AN ABSTRACT OF THE DISSERTATION OF

Scott E. Harpool for the degree of Doctor of Philosophy in Electrical and Computer Engineering presented on August 27, 2018.

Title: Renewable Energy in the Pacific Northwest - Technical and Economic Analysis of 100% Renewable Portfolios, including Seasonality Impacts and Potential Applications of Energy Storage

Abstract approved:

____

Annette R. von Jouanne

Renewable electrical energy sources are relatively easy to integrate at moderate penetrations, utilizing a combination of technical and market methods to increase grid flexibility. However, integrating high renewable portfolios is more challenging, and the optimal combination of resources will vary depending on the features of specific geographic areas. This study evaluates 100% renewable portfolios in the Pacific Northwest, including existing hydropower as a renewable source, plus existing and new wind, solar, wave and biomass generation. Using detailed time series data for a four-year period, a resistive power grid analysis, plus macro level cost estimates for new renewable generation, a set of diverse portfolios was selected for further analysis. With significant seasonality challenges in the Pacific Northwest, these portfolios provide a range of generation resources, capital and annual costs, and match/mismatch to load, allowing the impact of energy storage to be analyzed. If the amount of new biomass is constrained to 15%, the lowest cost portfolios include significant wave generation (20 – 30%). Pumped hydro storage reduces unserved load during the low hydro/wind generation season (summer/fall) by an average of $2.8M per year, and reduces curtailment during the high generation season by an average of $41k per year. The important contribution of this study is the modeled importance of wave energy and pumped hydro storage with high penetrations of variable renewable energy in the Pacific Northwest.

Renewable Energy in the Pacific Northwest - Technical and Economic Analysis of 100% Renewable Portfolios, including Seasonality Impacts and Potential Applications of Energy Storage

by
Scott E. Harpool

A DISSERTATION

submitted to

Oregon State University

in partial fulfillment of
the requirements for the
degree of

Doctor of Philosophy

Presented August 27, 2018
Commencement June 2019

Doctor of Philosophy dissertation of Scott E. Harpool presented on August 27, 2018.

APPROVED:

Major Professor, representing Electrical and Computer Engineering

Director of the School of Electrical Engineering and Computer Science

Dean of the Graduate School

I understand that my dissertation will become part of the permanent collection of Oregon State University libraries. My signature below authorizes release of my dissertation to any reader upon request.

Scott E. Harpool, Author

ACKNOWLEDGEMENTS

The author expresses sincere appreciation to:

Dr. Annette von Jouanne, Dr. Ted Brekken, Dr. Eduardo Cotilla-Sanchez, Dr. Alex Yokochi, and Dr. Solomon Yim for their continued mentoring, support and willingness to answer questions. I've really enjoyed working with all of you!

Jan Silverio for his support and encouragement!

My wife, Bethany Matthews, for her love, support and patience!

And especially to my parents, Laurie and Arthur Harpool, for their emphasis on getting a great education, and for all the opportunities they've provided. Dad, thank you for all the hands-on knowledge. And Mom, thank you for suggesting a solar energy project in middle school, and for all your proof-reading through the years!

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

Page

LIST OF FIGURES

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

LIST OF TABLES

LIST OF ABBREVIATIONS

AGC	Automatic Generation Control
ATB	Annual Technology Baseline (NREL)
BA	Balancing Authority
BAA	Balancing Authority Area
BOS	Balance of System
BPA	Bonneville Power Administration
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CHP	Combined Heat and Power
DOE	Department of Energy
EES	Electrical Energy Storage
EIA	Energy Information Administration (US)
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LFG	Landfill Gas
MHK	Marine and Hydrokinetic
NCDC	National Climatic Data Center
NCIA	National Centers for Environmental Information (previously NCDC)
NDBC	National Data Buoy Center (NOAA)
NERC	North American Electric Reliability Corporation
NMREC	National Marine Renewable Energy Centers
NNMREC	Northwest National Marine Renewable Energy Center
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NWP	Numerical Weather Prediction
OE	Operating Entity
O&M	Operations and Maintenance
PGE	Portland General Electric
PHS	Pumped Hydro Storage
PV	Photovoltaic
RPS	Renewable Portfolio Standard
SoC	State of Charge
STC	Standard Test Conditions
VRE	Variable Renewable Energy
WEC	Wave Energy Converter
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study

LIST OF DEFINITIONS

Balancing system - the set of institutions used to maintain and restore the short-term active power balance, including the interconnection and the balancing areas within the synchronous system [1].

Capacity factor - the amount of energy is produced by a plant compared with its maximum output, measured as a percentage, usually by dividing the total energy produced during a time period by the amount of energy the plant would have produced at full output during that time [2].

Capacity value (credit) - the contribution of a power plant to reliably meet demand, measured either in terms of physical capacity (kW, MW, GW) or the fraction of the power plant's nameplate capacity (%) [2].

Curtailment - a reduction in the output of a generator from what it could otherwise produce given available resources (e.g., wind or sunlight), typically on an involuntary basis [3].

Demand response - voluntary, compensated load reduction used as a system reliability resource [4].

Economic dispatch - selecting the optimum mix of generating facilities that meets the load at the lowest operating cost subject to transmission and operational constraints [5].

Efficiency - the ratio of a system's electricity output to the energy input [6].

Flexibility - the ability of a power system to respond to changes in electricity demand and supply [7].

Grid integration - the practice of developing efficient ways to deliver variable renewable energy to the grid.

G*rid integration study* - simulating the operation of the power system under various scenarios, identifying potential constraints to reliability, and evaluating the cost of actions to alleviate those constraints [7].

*Integration cost*s - the additional costs that are required in the power system to keep requirements (voltage, frequency) at an acceptable reliability level [8].

Load data - the magnitude, location and timing of electricity demand [9].

Negative net load - when generated renewable energy is more than the system demand; it may require curtailment of renewable resources or lead to negative electricity prices to encourage consumption and discourage generation [10].

Net load - the conventional load minus the non-dispatchable generation [10]; the demand that must be met by other generation sources if all non-dispatchable generation is consumed.

Peak shaving - storing energy during off-peak periods for use during periods of maximum power demand [6].

Ramps - increases or decreases in rate of output to follow net load [11].

Reliability - assuring resource adequacy to accommodate rare events in long term planning, and also the ability to maintain the system operationally [8].

Reserve sharing - when two or more balancing area authorities collectively maintain, allocate and supply the reserves required for each balancing area.

Reserves - capacity (generation, responsive load, or storage), under system operator control, that is capable of moving up or down to maintain the net generation/load balance [12].

Solar insolation - the amount of solar radiation that reaches the earth's surface [13].

Storage - the set of technologies capable of storing electricity generated at one time for use at a later time [14].

Time shifting - storing electrical energy when it is less expensive, then using or selling the stored energy during peak demand periods [6].

Uncertainty - the inability to perfectly predict electricity demand and/or generator output [7].

Unit commitment - the process of starting up a generator so that the plant is synchronized to the grid [15].

Variability - the changes in power demand or the output of a generator due to underlying fluctuations in resource or load [7].

1. INTRODUCTION:

The traditional power grid consisted primarily of large thermal (and sometimes hydroelectric) generating facilities, and a radial, one-way distribution system. Fuel such as coal and natural gas can be stored or delivered as required for generation. Water stored behind dams is also available for generation, with some seasonal and other water-flow constraints. Significant spinning generation contributes inertia for grid stability, and frequency response has traditionally been a service provided by large synchronous generators. System load was traditionally predictable based on historical information including weather conditions, day of week, and time of day. Therefore, forecasting and operational/dispatch decisions were relatively straightforward.

There are many reasons to increase the use of renewable energy in the power grid. Existing fossil fuels such as oil, coal and natural gas are being depleted rapidly, plus the use of these fossil fuels has created many environmental concerns. Dependence on fossil fuels can also create economic and political issues, and there is the risk of supply cuts of these conventional fuels. Increased use of renewable fuel sources will have many long term benefits, but many renewable energy sources are variable and non-dispatchable. This complicates the integration of renewable sources into the existing power grid.

This study will examine options for 100% renewable energy portfolios in the Pacific NorthWest (PNW), specifically the Bonneville Power Administration (BPA) Balancing Authority Area (BAA). Four years of historical weather, generation and load data will be used to model the addition of new renewable resources to the grid. Five renewable energy sources will be used: hydroelectric, wind, solar, wave, and biomass. The model will incorporate the effects of renewable energy source diversity, geographic diversity of renewable energy sources, and energy storage. A general workflow is outlined in Figure 1, and is explained in detail in the methods section. This thesis will utilize both technical and economic analyses to determine which portfolio options are the most promising for 100% renewable generation in the PNW, and how the addition of energy storage affects them. More specifically, the economic penalties of curtailment and unserved load, based on the historical time series data, will be used as a measure of how well the various portfolios match grid requirements.

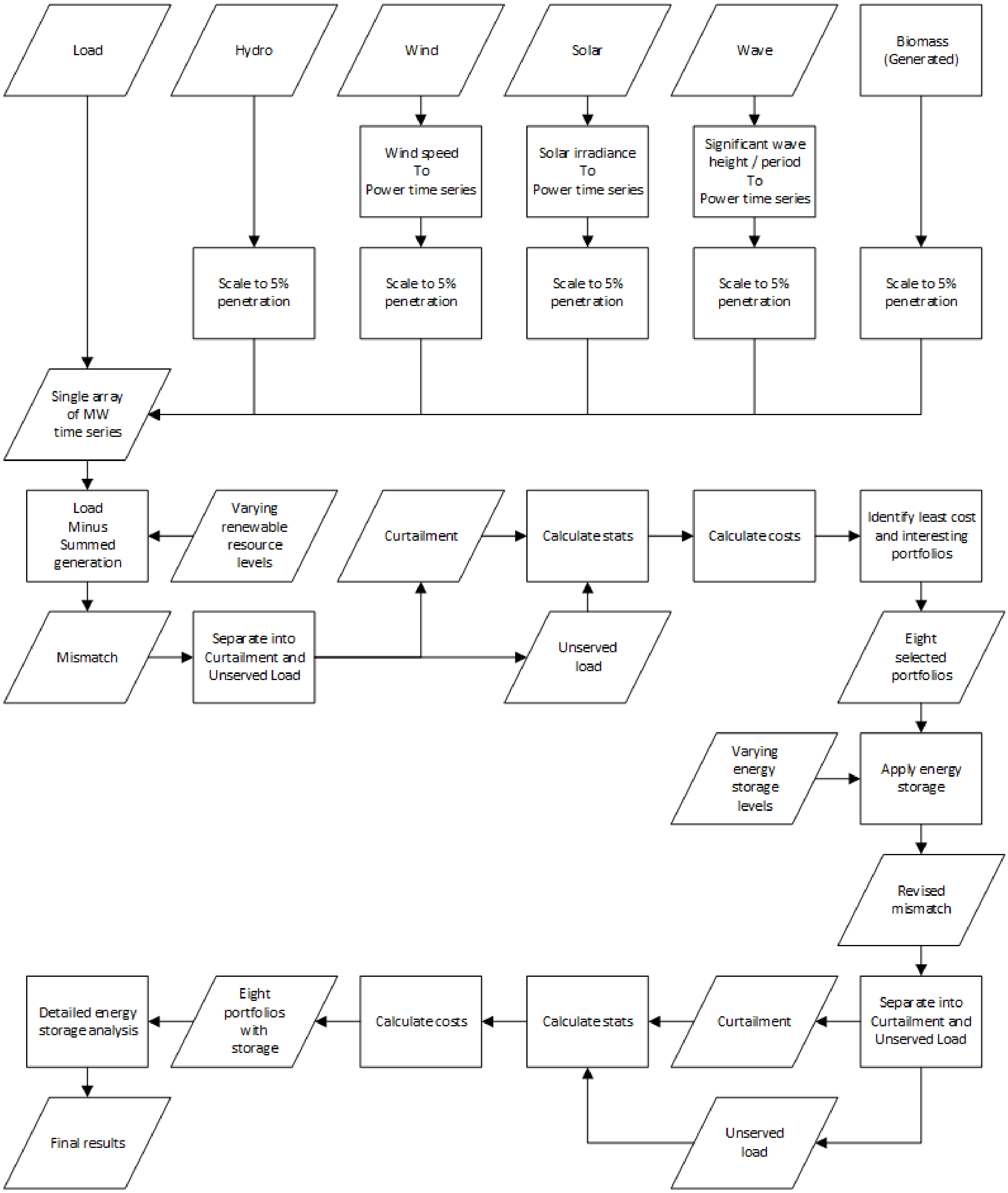

Figure 1 – General workflow of study, from raw downloaded data to results. Parallelograms: data sets. Rectangles: analysis processes.

2. OVERVIEW OF PACIFIC NORTHWEST

2.1 The Pacific Northwest:

The Northwest is characterized by its large amount of hydroelectric generation, and during average to wet spring runoff seasons, this hydro system can meet most or all energy needs on a day-to-day basis [16]. The Pacific Intertie connects Oregon's electricity grid to California's grid, allowing for large interstate energy transfers between the Pacific Northwest and the Southwest [17]. California and the Northwest are both electrically and institutionally close, where the Northwest can accommodate midday exports from California outside of the spring season, and the spring runoff and nighttime oversupply in the Northwest finds a market in both California and the Southwest. The Northwest Power and Conservation Council (NWPCC) assumes the availability of 2,500 MW of imports during the winter period due to California’s relatively low winter loads and the availability of capacity needed to meet its own summer peak.

Existing generation plants in the Northwest are shown in Figure 2, along with their relative capacities. This illustrates the huge concentration of hydro power along the Columbia River, as well as a significant portion of the wind generation capacity.

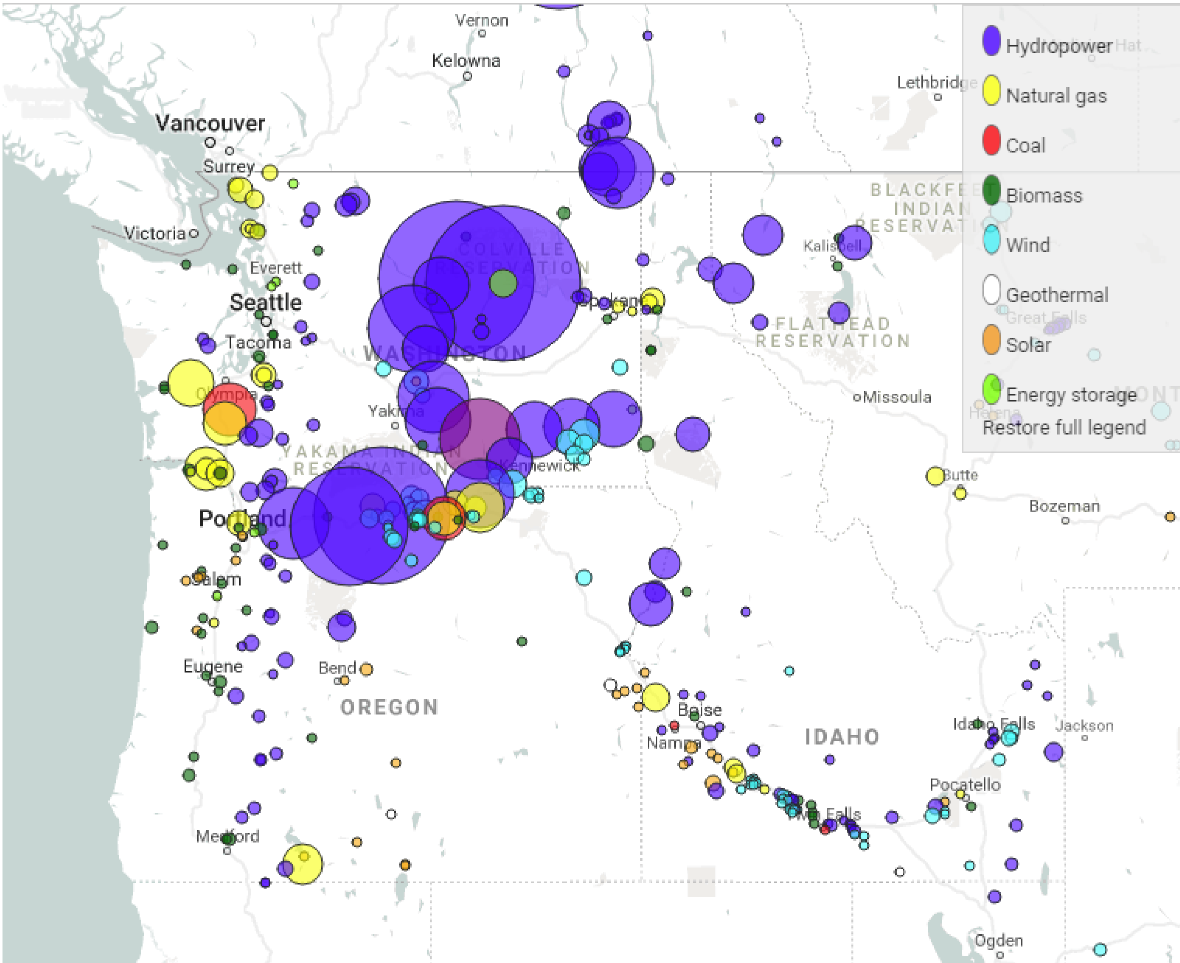

Figure 2 - Map of power generation in the Northwest (Northwest Power and Conservation Council) [18]

The population density in the Northwest can be seen in the 2010 US Census map, Figure 3 [19], with the highest density areas geographically separate from the largest generation locations. This has important implications relative to transmission and locations of new variable renewables. The transmission lines in the Northwest are shown in Figure 4. [20]

