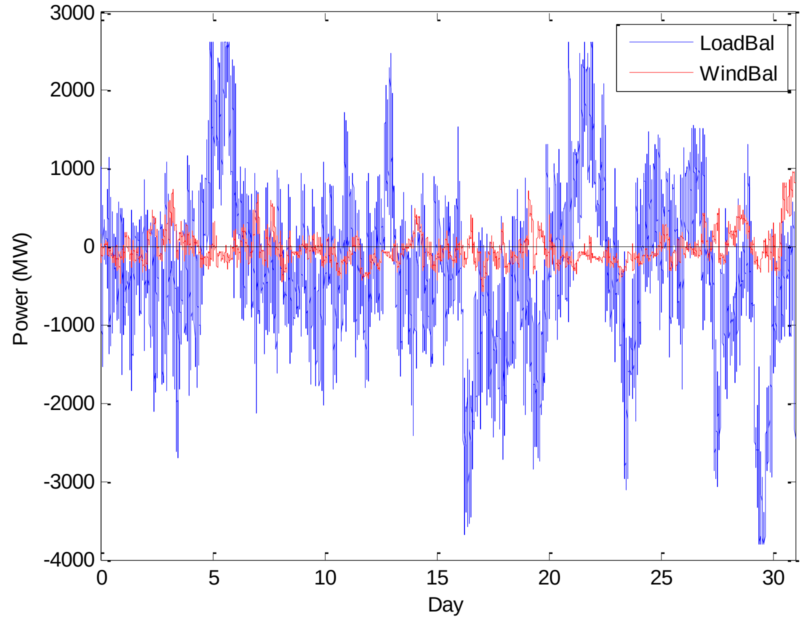

Figure A.147. One Month Balancing Requirements Caused by Load and Wind Respectively for SRVC

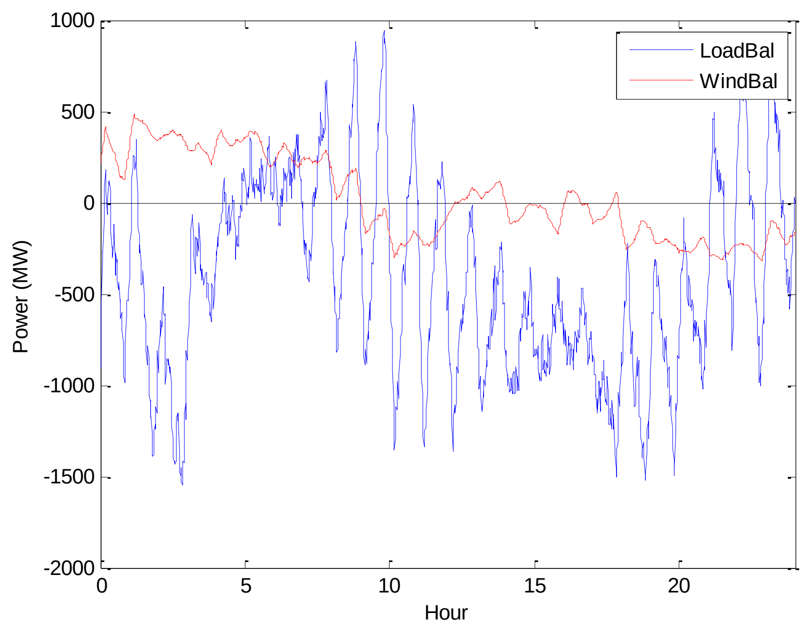

Figure A.148. One Typical Day Balancing Requirements Caused by Load and Wind Respectively for SRVC

A.20.2 Energy and Power Requirements

Table A.59, Figure A.149 and Figure A.150 show the results of energy and power requirements for the scenarios in the SERC Reliability Corporation/Virginia-Carolina (SRVC) area.

Table A.59. Power and Energy Requirements for Each Scenario for SRVC. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	1.78	-
C2	NaS	1.74	0.64
C3	Li-ion	1.74	0.63
C4	Flywheel	1.76	0.59
C5	CAES	3.36	18.97
	NaS	0.68	0.05
C6	Flow battery	1.73	0.66
C7	PH multiple modes	1.75	0.60
	4 min waiting period, NaS	1.00	0.26
C8	PH 2 modes	3.36	19.07
	4 min waiting period, NaS	0.53	0.03
C9	DR	5.82	-

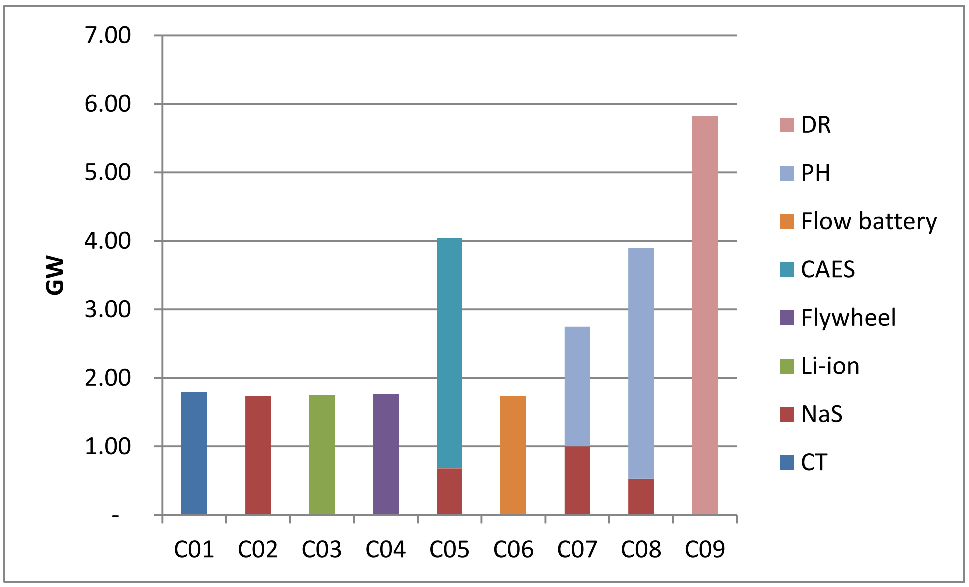

Figure A.149. Power Requirements for all the Technologies to Meet Balancing Signal for SRVC

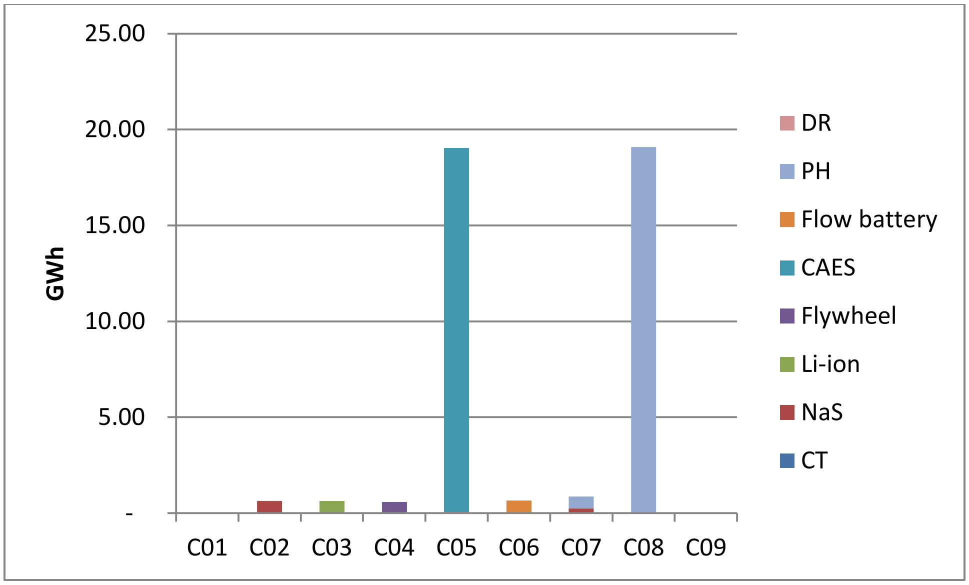

Figure A.150. Energy Requirements for Storage Technologies to Meet Balancing Signal for SRVC

Table A.60, Figure A.151 and Figure A.152 show energy and power requirements for the SRVC scenarios considering only the additional windpower and load expected between 2011 and 2012. These requirements assume that the 2011 level of balancing is still provided by existing resources.

Table A.60. Power and Energy Requirements for Each Scenario resulting from 2011-2020 Additional Wind and Load for SRVC. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	0.36	-
C2	Na-S	0.36	0.18
C3	Li-ion	0.36	0.17
C4	Flywheel	0.36	0.15
C5	CAES	0.67	4.34
	Na-S	0.19	0.03
C6	Flow battery	0.35	0.18
C7	PH multiple modes	0.36	0.16
	4-min waiting period, Na-S	0.20	0.05
C8	PH 2 modes	0.67	4.35
	4-min waiting period, Na-S	0.14	0.01
C9	DR	1.21	-

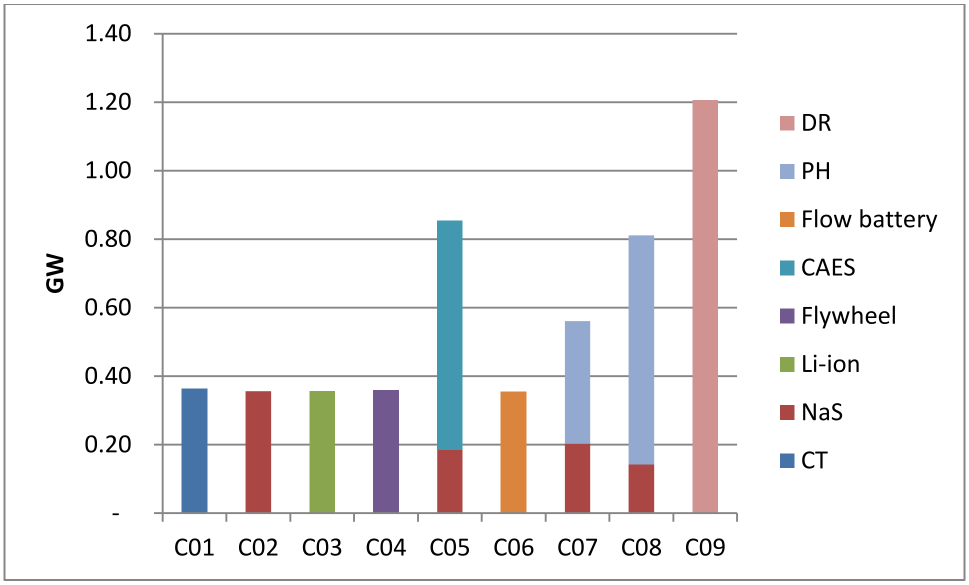

Figure A.151. SRVC Power Requirements for all the Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Wind and Load

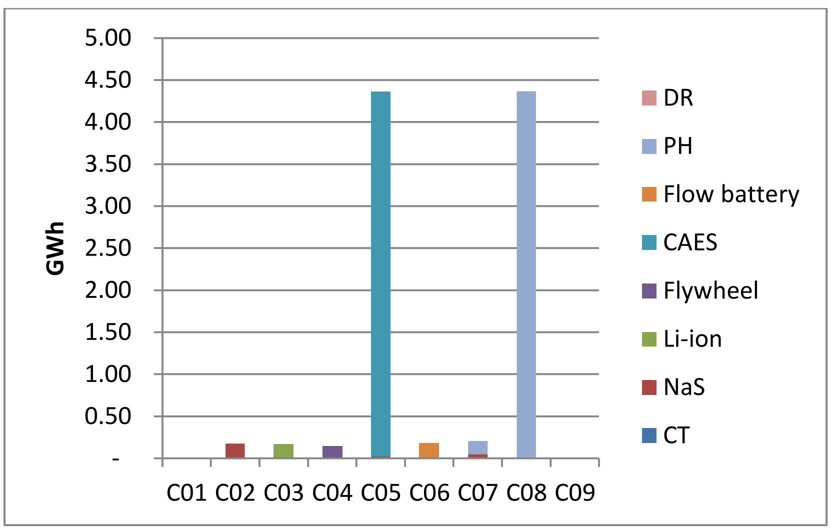

Figure A.152. SRVC Energy Requirements for Storage Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Windpower and Load

A.20.3 Life-Cycle Cost Analysis

The results of the economic analysis for the SRVC power area are presented in Table A.61 and Figure A.153. The values presented in Table A.61 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 4, which consists of flywheels , is the least cost alternative at $3.0 billion. Case 2, which employs Na-S batteries , represents the second least cost alternative with costs estimated at $3.1 billion or 3.2 percent higher than those estimated for Case 4. The costs associated with the DR-only case (Case 9) are nearly twice as expensive as those estimated for the two aforementioned cases, registering at $5.6 billion. The CAES case (Case 5) is also more expensive with estimated costs of $8.8 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $11.6 billion. Total costs under Case 6, redox flow batteries , are estimated at $5.4 billion.