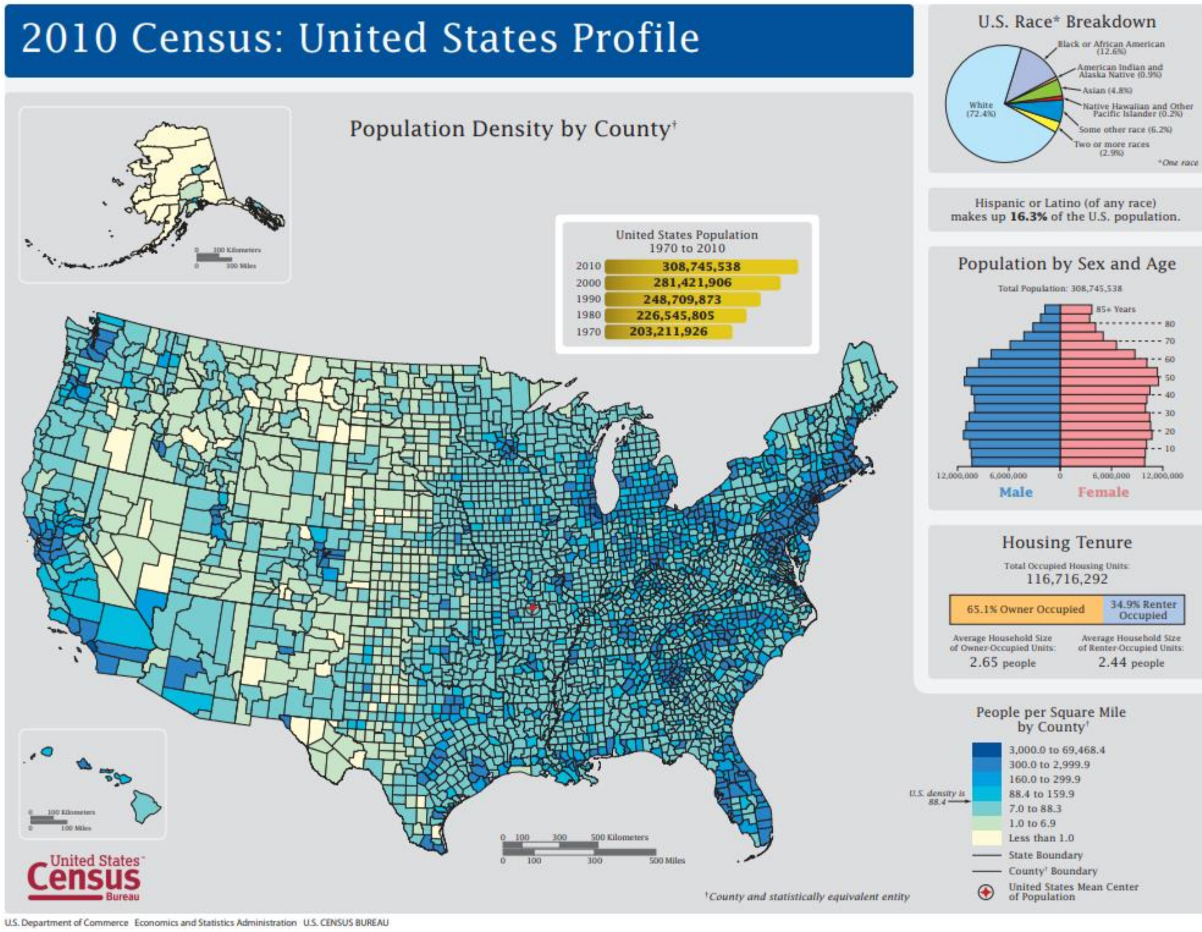

Figure 3 - 2010 US Census Results [19]

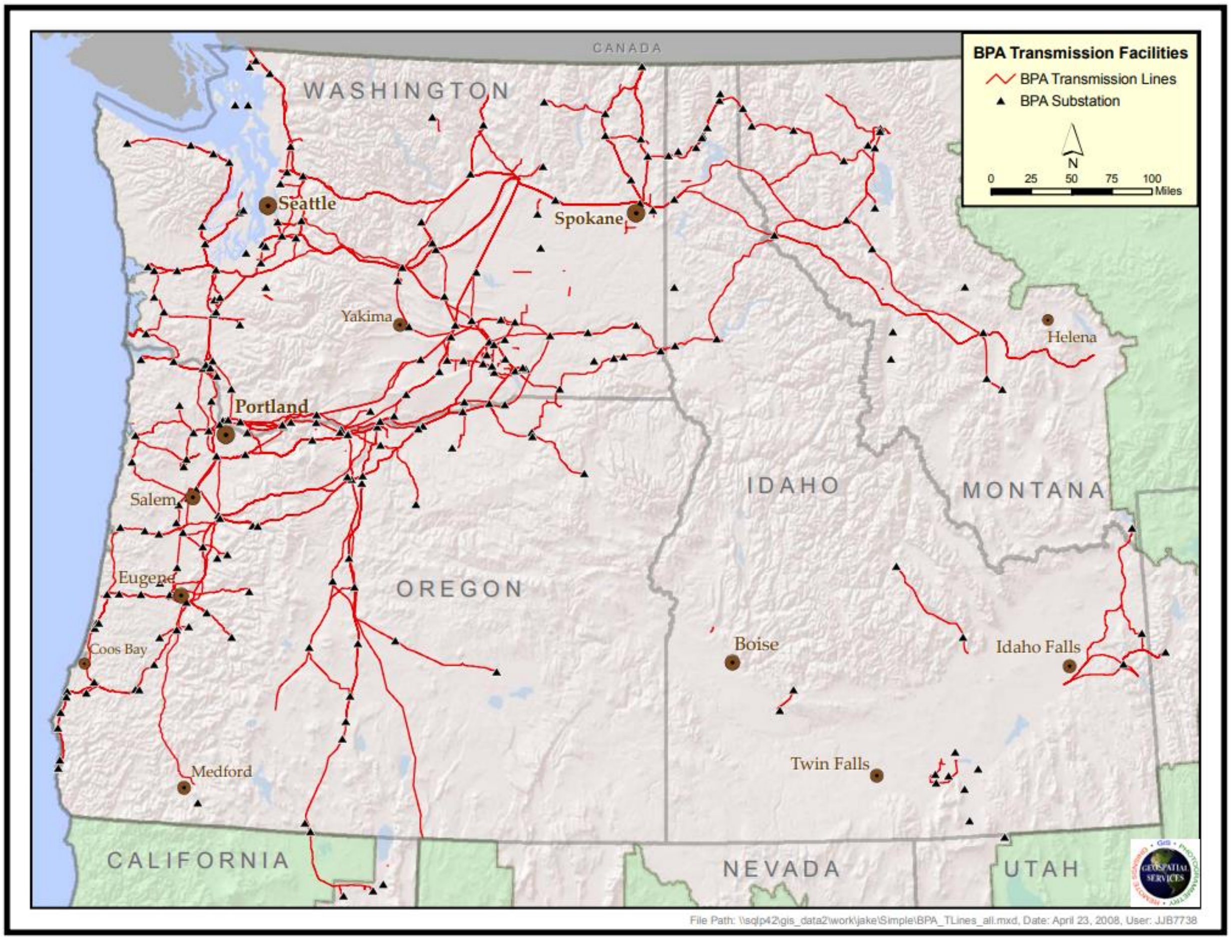

Figure 4 - BPA transmission lines [20]

Renewable resource potentials in the Northwest can be visualized on the following maps from the NREL RE Atlas: onshore wind in Figure 5, solar photovoltaic in Figure 6, wave power density in Figure 7, and biomass residue in Figure 8. [21]

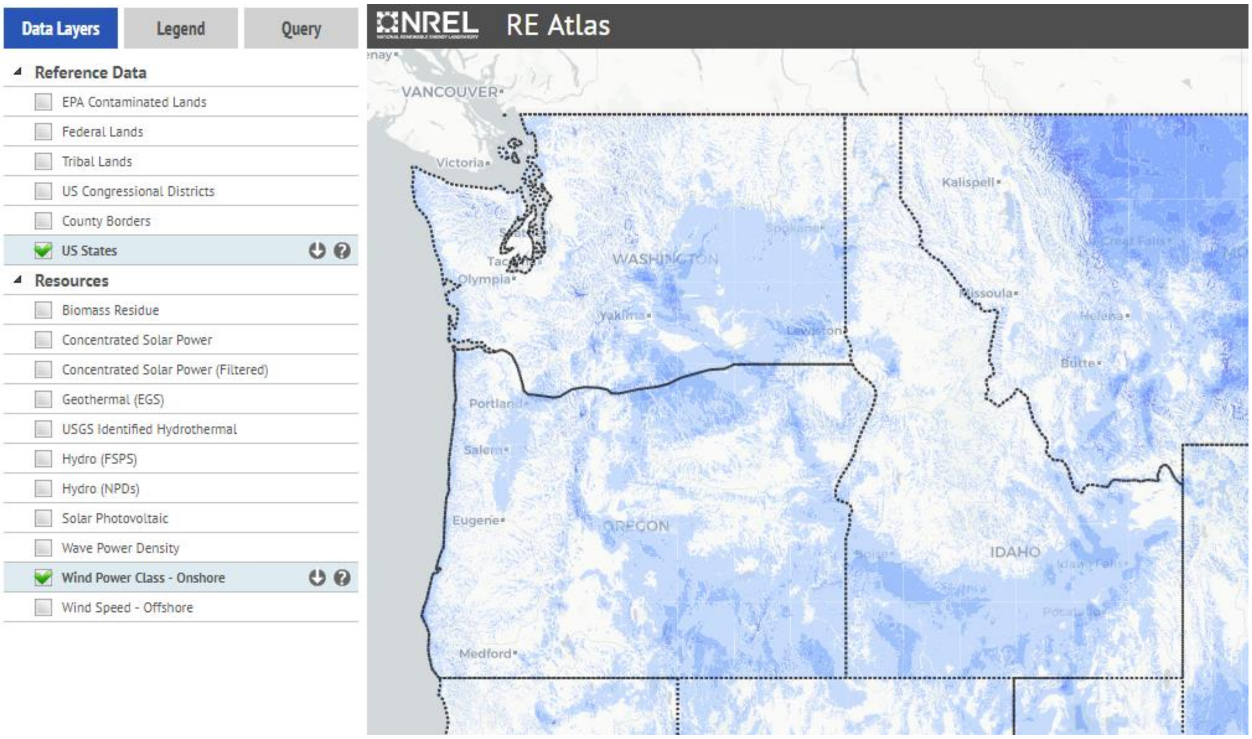

Figure 5 - Northwest wind power class - onshore [21]

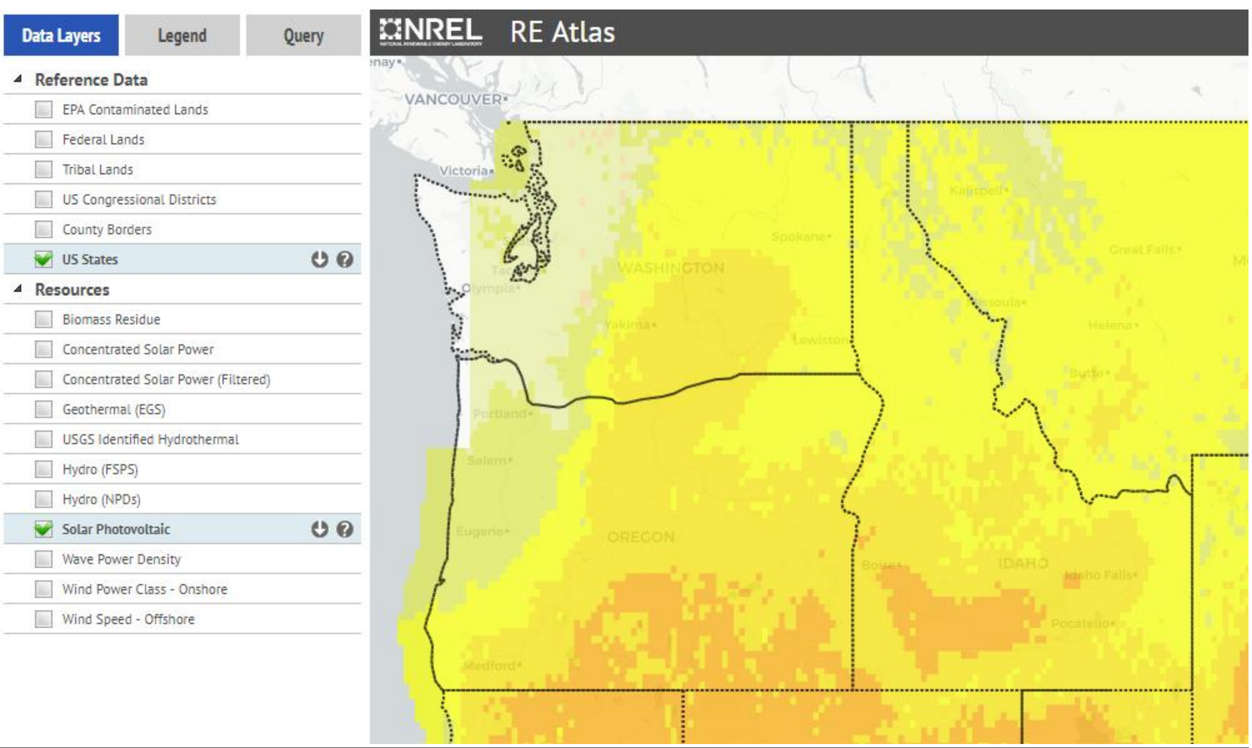

Figure 6 - Northwest solar photovoltaic [21]

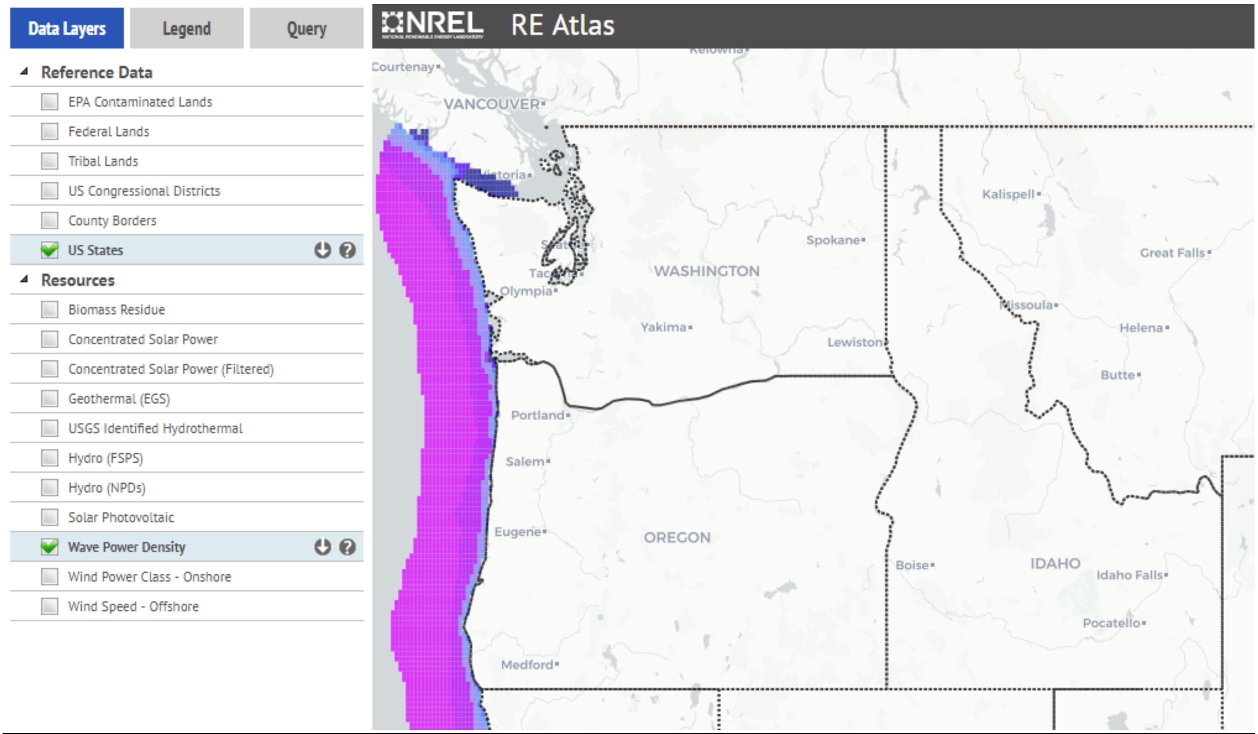

Figure 7 - Northwest wave power density [21]

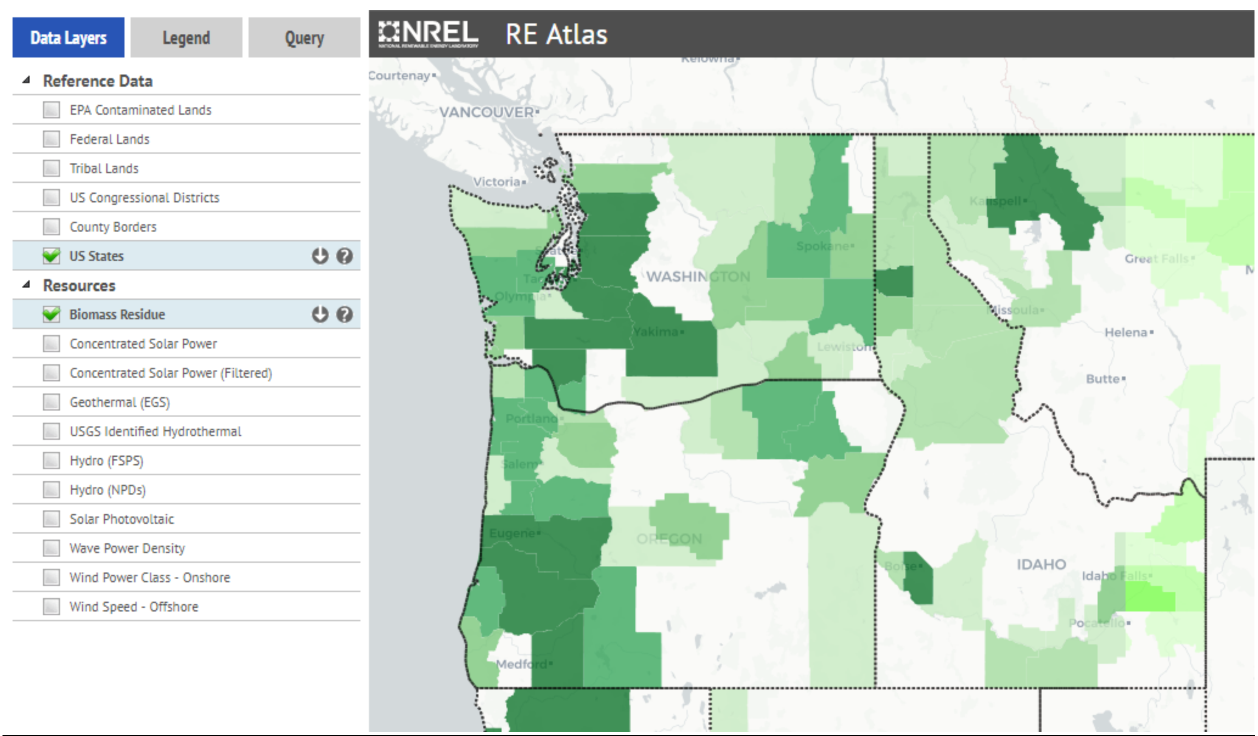

Figure 8 - Northwest biomass residue [21]

2.1.1 Oregon, Washington and Idaho overview:

Hydroelectric power dominates electricity generation in Oregon, which is the second-largest producer of hydroelectric power in the US after Washington. Hydro provides over half of the net electricity generated in Oregon, in some years approaching three-fourths of net generation. In 2015, 68% of Oregon's utility-scale generation came from conventional hydroelectric and other renewable resources, including a significant wind fleet in the Columbia River Gorge. Natural gas provides an increasing amount of generation in Oregon, over one-fourth of the net amount in 2015, and Mist is the only producing natural gas field in the Pacific Northwest. Although about one-third of Oregon's total electricity supply is generated at coal-fired power plants, most of that generation occurs out-of-state. Boardman, Oregon's only coal-fired power plant, provides less than 5% of Oregon's in-state net generation, and it is scheduled for retirement as a coal generation plant in 2021. Biomass is the most widely used source of renewable thermal energy, as forest covers almost half of the state, and many industrial facilities use woody biomass to provide heat and/or generate electricity. The geothermal potential is ranked third in the nation after Nevada and California, and there are no nuclear power plants in Oregon. Overall, Oregon's net electricity generation is greater than its consumption [17]. Large investor-owned utilities must ensure that the electricity sold to retail customers in-state be derived from eligible renewable energy resources according to the following schedule: 20% by 2020, 27% by 2025, 35% by 2030, 45% by 2035, 50% by 2040. By 2025 at least 8% of Oregon's aggregate electrical capacity must come from small-scale, community renewable energy projects with a capacity of 20 megawatts (MW) or less. The large utilities must also phase out coal generation imports, and pursue cost-effective energy efficiency and demand-response measures [22].