Table A.61. Economic Analysis Results – SRVC (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	4,777	1,373	461	543	7,153
2	2,459	211	344	84	3,098
3	4,159	190	338	75	4,762
4	2,342	90	534	35	3,001
5	5,527	1,685	924	666	8,802
6	4,840	245	253	97	5,435
7	5,692	187	302	74	6,255
8	10,330	410	710	162	11,612
9	5,583	-	-	-	5,583

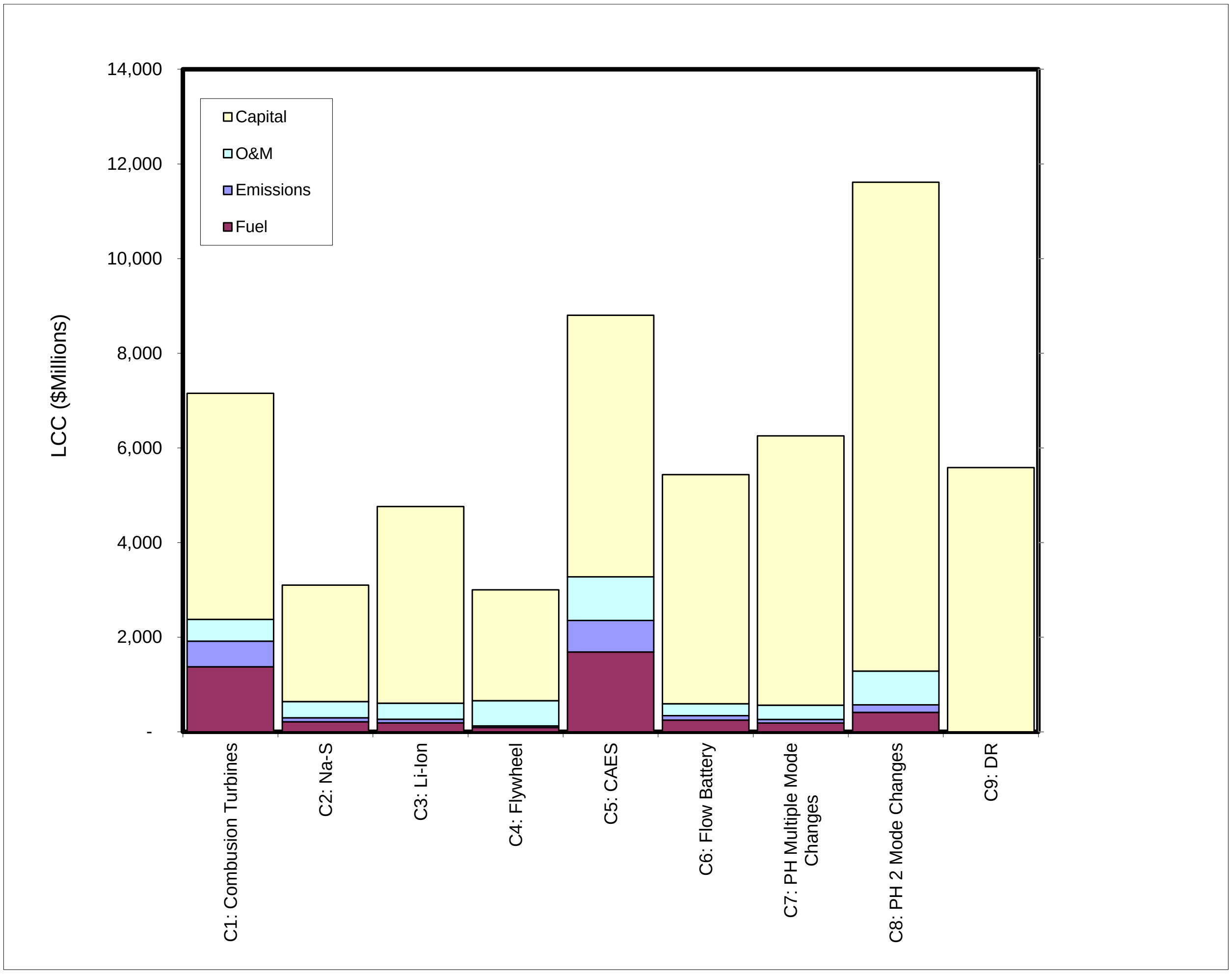

Figure A.153. LCC Estimates for SRVC

A.20.4 Arbitrage

Table A.62 presents the findings of the arbitrage analysis performed for the SRVC. As shown, annual arbitrage revenues are estimated to range from $21.7-$675.7 million based on energy storage size, which ranges from 359-14,340 MW. Annual revenue per MW falls from a high of $60,392 at 359 MW to $47,118 at 14,340 MW. While the simulation results reveal there are congested paths in the system, arbitrage revenue expectations fall short of the revenue requirements for each size considered in this analysis. When capacity reserve values are figured into the analysis, pumped hydro generates profits at energy storage capacities up to 8,963 MW. From 359 MW to 8,963 MW, annual profits range from a low of $2.7 million at 359 MW to a high of $21.9 million at 5,378 MW of capacity. Annualized costs are estimated to range from $72.8 million-$2.9 billion for pumped hydro, $163.4 million-$6.5 billion for Na-S, and $321.1 million-$12.8 billion for Li-ion. This result supports the conclusion that at a 30 percent reserve margin, the SRVC is not sufficiently congested for energy storage to be cost-effective when used to provide only arbitrage services. When capacity reserve revenue is added to the analysis, the gap between arbitrage revenue and annual capital costs is reduced but overcome only by pumped hydropower at storage sizes up to 8,963 MW.

Table A.62. Annualized Revenue and Capital Costs for Na-S Batteries, Li-Ion Batteries, and Pumped Hydro (SRVC)

Storage Size (MW)	Annual Revenue		Annualized Capital Costs		
	Arbitrage	Capacity	Pumped Hydro	Na-S	Li-Ion
359	21,650,569	53,775,000	72,768,330	163,368,450	321,108,450
717	43,214,426	107,550,000	145,536,660	326,736,900	642,216,900
1,434	85,858,582	215,100,000	291,073,320	653,473,800	1,284,433,800
1,793	106,935,546	268,875,000	363,841,650	816,842,250	1,605,542,250
3,585	209,261,656	537,750,000	727,683,300	1,633,684,500	3,211,084,500
5,378	306,832,246	806,625,000	1,091,524,950	2,450,526,750	4,816,626,750
7,170	396,824,390	1,075,500,000	1,455,366,600	3,267,369,000	6,422,169,000
8,963	479,035,337	1,344,375,000	1,819,208,250	4,084,211,250	8,027,711,250
10,755	551,607,824	1,613,250,000	2,183,049,900	4,901,053,500	9,633,253,500
12,548	618,571,649	1,882,125,000	2,546,891,550	5,717,895,750	11,238,795,750
14,340	675,676,177	2,151,000,000	2,910,733,200	6,534,738,000	12,844,338,000

A.21 SPNO

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.21.1 Balancing Requirements

Error! Not a valid bookmark self-reference. and Figure A.155 show monthly and daily balancing signals for SPNO, respectively. Based on the whole year simulation, the balancing power requirements are 4308 MW of inc. capacity and 3996 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability to happen.

Figure A.156 shows balancing signals caused by load and by wind separately for the SPNO region for one month. Balancing requirements are mainly caused by windpower uncertainty in 2020. Figure A.157 presents the same balancing signals for a typical day.

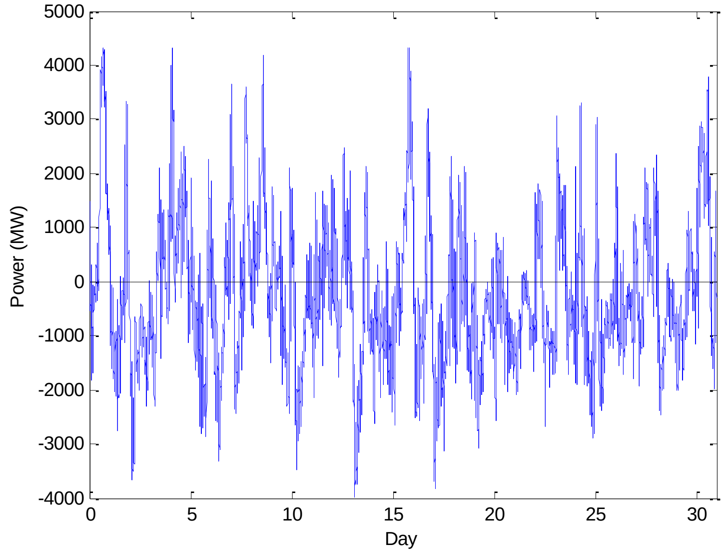

Figure A.154. One Month Total SPNO Balancing Signal in August 2020

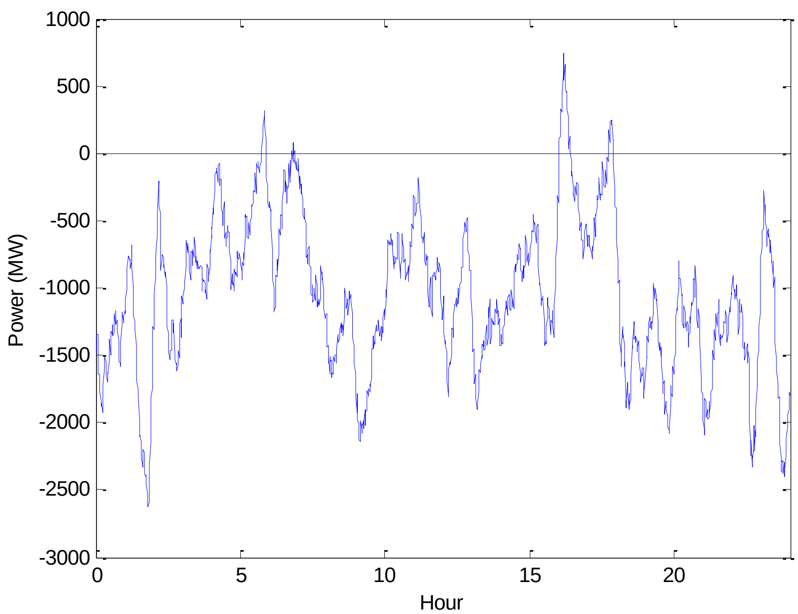

Figure A.155. Typical Day Total SPNO Balancing Signal in August 2020

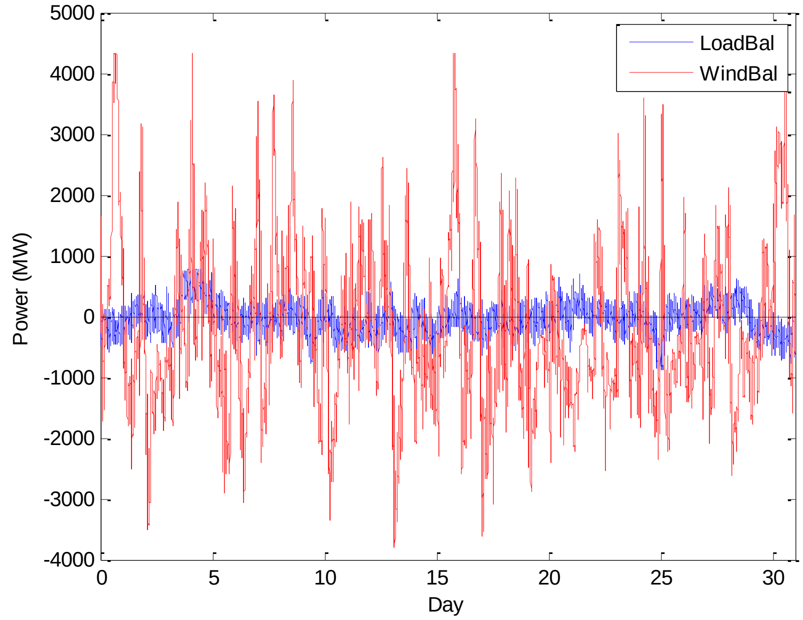

Figure A.156. One Month Balancing Requirements Caused by Load and Wind Respectively for SPNO

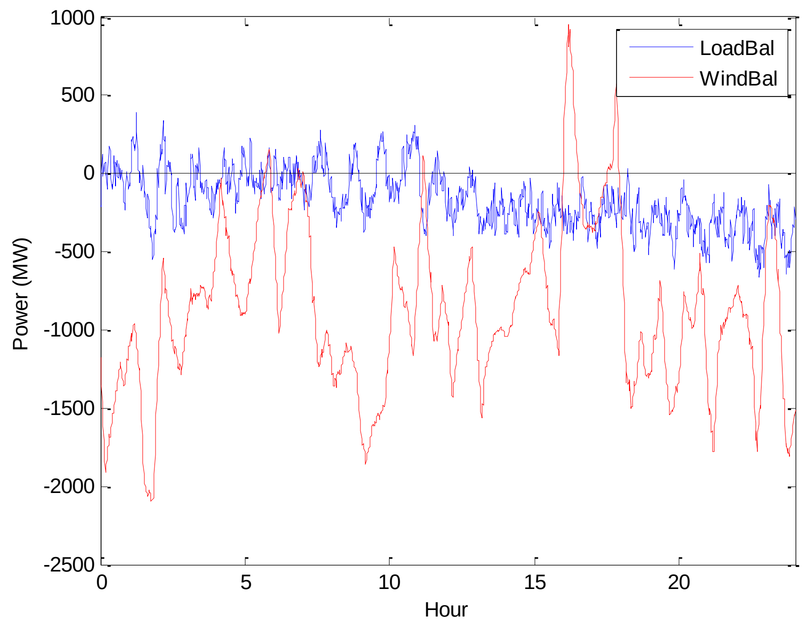

Figure A.157. One Typical Day Balancing Requirements Caused by Load and Wind Respectively for SPNO

A.21.2 Energy and Power Requirements

Table A.63, Figure A.158 and Figure A.159 show energy and power requirements for future scenarios in the Southwest Power Pool/North (SPNO) area.

Table A.63. Power and Energy Requirements for Each Scenario for SPNO. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.76	-
C2	NaS	2.71	1.40
C3	Li-ion	2.71	1.35
C4	Flywheel	2.73	1.22
C5	CAES	5.05	25.07
	NaS	1.11	0.09
C6	Flow battery	2.70	1.47
C7	PH multiple modes	2.72	1.25
	4 min waiting period, NaS	1.02	0.26
C8	PH 2 modes	5.05	25.16
	4 min waiting period, NaS	1.06	0.07
C9	DR	8.32	-

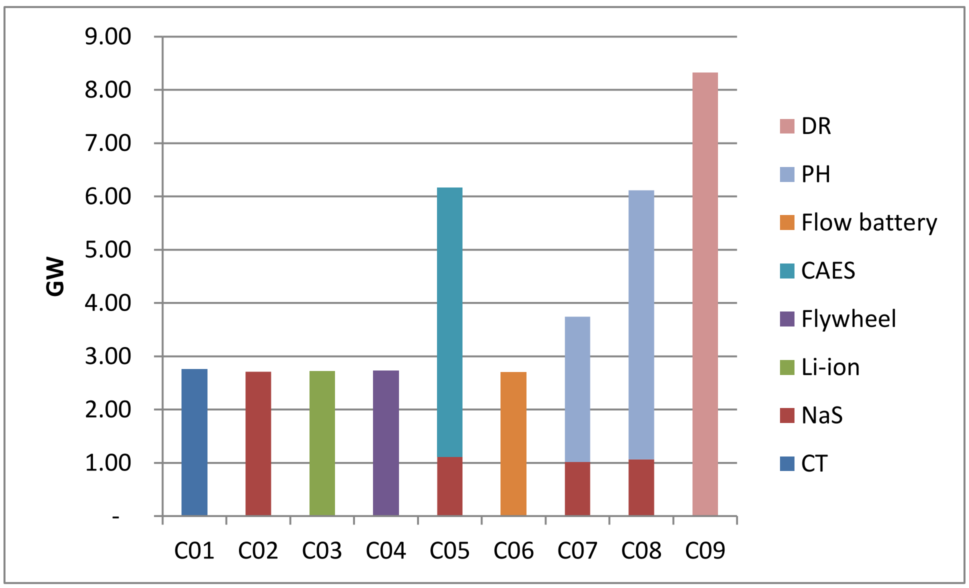

Figure A.158. Power Requirements for all the Technologies to Meet Balancing Signal for SPNO