Washington leads the nation in electricity generation from renewable and hydroelectric resources, with 30% of US utility-scale hydroelectricity generation in 2015. More than three-fourths of the state's net electricity generation originates from renewable resources, predominantly hydro, and Washington produced more than one-seventh of the electricity generated nationwide from renewables in 2015. Hydroelectric power provides more than two-thirds of Washington's net electricity generation and nine-tenths of its renewable power generation, but non-hydro renewables, including significant wind generation, also provide almost one-tenth of the state's net electricity generation. The Grand Coulee Dam is the largest hydroelectric power producer in the United States, with a total generating capacity of 6,809 megawatts, and is the nation's largest electricity generating facility of any kind when measured by capacity. Washington's coal-fired power plant has two coal-fired units, but is scheduled to be decommissioned, one unit in 2020 and the other in 2025, moving towards a coal-free future. Conversion of the units to natural gas or construction of a new natural gas-fired power plant at the site is being considered. Washington's only nuclear power plant, the Columbia Generating Station at Hanford, has been in operation since 1984. The state RPS requires utilities with at least 25,000 retail customers to obtain 15% of their electricity from qualified new renewable resources by 2020 and to undertake cost-effective energy conservation. Overall, electric power generation in Washington exceeds the state's needs, and the state exports electricity to the Canadian power grid and U.S. markets in California and the Southwest [23].

Hydroelectric plants dominate Idaho's electricity generation, typically supplying between three-fifths and four-fifths of in-state net generation, except in recent years when drought has cut hydro's share to a little over half. The balance of Idaho's net electricity generation is supplied by natural gas, wind, biomass, geothermal, and coal generation. In 2015, 75% of Idaho’s utility-scale net electricity generation came from renewable energy resources. However, Idaho gets about one-third of the electricity consumed in the state from coal-fired power plants located in other states, including Boardman which is scheduled to close in 2020. The interstate transmission lines have grown increasingly congested, and projects are under way to expand capacity both to supply Idaho and to transport power from other mountain states to West Coast markets. Most new generating capacity planned in the region is natural gas-fired, but the transmission projects should also enable development of renewable resources. Idaho has good renewable energy potential with substantial hydropower, wind, geothermal, solar, and biomass resources. Wind developers typically sell their electricity to Idaho electricity retailers and sell their renewable energy certificates to electricity providers who are subject to RPS requirements in neighboring states. Geothermal development in Idaho may be limited by availability of groundwater, since utility-scale geothermal technology is water-intensive [24].

2.1.2 Characteristics of the Pacific Northwest:

Hydropower is one of the most efficient ways to generate electricity, with modern hydro turbines converting as much as 90% of the available energy into electricity. It has the lowest operating cost and the longest plant life compared with other large-scale generating options [14]. However, the operations of many hydroelectric generators are governed not only by electric system conditions, but also by factors such as flood control, navigation, and irrigation. The storage potential vs annual runoff is limited relative to other river systems (Figure 9), meaning careful management of the river is required to meet conflicting requirements. Capturing the full physical capability of the hydro system is difficult; rather than relying on the physical ratings and capabilities of the hydroelectric generators, a model from analysis of the historical operations of the hydro fleet can be used [16].

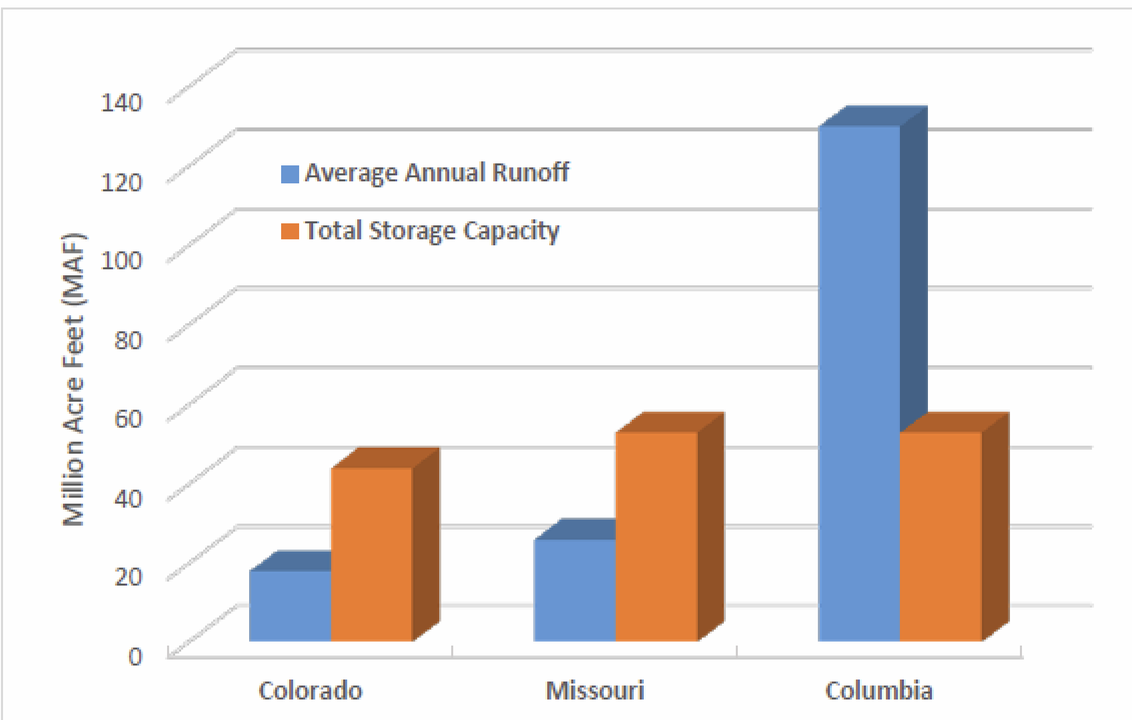

Figure 9 - Water storage on the Columbia River system [25]

The spring months (March through June) represent the most challenging period for renewable integration in the Northwest. This situation is unique in the Western Interconnection; oversupply in California and the Southwest is driven by the concentration of solar PV in the middle of the day, but oversupply in the Northwest is due to the combination of high hydroelectric output and wind generation during the spring runoff months, along with relatively low loads. This oversupply challenge in the Northwest is greater under higher renewable penetrations, leading to the potential for increased renewable curtailment, especially in the middle of the night (when loads are relatively low) and in the middle of the day (when the ability to export surplus power to other regions is limited by oversupply in neighboring regions) [16]. A graph illustrating this spring nighttime curtailment is shown in Figure 10.

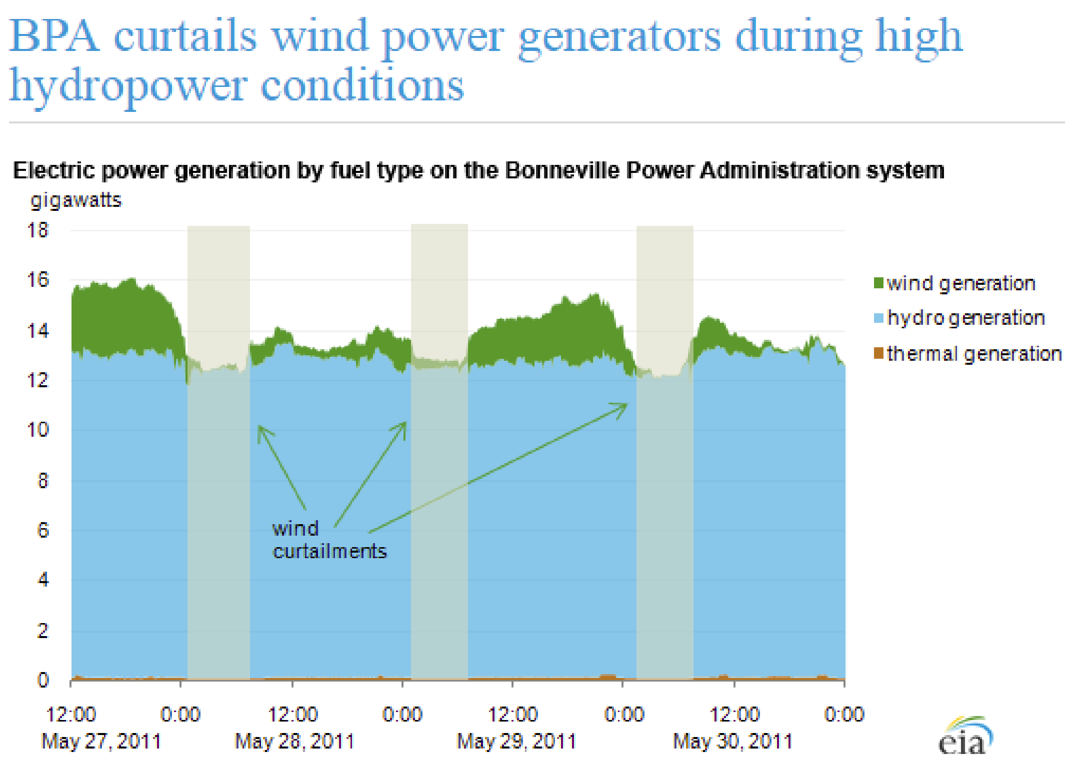

Figure 10 - Example of nighttime curtailment during spring runoff season. [26]

At the same time, the Northwest experiences many fewer hours with significant subhourly curtailment than other regions, as the hydroelectric system has the capability to provide a high degree of hour-to-hour flexibility, largely eliminating renewable integration challenges related to ramping and forecast error. In addition, the region's export capability allows it to export between 2,000 and 10,000 MW over the course of the day [16]. BPA has implemented two processes that curtail wind generation: Dispatch Standing Order (DSO) 216 and the Oversupply Management Protocol (OMP). BPA uses DSO 216 when planned amounts of balancing reserves are exhausted and OMP when hydropower generation creates oversupply. Historical curtailment has typically been less than 2% of wind production [3].

The transmission system in the PNW, as with most power grids, has capacity constraints which must be considered in locating additional generation or energy storage. Transmission congestion occurs when the throughput on a given transmission path exceeds the rated capability of that transmission path. Congestion can increase the cost of electricity supply, limit flexibility, and threaten instability. Reducing congestion caused by heavy load has traditionally been through additional generation close to load centers, additional transmission capacity in appropriate locations, and/or reducing load through energy efficiency or demand response. A comprehensive study of locating additional generation / energy storage would include detailed modeling, such as the PowerWorld model in [27]. This detailed modeling allowed the transmission system constraints to be included when identifying optimal locations for energy storage, demand response, or flexible industrial loads in the PNW. Sensitive buses were identified, concentrated in three geographic areas (Yakima, Ninemile, and Hopkins Ridge), Figure 11, and it was determined that withdrawing power has a greater impact on reducing congestion than injecting power at the critical buses [27].

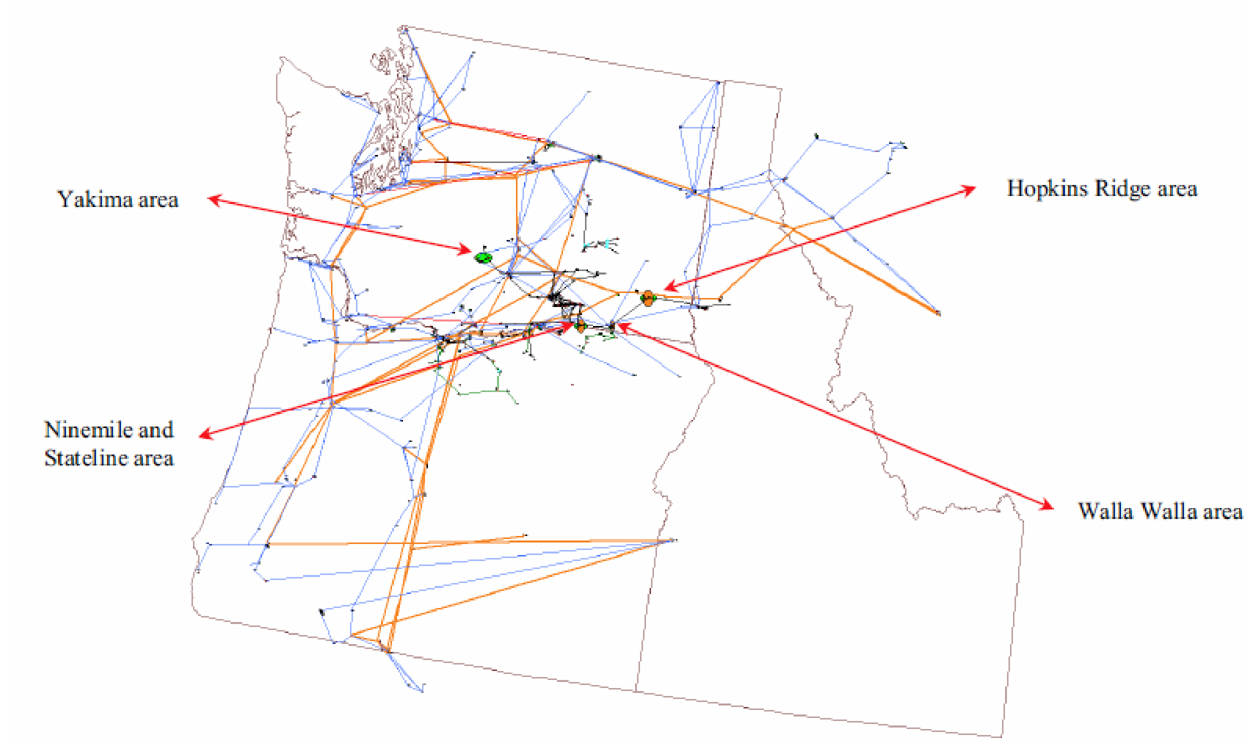

Figure 11 - Sensitive buses in the Northwest [27]

Overall, the factors influencing the PNW include seasonality and diurnal characteristics of load, generation and transmission capacity locations and limitations, power generation and load in adjoining balancing areas (with the resulting potential for energy trade), and RPS requirements, environmental laws and concerns, etc. With this complexity, simplifying assumptions were made in this study, specifically: the analysis assumed historical generation, load, and net interchange; and a copper sheet analysis (simplified resistive power grid, with all resistances set to zero).

3. TECHNICAL BACKGROUND

It is important to understand the characteristics of renewable energy sources, the importance of forecasting to reliable integration of these sources, the characteristics of demand response and various types of energy storage, and the possible methods of modeling the addition of these renewable sources into the grid. This section provides a general overview of these topics, and a framework for understanding the modeling method, constraints and assumptions of this study.

3.1 Renewable sources:

Renewable energy sources are continually replenished by nature and derived directly from the sun (thermal, photo-chemical, and photo-electric), indirectly from the sun (wind, hydropower, and photosynthetic energy in biomass), or from other natural movements and mechanisms such as geothermal and tidal energy [28]. Due to the geography and climate of the Pacific Northwest, this study includes onshore wind, solar PV, wave energy and biomass. Offshore wind is excluded due to the presence of significant onshore wind resource availability, combined with the additional cost and difficulties of offshore relative to onshore wind. Concentrating solar is excluded as it is better suited to the desert Southwest; with limited potential locations and relative predictability, tidal energy and geothermal are excluded as well.

Solar, wind, and wave sources are all variable and non-dispatchable. Two major factors determine the possibilities for integration of these sources into existing power systems: the variability of the output from renewable power plants, and the accuracy of forecasts for the variable generation [29]. There is an inherent correlation between weather conditions, wind/solar generation, and electric load in a power system [10]. Therefore, the ideal renewable portfolio will vary depending on the geographic area of interest. Utility scale renewable energy is considered to be 10 MW or larger [30].

3.1.1 Wind:

Wind power varies on time scales from sub-seconds to decades, with many geographic areas having significant seasonality in wind speed. In addition, some sites have diurnal patterns of wind speed (depending on the season), while others have a relatively flat profile throughout the day. An important characteristic of wind power is its geographic diversity; the capacity value increases with larger region sizes, as these larger areas decrease the number of hours with low wind output [8].

The power curve of a wind turbine is characterized by four regions defined by three wind speed limits, cut-in, rated and cut-out wind speeds. Due to the non-linear shape of this power curve, variability in wind speed can have different effects on the power output variability; in the steep part of the power curve small changes in wind speed have large impact, but above rated and below cutout wind speed the electric power is constant [29].

The conversion from wind speed to wind power is shown in equation 1

$$P = \frac{1}{2} * \rho * A * C_p(\lambda, \beta) * v^3 \quad (1)$$

where ρ is the air density, A is the area of the turbine when rotating, $C_p(\lambda,\beta)$ is the efficiency which is affected by two parameters: tip speed ratio λ and blade pitch β, and v is the up-wind speed. $C_p(\lambda,\beta)$ can also be replaced with a power curve, based on hardware characterization testing, supplied by the manufacturer (Figure 12).

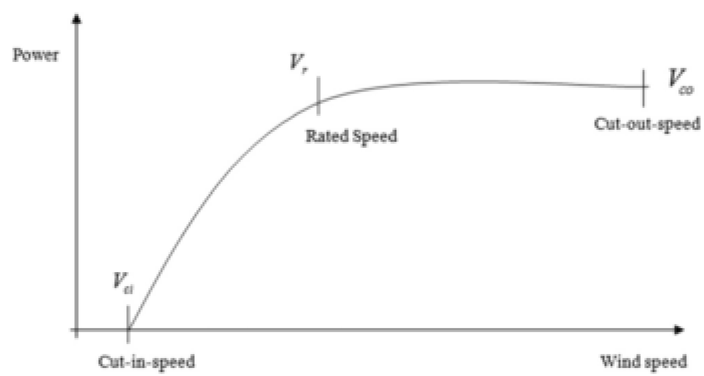

Figure 12 – Example power curve supplied by wind turbine manufacturer [31]

If the wind turbine is placed in a wind farm, wake effects should also be considered. Wind power forecasting and wind speed forecasting are considered equivalent if a proper wind speed to wind power conversion is used [31], as the use of manufacturer power curves does not guarantee accurate conversion [32]. Turbine specifications play a significant role in wind power economics by impacting the capacity factor. The rated speed has been found to be the most influential factor followed by cut in and cut out speeds respectively [33].

The Department of Energy defines utility-scale wind projects—both land-based and offshore—as turbines larger than 1 megawatt [34] Examples of widely used turbines are the GE 1.5 MW model and the 1.8 MW Vestas V90. For land use, an approximate industry rule of thumb is 5 MW/km^2 [35]. In addition to onshore wind, the US DOE is pursuing a plan to deploy 10 GW of offshore wind capacity by 2020, and 54 GW by 2030. Offshore Wind Initiation and Demonstration (OSWIND) is an initiative to promote and accelerate commercial off shore wind development in the US [36].