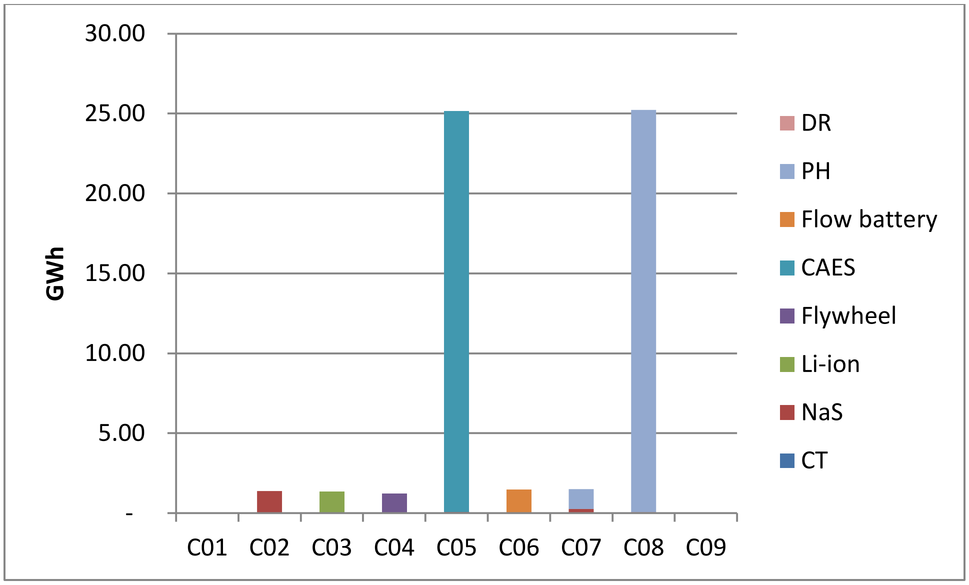

Figure A.159. Energy Requirements for Storage Technologies to Meet Balancing Signal for SPNO

Table A.64, Figure A.160 and Figure A.161 show energy and power requirements considering only the additional wind generation and load expected between 2011 and 2012. These requirements assume that the 2011 level of balancing is still provided by existing resources.

Table A.64. SPNO Power and Energy Requirements for Each Scenario resulting from 2011-2020 Additional Windpower and Load. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.34	-
C2	Na-S	2.30	1.37
C3	Li-ion	2.30	1.33
C4	Flywheel	2.32	1.15
C5	CAES	4.16	22.06
	Na-S	0.97	0.09
C6	Flow battery	2.29	1.44
C7	PH multiple modes	2.30	1.29
	4-min waiting period, Na-S	0.95	0.14
C8	PH 2 modes	4.16	22.17
	4-min waiting period, Na-S	0.97	0.06
C9	DR	6.61	-

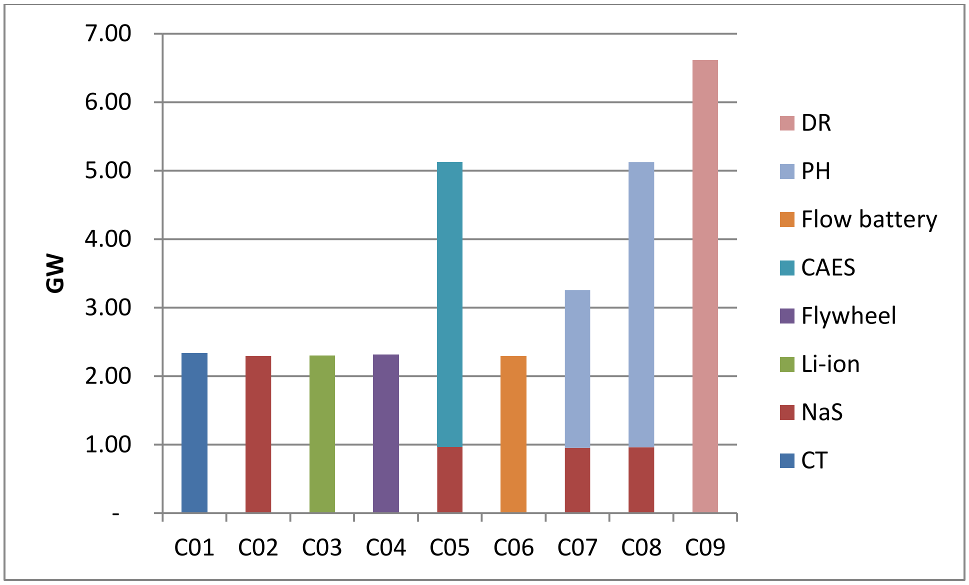

Figure A.160. SPNO Power Requirements for all the Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Windpower and Load

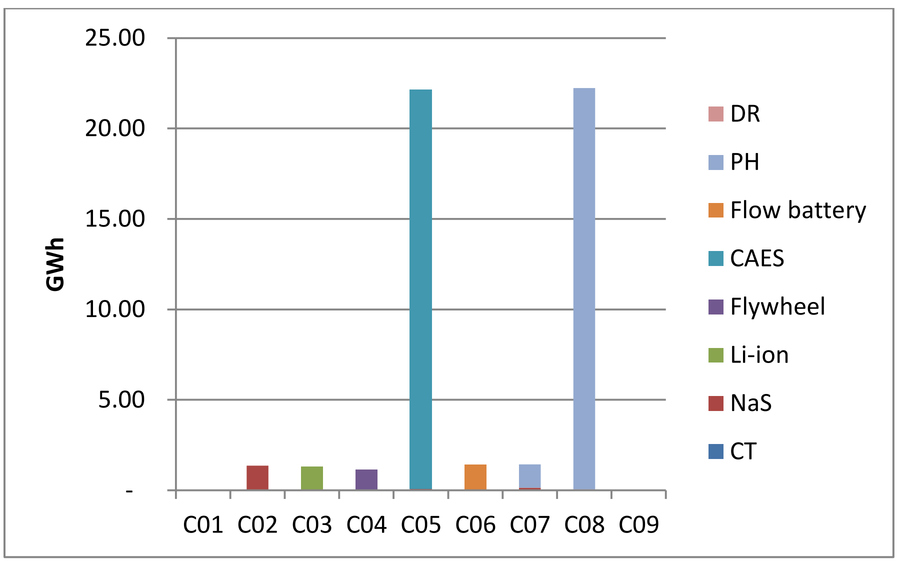

Figure A.161. SPNO Energy Requirements for Storage Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Windpower and Load

A.21.3 Life-Cycle Cost Analysis

The results of the economic analysis for the SPNO power area are presented in Table A.65 and Figure A.162. The values presented in Table A.65 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $3.8 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $4.6 billion or

22.7 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are nearly twice as expensive as those estimated for the two aforementioned cases, registering at $8.0 billion. The CAES case (Case 5) is also more expensive with estimated costs of $11.9 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $17.1 billion. Total costs under Case 6, redox flow batteries , are estimated at $8.4 billion.

Table A.65. Economic Analysis Results – SPNO (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	7,165	1,328	610	525	9,629
2	3,132	205	357	81	3,776
3	5,081	184	350	73	5,688
4	3,705	87	806	34	4,632
5	8,334	1,731	1,139	684	11,888
6	7,678	237	359	94	8,369
7	8,584	183	372	72	9,211
8	15,589	414	919	164	17,085
9	7,977	-	-	-	7,977

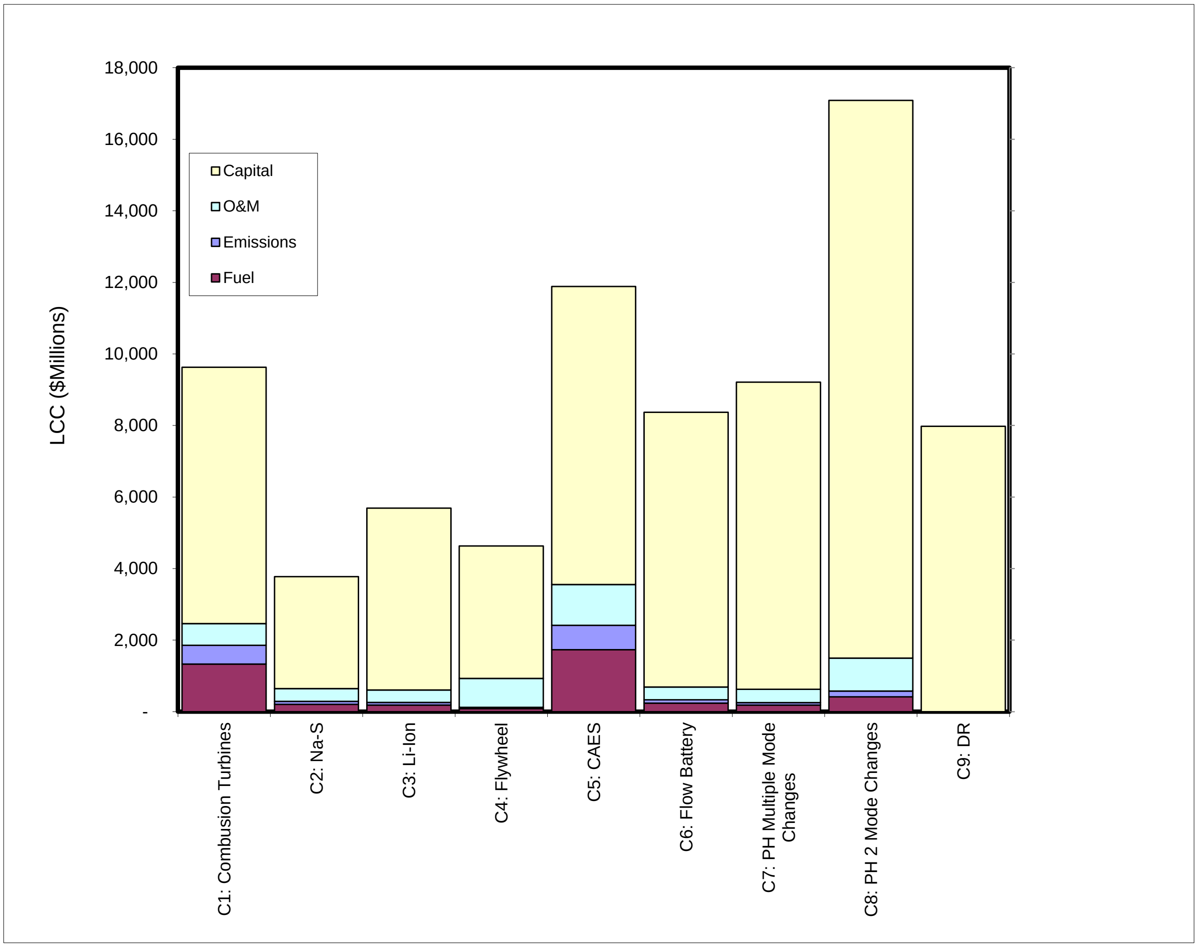

Figure A.162. LCC Estimates for SPNO

A.21.4 Arbitrage

Arbitrage analysis was not performed for the SPNO because of the low economic value expectations.

A.22 SPSO

The pattern of the balancing signal determines the amount of energy storage needed and the magnitude of the signal determines the power delivery capacity requirement of the energy storage system.

A.22.1 Balancing Requirements

Figure A.**163** and Figure A.164 show monthly and daily balancing signals for SPSO, respectively. Based on the whole year simulation, the balancing power requirements are 4575 MW of inc. capacity and 4438 MW of dec. capacity, using the BPA's customary 99.5 percent probability bound. The balancing requirements for August have a spike which is over the annual inc. capacity, but the spike has a less than 0.5 percent probability to happen.

Figure A.165 shows balancing signals caused by load and by wind separately for the SPSO region SPSO for one month. Balancing requirements are mainly caused by windpower uncertainty in 2020. Figure A.166 presents the same balancing signals for one day.

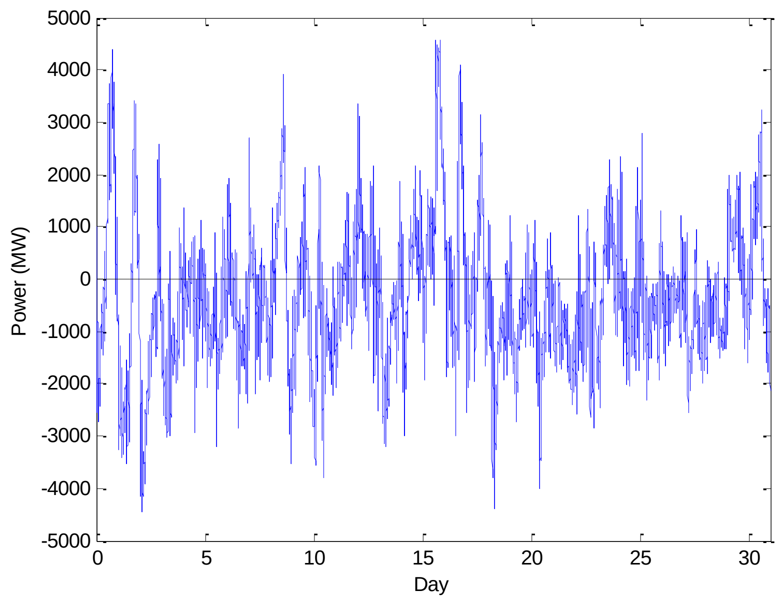

Figure A.163. One Month Total SPSO Balancing Signal in August 2020

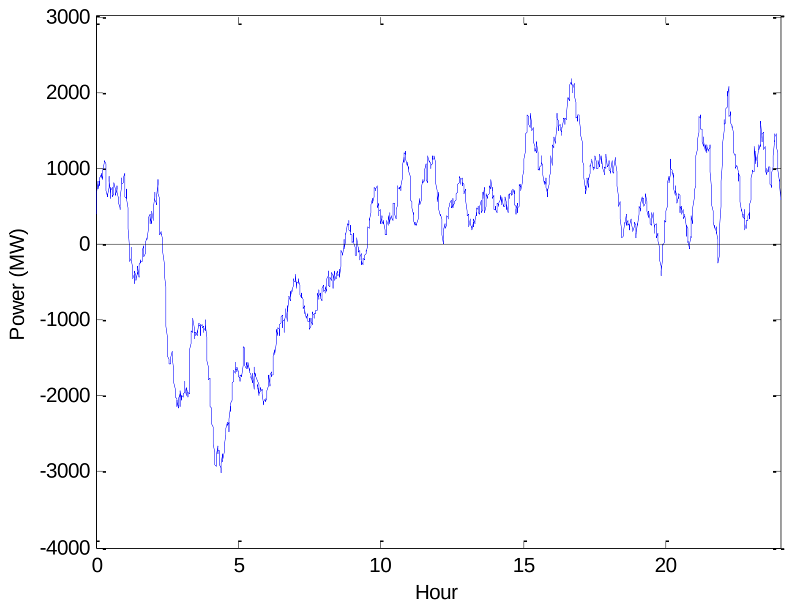

Figure A.164. Typical Day Total SPSO Balancing Signal in August 2020

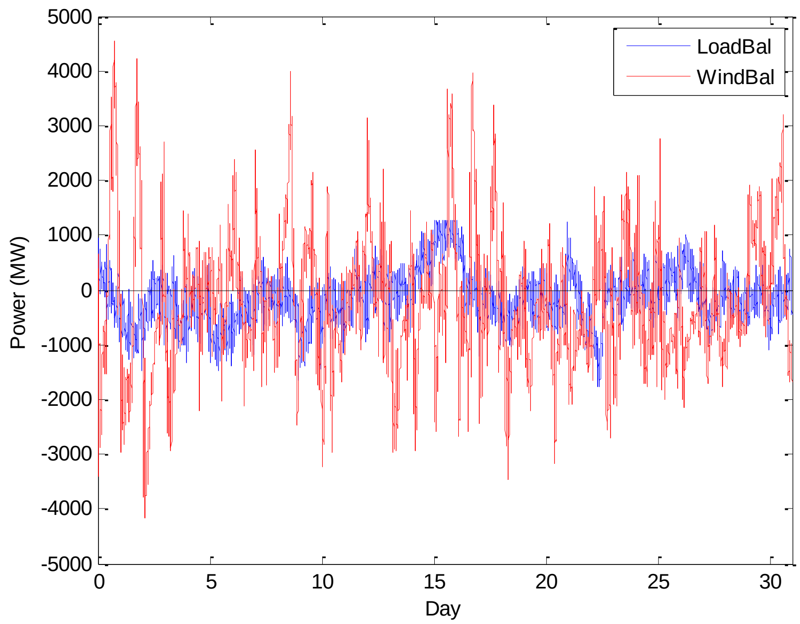

Figure A.165. One Month Balancing Requirements Caused by Load and Wind Respectively for SPSO

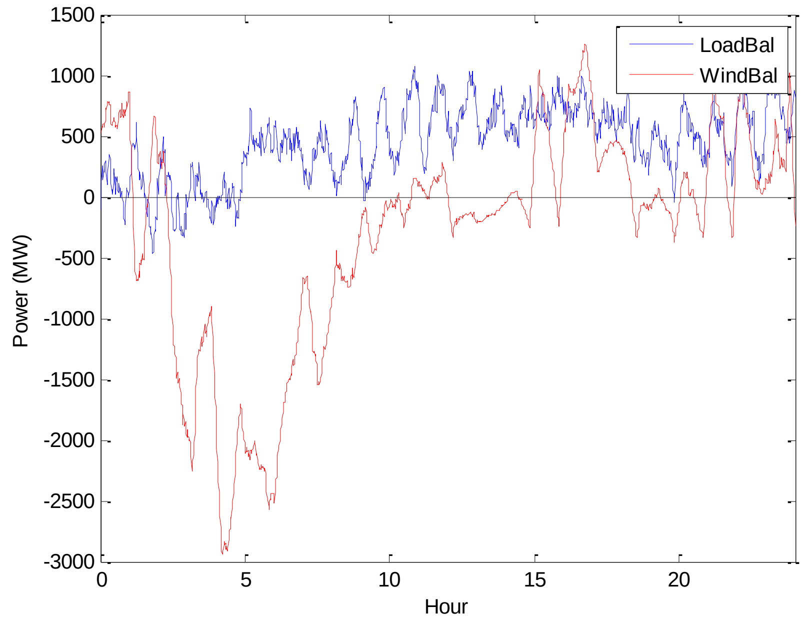

Figure A.166. Typical Day Balancing Requirements Caused by Load and Wind Respectively for SPSO

A.22.2 Energy and Power Requirements

Table A.66, Figure A.167 and Figure A.168 show the results of energy and power requirements for the scenarios in the Southwest Power Pool/South (SPSO) area.

Table A.66. Power and Energy Requirements for Each Scenario for SPSO. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.54	-
C2	NaS	2.49	1.18
C3	Li-ion	2.50	1.17
C4	Flywheel	2.52	1.12
C5	CAES	4.70	24.40
	NaS	1.18	0.13
C6	Flow battery	2.49	1.20
C7	PH multiple modes	2.51	1.11
	4 min waiting period, NaS	1.10	0.27
C8	PH 2 modes	4.70	24.53
	4 min waiting period, NaS	0.88	0.07
C9	DR	8.70	-

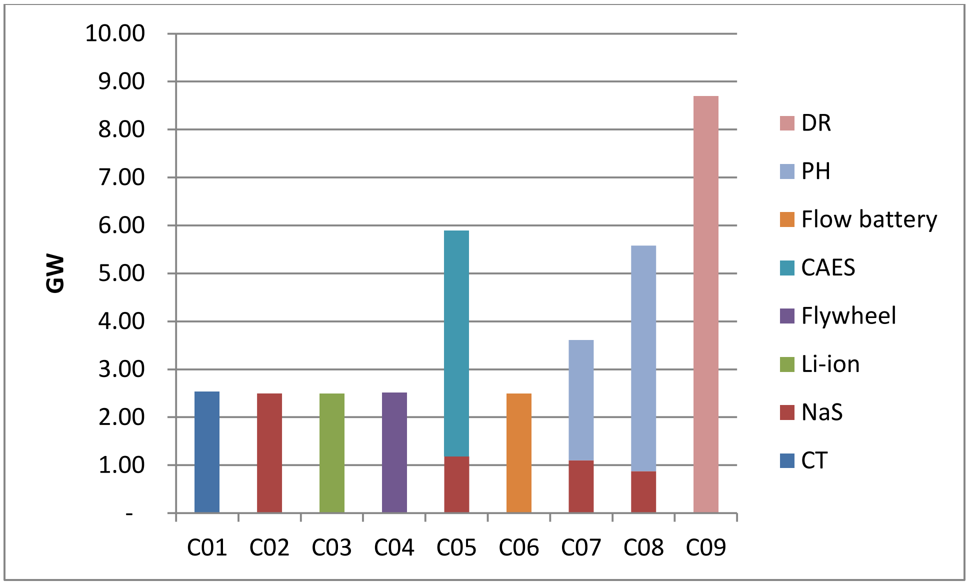

Figure A.167. Power Requirements for all the Technologies to Meet Balancing Signal for SPSO

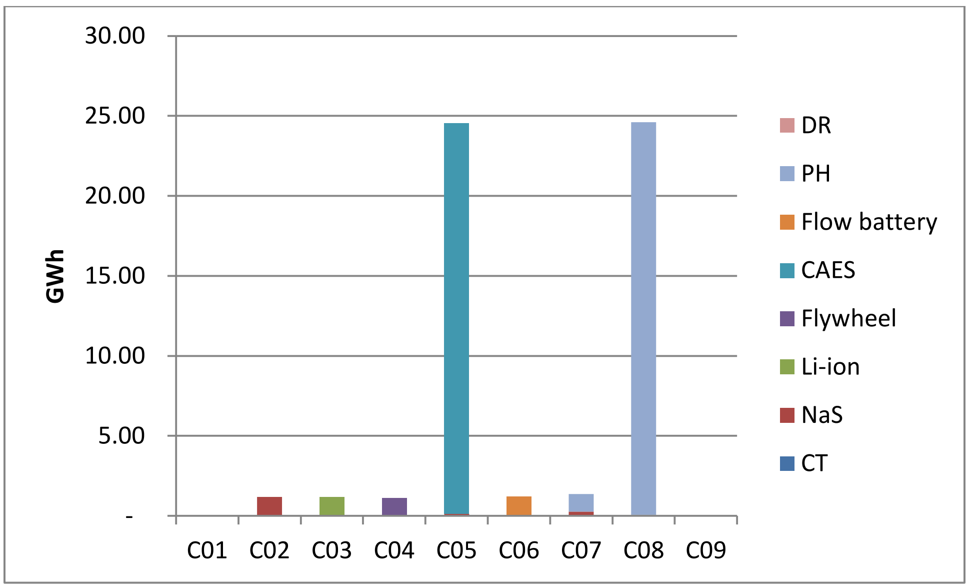

Figure A.168. Energy Requirements for Storage Technologies to Meet Balancing Signal for SPSO

Table A.67, Figure A.169 and Figure A.170 show the results of energy and power requirements for the scenarios in SPSO area, considering only the additional wind generation and load expected between 2011 and 2012. These requirements assume that the 2011 level of balancing is still provided by existing resources.

Table A.67. Power and Energy Requirements for Each Scenario resulting from 2011-2020 Additional Wind and Load for SPSO. Note: The energy capacity (GWh) for the batteries is nominated at a DOD of 100 percent.

Case	Technology	GW	GWh
C1	Combustion turbine	2.09	-
C2	Na-S	2.13	1.08
C3	Li-ion	2.12	1.06
C4	Flywheel	2.11	1.00
C5	CAES	4.06	23.42
	Na-S	0.86	0.11
C6	Flow battery	2.13	1.10
C7	PH multiple modes	2.12	1.01
	4-min waiting period, Na-S	0.81	0.18
C8	PH 2 modes	4.06	23.53
	4-min waiting period, Na-S	0.63	0.06
C9	DR	7.57	-

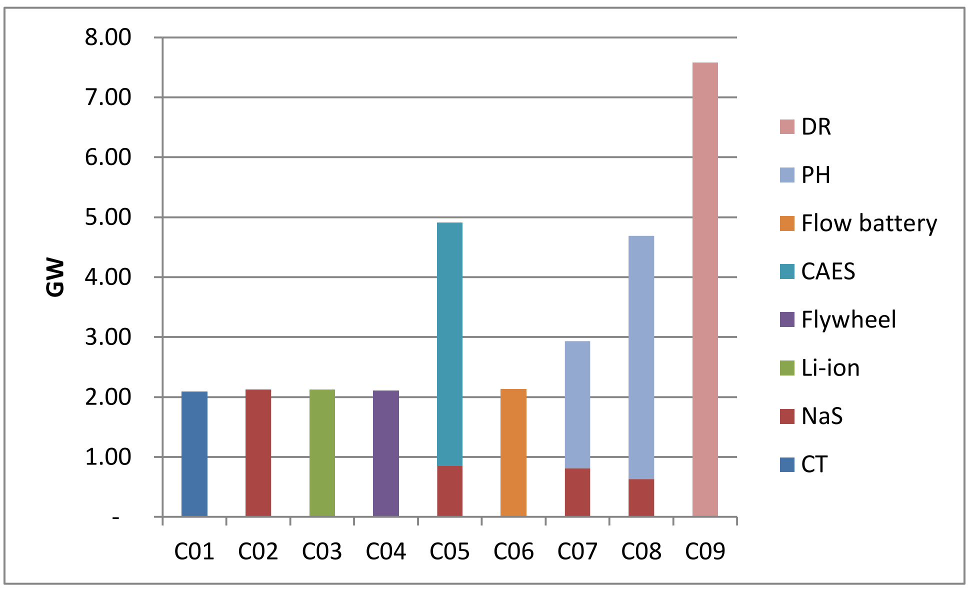

Figure A.169. SPSO Power Requirements for all the Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Windpower and Load

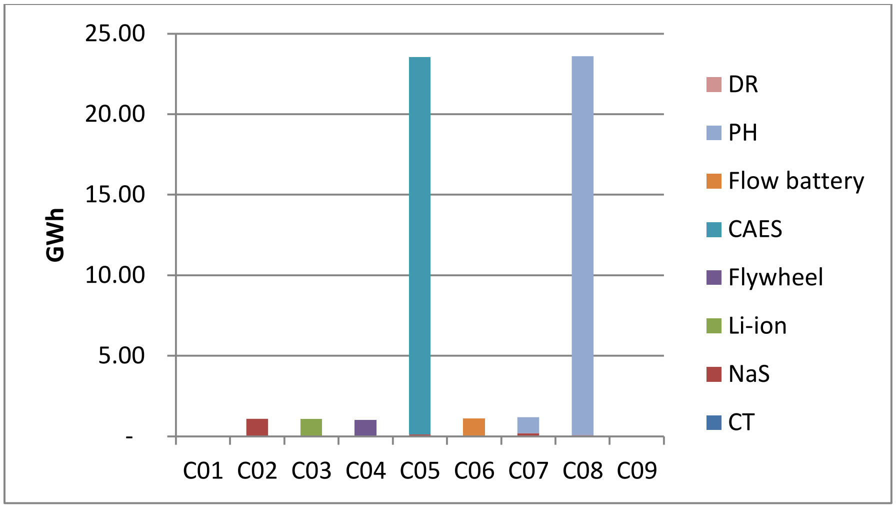

Figure A.170. SPSO Energy Requirements for Storage Technologies to Meet Balancing Signal resulting from 2011-2020 Additional Wind and Load

A.22.3 Life-Cycle Cost Analysis

The results of the economic analysis for the SPSO power area are presented in Table A.68 and Figure A.171 The values presented in Table A.68 represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon, using the 2020 price values presented in Section 6.0, Vol. 2, discounted at 8.0 percent.

Case 2, which employs Na-S batteries , is the least cost alternative at $3.6 billion. Case 4, which consists of flywheels , represents the second least cost alternative with costs estimated at $4.3 billion or 18.5 percent higher than those estimated for Case 2. The costs associated with the DR-only case (Case 9) are nearly twice as expensive as those estimated for Case 4, registering at $8.4 billion. The CAES case (Case 5) is also more expensive with estimated costs of $11.5 billion. In the predominantly PH case with two mode changes per day (Case 8), total costs are estimated at $15.9 billion. Total costs under Case 6, redox flow batteries , are estimated at $7.7 billion.