3.1.2 Solar:

Extraterrestrial radiation is the intensity of the sun at the top of the atmosphere and can be calculated using solar geometry for the region. It varies throughout the year because of the earth's elliptical orbit, which results in a predictable earth-sun varying distance. Hourly extraterrestrial global solar radiation can be calculated using the Measurement and Instrumentation Data Center (MIDC) Solar Position and Intensity (SOLPOS) calculator available from the NREL website [37]. The path length of radiation through the atmosphere at a given site and time determines how much energy passes through; since air mass varies depending on the sun's position in the sky, the radiation available after passing through the atmosphere will also vary with time of day and year [29].

The extraterrestrial beam radiation can be divided into two distinct components – direct normal irradiance (DNI) and diffuse horizontal irradiance (DHI). The geometric sum of these is the global horizontal irradiance (GHI) which is shown in equation 2

$$GHI = DHI + DNI * \cos\theta \qquad 2$$

where θ is the solar zenith angle [38]. The distinction between the direct component (sunlight that has not been scattered by the atmosphere) and the diffuse component (sunlight that has been scattered by the atmosphere) is important because only the direct solar component can be focused effectively by mirrors or lenses. Technologies that concentrate solar intensity (CSP and concentrating PV) perform best in arid regions with high DNI. Solar technologies that do not concentrate sunlight (most PV and passive solar heating) can use both the direct and diffuse components and are suitable for use in a wider range of locations and conditions than concentrating technologies [35].

The direct component typically accounts for 60%–80% of surface solar insolation in clear-sky conditions and decreases with increasing relative humidity, cloud cover, and atmospheric aerosols [35], with the most important factor being cloud cover [38]. The clearness index (k) is the ratio of GHI to the extraterrestrial radiation at a certain time, and quantifies the amount of cloud cover [37]. The absolute level of cloud impact is lower near sunrise or sunset, although the relative variation may be much larger [39]. When the clearness index is multiplied by the top of atmosphere GHI to convert back to the GHI at the surface, it inherently corrects for changes in solar elevation with time [40].

For PV systems, the peak power is for standard test conditions (STC), a fixed irradiance level of 1000 W/m^2. However, this is not a good measure when evaluating forecast error relative to the maximum output, as it does not consider the daily and seasonal variations that put an upper limit on the power generation. PV systems have additional time-varying factors that affect the power output; the conversion efficiency is dependent on the cell temperature, which is in turn determined by absorbed radiation, ambient temperature, wind speed and mounting [29].

The solar resource available to PV is greatest in the southwestern United States, but the solar resource is generally high in all U.S. states except for Alaska and coastal regions in the Pacific Northwest [35]. However, the timing of the peak demand in the Northwest (during the evening in the winter) results in very low ELCC values for solar resources [16]. The land use requirement for large scale (> 20 MW) fixed panel PV projects is estimated to be 7.5 acres per MWac [41].

In distributed solar, small PV systems generate electricity for on-site use, and interconnect at low-voltage points of the grid, typically 600 v and below [42]. Typical sizes are 1 to 4 kW for residential systems, and 10 kW to several MW for rooftops on public and industrial buildings [28]. Distributed PV can reduce transmission and distribution line losses, increase grid resilience, lower generation costs, and reduce requirements to invest in new utility generation capacity [42].

3.1.3 Wave:

The most energetic areas for wave power are located between 40° and 60° latitude in both hemispheres [29] and on deep water (> 40m), reaching power densities of 60 - 70 kW/m [43]. Data on wave height and period is available for many buoy sites from the National Data Buoy Center, operated by NOAA [44]. This information can be used to calculate the wave energy flux, E_{Ft}, as shown in equation 3

$$E_{Ft} = \left(\frac{g^2 * \rho}{64 * \pi}\right) * H_{St}^2 * T_{Mt} \qquad 3$$

where g is the acceleration caused by gravity (9.8086 m/s^2), ρ is the density of seawater (1025 kg/m^3), H_{St} is the significant wave height in meters, and T_{Mt} is the mean wave period in seconds [45]. Equation 3 can then able to be simplified to equation 4.

$$E_{Ft} \approx 0.491 * H_{St}^2 * T_{Mt} \qquad 4$$

Recent tools for obtaining more representative wave data include combining buoy measurements with deep water numerical models, and incorporating radar measurements to model wave generation and propagation [46].

In general, the variability of wave power on a short time scale is not as large as for solar and wind, but the seasonal variability can be great [46]. Wave buoy data can show significant local noise, but the variance is significantly reduced when multiple Wave Energy Converters (WECs) are located in the same area. Both the wave height and wave period show significant seasonality, as can be seen in Figure 13.

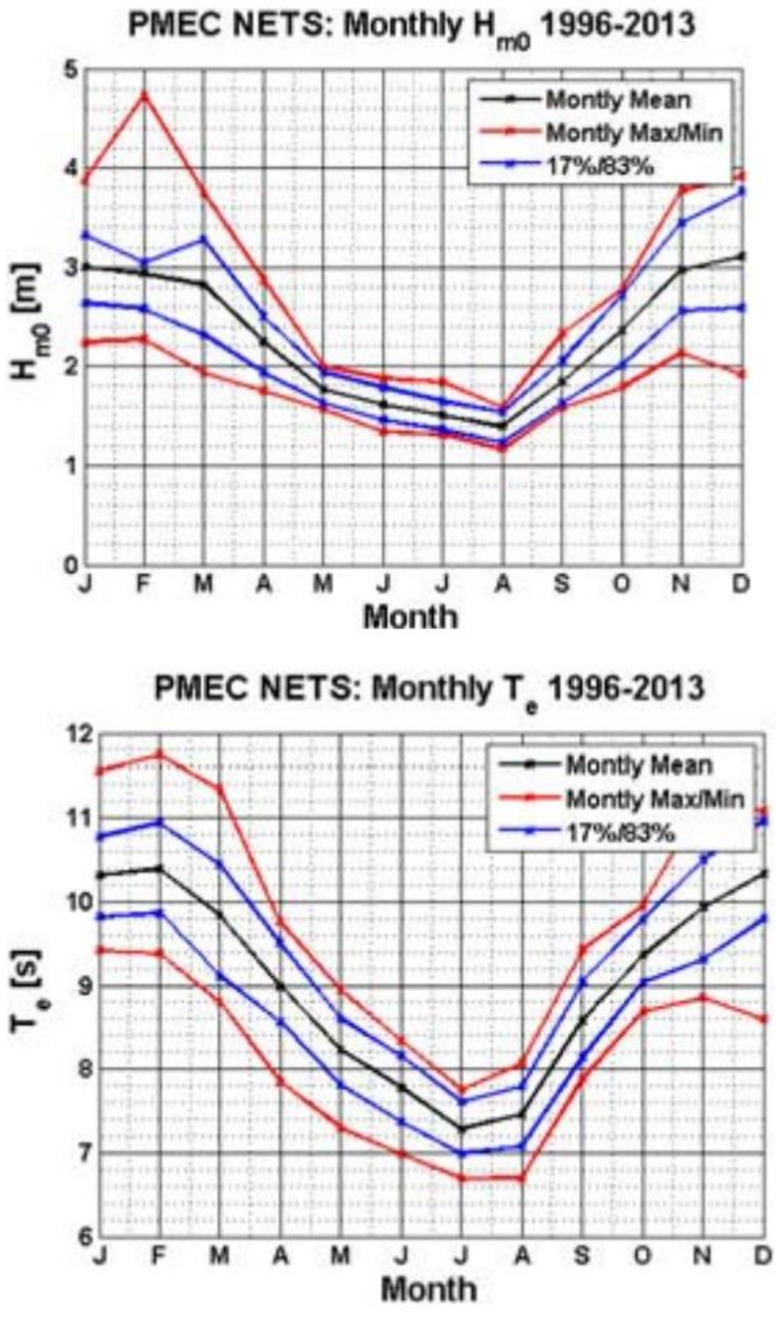

Figure 13 - Top: Wave height variability by month. Bottom: Wave period variability by month. [47]

There is no industry standard technology for wave energy converters. Oscillating water columns have a semi-submerged chamber, keeping a trapped air pocket above a column of water. Waves cause the column to act like a piston, generating a reversing stream of high-velocity air which is channeled through a turbine-generator to produce electricity. Oscillating bodies harness the wave energy through a floater or a buoy with a heave, roll or pitch motion. In general, they are more complex than oscillating water columns, especially the power takeoff system. Overtopping devices are either offshore floating or shoreline fixed water reservoirs, usually with reflecting arms to focus the wave energy. The waves overtop a ramp structure and are restrained in the reservoir, then the potential energy of the collected water above the sea surface is transformed into electricity using conventional low head hydro turbines [43]. A good visual overview is given in Figure 14.

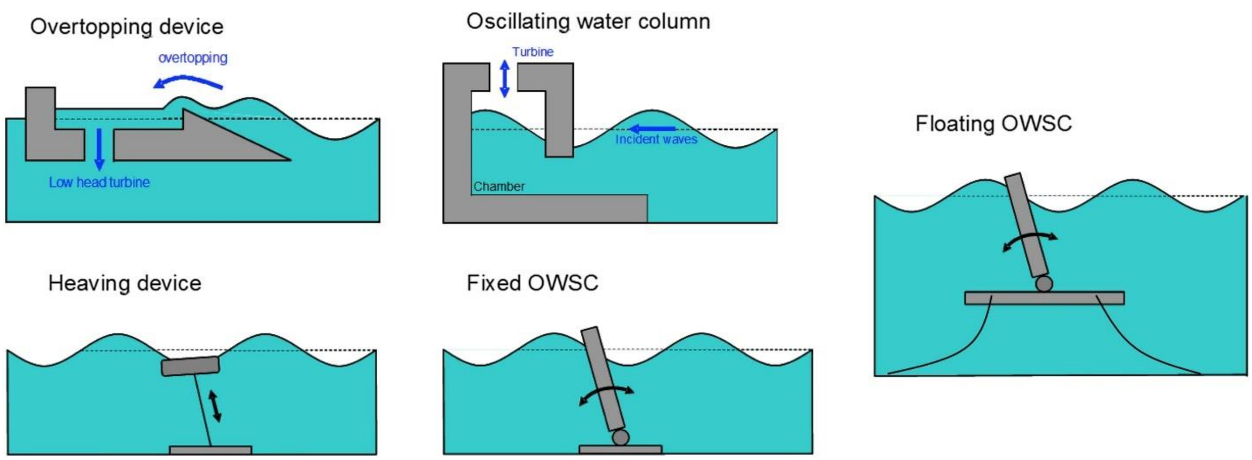

Figure 14 – Overview of different WECs [48]

There are many potential difficulties with harnessing and integrating wave energy. WECs will occasionally face extreme wave conditions; even though this is likely to be infrequent, the extreme waves could harm the structural integrity of the WEC or mooring system. Large storm waves are more likely in areas with high wave energy density, the same areas that are preferred for WEC installations. Design tradeoffs occur in these areas, as designing for better survivability usually reduces the device performance [49]. Two other common issues are corrosion and bio-fouling [46]. Areas with energetic waves also have significant biological activity, so the best sites for wave energy will also include the risk of biofouling. Using antifouling paints on WECs is considered impractical, especially on devices fixed into position, as even the more expensive paint techniques have a maximum lifetime of 3 - 5 years. The impact on WECs (and their associated systems) of wave loads, corrosion and biofouling will likely require maintenance intervals significantly shorter than for similar on-shore technologies. Performing maintenance at sea is both expensive and risky. In addition, deployment and maintenance activities require sufficient time when the weather and sea state are relatively calm, potentially reducing the capacity factor and capacity value of the installation [49].

Capital costs for wave devices include the WEC structure, power takeoff system, mooring system, installation and electrical connection [48]. The installation requirements and costs will significantly depend on the location. Mooring devices with drag-anchors is often feasible and economical, but the sea-bed may require more expensive mooring methods. A subsea electrical system and a submarine cable connection to shore will also be needed. Areas with great wave energy potential are often in regions with low population density, which means an expansion of existing transmission may be required [46].The current costs are quite high in comparison with conventional generation, and even when compared with other renewable technologies. However, the technology is immature, and other renewable energy technology costs started out as high when research was first initiated in the 1970s and 1980s. It is important to remember that innovative concepts tend to be most successful during the early stages of development, when the cost of innovation is minimal and change involves little additional risk [35].

The DOE has designated three National Marine Renewable Energy Centers to perform testing of MHK devices. These centers are the Northwest National Marine Renewable Energy Center (wave and tidal energy development), National Marine Renewable Energy Center of Hawaii (commercial wave energy systems and ocean thermal energy conversion systems), and the Southeastern National Marine Renewable Energy Center (ocean current systems, ocean thermal energy conversion systems, and ocean water-cooling systems research) [35].

3.1.4 Biomass:

Biomass is organic material from plants, trees and crops, and is essentially the collection and storage of the sun's energy through photosynthesis; this biomass can then be converted into useful forms of energy such as heat, electricity and liquid biofuels [28]. A key feature of biomass is that it can be transported, with the energy stored in the biomass until it is needed. It is clean, domestic, and dispatchable, and is also carbon-neutral (biomass absorbs carbon dioxide from the atmosphere during growth, then emits an equal amount when processed) [50]. Biopower resources can be classified into five categories: urban wood wastes, mill residues, forest residues, agricultural residues, and dedicated energy crops [35]. The forest products industry has used biomass for power and heat for decades. After hydropower, biopower provides a larger share of the world's electricity than any other renewable energy resource [51].

Perennial energy crops (grasses and trees) have lower environmental impacts than conventional farm crops, requiring less fertilizer and herbicide [50]. Two commonly discussed energy crops with growth potential in the Northwest are switchgrass and miscanthus, warm-season perennial grasses [21]. Switchgrass seed can be planted with standard equipment, while miscanthus rhizomes are best planted with a specialized planter. Switchgrass has the yield potential of 4 – 6 tons per acre, with an average stand life of 10 – 15 years, and, if necessary, can be used as a forage crop as an alternative to sale as fuel. Miscanthus has a higher potential yield of 12 – 15 tons per acre, with stands lasting up to 25 years, but it is a dedicated energy crop and has very little value for other uses [52]. A dry ton of biomass typically yields about 1 MWh of electricity [53]. Since energy crops need transportation to generating facilities, one study assumed a maximum 50 mile potential supply radius around a biopower plant [54].

Biomass can be torrefied at temperatures below 300°C, resulting in mild pyrolysis. This torrefaction is an energy densification process, producing a material with much of the free water removed, with 70% by mass of the original biomass and 90% of the original energy content (about 1.3 times the energy density of the original biomass) [35]. Torrefied biomass is a dry, brittle material that can easily be pulverized and burned, either co-fired at a coal generating facility, or with minimal modifications required to retrofit a coal generation plant to a biomass plant. Portland General Electric is currently evaluating the conversion of the Boardman coal plant to biomass, and will need as much as 8,000 tons of biomass fuel per day; PGE has also stated that a Boardman biomass plant could be operated on a seasonal basis as necessary [55] [56].

There are four general classes of biopower systems: direct-fired, co-fired, gasification, and modular systems. Direct-fired systems are most common, and are similar to fossil-fuel thermal generation plants utilizing steam turbines. Thermal generation technology is dependable and proven, but its efficiency is limited. Biomass power boilers are typically in the 20–50 MW range, and these small capacity plants tend to be lower in efficiency (18% - 33%), as efficiency-enhancing equipment is not cost-effective. Co-firing involves substituting biomass for a portion of coal in an existing power plant, with some modification of the equipment, allowing the energy in biomass to be converted to electricity with the higher efficiency (33%–37%) of coal plants. Biomass gasifiers heat biomass in an environment where the solid biomass breaks down to form a flammable gas. This biogas can be cleaned and filtered, and the gas used in more efficient combined-cycles, with the efficiency of these systems reaching 60%. Modular systems employ the same technologies on a smaller scale, and could be most useful in remote areas with abundant biomass and limited electricity [57]. Co-generation power plants allow use of the heat produced in biomass power generation, and can significantly increase the overall efficiency of a power plant (to 80 - 90%) if a good match exists between heat production and demand [14].

The collection and transportation of biomass fuels can be expensive, and the price paid for electricity seldom offsets the full cost of the biomass fuel [28]. Therefore, if selling electricity at market price is the only revenue for a biopower plant, it may be difficult to support the establishment of biopower [54]. The U.S. DOE established the Biopower Program to integrate sustainable farms and forests with efficient biomass power production to provide significant, cost-competitive power. The goals of the program include developing and producing environmentally acceptable energy crops, commercializing high-efficiency biomass power conversion technologies, using biomass resources to provide electricity at high environmental standards, enhancing public understanding, and supporting the establishment of biomass power as a credible and attractive option [50]. The DOE's Bioenergy Knowledge Discovery Framework (DOE-KDF) database is a source of information regarding biomass supply on a county by county basis for the contiguous United States [54].

Landfill gas (LFG) is a natural byproduct of the decomposition of organic material in anaerobic conditions. Landfill waste decomposes in four phases; the gas composition changes with each phase and waste in a landfill may be undergoing several phases of decomposition at once. First, aerobic bacteria consume oxygen while breaking down the long molecular chains of complex carbohydrates, proteins, and lipids. The primary byproduct of this process is carbon dioxide, and this phase continues until available oxygen is depleted. Next, in an anaerobic process, bacteria convert compounds created by aerobic bacteria into acetic, lactic and formic acids and alcohols such as methanol and ethanol. As the acids mix with the moisture present in the landfill and nitrogen is consumed, carbon dioxide and hydrogen are produced. Third, anaerobic bacteria consume the organic acids and form acetate. The landfill becomes a more neutral environment in which methane-producing bacteria are established by consuming the carbon dioxide and acetate. Finally, the composition and production rate of LFG remains relatively constant for about 20 years. LFG usually contains approximately 50-55% methane by volume, 45-50% carbon dioxide, and 2-5% other gases, such as sulfides. Methane is a potent heat-trapping gas (more than 20 times stronger than carbon dioxide) and has a short atmospheric life (10 to 14 years) [58].

The most common method of LFG collection involves drilling vertical wells in the waste and connecting the wellheads to lateral piping that transports the gas to a collection header. Another type of collection system uses horizontal piping laid in trenches in the waste; the design chosen depends on site-specific conditions [58]. Using the LFG usually requires some treatment to remove excess moisture, particulates and other impurities, with the treatment requirements depending on the end use of the LFG. The most common applications include direct use of medium-Btu gas (treated LFG as a direct source of fuel), electricity (power production and cogeneration), and upgrade to vehicle fuel or pipeline-quality gas (the equivalent of natural gas, CNG or LNG). Minimal treatment is required for direct use in boilers, furnaces or kilns. Treatment for electricity generation typically includes a series of filters to remove contaminants that could damage the engine or turbine. Advanced treatment is required to produce high-Btu gas for injection into natural gas pipelines or production of alternative fuels. The treatment systems can be categorized as primary and secondary treatment processing. Primary processing systems include de-watering and filtration to remove moisture and particulates. Secondary treatment systems provide much greater gas cleaning, and may employ both physical and chemical treatments [59].

The internal combustion engine is the most commonly used conversion technology in LFG applications because of its relatively low cost, high efficiency and engine sizes that match the gas output of many landfills (where gas quantity is capable of producing 800 kW to 3 MW, or where flow rates to the engines are approximately 300 to 1,100 cfm at 50 percent methane). Internal combustion engines are efficient at converting LFG into electricity, with electrical efficiencies in the range of 30 to 40 percent. Even greater efficiencies are achieved in CHP applications where waste heat is recovered from the engine cooling system to make hot water, or from the engine exhaust to make low-pressure steam. Combined cycle applications combine a gas turbine with a steam turbine, so that the gas turbine combusts the LFG and the steam turbine uses the steam generated from the gas turbine's exhaust to create electricity. Gas turbines are typically used where the LFG flow is greater than 1,300 cfm and is sufficient to generate a minimum of 3 MW. They have significant economies of scale, but require high gas compression, with more of the plant's power required to run the compression system. LFG is converted into a high-Btu gas by increasing its methane content (reducing its carbon dioxide, nitrogen and oxygen content). Four methods have been commercially employed to remove carbon dioxide from LFG - water scrubbing, amine scrubbing, molecular sieve, and membrane separation. After purification, the gas can be directly injected into a natural gas pipeline [59].

There are over 600 LFG energy projects operating in the US. About three-quarters of the projects generate electricity, while the rest are direct-use projects where the LFG is used for its thermal capacity. The projects are estimated to generate 16 billion kWh of electricity and supply 100 billion cubic feet of LFG to direct end users and natural gas pipelines annually [58].

3.2 Forecasting:

Forecasting is an extremely important tool for integrating VRE sources into the power grid. Significant research efforts have been (and continue to be) made to improve the accuracy of forecasting both the meteorological factors and the resulting power output of variable renewable generation. A brief summary is presented in this section, showing the wide scope of these research efforts and their importance to the reliable integration of variable renewables. Since this study utilizes four years of historical time-series data, it was decided to focus on the modeled impact of the 100% renewable portfolios based on this historical data, excluding the impact of any forecasting methods.

The primary objectives of forecasting are assurance of reliability while minimizing operating costs, as forecasting impacts decisions related to scheduling, dispatch, real-time balancing and reserve requirements [60]. Forecasting allows grid operators to prepare for extremes and ramps in VRE production, plus schedule and dispatch generating plants more efficiently; in the day ahead timeframe, forecasting informs choices relative to hydro reserves, natural gas purchases, and transmission congestion. It also allows operators to maintain fewer reserves than would be needed without forecasting [13]. Complications include the increasing interaction between the transmission and distribution systems with roof-top solar, demand response strategies, electric vehicles, more affordable storage, and multi-megawatt power plants on distribution feeders [61].

Although definitions vary, short-term scheduling may be viewed as hour-ahead, medium-term as day-ahead, and long-term as multiple-day-ahead. Shorter scheduling intervals and updating forecasts throughout a day improve forecast accuracy, because forecast errors decrease closer to the time at which generation is dispatched to meet load [13]. The accuracy of forecasts is impacted by the variability of the sources, as smoother production is usually easier to predict [29]. Also, different forecasting methods are preferred for different temporal and spatial resolutions.

Forecasting methods fall into two general categories. Physical methods input weather data, usually from public agencies such as NOAA, into models which create a time series of energy production [60]. For the best accuracy, specific knowledge of the facility output relative to the atmospheric conditions is required [62]. OEs usually supplement NWP forecasts by gathering local weather observations, and may also develop statistical models to account for variations due to local terrain [13]. Inputs to NWP models could include data on wind fields, temperature, humidity, pressure and insulation, but as models become more site specific, inputs could be added such as aerosols, obstacles and ground roughness [29].

Statistical models apply statistical methods on existing time series of the resource, and do not involve any physical modeling. One advantage of statistical modeling is the ability to generate long time series. Hybrids of physical and statistical models are common, especially in commercial forecasting software for wind, solar or wave energy [29]. Three widely used metrics of forecast error are MBE, MAE and RMSE [60], however a wide variety of factors are of interest to companies, including bias, ability to use a forecast during all weather conditions, and performance during extreme weather [13].

Persistence forecasting is a simple statistical method that assumes current generation levels will remain unchanged in the very near future; persistence forecasts are often used as a benchmark to evaluate more advanced methods [60]. It is commonly agreed that persistence forecasts are very accurate in brief time periods, especially for wind power. In a survey of operating entities, the view was that nothing beats a persistence forecast in the 0- to 45-minute timeframe [13]. However, persistence for wind is accurate for a wider range than for solar [29], and it is not recommended to use a persistence model when the forecast time horizon is more than a few hours [32]. With longer time scales, statistical methods work best up to 6 hours ahead, while physical models are generally preferred for longer time horizons and lower spatial resolutions [29].

In learning algorithms, a model is trained on a dataset and learns how to generate an output from a given input dataset. Sophisticated learning techniques include artificial neural networks (ANN) and wavelet neural networks (WNN). ANN is widely used for wind speed and power forecasts. It consists of an input layer, one or more hidden layers, and an output layer. Each layer has a number of artificial neurons, and it uses a connectionist approach to connect the neurons to the neurons of the previous layer; it is able to model the complex non-linear relationship between the input and output layers through a training and learning process. It does not require explicit mathematical expressions, and has the abilities of self-learning, self-organizing and self-adaptation [32]. WNN analysis is based on wavelets (wave forms that are irregular and asymmetric) and separates a signal into shifted and scaled versions of the original wavelet; the function is used for both wavelet decomposition and composition transform [29].

The Fuzzy logic approach may also be employed when the system is difficult to model accurately but an inexact model is available, because it allows use of approximate values and incomplete or ambiguous data. The Fuzzy logic approach alone has weak learning ability, so a combination of ANN and Fuzzy may be used. ANN performs well in low-level computation with raw data, while Fuzzy logic performs well with human-like reasoning in high-level computation; the combination of the two approaches may compensate for the weaknesses of each [32]. However, the conclusion of one study was that “traditional” forecasting approaches have outperformed neural networks in VRE forecasting, as the neural networks tend to require large training sets to perform well under even the best conditions [13].

In practice, centralized VRE forecasting is widely considered a best approach for economic dispatch; these are system-wide forecasts administered by the OE or BA for all VRE generators within the balancing area. In contrast, decentralized VRE forecasting is administered by individual plant operators, and provides plant-level information to help inform system operators of potential problems such as transmission congestion. A common way to improve centralized forecasts is through the use of ensemble forecasting, where the results from different forecast providers or methods are combined and aggregated [60]. Comparison of differently calibrated NWP models, or slightly varying the initial conditions, can identify the expected spread of weather conditions and determine the probability of extreme weather events. The result can be a best-guess forecast based on the ensemble, plus an estimation of the reliability. When different forecasts within the ensemble vary widely, the forecast has a high uncertainty; when there is closer agreement, the uncertainty in the prediction is less. Commercial forecasting systems are offered by companies who work closely with the electric utility to tailor their service to the specific challenges based on the region of the country, the amount of current/projected VRE, and the business environment [62]. A recent survey shows there has been a shift away from viewing forecasting as a cost-benefit decision, to viewing it as a basic necessity to meet reliability requirements and schedule resources efficiently. Although operators consider cost, accuracy and function when evaluating forecasting systems, cost is not always correlated with quality. An estimated cost of $300 - 400 per month per plant is normal for forecasting fees, and the internal costs associated with changing VG forecasters can be significant [13].

Although many studies have been completed comparing different forecasting methods, it is very difficult to draw strong detailed conclusions as to the best methods. There are often differences in approach and presentation of results [29], and site dependency may influence the model results [32]. Also, the data available for use is limited - more and better data is a need universally cited by VRE forecasters [62]. Overall, for solar, wind and wave, the forecasting skill for statistical models is higher than for physical models for the short time horizons and lower for long term horizons [29].

Many efforts have been made, and continue to be made, to improve the ability to forecast VRE. In 2012, NOAA commissioned a new NWP model, the High Resolution Rapid Refresh (HRRR) model. It has improved spatial resolution and improved data from additional sources of observation, executed every hour and generating a forecast for the next 15 hours [62]. This includes various solar energy related parameters, such as outgoing longwave radiation and incoming shortwave radiation, as well as direct and diffuse irradiance [39]. DOE, in partnership with NOAA, has funded two major studies to advance renewable energy forecasting capabilities. The Wind Forecasting Improvement Project (WFIP) and the Improving the Accuracy of Solar Forecasting Project are intended to enhance NWP physics, data assimilation, model grid resolution, and output parameters to benefit VRE applications. The WFIP will provide additional meteorological data at commercial wind turbine hub heights for use in NOAA forecast models, evaluate impacts of the HRRR model on short-term wind speed and power forecasts, and quantify the economic benefits of improved forecasting on power system operations [61]. The goal of the Improving the Accuracy of Solar Forecasting project is to achieve significant advances in solar irradiance and power forecasting. These will include a new rapid update Weather Research and Forecasting Solar (WRF-Solar) model, improved radiative transfer, cloud and aerosol physics, incorporation of enhanced NOAA satellite imagery, and a big data driven machine learning multiscale forecasting platform, plus wide dissemination of the results [61].

3.2.1 Wind forecasting:

Wind speed physical forecasting methods require significant data, including wind speed and direction, temperature, barometric pressure, turbine location (latitude and longitude), turbine power output, turbine availability, turbine outages, and the wind turbine power curve. There is value in gathering data from both meteorological towers and plant-mounted sensors [13]. This data is input to a model which predicts wind speed at hub height, including the impact of local terrain and plant layout; the wind power output then can be calculated, followed by any regional or aggregated forecasts. The forecast error for different wind plants can vary significantly depending on the terrain complexity, which impacts the spatial variability of the wind speed. The physical forecasting approach does not require any training input from historical data, however acquiring the required physical data may be a drawback [32]. In practice, many OEs receive all the data they need from generators through contract-based requirements [13].

The statistical approach represents the relation between variables, such as NWPs and measured data, with wind speed or power. There are four main steps: identifying the model to be used, data input and estimating with the model, model diagnostics and verification, and forecasting [32]. The most popular statistical models for wind power forecasts identified by one source are autoregressive and Markov chain Monte Carlo methods [29]. Another source identifies autoregressive, moving average, autoregressive moving average and autoregressive integrated moving average models as useful models. Statistical approaches provide good results in short-, medium-, and long-term forecasting. However, in the very-short-term and short-term horizons, the influence of atmospheric dynamics becomes more important, and the use of physical approaches may become more important. It is difficult to draw conclusions as to which model is best because each one has significant site dependencies [32].

At a practical level, since wind power is relatively constant over a period of up to 10 – 15 minutes, especially when the output of multiple turbines are aggregated, a persistence forecast at any point will have a small error relative to the overall generation of the system [61]. In fact, persistence usually performs better than NWP methods for short-term prediction horizons of up to about 3 – 6 hours at a local level [64]. One study determined that within the next 10 minutes or less, the error of wind persistence forecasts is similar to load forecast error [13].

Spatial correlation forecasting may be used to characterize the wind resource at a site where sufficient information is not available, but where a neighboring measuring station is available [32]. An approach called upscaling may also be used create a forecast for a region when predicting the power output from each individual wind farm is too time consuming. The wind power output from a sample number of wind farms forms the basis for the region, and this upscaling may reduce apparent forecast error because it becomes averaged over the entire region. In contrast, downscaling involves creating detailed spatial information from course NWP outputs using either physical or statistical models [64].

Both meteorological models and scaled up real power data run the risk of overestimating the variability, due to an underestimated spatial smoothing effect. Scaled up data may overestimate the variability if too few sites are used, while modeled wind power may be too variable if the meteorological model overestimates the correlation between grid points [29]. Under-forecasting wind does not pose as much of a risk to system stability as over-forecasting it, since greater than forecast wind can be managed by curtailing plants (although curtailment reduces the economic competitiveness of wind plants) [65]. Wind generation forecasting has advanced to the point where the emphasis may shift from raw accuracy metrics towards applications that integrate the forecasts with energy management systems [62].

Both low wind height wind measurement data and output data from many global models are available in public databases [29]. Synthetic data sets, based largely on observations, are available for wind energy integration studies [66].

Off-shore wind farms have more challenging forecasting than on-shore plants, as the sea surface is relatively flat with very few obstacles. This means that changes in wind speed and thermal effects as weather fronts pass over have more impact than on land [64].

In the Pacific Northwest, BPA utilized wind forecasts from five external vendors over a recent four year period, intentionally using short 1- or 2-year contract cycles. At the time of the survey summarized in the referenced report, BPA gave vendors a standardized observation data page, and vendors delivered their forecasts in a standardized format to a single point at BPA, which fed into all other BPA systems. BPA developed an algorithm to choose a "winning" forecast for each hour, instead of using ensemble forecasts. This method evaluated each vendor's performance every hour at each of the 31 wind plants in BPA's service area over the past seven days. Whichever vendor's forecast was most accurate during the hour 1 time slot was chosen as BPA's official forecast for the next day's hour 1, etc. This allowed vendors to specialize in a time horizon, geographic location or weather regime. In 2012, BPA began recovering its forecasting costs through its Variable Energy Resource Balancing System (VERBS) charge. Also, BPA has made gains in gathering close to real-time information, as it receives plant capacity information every 10 minutes along with information on plant operating limits and high speed cut-outs. Having timely information on outages and dynamic output has greatly improved BPA's forecasting [13].

3.2.2 Solar forecasting:

Solar forecasting is very complex due to the effect of cloud motion on solar irradiance at ground level; other factors that can have a similar impact are fog, snow and dust. Solar power forecasting techniques are considered less mature than those for wind power due to lower solar penetration levels and the difficulty in accurately predicting clouds in NWP models [61]. In addition, the application of day-ahead GHI forecasts to prediction of day-ahead power output of PV plants is poorly understood, partly due to difficulty in obtaining data from operating PV plants (security restrictions and lack of data infrastructure) [67]. A general over-prediction of GHI with the North American Model (NAM) is also well known [68].

While the persistence model assumes that the current conditions will persist, an option for solar forecasting is smart persistence, which corrects for the deterministic diurnal variation in solar irradiance [68]. One source states that this smart persistence forecast is difficult to improve upon when the cloud cover stays constant or when skies are clear [40]. However, another source counters that since solar exhibits significant ramps and variability within a 10 – 15 minute period due to cloud shadowing, persistence forecasts are less reliable and other mechanisms may be needed to reduce scheduling error [61]. Short-term forecasting (< 1h) is often based on sky imaging technologies and time-series models, while satellite-based forecasts are used for time horizons of 1 – 6 hours [67].

Sky imagers are digital cameras that produce high-quality images of the sky from horizon to horizon, used for detecting clouds, estimating cloud height above ground, and calculating cloud motion. Clouds scatter some wavelengths of light more than others, and these can be used to categorize clouds as thick and thin as well as to differentiate them from aerosols or dust. Consecutive images can estimate cloud velocity and provide a very short-horizon forecast [39]. The identification of cloud types is valuable in short-range irradiance forecasting because each type is associated with particular properties such as cloud optical depth, cloud growth rate and cloud dissipation rate, therefore having various degrees of irradiance attenuation. The cloud type also impacts the short-range irradiance variability and the corresponding forecast uncertainty [40].

Geostationary satellites (from networks such as NOAA) supply information about cloud properties and movement. First, a physical model predicts clear sky conditions at a specific site, then the modeled irradiance is adjusted using estimated irradiance from the satellite images. Sequential satellite images are combined to predict future cloud locations. This technique is viewed as effective in forecasting irradiance from 1 minute to as much as 5 hours ahead [39]. Longer time horizons usually require NWP models for accurate results [67].

Most NWP models generate GHI at ground level as one of the outputs, with some newer models including DNI. Studies have shown that forecast errors for all sky conditions can be reduced by averaging the GHI forecasts from all NWP grid points within a set distance of the site. In addition, the forecast performance could be further improved through bias removal using a polynomial regression based on the solar zenith angle and clear sky index [67].

Two publicly available solar NWP models are the North American Mesoscale Forecast System (NAM) and the Regional Deterministic Prediction System (RDPS). NAM is provided by NOAA on an approximately 12 km x 12 km grid that covers the continental US. Forecasts are generated 4 times daily, with hourly temporal resolution for 1 – 36 hour horizons, and 3 hour resolution for 39 – 84 hour horizons. GHI is forecast, along with total cloud cover, where the entire atmosphere is treated as a single layer. The RDPS model is generated by the Canadian Meteorological Centre on a 10 km x 10 km grid covering North America. RDPS also forecasts total cloud cover as a percentage for each grid section, not distinguishing between the layers of the atmosphere. RDPS generates forecasts four times daily with hourly temporal resolution [67].

There are different categories of available databases for solar forecasting or analysis. One category consists of collections of ground-measured irradiances typically provided by national meteorological services. Another category consists of models that combine data from solar irradiance monitoring networks with physical models to generate solar irradiance data for an arbitrary site. A third category is the satellite-based models where recordings of earth radiances from weather satellites are used to determine cloud cover and global irradiance at the earth's surface. One option when lacking dense radiation networks is to use virtual radiation networks, where a high-resolution monitoring series for a point location is time-shifted to mimic cloud movement over a series of stations [29]. In the Pacific Northwest, data sets from various solar stations, primarily in Oregon, are publically available from the University of Oregon solar radiation measurement laboratory [69].

The amount of distributed solar (behind the meter PV) is likely to increase in the future. No consensus on how to forecast this distributed solar exists, but it is viewed as an upcoming need [13]. The problems associated with large scale PV systems are different compared to the problems in distribution systems. With transmission level PV systems, the impact of moving clouds is reduced by the natural averaging effect of the large area, unlike with smaller distributed systems [70]. Distributed solar affects both load and system variability, but due to the smaller size, a regional forecast might be as useful as attempting to obtain site-specific forecasts [13].

Forecasts for distributed PV can be integrated with load forecasting to obtain net load forecasts, increasing the visibility of demand-side variability [60].

3.2.3 Wave forecasting:

Quality wave forecasting already exists on a broad scale as developed for the maritime industries. NOAA and the National Weather Service use WAVEWATCH-III to produce forecasts of up to 180h in 3h steps, based on wind information from the Global Data Assimilation Scheme (GDAS) [46]. It provides wave climate datasets which have excellent quality in the offshore, but lack spatial resolution and inadequately treat near-shore physical processes [49]. Similar to other forms of VRE, statistical models are generally viewed as more accurate for short time horizons (up to 6h) while physics based models perform better for longer time horizons [46]. NOAA maintains a database of historical sea state readings through the National Data Buoy Center [44], which can be used to model WEC power generation.

3.2.4 Biomass forecasting:

As a dispatchable resource, biomass can be controlled to a constant baseline output. Therefore, biomass does not have the same forecasting difficulties as the variable sources of wind, solar and wave energy.

3.3 Demand response and electrical energy storage:

Historically, electrical energy systems have been “demand led” due to the ease of storing fossil fuel for conversion to electrical energy when required. As power systems transition to higher penetrations of variable renewable generation sources, the process of matching generation to load becomes much more complex. Two possible methods to aid in this process include demand response and electrical energy storage. Both topics are described in this section, although this study models only the impact of energy storage. More specifically, pumped hydro storage and lithium-ion batteries were chosen for their established technologies yet differing time-scales of storage.