Table A.68. Economic Analysis Results – SPSO (2020 Prices)

Case	Capital	Fuel	O&M	Emissions	**Total**
1	6,369	1,396	584	552	8,902
2	2,930	215	384	85	3,614
3	4,859	193	378	76	5,506
4	3,408	91	747	36	4,282
5	7,855	1,789	1,125	707	11,477
6	7,027	249	339	98	7,714
7	7,960	191	365	75	8,591
8	14,494	402	856	159	15,911
9	8,338	-	-	-	8,338

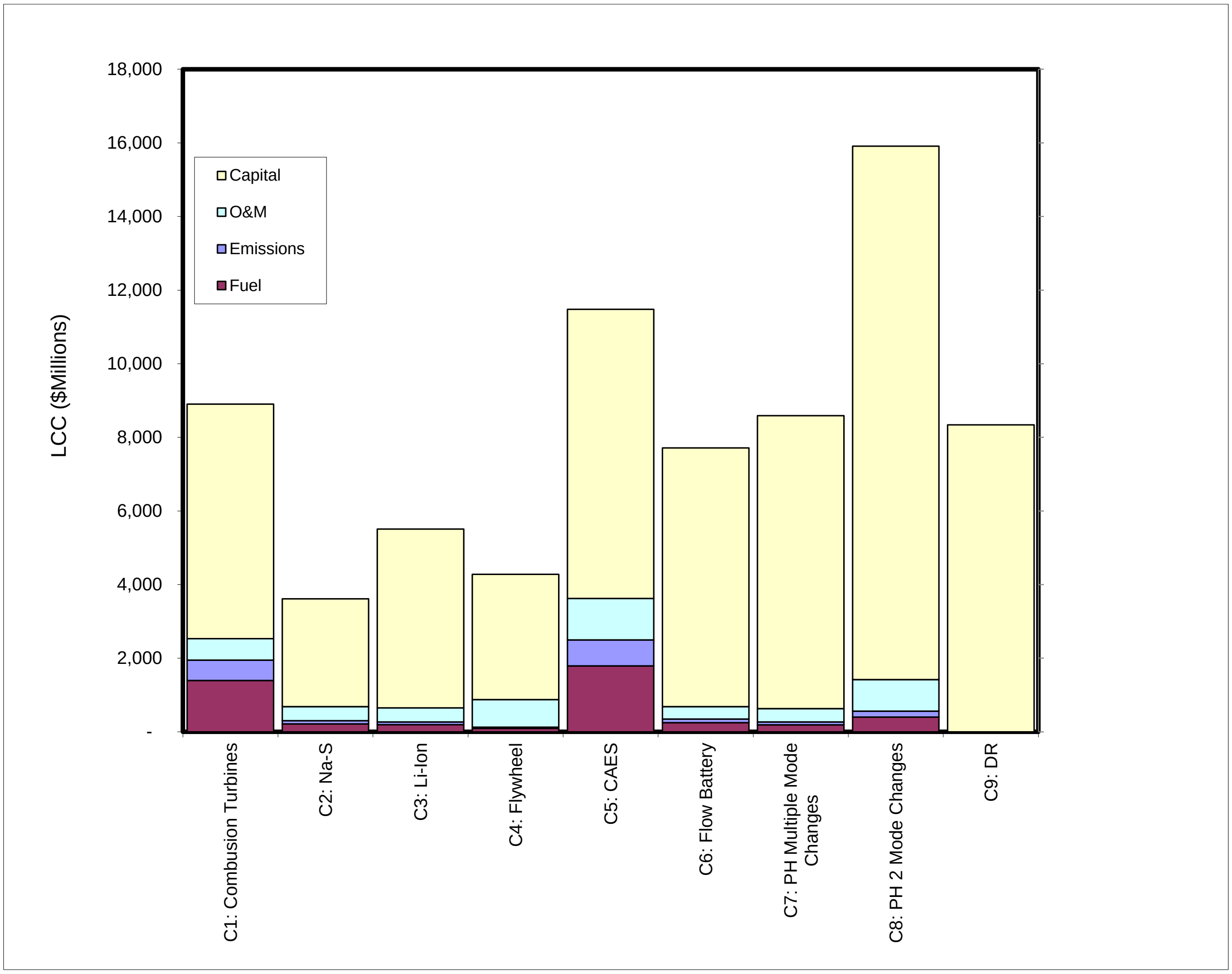

Figure A.171. LCC Estimates for SPSO

A.22.4 Arbitrage

Arbitrage analysis was not performed for the SPSO because of the low-economic value expectations.

A.23 Sensitivity Analysis: How sensitive are the Balancing Requirement Results on the Wind Forecasting Error Assumptions?

The accuracy of windpower and load forecasts are main factors which affect the estimation of balancing requirements. In this assessment, we investigated the impacts of wind forecast accuracy on balancing requirements and required energy storage size by assuming the wind forecast to be more accurate than current forecast accuracy. Because the mean value of the wind forecast is close to zero, standard deviation of wind forecast error is used as metric to evaluate the accuracy of the wind forecast. When the accuracy of the wind forecast decreases, (i.e., meaning the standard deviation of wind forecast error becomes greater), balancing requirements are very likely to increase as shown in Figure A.172 and Figure A.173. It should be noted that the incremental (inc.) and decremental (dec.) power requirements shown below are the results for the total, not intra-hour, balancing requirements. The balancing requirements results shown in sections above, were defined as intra-hour balancing requirements, which means that they represent the imbalances over a time period longer than 1 hour. Thus, they are larger than the intra-hour requirements as discussed in Sections A.1 - A.3. However, the results shown below are instructive as they are showing the sensitivity of balancing requirements with respect to improving or worsening the wind forecasting error. In the assessment, we used a standard deviation of the wind forecasting error of 7%, which was based on the customary fidelity of wind forecasts in the Pacific Northwest.

Forecast accuracy has higher impacts if the windpower adoption level in the region is high. Thus, greater changes are observed for regions with more wind capacity installed such as NWPP and CAMX. If the standard deviation of the wind forecast error is zero, this means the wind resource has been forecast perfectly. The resulting balancing requirements are then mainly caused by load forecast error, load within an hour variations and windpower variations within an hour.

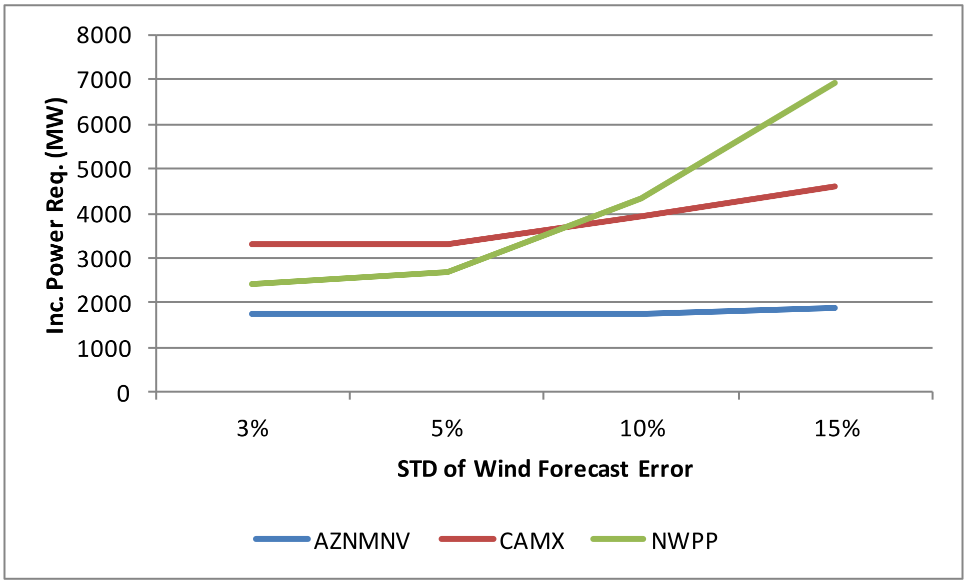

Figure A.172. Impacts of Wind Forecast Error on Incremental Power Requirements

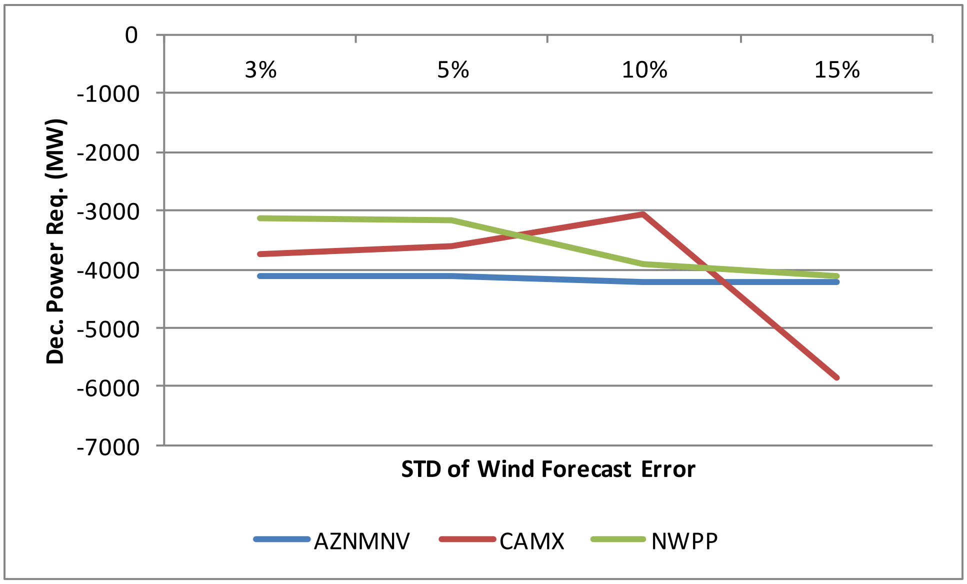

Figure A.173. Impacts of Wind Forecast Error on Decremental Power Requirements

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 CTs for energy balancing requirements. Part load efficiencies are considered in the CT implementations. This scenario represents a case similar to current operational procedures.

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.

B.2 Case 2: Na-S batteries + CCGT

The second scenario utilizes Na-S batteries and CCGT generation to meet balancing requirements. Figure B.1 shows the typical power output of the Na-S battery storage and CCGT generator over a two-day period. CCGT 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 Na-S contributions are actually the difference between the blue line and red line at each interval. If above the red line, the Na-S battery is discharging into the system. If below the red line, the storage is charging.

Table B.1. Definition of Technology Cases

	Case	Technology	Comments
Individual Technologies	C1	Combustion turbine	Conventional technology considered as the reference case
	C2	Na-S	Sodium sulfur battery only
	C3	Li-ion	Lithium-ion battery only
	C4	Flywheel	Flywheel only
	C5	CAES with 2 mode changes	CAES with a 7-minute waiting period for mode changes (compression-generation and vice versa). Balancing services will be provided during compression mode at night (8pm-8am) and during generation mode during the day (8am-8pm). Na-S battery is assumed to make up operations during 7 minute waiting period.
	C6	Flow battery	Flow battery only
	C7	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. Na-S battery is assumed to make up operations during 4 minute waiting period.
	C8	PH with 2 mode changes	Same as (C7), 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). Na-S battery is assumed to make up operations during 4 minute waiting period.
	C9	DR	Demand response only. This assumes that balancing services will be provided as a load. Only considered is PHEV charging at home and work. Resources are expressed in MW of DR capacity as well as in numbers of PHEV with demand response capability.
Technology Packages	C10	Na-S DR	Sodium sulfur battery and DR combined
	C11	Li-ion DR	Lithium-ion battery and DR combined
	C12	CAES Flywheel	CAES with no constraints for mode changes with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.
	C13	PH with multiple mode chances Na-S	Pumped hydro with no constraints for mode changes with Na-S battery. The balancing requirement is allocated to each technology according to minimum cost.
	C14	PH with 2 mode changes Na-S	Pumped hydro with two mode changes per day (see C8) with Na-S battery. The balancing requirement is allocated to each technology according to minimum cost.
	C15	PH with multiple mode chances Flywheel	Pumped hydro with no constraints for mode changes with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.
	C16	PH with 2 mode changes Flywheel	Pumped hydro with two mode changes per day (see C8) with Flywheel. The balancing requirement is allocated to each technology according to minimum cost.

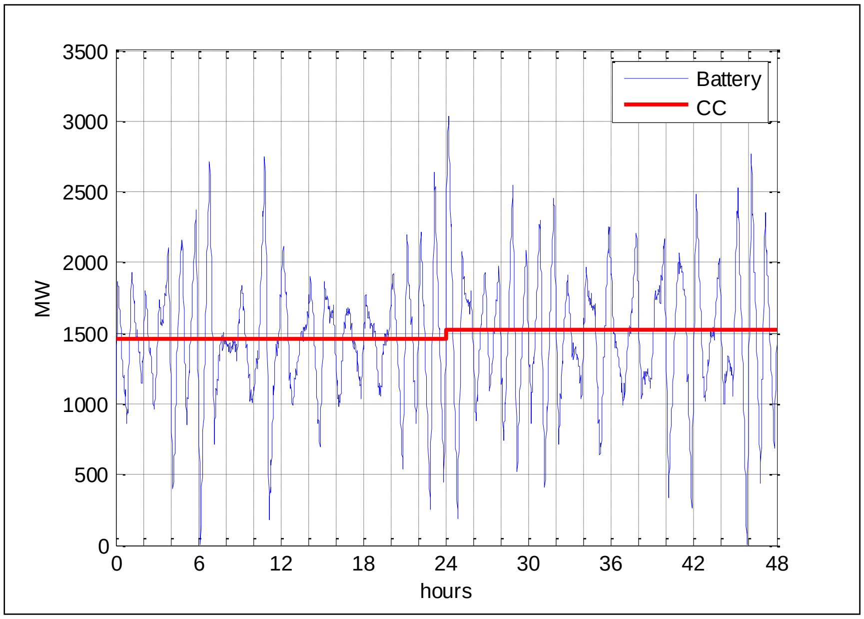

Figure B.1. Power Output of Na-S Battery and CCGT Generation for Two-Day Period

B.3 Case 3: Li-Ion + CCGT

The third scenario focuses on the use of Li-ion batteries and CCGT generation. The scenario is executed in an identical manner to Case 2 above, but the lower efficiency Na-S batteries are replaced with Li-ion batteries. CCGT 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 Na-S batteries for this case (80% compared to 78%). The typical power output of Figure B.1 is also representative of the Li-ion battery and CCGT case.

B.4 Case 4: Flywheel + CCGT

The fourth scenario focuses on the use of flywheels and CCGT generation. The scenario is executed in an identical manner to Case 2 above, but the lower efficiency Na-S batteries are replaced with flywheels. CCGT generation is once again utilized to compensate for efficiency losses in the flywheels and to ensure a balanced energy transfer over the day. The efficiency of flywheel was higher than that of Na-S batteries (90% compared to 80%). The typical power output of Figure B.1 is also representative of the Flywheel and CCGT.

B.5 Case 5: CAES with Two Mode Changes + CCGT

The CAES is restricted to two mode changes (changes between compression-generation and vice versa) per day. The CAES operates in compression mode from 8 p.m. to 8 a.m., and operates in generation mode from 8 a.m. to 8 p.m. each day. A 7-minute changeover delay is incorporated into the CAES system. This changeover delay is handled by supplementary Na-S battery storage. CCGT generation is not only utilized to compensate for efficiency losses in the battery and CAES, but also to provide additional compressing power. Figure B.2 represents the power output of the CAES storage when restricted to only two operating modes. The areas associated with the Na-S storage are not visible on this plot, as they only represent 14 minutes out of the 24-hour period.

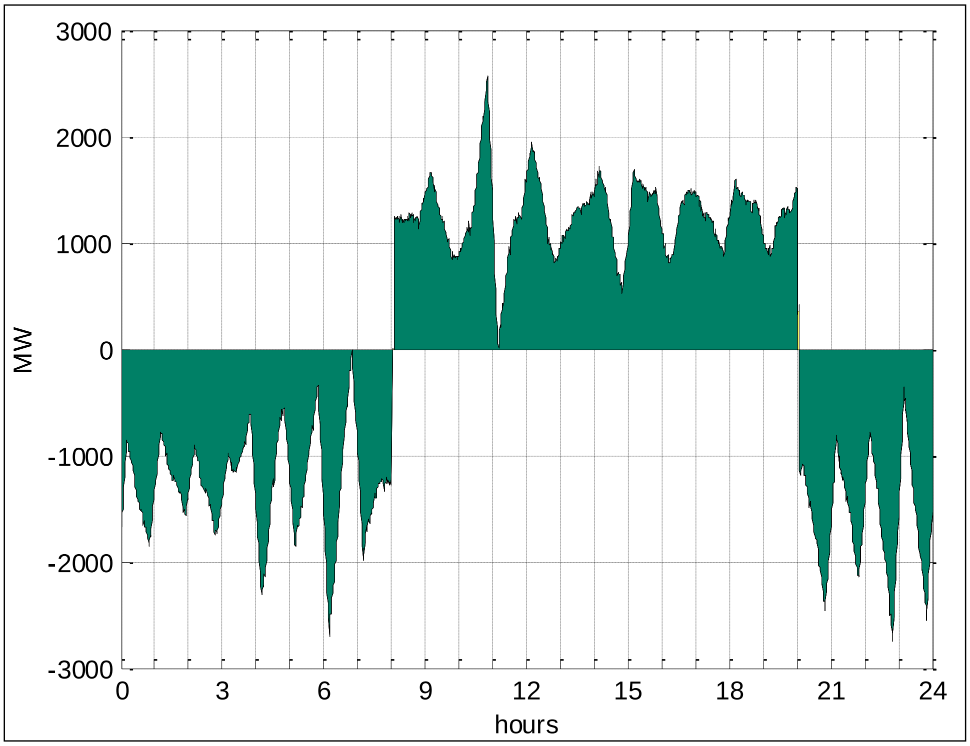

Figure B.2. Power Output of CAES with Only Two Mode Changes Per Day

B.6 Case 6: Flow battery + CCGT

The sixth scenario focuses on the use of flow battery and CCGT generation. The scenario is executed in an identical manner to Case 2 above, but the higher efficiency Na-S batteries are replaced with flow batteries. CCGT generation is once again utilized to compensate for efficiency losses in the flow batteries and to ensure a balanced energy transfer over the day. The efficiency of flow battery was lower than that of Na-S batteries (75% compared to 80%). The typical power output of Figure B.1 is representative of the flow battery and CCGT case as well.

B.7 Cases 7: Pumped Hydro with Multiple Mode Changes + CCGT

Technology Case 7 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, Na-S batteries are utilized to cover the balancing requirements. Figure B.3 demonstrates this implementation. As with the previous cases, CCGT generation is utilized to compensate for the efficiency losses of both the Na-S battery and pumped hydro, as well as balance the energy consumption in the storage.

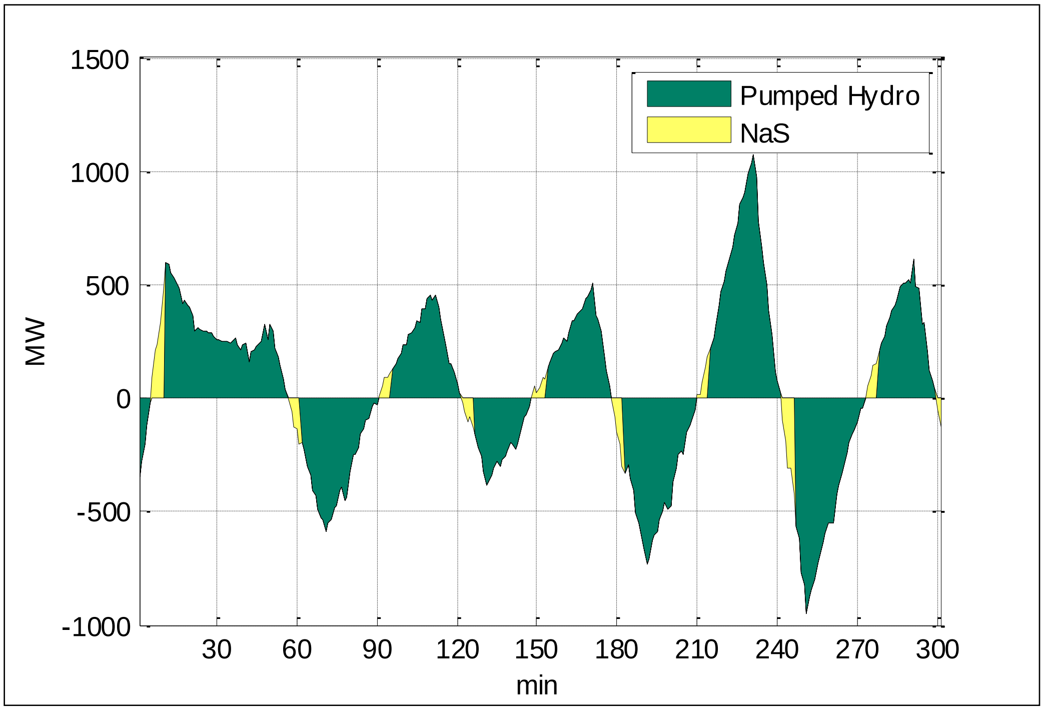

Figure B.3. Balancing Signal Taken by Pumped Hydro and Na-S Battery When the Changeover Delay is Modeled

B.8 Case 8: Pumped Hydro with Two Mode Changes + CCGT

Technology Case 8 is very similar to the scenario in Case 7. However, the pumped hydro storage is restricted to two mode changes per day. The pumped hydro operates in pump mode from 8 p.m. to 8 a.m., and operates in generation mode from 8 a.m. to 8 p.m. each day. This reduced number of mode changes increases the expected lifetime of the equipment, when compared to Case 7. As with Case 7, a 4-minute changeover delay is incorporated into the pumped hydro system. This changeover delay is again handled by supplementary Na-S battery storage. CCGT 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.4 represents the power output of the pumped hydro storage when restricted to only two operating modes. The yellow areas associated with the Na-S storage are not visible on this plot, as they only represent 8 minutes out of the 24-hour period.

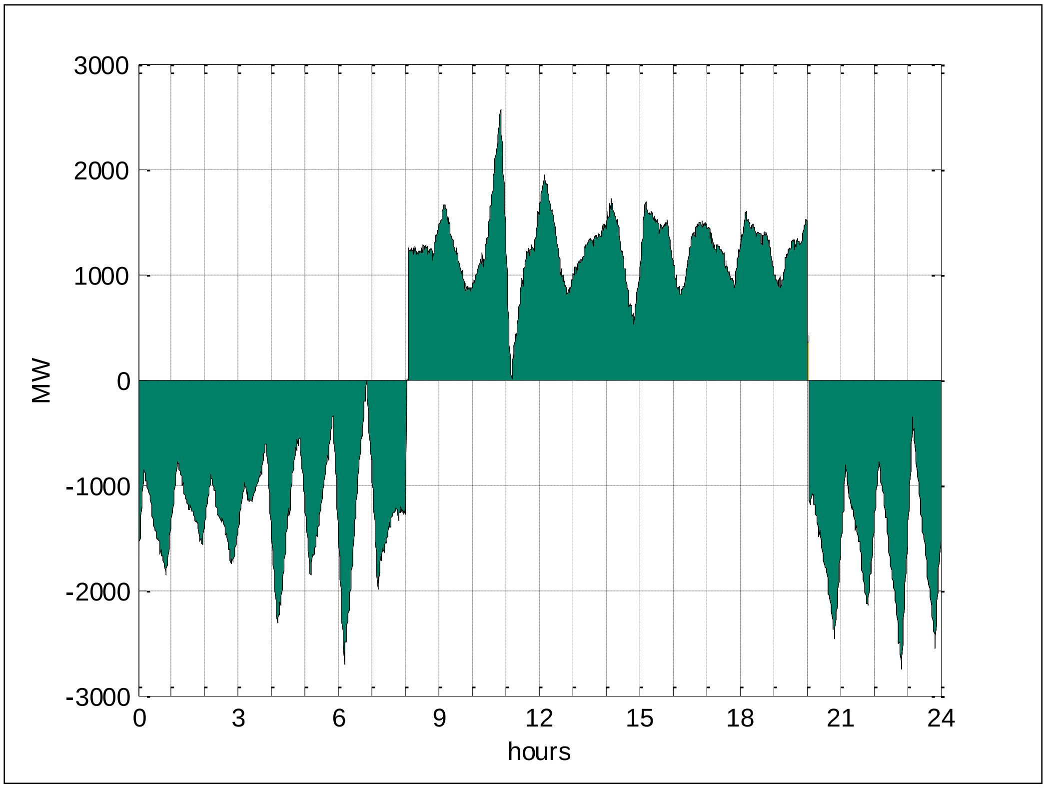

Figure B.4. Power Output of Pumped Hydro with Only Two Mode Changes Per Day

B.9 Case 9: Demand Response

Technology Case 9 utilizes a different scenario to meet the balancing requirements. Using DR, the load of the system is adjusted to meet the varying energy demands of the system, rather than using an energy storage solution. Pure DR balancing was accomplished using PHEV charging where both home and work charging was assumed available.

Figure B.5 shows the balancing signal and the load resource availability of EVs. The balancing would be achieved solely during the charging mode. No Vehicle-to-Grid (V2G) is necessary to meeting the balancing requirements. The balancing services can be furnished only during the charging mode. PNNL coined the term V2Ghalf, expressing the feature of intelligent or smart charging whereby the balancing is provide by a load resource (i.e., charging of a EV/PHEV battery) in such a manner that the charging is varied around an operating point. The aggregated EV battery charging load is not constant but varies as a function of time-of-day and availability of public charging stations at the workplace to allow for making the vehicle resource available to grid services. The number of vehicles necessary to provide sufficient load resources is then the number of vehicles that will furnish just enough load to meet the maximum balancing capacity, as seen in Figure B.4, at 6:00 a.m. when most of the chargers are turned off after having recharged the battery overnight.

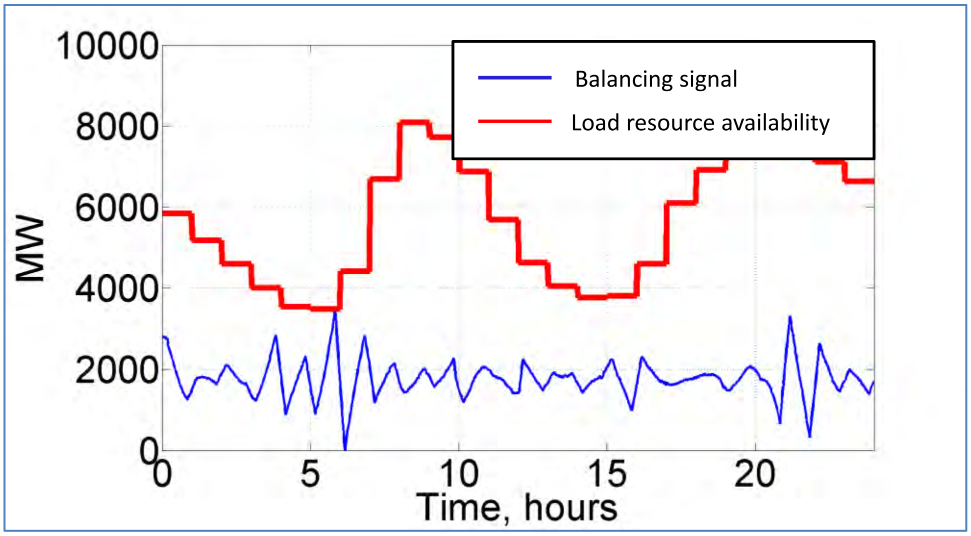

Figure B.5. Load Curves for PHEV with Home and Work Charging and Balancing Signal for the Average PHEV

Once a proper battery size was obtained, the vehicle's current SOC was randomized. As part of this randomization, it is often necessary to remove the first day of simulation results from each parameter investigation. This first day is often used to initialize the population into its charging routine, so some abnormal behavior is often present. Figure B.6 shows the first three days of a simulation investigating a particular ratio of home-only and work-home charging. While variations in the individual days are expected (due to the nature of the balancing signal), the first half day is noticeably different.

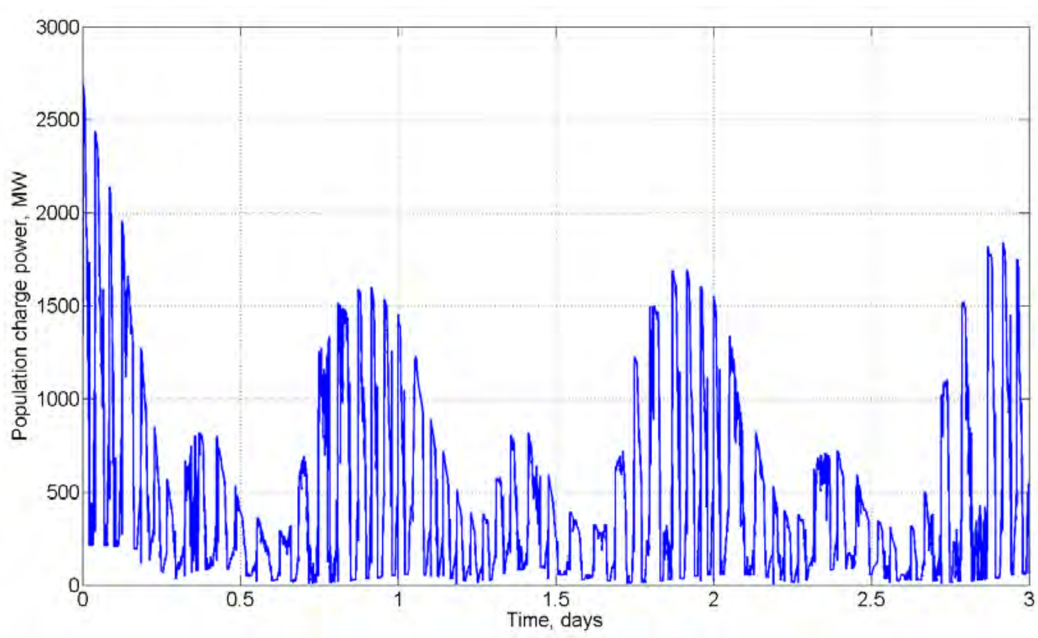

Figure B.6. Load Curves Population Charge Rate over Three-Day Period

It should also be noted that vehicle battery sizes and states of charge are calculated as the fully available capacity. That is, a 3.0-kWh battery is assumed to have all 3.0 kWh of energy available for use. The industry practice of keeping a battery in an optimal SOC band (i.e., 25% to 90% (Tate et al. 2008) to extend life is not utilized here. One can reasonably assume that the battery capacities mentioned could merely be an "adjusted battery size." That is, the 3.0-kWh battery is really a 4.62-kWh battery, but only 3.0 kWh is normally available for use.