Generation has traditionally been controlled to closely match the demand at any point in time [71]. The capacity value of variable renewable generation sources is dependent on the extent to which their generation aligns with demand patterns. When generating during peak demand periods, VRE provides capacity value to the system. Challenges occur when increased penetration of variable generation (especially solar) actually changes the net load pattern. The capacity value of solar can decline significantly as penetration increases; the capacity value of wind also declines as a function of penetration, but to a lesser extent than solar. At high penetrations of solar and wind, demand response and energy storage could help maintain high capacity values [2].

Demand response is voluntary, compensated load reduction used as a system reliability resource. There are two broad categories of demand response mechanisms. Price-based programs vary the price of electricity over time to encourage customers to change their usage patterns, with time-of-use pricing, critical peak pricing, and real-time pricing programs. Incentive or event-based programs provide financial compensation to customers who either allow direct control of certain electricity consuming equipment or reduce their electricity demand upon request [4].

Electrical energy storage is the set of technologies capable of storing electricity generated at one time for use at a later time, so storage can act as an energy buffer between the generation source and the load. Storage technologies can be categorized as mechanical (pumped hydro, compressed air energy storage and flywheels), electrochemical (conventional and flow batteries), electrical (capacitors, supercapacitors and superconducting magnetic energy storage), thermochemical (solar fuels), chemical (hydrogen storage with fuel cells) and thermal energy storage (sensible heat storage and latent heat storage) [14]. They can also be divided into two general categories based on the amount of energy stored. Some technologies provide operating reserves by responding rapidly and discharging within seconds to minutes (flywheels and some battery types). Technologies for energy management provide flexibility over longer time periods and require continuous discharge over several hours. In addition to operating reserves, these longer storage technologies (long duration batteries, pumped hydro storage, compressed air storage, and thermal energy storage) may provide firm system capacity, which could help reduce the need for conventional peaking capacity. This is especially important at high penetrations of VRE, when the marginal value of these variable sources can drop significantly [72].

Different storage technologies can be used for each of three main electric sector goals: energy management for daily/hourly scheduling, operating and ramping reserves for load following, and frequency response and regulation to maintain power quality [73]. Optimal operation and sizing of storage is difficult because many variables must be considered to identify cost-effective solutions [74]. A more detailed list of potential applications of energy storage includes: time-of-day arbitrage, peak capacity, ancillary services, load following and renewable integration, voltage support, black start, and transmission and distribution upgrade deferral [75]. Investments in energy storage help renewable integration by increasing both the upward and downward flexibility in a system. The storage systems provide flexibility reserves in discharging mode, based on the full discharging operating range, but not in charging mode [16].

The US DOE has identified energy storage as a solution for grid stability, through the Energy Storage Systems Program (DOE OE/ESSP) for developing technologies and systems [76]. Bulk energy storage can facilitate increased deployment of low-carbon generation, time-of-use energy management, and reduce the need for transmission system upgrades [71], and the benefits of energy storage have been shown to increase with increasing levels of variable renewables [77]. California was the first state to mandate energy storage, with 1325 MW of energy storage capacity required by the end of 2020 [10]. Other states now have targets or mandates for energy storage, including Oregon with the requirement for the state's two largest utilities to each have at least 5 MWh of storage by January 2020 [78]. (PGE has plans to add 4 to 6 MW of transmission-connected storage to create a “hybrid plant” at Port Westward 2 [79].)

About two-thirds of utility-scale battery storage power capacity installed in 2016 in the United States is located in two electricity markets, CAISO and PJM. Utility-scale battery storage systems in California tend to serve energy-oriented applications, with smaller power capacities but longer discharge durations, while systems in PJM tend to serve power-oriented applications, with larger power capacities but shorter discharge durations. Utility-scale battery storage installations in California tend to have power capacities averaging 5.7 MW, and discharge durations averaging slightly less than 4 hours. These installations in California also serve a wider array of applications because many are used by regulated utilities for multiple applications without necessarily being compensated for each application through the market [80].

There is a wide range of energy storage technologies commercially available and in development, each with different configurations of power and energy capabilities, round-trip efficiencies, self-discharge efficiency, cycle life and other operating parameters [81]. Many storage technologies are still costly and somewhat inefficient, because only a percentage of the stored energy is recoverable. Demand response programs don't incur this sort of energy penalty, but they do have significant implementation costs. The value of storage has been difficult to justify, partly because it is difficult to quantify the value of the services it provides, especially operational benefits such as ancillary services. The ability to simulate the cost impacts of VRE and benefits of storage is still limited by the methods and datasets available [4].

The value of energy storage is best captured when selling to the entire grid as a system asset (value stacking), with the availability and costs of grid flexibility options varying by region [72].While hybrid renewable and storage projects are being deployed to share common components and reduce costs, using storage to balance a single plant may result in injecting power at one point on the grid, while a nearby storage system is withdrawing power at another plant location [82]. When modeling energy storage, it is important to prevent the system from storing and discharging energy at the same time, as energy storage is always associated with an energy loss due to the efficiency of the system [74].

3.3.1 Batteries:

Batteries convert chemical energy to electrical energy through oxidation and reduction reactions (Figure 15). Although the specific properties vary depending on the type of battery utilized, electrochemical batteries have fast response time, scalability, and modularity that allows both power and energy applications [83], and they are non-emitting and quiet [74]. The grid support applications may include transmission curtailment, time-shifting, forecast hedging and grid frequency support [84]. However, batteries are more expensive than many other technologies on a per KW basis [74], and may have safety or environmental hazards during use or disposal. In a typical plant life cycle, batteries may need to be replaced at least 3 - 4 times, and also require frequent maintenance [85]. Batteries are characterized by two metrics: power capacity and energy capacity. Power capacity (MW) is the maximum instantaneous amount of power that can be produced on a continuous basis, and energy capacity (MWh) is the total amount of energy that can be stored or discharged by the battery [80].

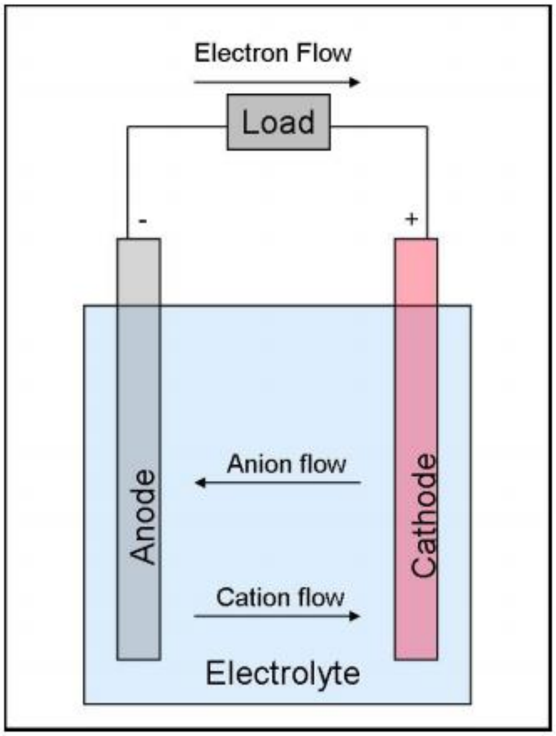

Figure 15 - Battery basics [86] https://www.sandia.gov/energystoragesafety-ssl/wp-content/uploads/2017/08/ESS-Fundamentals-Presentation.pdf

Lead Acid: Lead acid batteries (Figure 16) are a mature technology, are low cost and reliable, and have the ability to supply high currents; they are the most economical choice for large power applications where weight is not a concern. They have been a common choice in microgrids, power quality, UPS and spinning reserve applications [76]. However, they suffer from performance degradation when operating under prolonged partial state of charge, the low energy density and heavy weight of the batteries narrow the areas of application [84], and if not operated within a limited temperature range there will be a significant reduction in expected lifetime. In addition, the toxicity of lead creates environmental concerns at the end of the battery's life, and it must be recycled. Conventional lead acid batteries have high efficiency (65 – 80%) [74], low energy density (≈50 Wh/kg) [76], low self-discharge rate (<0.3%) [74], limited operating temperature range (-5 - +40 C) [76], and limited lifetime (estimates include 500 – 1000 cycles [74], 2500 cycles [76]).

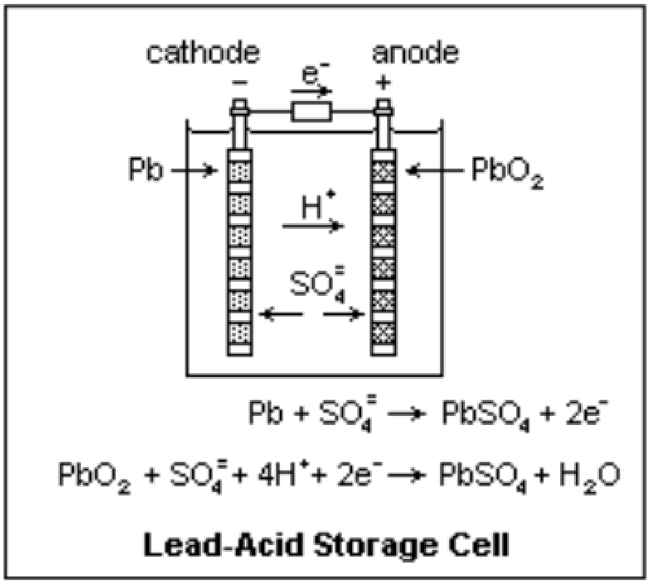

Figure 16 - Lead-acid battery basics [86]

Lithium-ion: Lithium-ion batteries (Figure 17) have higher energy and power density than lead acid batteries, and are one quarter the weight and half the size [74]. They have high cell voltage compared to other batteries, no memory effect, extremely low self-discharge rate, negligible maintenance requirement, and flat discharge characteristics [84]. However, the lifetime is significantly affected by higher temperatures [74] and the cycle DoD, and the battery pack usually requires an on-board computer to manage its operation, which increases its overall cost [6]. In one survey of installed grid-scale installations, lithium-ion battery systems were used in over half the projects. The study conclusion was that their ability to serve both energy and power applications to some extent make lithium-ion batteries well suited for integration of renewable energy [83]. Another paper stated that the future of lithium-ion in future grid-scale applications is promising because the price is declining, and the functionality is improving due to extending the lifetime, using new materials, and improving the safety parameters [76]. The characteristics of lithium-ion batteries include high efficiency (estimates include 73 – 90% [81], 85 – 90% [76], 90 – 100% [74]), high energy density (≈ 200 Wh/kg) [76], low self-discharge rate (about 5% per month) [74], and relatively longer lifetime (3000 – 4000 cycles [81], 10,000 cycles [76]). Current utility scale Li-ion storage systems cost about $764/kWh installed ($250/kWh for the battery pack and $514 for the power electronics, racking, grid connection, etc.) However, the DOE targets a capital cost of $125/kWh for Li-ion battery packs by 2022; if a

20% reduction in balance of system costs is also achieved the total installed system costs would be roughly $536/kWh [81].

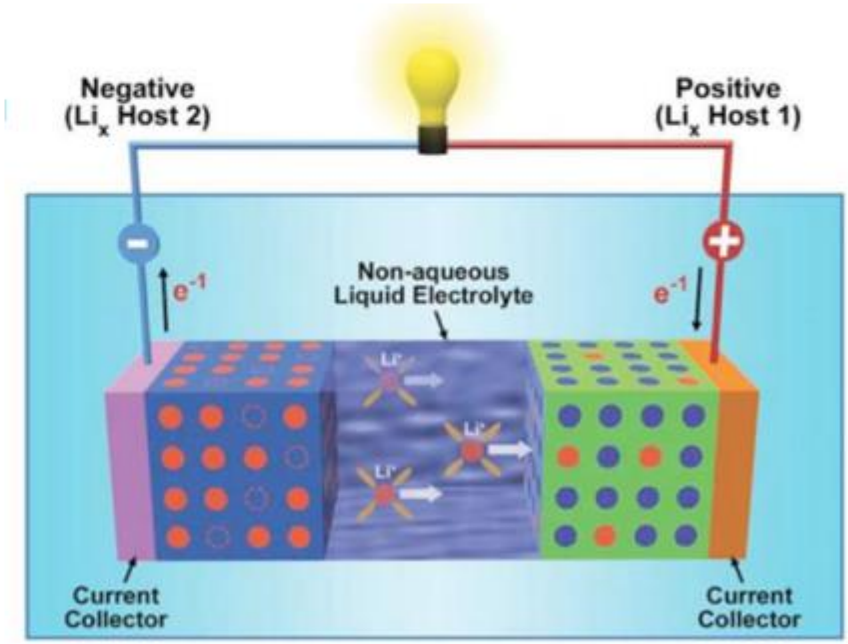

Figure 17- Lithium ion battery basics [86]

Sodium-Sulphur: Sodium-sulphur batteries use molten salt as the conductive medium. The positive electrode is molten sulphur, and the negative electrode is molten sodium. The separation between the electrodes is achieved by a proton conductive solid beta alumina ceramic which also acts as the electrolyte, Figure 18. These batteries operate at a high cell temperature of 300 – 400 C; this high temperature ensures the liquid state of the sodium and sulphur. Energy is generally required only during startup of the battery, as the energy released during the charging and discharging cycle is enough to maintain the operating temperature [84]. The main advantages of sodium-sulphur battery systems include high energy and power density, high efficiency, long life, pulse power capability, instantaneous response, high scalability, reliable operation, and high commercial performance and reliability. One important disadvantage is the safety concern due to the high operating temperature and the reactive nature of sodium metal. Direct contact between the molten sodium and sulphur would result in a highly exothermic reaction which would jeopardize the integrity of the battery enclosure; therefore a complex thermal management system is required [84]. Sodium-sulphur batteries have a good efficiency (75 – 90%), and can be cycled approximately 2500 times [74].

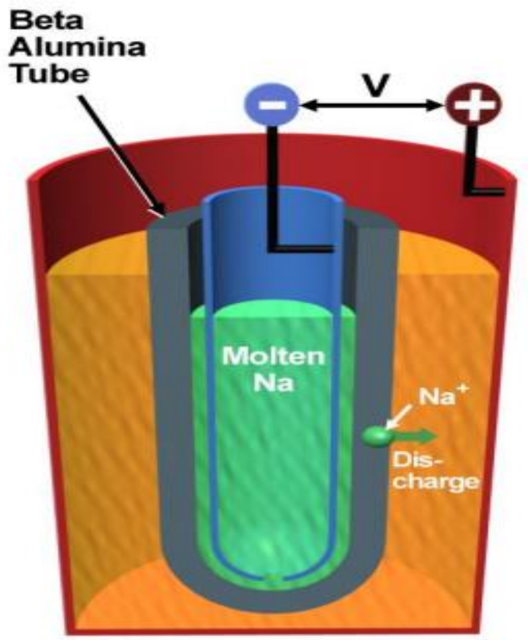

Figure 18 - Sodium Metal battery basics [86]

Flow batteries: Flow batteries (Figure 19) are different from conventional batteries in two main aspects – the electro-active material is stored externally in an electrolyte and introduced to the cell only when required, and the electrodes are not part of the electrochemical fuel, so they can be designed for optimum performance without affecting the storage density. When the active material is dissolved in the electrolyte to enable reduction/oxidation reaction, the battery is known as a redox-flow battery. Flow batteries are cost effective for grid level energy storage due to the advantages of moderate cost per kWh, ease of construction due to the modular design, scalability due to the external electrolyte storage, and large volume storage tanks [84]. The ratings of power and energy can be designed independently – energy capacity is determined by the concentration and amount of electrolyte stored in the external tanks, while power rating is based on the active area of the cell compartment [76]. Disadvantages include requirements for complex pumps, sensors and flow management systems, and difficult maintenance due to the toxic and corrosive electrolytes involved [84]. The efficiency of flow batteries is around 75% [74].

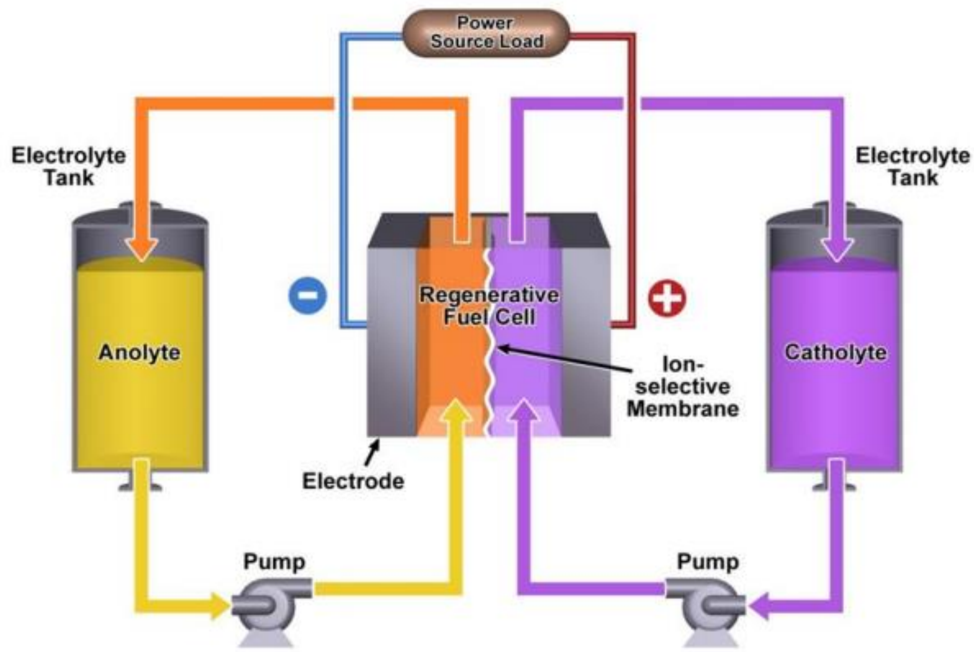

Figure 19 - Redox flow battery basics [86]

Other battery types: Ni-Cd batteries have relatively high capital costs, plus problems with disposal due to the heavy metal toxicity. In addition, they have the problems of memory effect, susceptibility to overcharging, and relatively low efficiency [76]. Nickel-iron batteries have long lifetimes and tolerance to adverse operating conditions like overcharging, deep discharging and short circuit. The major limitations are low power density, high self-discharge rate, steep voltage dropoff with SoC, and low efficiency. Ultra (advanced) lead acid batteries utilize a supercapacitor formed by a lead-carbon electrode, which replaces the conventional lead based negative electrode and enhances the battery efficiency [84].

3.3.2 Supercapacitors:

Capacitors and supercapacitors are the most direct way to store electricity. They have a very fast response, life cycles of tens of thousands and very high efficiency. Supercapacitors are quickly rechargeable as they require no chemical reactions, plus they have excellent low temperature charge and discharge performance. Supercapacitors are mainly employed in power quality services such as ride-through and bridging [76]. For applications that require high bursts of power, supercapacitors are considered a good storage option [74]. The main disadvantages include short storage duration, low energy density, high self-discharge loss [76], and the relatively high expense [74]. Supercapacitors have efficiencies of about 90 – 95%, and the daily loss of charge is approximately 5% [74]. Supercapacitors are well suited for short-term storage applications but not for large scale and long-term EES [6].

3.3.3 Flywheels:

Flywheels store energy mechanically in the form of kinetic energy, and are mature technology. They are fast-responding (milliseconds), with short duration discharge (seconds to minutes), which makes them suitable for power-related services such as UPS, frequency regulation and integration of variable renewables [76]. A modern system is composed of five primary components: a flywheel, a group of bearings, a reversible electrical motor/generator, a power electronic unit and a vacuum chamber (for reducing wind shear and energy loss from air resistance) [6]. The most common application is for ride-through to switch between different sources of power. Flywheels can be categorized as low speed (less than 6000 rpm) and high speed, with the high speed flywheels having more advanced materials and machinery to increase the overall efficiency; however, the cost of high-speed flywheels with magnetic bearings can be 5 times higher than low speed types. Flywheels are insensitive to the depth of discharge, have high peak power capacity without overheating, and have very good energy efficiency [87]. They can be scaled up to tens of megawatts for grid-scale applications, and have fewer environmental and safety issues relative to batteries [76]. A 20 MW plant in commercial operation in New York employs 200 high speed flywheel systems to provide fast response frequency regulation services to the grid [6].

The efficiency of flywheels is typically high (>85% [76], 90 – 95% [74]) and they are especially good in applications that require short duration (1 -2 s) in MW capacity. They have long lifetimes on the order of a hundred thousand discharges and more than 15 years [76]. The main weakness is that flywheel devices suffer from idling losses during the time when the flywheel is on standby. This can lead to relatively high self-discharge, up to 20% of stored capacity per hour [6]. Another disadvantages is a very high capital cost [87]. They are only an effective storage option for short-term, rapid-response and reliable standby power [74].

3.3.4 Superconducting magnetic energy storage (SMES):

Superconducting magnetic energy storage stores energy in a magnetic field so it can be instantaneously discharged back, providing electricity storage purely electrically. A typical SMES system is composed of three main components - a superconducting coil unit, a power conditioning system, and a refrigeration/vacuum system. The SMES system stores electrical energy in the magnetic field generated by the DC in the cryogenically cooled superconducting coil. In the discharge phase, the SMES system releases the stored electrical energy back to the AC system by a connected power converter module [6]. It has high energy density and very quick response, so it can be used for power quality services, carryover energy during voltage sags and momentary power outages, and frequency regulation. Disadvantages include high capital cost, environmental considerations related to the strong magnetic fields [76], and a high daily self-discharge (10–15%) [6]. In addition, SMES can only store energy for short durations [85]. SMES systems have high storage efficiencies of about 97%, fast response (milliseconds) and long life cycles (100,000) [76].

3.3.5 Compressed air energy storage (CAES):

A compressed air energy storage facility uses electricity to compress air into an underground cavern. The air is later withdrawn from the storage and heated with natural gas to operate a combustion turbine generator, burning about 2/3 the natural gas of a conventional combustion turbine generator [77]. However the feasibility of constructing a CAES facility depends heavily on the local terrain; underground salt caverns, natural aquifers, and depleted natural gas reservoirs are respectively the most cost efficient options for capacities up to several hundreds of MW with discharge times of 8 – 26 hours. Above ground CAES (pressure vessels) may have capacities of 3 – 15 MW (with a 2 – 4 hour discharge time) at higher costs yet easier implementation relative to the underground systems. Disadvantages include the dependence on geography, and low energy density of around 122 kWh/m^3 [74]. In addition, the heat developed during compression is lost with longer storage times; fossil fuel is then burned to reintroduce the lost heat so the air will expand and the energy can be recouped [87]. CAES has good efficiency (60 - >80%), high capacity (2 - >50 h; power capacity around 300 MW), quick startup (9 - 12 minutes), and over a year of storage period [74]. It is difficult to generalize the cost of CAES, as it can be very site specific, but one source estimates the capital cost at \$400 - \$800 / kW [87].

3.3.6 Pumped hydro storage (PHS):

Over 99% of the existing bulk energy storage capacity worldwide is pumped hydro storage (Figure 20), with a global installed capacity exceeding 125 GW [71]. Much of the pumped hydro storage in the US was installed during the mid to late 1970s, justified based on high-cost peaking oil and natural gas–fired generation and low-cost power during off-peak periods. However, energy arbitrage is typically not sufficient to justify new pumped storage plants today. One of the advantages of storage is its charging capability, which can be extremely valuable during off-peak hours when system loads are low, most conventional thermal generators are base load units operating at their minimum capacities, and demand response options are limited [88].

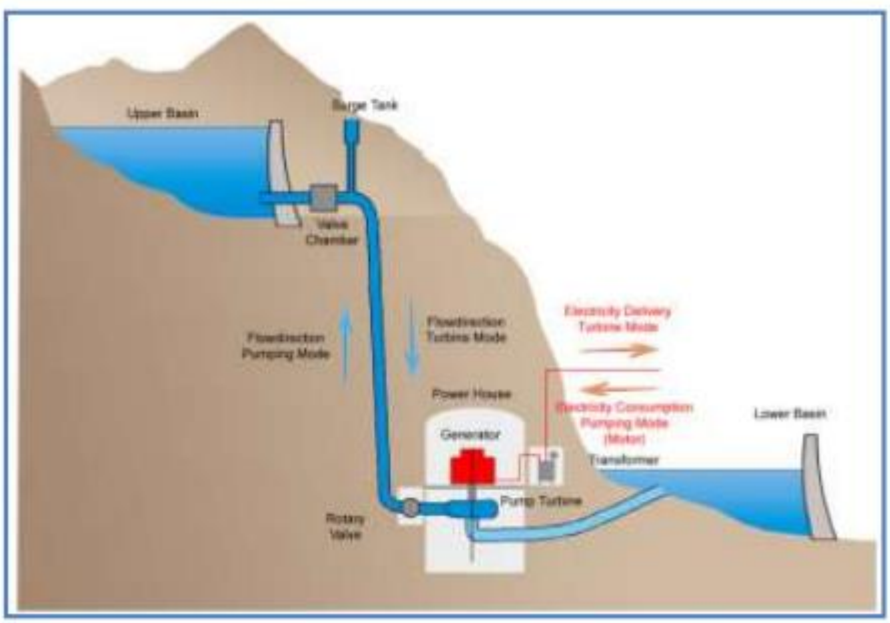

Figure 20 - Pumped Hydro Storage [89]

PHS is generally viewed as the most promising technology to increase renewable energy penetration in power systems [90]. It stores gravitational energy by elevating water from a lower reservoir to a higher level reservoir; electricity during off peak times is used to run the pumps to raise the water to the higher reservoir, then the water is later released through hydro turbines to produce electricity as needed. It responds to load changes within seconds, can modulate the frequency and provide voltage stability, and is currently the most cost-effective method of storing large amounts of electrical energy [76]. PSH can ramp rapidly while generating, making it useful for load following and providing ancillary services including contingency spinning reserves and frequency regulation [35]. The use of variable speed pumping may allow new capabilities and flexibility for ancillary services in the pumping (charging) phase as well. However, PHS is expensive, time consuming to make operational, and depends heavily on local geography for feasible sites. The construction and installation costs of PHS are estimated to be twice that of conventional hydropower plants with similar capacity, while operating costs are about equal [76]. In addition, public opposition to PHS can be a significant barrier, partly due to a lack of understanding of the benefits of energy storage [71].

The relatively low energy density of PHS systems means either a very large body of water or a significant variation in height is required. The relation between the difference in height between the two bodies of water (the head) and the distance between them (the overall water conduit and tunnel distance) is important; the shorter the distance relative to the head, the more cost effective the layout is. A ratio (L/H) of less than 10 is preferred. The largest PHS systems are in the range of 2000 - 3000 MW installed capacities, however 1000 - 1500 MW systems are more common [90]. The product of the total volume of water and the differential height between reservoirs is proportional to the amount of stored electricity [88].

In practical applications, the transition from a generating to a pumping mode of operation (or vice versa) is performed by the operator and takes several minutes. Therefore, in most power system simulation studies, the generating and pumping modes of operation for conventional PSH units are studied separately. The transition time for a reversible pump/turbine in the opposite direction, from pumping mode to generating mode, ranges from 1.5 to 5 minutes, while the transition time for the ternary units is less, on the order of 0.5 to 1 minute [88].

The value of PSH to the grid depends on many factors, including the technology's location in the system, capacity mix of other generating technologies, level of renewable energy penetration within the power system, the load profile, and topology and available capacity of the transmission network. A PSH plant located in a "load pocket" has a much higher value than one located in an area with a significant amount of flexible generating capacity and a strong transmission network [88].

PHS has good round trip efficiency (70 – 85% [71], 76 - 85% [91]), a wide spread of feasible power ratings (10 – 4000 MW [71], with 1000 – 1500 MW the most common rating [90]), a range of discharge duration at rated power (1 hour – days [71]), negligible self-discharge, a response time in minutes, and long lifetime (40 – 60+ years [71]). As a general rule, a reservoir one kilometer in diameter, 25 meters deep, and having an average head of 200 meters would hold enough water to generate 10,000 MWh [91]. The price of a storage reservoir varies significantly depending on the local geography, in the range of $1 - $20 /kWh for storage capacity, and $600 - 1000 /kWh for the turbines [90]. The cycle cost is in the range of $0.1 - $1.4 / kWh cycle [87]. Detailed simulation models have been developed for PHS technologies to analyze their ability to provide various grid services and to assess the value of these services under different market structures and for different levels of renewable generation resources in the system [88].

3.3.7 Hydrogen Storage:

In hydrogen storage, hydrogen is produced via electrolysis and then stored as a compressed gas in above ground steel tanks or in geologic storage. Although it is currently a high-cost option, hydrogen storage offers some advantages, including a high storage energy density and the potential for co-firing in a combustion turbine with natural gas. Initial cost analysis indicates that hydrogen systems could eventually be competitive with battery systems for energy storage, and could be a viable alternative to pumped storage hydro and CAES at locations where they are not feasible [73].

<u>3.3.8 Comparison and selection of storage technologies:</u>

Figure 21, copied from [92], compares various types of energy storage. Based on system power ratings and discharge time at rated power, the best applications of the various technologies are identified.

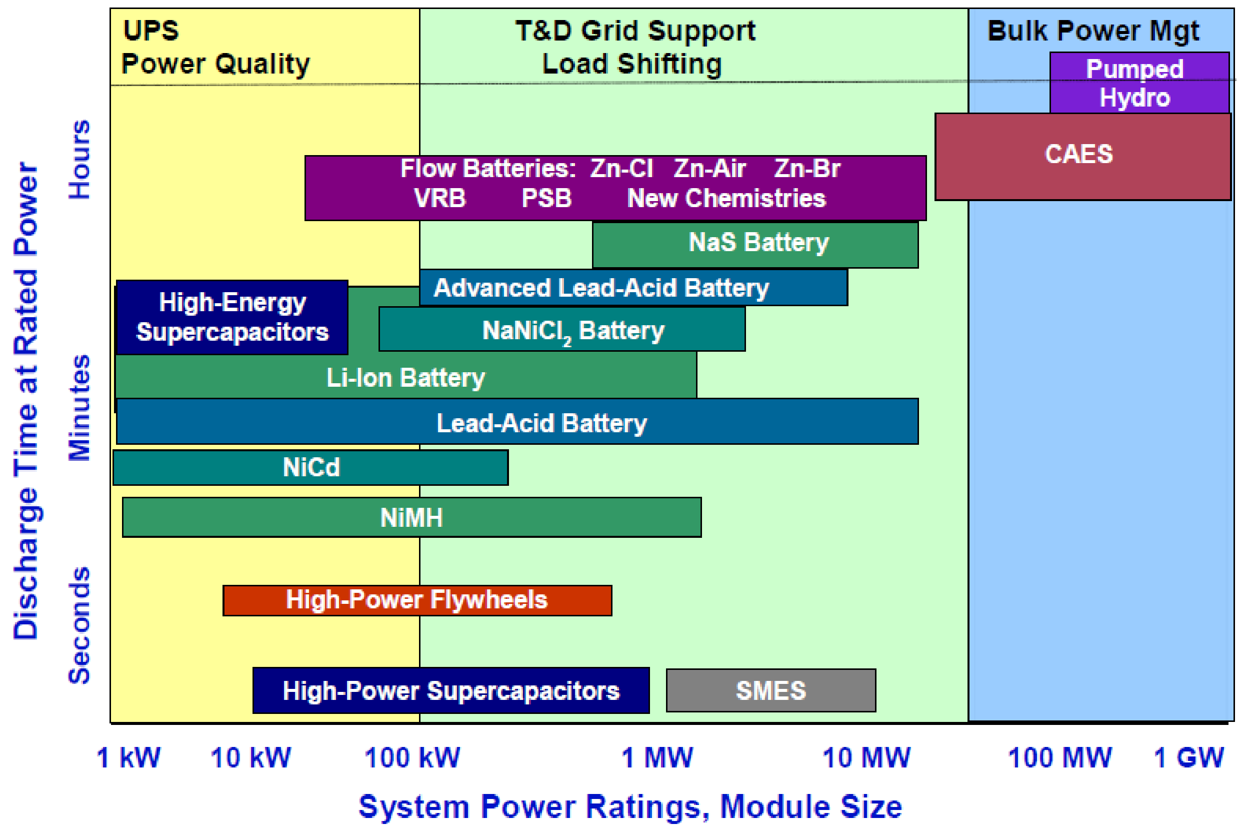

Figure 21 - Positioning of energy storage technologies [92]

No single storage technology meets the requirements for all power system applications. Size of storage devices is an important factor for many applications. For a given amount of energy, the higher the power and energy densities are, the smaller the volume of the required energy storage system will be. The level of self-discharge is a major factor in deciding the suitable storage duration. Technologies with very small daily self-discharge ratios (PHS, CAES, NaS batteries, flow batteries) could technically have the energy stored for long durations (up to months). Most conventional batteries (except NaS) have daily self-discharge ratios from 0.03% to 5%, and can be used for medium-term storage durations (up to days). SMES, flywheel, capacitors and supercapacitors have very high daily self-discharge ratios from 10% to 100%, could completely release their stored energy after a few hours, and can only be utilized for short-term storage durations. Mechanical energy storage systems (PHS, CAES and flywheels) normally have high cycling times (10,000 or more) which mainly depend on their mechanical components. The cycle times for systems with energy stored in electrical energy (SMES, capacitors and supercapacitors) are normally higher than 20,000. The cycle abilities of conventional batteries are not as high as other types of systems mainly due to chemical deterioration with accumulated operating time [6].

It is difficult to estimate the cost of energy storage systems, as the use of large scale systems is still relatively scarce, and costs may be proprietary. In addition, since many technologies are in the early stages of development, scaling cost data to larger sizes may not be accurate [76]. When discussing the costs of storage technologies, it is important to remember that they have both a power component (kW of discharge capacity) and an energy component (kWh of discharge capacity, hours of discharge at rated output) [35].

3.4 System modeling:

Understanding of the costs and effects of VRE integration and the benefits of technologies like grid-scale storage requires at least some power system modeling. Different types of models are used to understand the behavior of power grids at different time scales. These models are based on the power flow equations 5 and 6, and are discussed below.

$$P_{g,i} - P_{d,i} = \sum_{k=1}^{N} |V_i||V_k|(g_{ik} * \cos\theta_{ik} + b_{ik} * \sin\theta_{ik}) \tag{5}$$

$$Q_{g,i} - Q_{d,i} = \sum_{k=1}^{N} |V_i||V_k|(g_{ik} * \sin\theta_{ik} + b_{ik} * \cos\theta_{ik}) \tag{6}$$

Equations 5 and 6 describe the basic AC power flow analysis. Utilizing an AC power flow analysis, the voltage magnitude and angle at each bus can be determined, based on the specific set of generation and load information. Once the voltages have been determined, power flow in each branch can be calculated and compared to known transmission limits. AC power flow also allows for the calculation of reactive power output of generators. AC power flow can then be simplified to DC power flow, which opts to ignore reactive components to decrease computational time.

Another interesting extension of AC power flow is the Optimal Power Flow (OPF) formulation. The goal of OPF is to calculate the best output levels for generating plants on the grid, typically with the objective of minimizing cost (however, like any other optimization problem, the objective will depend on the problem definition). Similar to OPF is the economic dispatch problem. While OPF includes operating constraints of items within the system, economic dispatch is more focused on short-term planning by scheduling generation on a low to high cost basis to meet the demand of the system.

It is difficult to extract conclusions about phenomena that occur on short time scales (seconds to minutes) using steady state models. Power system stability calculations and estimating the effect of VRE on balancing (especially regulating) reserve requirements depend heavily on short time scale phenomena [65]. The net load model gives a rough estimate of how quickly power production needs to ramp to maintain balance; the time series is analyzed to find when there are very high rates of change in net load, and compares these with the ramping capabilities of the power plants. However net load models do not represent the transmission system and cannot account for the ability of an operator to quickly exchange power with neighboring operators [65].

Quasi-steady state network models improve on the net load model and model power flows between locations over a sequence of time intervals. If the load and generation (conventional and VRE) can be estimated at each node for a sequence of time periods, the regional effects of VRE on power flows can be modeled. However, this approach also has limitations, as estimating which power plants will be operating at what levels for particular time intervals requires production cost modeling, and capturing second by second variations in frequency requires a dynamic model [65].

Estimating the hourly state of power plants, with various fuel types and costs, for VRE penetration scenarios is both important and difficult. Production cost simulation models are often proprietary commercial tools, using cost data for a set of power plants and estimates of load/VRE to estimate the amount of power produced by each power plant for each time interval. The most sophisticated model generator ramp rates, startup/shutdown costs, and transmission limits, and solve for power flows and account for transmission constraints [65].

A critical responsibility of system operators is to ensure sufficient generation capacity to supply load during future periods of high demand. An important reason for this supply adequacy analysis is for setting the capacity credit due to VRE plants, since many system operators provide plants with financial payments based on their contributions to system adequacy. Since unit commitment and system adequacy are long-time-scale calculations, dynamic models are usually unnecessary [65].

Transmission grid simulation can evaluate the steady state adequacy and utilization of the system infrastructure, and determine if the portfolio and grid is strong enough to handle temporary disturbances and significant failures, and stable enough to recover satisfactorily from those events. When performing transmission system studies, it is important to create load flow cases that represent high penetration of VRE, with both peak and low demand situations, and include cases with high non-synchronous generation. Deterministic steady state security analysis can evaluate N and N-1 security criteria, and load flow analyses both identify transmission congestion and assess the system's ability to control the voltage profile. Network loading assessment allows bottlenecks to be identified in a probabilistic manner, quantifying the frequency of network overloads (hour/year), the volume of overloads (MWh/year), and the risk of curtailment (MWh/year) due to system constraints [8]. It has been viewed that considering even a few scenarios may capture most of the economic benefit of stochastic planning, as the transmission investments recommended are inherently robust against future uncertainties (even if not explicitly modeled) compared to deterministic solutions. However, plans that are optimal under uncertainty may not be best for any individual deterministic scenario [93].

When studying voltage stability, the possibility of deploying reactive power control capabilities from wind turbines is an important consideration, which may result in unaffected or enhanced voltage stability [94].

One widely used simulation tool is the Hybrid Optimization Model for Electric Renewables (HOMER), but it does not automatically optimize the design of the system, as it is necessary to pre-set the size of the components [95]. When modeling power systems, it is also important to perform sensitivity analysis to verify that the model functions consistently in a variety of circumstances [33].