B.10 Case 10: CCGT + Na-S + DR

The tenth technical case utilizes a combination of CCGT generation, Na-S battery storage, and DR to meet the balancing requirements. CCGT generation is again utilized for energy balance, as well as compensating for battery efficiency.

The balancing requirements were divided between the Na-S storage and DR. Twelve combinations of "slow storage" (DR) and "fast storage" (Na-S) components were defined, including the extreme cases of one single technology. The lower frequency contents of the intra-hour balancing signal are assigned to the "slow storage" component, while the higher frequency contents of the intra-hour balancing signal are assigned to the other component ("fast storage"). The 12 technology shares are defined using the filtering process discussed in Section 4.3.

DR capabilities were modeled as PHEV-home and work charging as explained in the previous technology case. Supplemented with Na-S battery storage, the amount of DR required is changes according to the division of the balancing signal that defines the 12 technology shares.

To determine the optimal combination, the 12 technology shares are further optimized using the economic procedure discussed in Section 5. The full process is explained in Section 4.3.

B.11 Case 11: CCGT + Li-ion + DR

This case is similar to Case 10 discussed in the previous subsection; there is only a difference in the battery efficiency.

B.12 Case 12: Flywheel + CCGT + CAES with Two Mode Changes

The CAES was restricted to a night pump and day generation cycle, as per Case 5. However, the flywheel storage capacity was used instead of Na-S batteries. CCGT generation is again utilized for energy balance, as well as compensating for battery efficiency.

The balancing requirements were divided between the flywheel storage and CAES. Twelve combinations of "slow storage" (CAES) and "fast storage" (Flywheels) components were defined, including the extreme cases of one single technology (notice that CAES only still requires flywheels to make up operation during changeover waiting period). The lower frequency contents of the intra-hour balancing signal are assigned to the "slow storage" component, while the higher frequency contents of the intra-hour balancing signal are assigned to the other component ("fast storage"). The 12 technology shares are defined using the filtering process discussed in Section 4.3.

Figure B.7 shows the power output of the CAES for one of the 12 technology shares. Figure B.8 shows the power output for the flywheel storage. The addition of the flywheel storage helps alleviate the amount of CAES required. Figures B.7 and B.8 change according to the division of the balancing signal that defines the 12 technology shares.

To determine the optimal combination, the 12 technology shares are further optimized using the economic procedure discussed in Section 5. The full process is explained in Section 4.3.

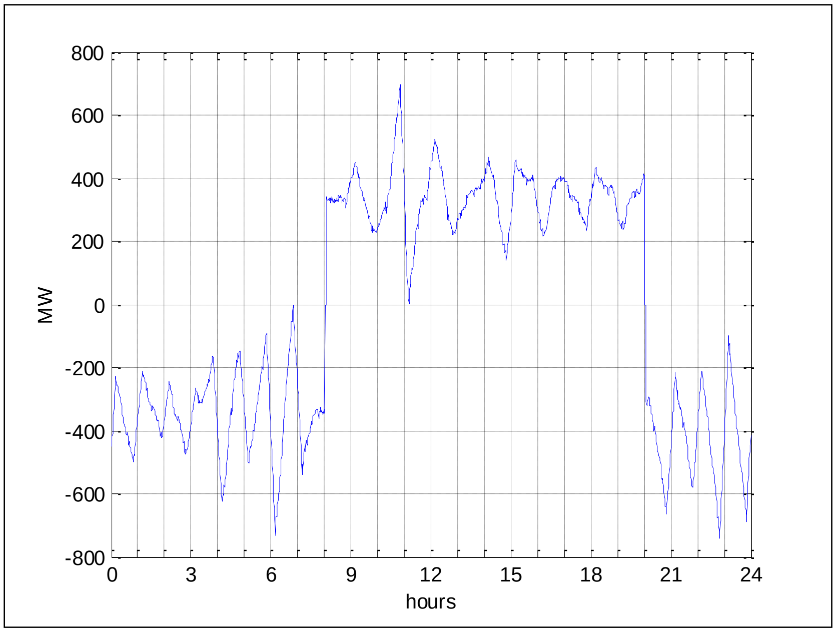

Figure B.7. Power Output of CAES with Only Two Mode Changes per Day for One of Twelve Technology Shares Options

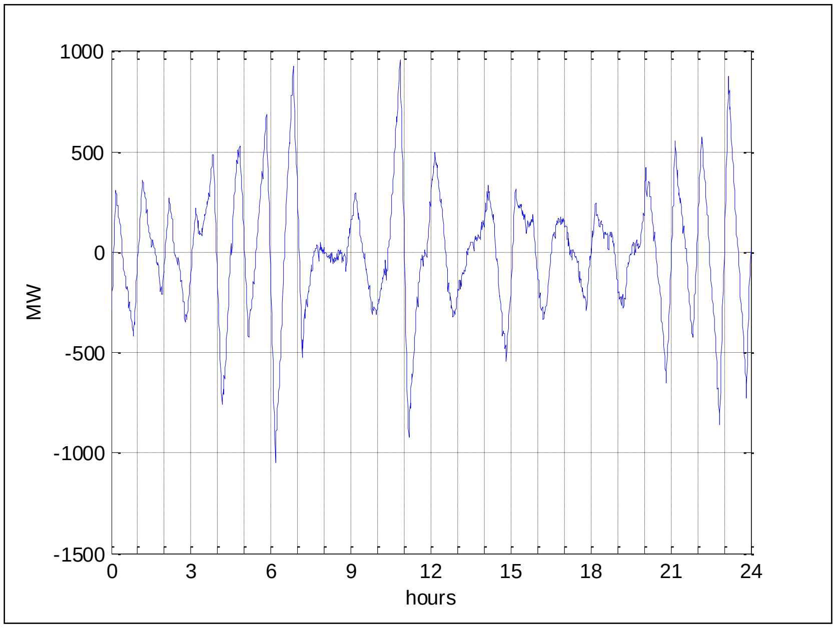

Figure B.8. Power Output of Flywheel for One of Twelve Technology Shares Options

B.13 Case 13: Na-S + CCGT + Pumped Hydro with Multiple Mode Changes

Technology Case 7 earlier utilized pumped hydro storage with multiple mode changes in a day, which was supplemented by Na-S battery storage. This technology case supplements that analysis with a larger amount of Na-S battery storage available. Unlike Case 7, the balancing requirements are divided between the Na-S and pumped hydro storage. CCGT generation is again utilized for energy balance, as well as compensating for battery efficiency.

The balancing requirements were divided between the Na-S battery storage and CAES. Twelve combinations of "slow storage" (pumped hydro) and "fast storage" (Na-S) components were defined, including the extreme cases of one single technology (notice that pumped hydro only still requires Na-S to make up operation during changeover waiting period). The lower frequency contents of the intra-hour balancing signal are assigned to the "slow storage" component, while the higher frequency contents of the intra-hour balancing signal are assigned to the other component ("fast storage"). The 12 technology shares are defined using the filtering process discussed in Section 4.3.

Figure B.9 shows the power output of the pumped hydro for one of the 12 technology shares. Figure B.10 shows the power output for the Na-S battery storage. The addition of the flywheel storage helps alleviate the amount of pumped hydro required. Figures B.9 and B.10 change according to the division of the balancing signal that defines the 12 technology shares.

To determine the optimal combination, the 12 technology shares are further optimized using the economic procedure discussed in Section 5. The full process is explained in Section 4.3.

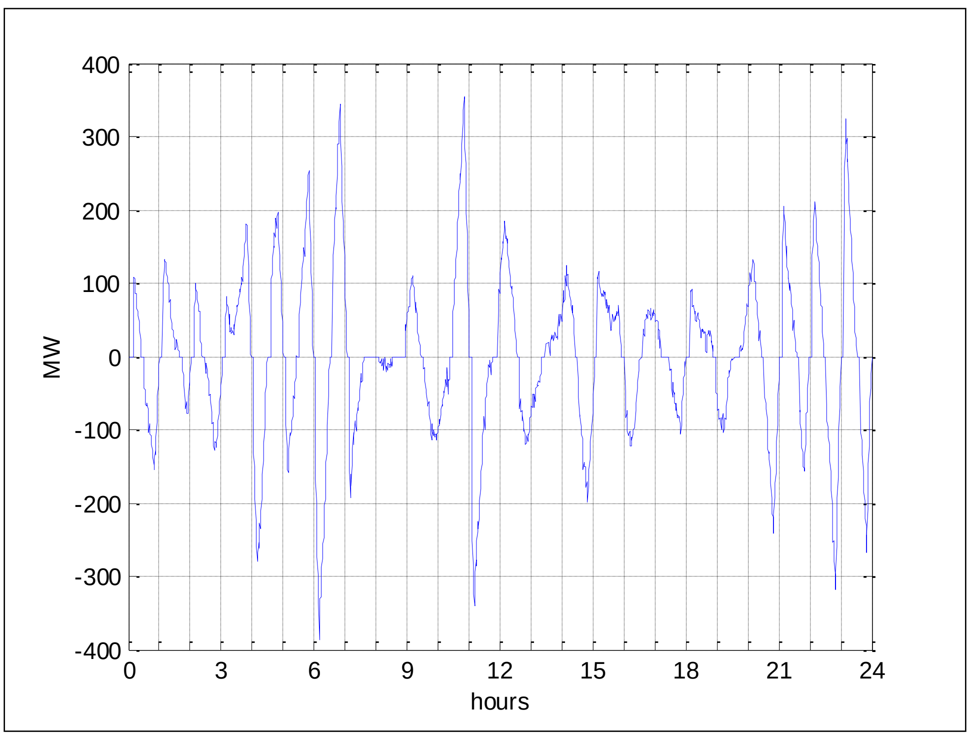

Figure B.9. Power Output of Pumped Hydro with Multiple Mode Changes per Day with Na-S + CCGT Technology Shares Options

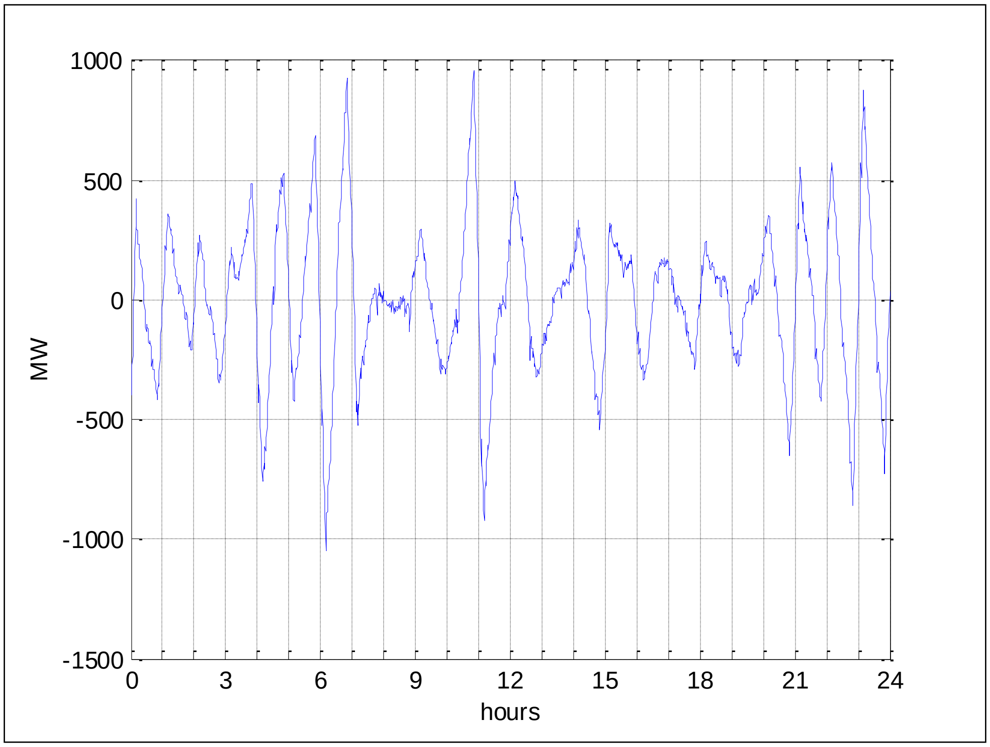

Figure B.10. Power Output of Na-S Battery for Na-S + Pumped Hydro + CCGT Scenario Technology Shares Options

B.14 Case 14: Na-S + CCGT + Pumped Hydro with Two Mode Changes

The pumped hydro and Na-S battery technology Case 8 was re-evaluated with various amounts of Na-S storage available. The procedure is similar to Case 12; there are the following differences: the storage efficiencies, the "slow storage" corresponds to pumped hydro, and the "fast storage" corresponds to the Na-S battery.

B.15 Case 15: Pumped Hydro + Flywheel + CCGT + DR

Case 15 considers pumped hydro with multiple mode changes and flywheel storage. Various combinations of these two technologies are evaluated. The procedure is similar to Case 13; there are the following differences: the storage efficiencies, the "slow storage" corresponds to pumped hydro storage, and the "fast storage" corresponds to the flywheel storage.

B.16 Case 16: Pumped Hydro + Flywheel + CCGT + DR

Case 16 considers pumped hydro with 2 mode changes and flywheel storage. Various combinations of these two technologies are evaluated. The procedure is similar to Cases 14 and 12; there are the following differences: the storage efficiencies, the "slow storage" corresponds to pumped hydro storage, and the "fast storage" corresponds to the flywheel storage.

B.17 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 <u>does</u> reduce the capacity requirements (MW) slightly, but increases the energy capacity requirements (if energy storage is used). This is a 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 Na-S batteries only (Case 2). If the complete over-generation part of the balancing signal is curtailed by wind spillage, the balancing signal taken by the Na-S batteries is as shown in Figure B.11. Charging and discharging of the Na-S batteries is decided by the difference between the balancing signal and a daily fixed power output of a CCGT generator as shown in Figure B.12. It can be seen from Figure B.12 that the maximum power requirement for Na-S batteries (difference between balancing signal and constant power output of CCGT) is not considerably reduced by curtailing half of the balancing signal using wind spillage. What is more, the energy requirements for Na-S batteries are larger than the energy requirements without wind spillage as it can be seen comparing Figure B.13 and Figure B.14.

Figure B.15 and Figure B.16 show the energy and power requirements for several levels of wind spillage. A 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.15 and Figure B.16 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. DR can be used to curtail under-generation peaks. Symmetry in the balancing signal can be maintained by using both DR and wind spillage.

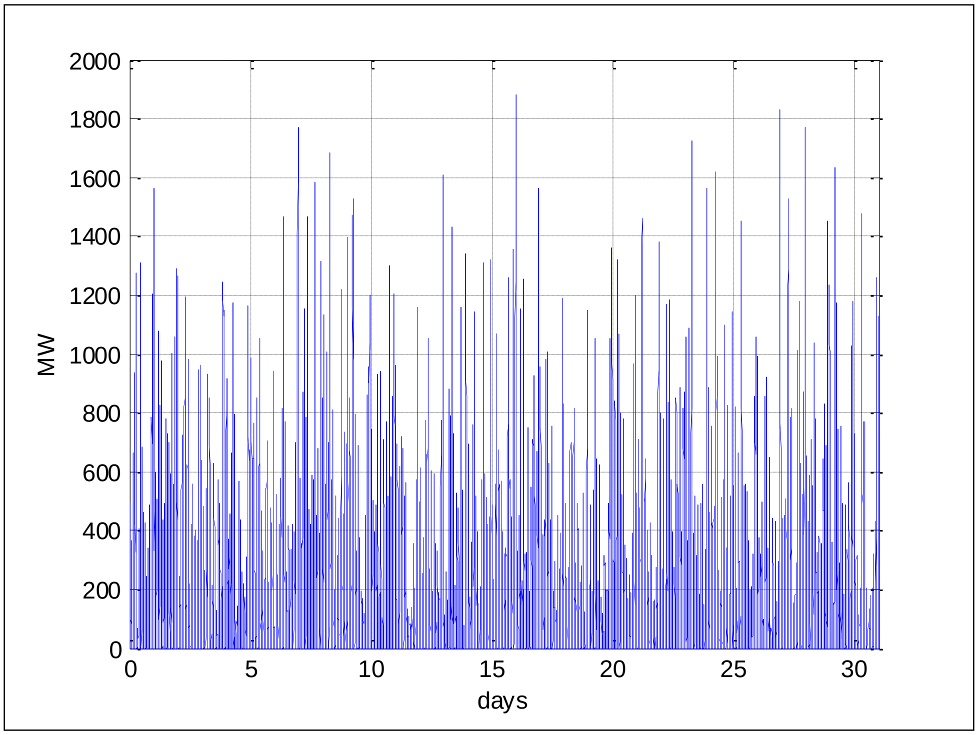

Figure B.11. Balancing Signal Taken by Na-S Batteries After the Complete Over-Generation Component is Curtailed by Wind Spillage

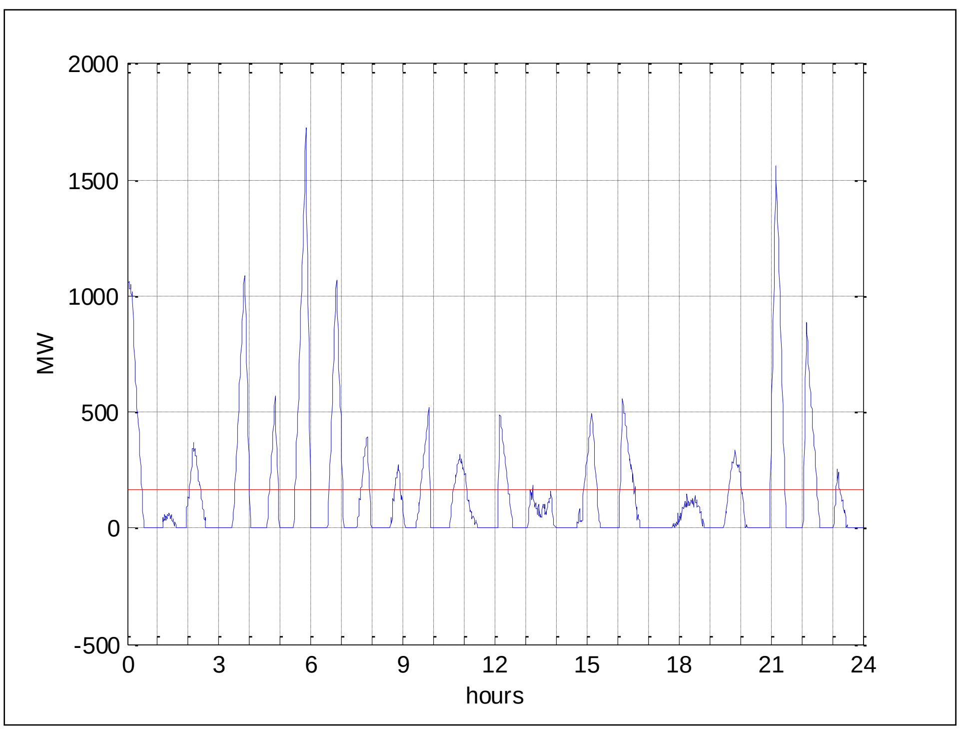

Figure B.12. Balancing Signal Taken by Na-S Batteries After the Complete Over-Generation Component is Curtailed by Wind Spillage, and Constant Power Output of CCGT Generation

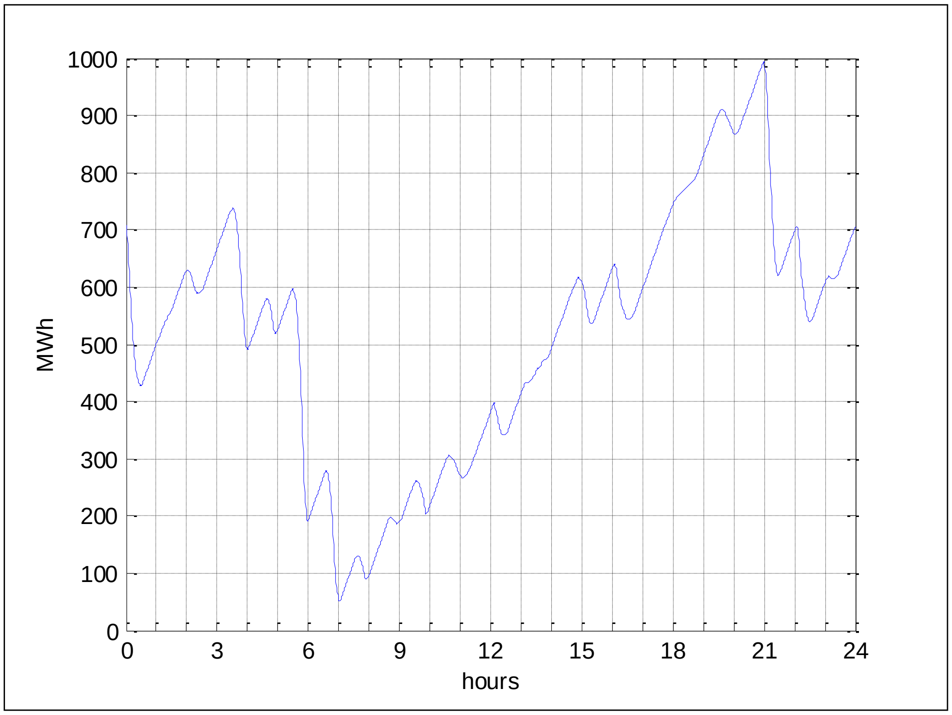

Figure B.13. Charging Status of Na-S Batteries, for Day 24, After the Complete Over-Generation Component is Curtailed by Wind Spillage

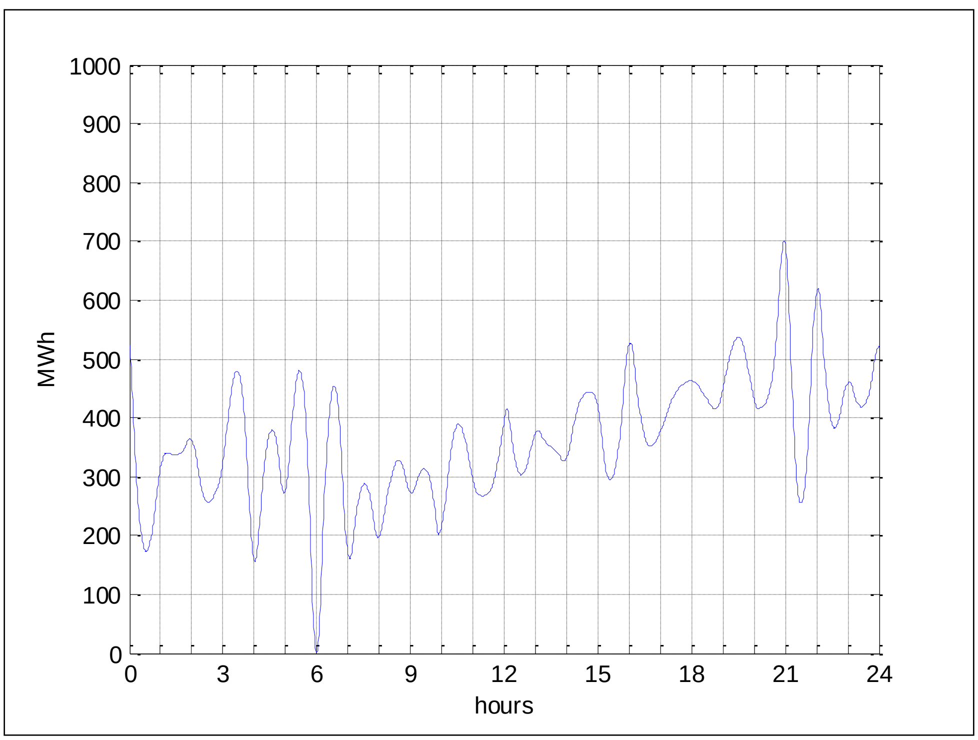

Figure B.14. Charging Status of Na-S Batteries Without Wind Spillage for Day 24

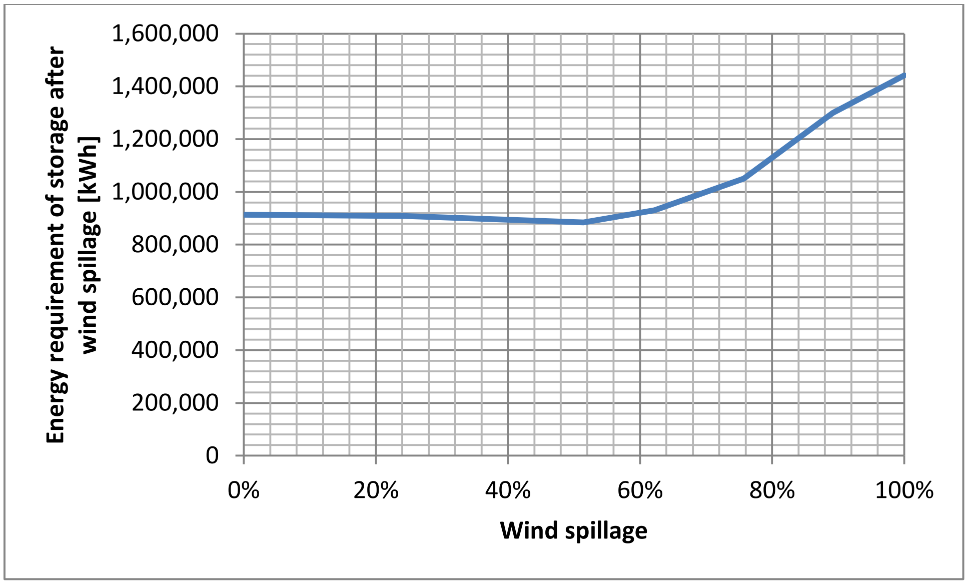

Figure B.15. Energy Requirements for Storage after Wind Spillage is Applied

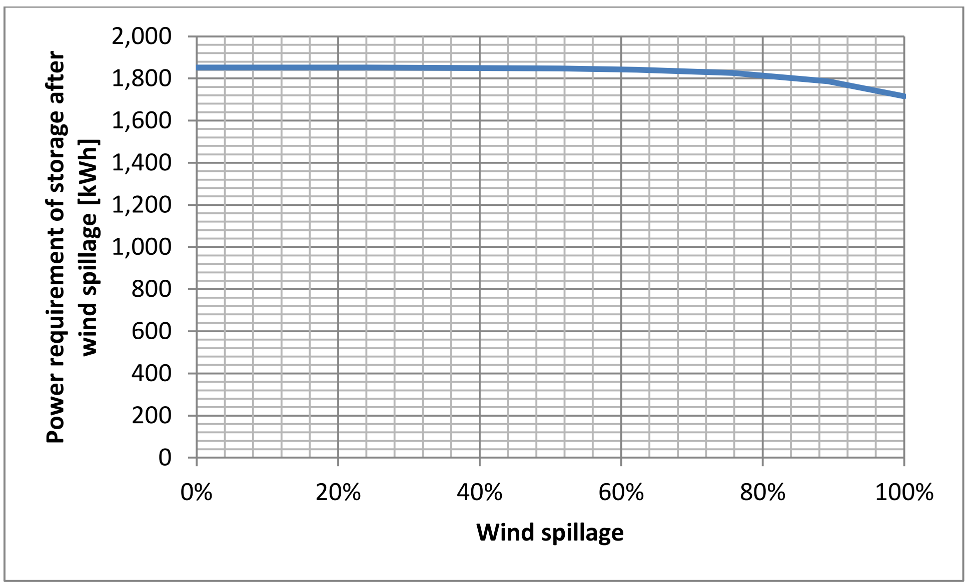

Figure B.16. Power Requirements for Storage After Wind Spillage is Applied

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