Many commercial modeling tools exist, often essentially black-boxes, plus related open-source tools such as Calliope: a multi-scale energy systems (MUSES) modeling framework [96]. Figure 22 from NREL shows the relation between temporal resolution and geographic scope of different modeling tools.

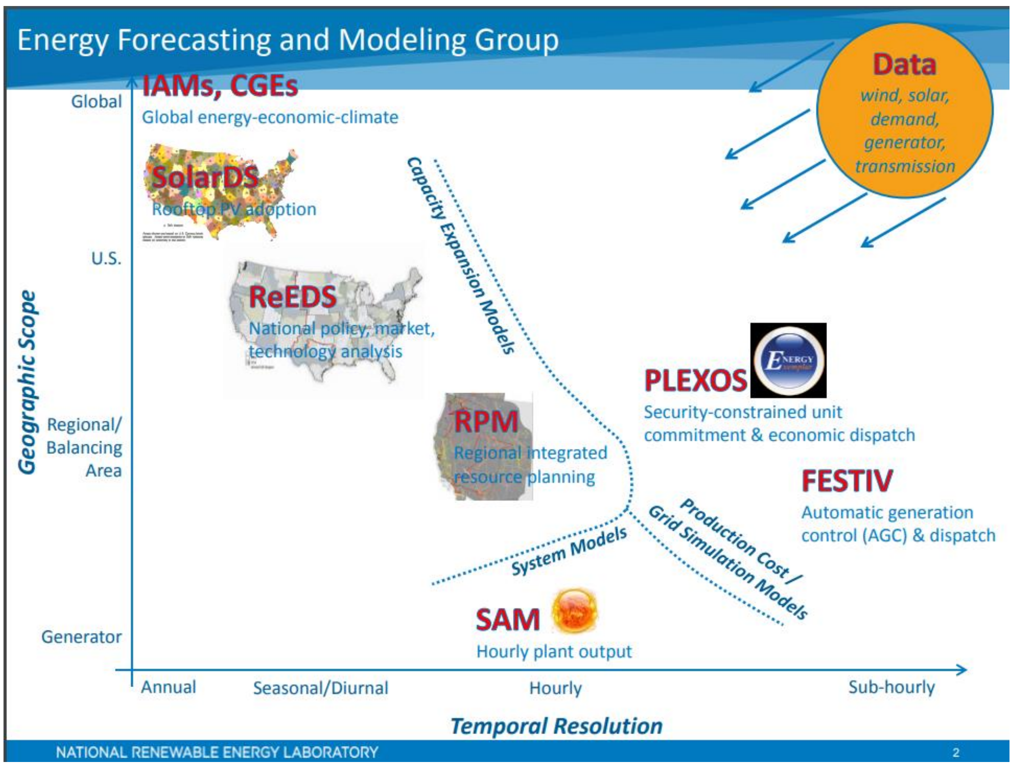

Figure 22 - Temporal resolution and geographic scope of various modeling tools [97]

In addition, modeling tools can be categorized by their time step vs. spatial focus. These different groupings emphasize technical, techno-economic or economic-focused approaches, and are shown in Figures 23, 24, and 25.

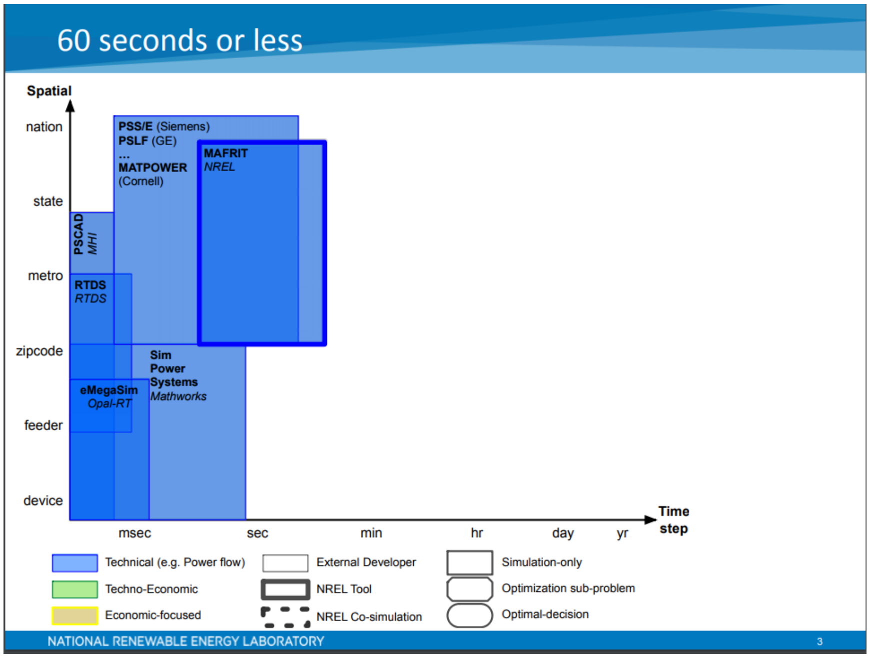

Figure 23 - Technical modeling tools [97]

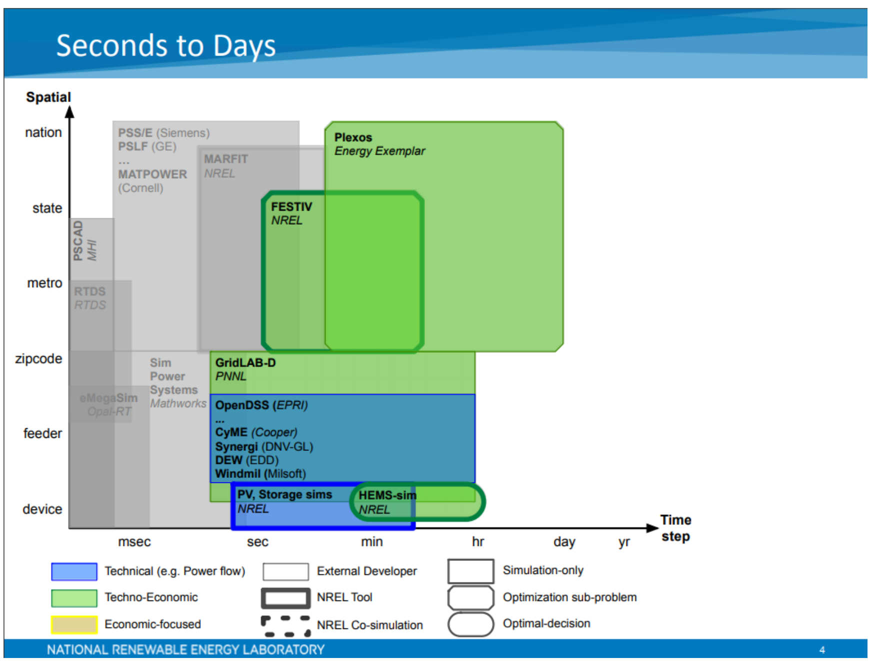

Figure 24 - Techno-economic modeling tools [97]

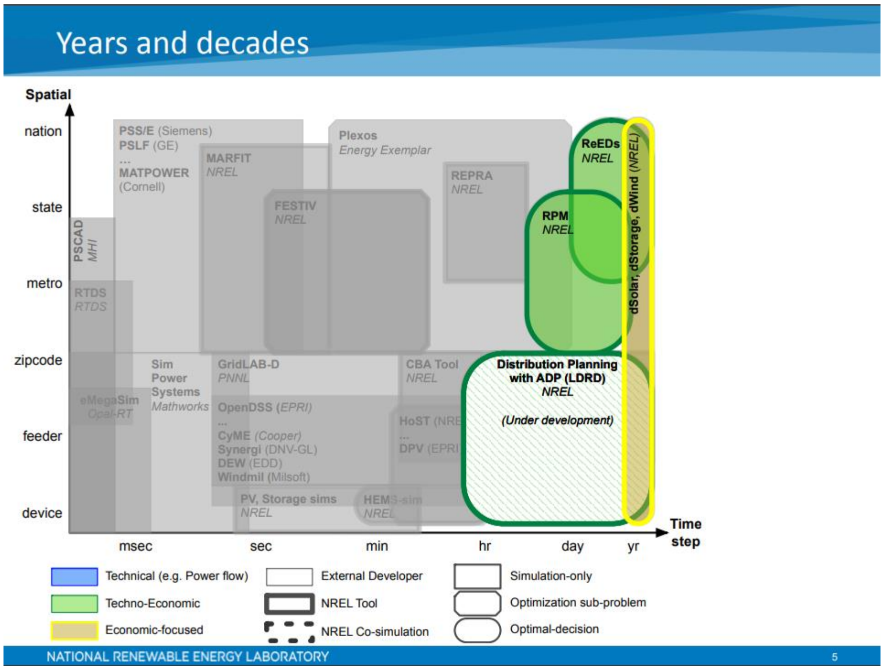

Figure 25 - Economic-focused modeling tools [97]

The custom modeling in this study can be considered a techno-economic model. This unique approach was selected as none of the previously developed models seemed ideal for the geographically specific seasonality study of the Pacific Northwest, and the potential use of energy storage to moderate the seasonality issues. Most of the analysis could be considered as economic/planning, then narrows to the shorter timeframes with the custom battery algorithms (power management).

3.4.1 Integration studies:

Good integration methods maximize the cost effectiveness of incorporating VRE into the power system, while maintaining or increasing system stability and reliability. New renewable energy generation, new transmission, increased system flexibility, and planning for a high VRE future all need to be considered. Grid integration studies help establish the flexibility requirements and build confidence that the power system can be operated reliably at increased VRE levels [7]. These grid integration studies include five steps: data collection, system configuration and reserve estimation, capacity estimation, system flexibility, and transmission simulation [65]. Load flow and dynamic simulations involve contingency analysis and stability studies; dynamic simulations and flexibility assessment are necessary especially when studying higher penetration of renewables [8].

Gathering representative data for potential future VRE plants is one of the most significant challenges to a successful integration study; the data should show an appropriate level of spatial averaging, be time synchronized, and sufficiently long-term to capture rare events (ideally five years or more). Data collection is also complicated by the fact that actual plant performance data is usually proprietary [65]. Input data may include renewable energy resource data, load data, forecast and forecast error data, VRE equipment characteristics, conventional fleet characteristics, demand response and storage characteristics, and transmission data [9].

Resource data describes the quantity and type of fuel available at a specific location and time, while forecast and forecast error data shows the operational uncertainty. Data on conventional generators includes location, fuel type, and performance factors such as ramp rates, minimum output levels, start-up time, heat rates as a function of load, active and reactive power capabilities, outage rates and projections of future fuel prices and efficiencies; ramping related maintenance costs, numbers and costs of hot, warm and cold starts, and emission factors during ramping are also relevant. For hydropower plants, data needs include storage levels, water inflow, and non-power constraints to outflow. Demand response and storage data includes: timing, magnitude, and duration of demand response measures; types, capacities, charge/discharge times, and efficiency rates of storage technologies; and operational practices and costs. Transmission data includes the spatial distribution of the existing/planned network and provides information on rated line capacities, impedance, and line ratings; the number, location and characteristics of interconnections to neighboring grids are also useful [9]. For neighboring systems, alternatives to complete modeling are to assume full availability of interconnectors, fixed flows obtained from other studies, or flows based on market prices in the regions [94].

When performing integration studies, reliability constraints from transmission, capacity or reserves will require iterations, changing the installed portfolio, the transmission grid, and the operational methods of system management, as the time steps chosen for dispatch and market operation can influence the reserve requirements [8]. Since it is likely that some power plants would be retired in high renewables cases, it is important to include potential retirements in simulations to understand which types of plants should remain operational [65]. Including limits on the instantaneous penetration of non-synchronous generation sources should be considered, with the decision very system specific, depending on the generator portfolio, power quality requirements, AC vs. DC interconnection, and synchronous interconnection with other networks [98].

Since real systems differ substantially from study scenarios, it has been suggested that future studies focus on quantifying the relative effect of changes in operating policy or technologies, rather than trying to precisely quantify the economic or reliability effect of a particular scenario. As methods for optimal system expansion planning improve, future large-scale studies should study creative combinations of off-shore wind, strategically located on-shore wind, solar, battery storage, pumped hydro, controllable AC or DC transmission lines, and demand response resources. There may be synergies between these technologies that enable higher penetration scenarios, while minimizing curtailment, ancillary service costs, and reliability effects [65].

3.4.2 Optimization:

Optimization includes finding the best available values of some objective function given a defined domain or a set of constraints; these models are usually used for resource and equipment planning, with a time range of ten to forty years. The complexity of optimization results from the diverse technologies available, the temporal/spatial evolution of the parameters, and any environmental/social factors that need to be included. Although complex, the use of optimization methods along with sensitivity analysis can take into account the interaction between all elements in the electricity system, which is fundamental for long range planning [99].

The objective of the optimization may be to minimize electricity procurement cost subject to certain constraints [33]. The objective function may be set up as the sum of fixed and variable costs, as well as a weighted term to represent the environmental burden, as seen in equation 7

$$C_{proc} = \sum C_{cap} + \sum C_{OM,fixed} + \sum C_{OM,var} + \sum C_{fuel} + \sum C_{CO2} + \alpha \sum C_{EB} \qquad 7$$

where C_{proc} is the procurement cost of electricity, C_{cap} is the investment cost of the new power plants, $C_{OM,fixed}$ is the fixed O&M costs, $C_{OM,var}$ is the variable O&M cost, C_{fuel} is the fuel and pumping costs, C_{CO2} is the CO2 emission allowance costs for each power plant, α is a scaling factor to adjust the weight of the environment burden of power plants, and C_{EB} is the cost of environmental burden of each power plant. Constraints are related to physical processes, demand requirements, capacity limitations, and legal/ policy requirements. The integration of Variable Renewable Energy (VRE) can increase the complexity of the optimization models [99]. When the objective is to select the optimum mix of generating facilities that meets the load at the lowest operating cost subject to transmission and operational constraints, the modeling is usually referred to as economic dispatch [5].

To illustrate the potential complexity of optimization problems, it is helpful to consider a generic resource allocation problem: given a set of inputs (number/type of generating units, amount of land used, atmospheric conditions or meteorological data, efficiency, O&M cost, geographic locations of generating units, etc.), find the best combination (of total generation, portfolio mix, number/capacity of generating units, total investment, O&M cost, reliability, expected profit, estimated land use, etc.), to meet the objectives (minimize total system cost, cost per unit of energy produced, land area, investment, maintenance cost, noise and pollution emission, loss of power supply probability; and/or maximize thermal efficiency, total power generation, system reliability, profit, life span, total revenue, etc.), subject to constraints (generating units, power rating, minimum operating level, demand/load management, ramp rates, storage capacity, charge/discharge rate of storage, loss of power supply probability, life time of components, maximum power flow for distribution lines, fuel price, economics/budget, area of the land to be used, environmental/social/regulatory, cost of energy, etc.) [100].

Due to this complexity, and to aid in the addition of renewable energy sources, NREL has developed REopt, an early screening tool to identify and prioritize renewable energy projects at one or more sites [70]. It is promoted as a quick and low cost method for companies or organizations to identify the best technologies for further study, through a deterministic optimization model that identifies the most cost effective technologies and models the hourly interactions of multiple renewable and conventional sources. It combines site, resource, interconnection, cost, incentive, tariff structure and other financial data, with the objective function to minimize the present value of all future energy costs over the analysis period. REopt achieves an energy balance between consumption and generation during every time period, and identifies the technology sizes that meet the defined goals at minimum cost. The program includes PV, wind, solar ventilation air preheating, solar water heating, biomass, waste to energy and landfill gas, plus energy storage, with constraints including load, resource, operating, sizing, policy, emissions and any other specific scenario constraints. REopt's results include optimum technologies for a site, prioritization across a portfolio of sites, optimal dispatch strategies, and sensitivity analysis. Typical scenarios may include base case, minimize energy costs, net zero electricity, and energy security [101].

REopt estimates the value of the energy produced at a site by comparing the hourly generation to the hourly site load. All energy produced that is less than the load is assumed to be used on site and is valued at the retail rate. Energy produced in excess of the load is valued at the retail rate if total onsite generating capacity is under the net metering limit, the wholesale if it is under the interconnection limit, or zero if it is over the interconnection limit. REopt obtains information on incentives from the Database for State Incentives in Renewable Energy (DSIRE), sellback rates for excess energy production are based on the utility wholesale rates in the Ventyx database, and interconnection limits and net metering limits are obtained from DSIRE. Escalation rates are based on Energy Information Administration projections [101].

For individual renewable technologies, the REopt PV model assumes a fixed panel tilted towards the equator at an angle equal to the latitude of the installation, and the three categories of wind turbines included are 10 kW, 100 kW and utility scale (>1MW). Four types of biomass resource are included: crop residues, forest residues, primary mill residues, and secondary mill residues, and each system is assumed to be capable of operating at partial loading down to a given fraction of its nameplate capacity, but then it must shut off. Energy storage is modeled as a device that allows energy to be shifted from one time period to another; a round trip efficiency is assumed and limits are imposed on the minimum state of charge, the charging and discharging rates, and the number of cycles per day [101].

4. INTEGRATING VARIABLE RENEWABLE ENERGY

4.1 Impact of renewable generation on the power grid:

The variable nature of the atmosphere impacts not only renewable power generation, but also the load - the combination accounts for the variability that must be balanced by the power system [61]. In systems with substantial renewable penetration, this variability makes the net load time series more volatile than the conventional load time series. In one study of future scenarios, high integration of wind and solar power resulted in up to eight times higher volatility of the net load compared to the conventional load. When the net load factor is low, the transmission and generation infrastructure may be significantly under-utilized, with much of the generating capacity often offline or generating at the allowable minimum. Higher variability and less predictability of the net load will cause more cycling of conventional units, with more wear-and-tear and higher maintenance costs. When conventional generators are dispatched less often, the available ramping capability will be limited. In general, a smoother net load shape is more desirable from a planning point of view because the available transmission and generation infrastructure can be more evenly utilized [10]. A useful question to ask is what minimum level of thermal generation is necessary within a system for frequency response and voltage support [16].

4.1.1 System reserve requirements:

The cost of grid integration can be quantified in terms of reserves, defined as: the generating capacity available to buffer against the uncertainty of variable sources [45]. NERC defines two reserve types that are commonly estimated in integration studies: regulation reserves that must be responsive to AGC, and contingency reserves that are available to cover the unexpected loss of a generating unit. NERC requires regulating reserves to be responsible for maintaining system balance in the period between economic dispatch 95% of the time, often heuristically implemented as 1% of peak load. For contingency reserves, NERC requires available reserves equal to the most severe single contingency; in WECC this is implemented as the larger of the most severe contingency or the sum of 5% of hydro generation and 7% of thermal generation, at least half of which must be spinning reserves [65].

Reserve sizing methodologies can be probabilistic or deterministic, and static or dynamic. Deterministic approaches size the reserve according to a specific event, such as the largest credible contingency (N-1), but do not account for less severe events, their probability, or correlation between sources of imbalances. Probabilistic methods size the reserve such that a predetermined level of system reliability is met, estimating the probability density function of system imbalances, and use the reliability target as a cut off to determine the size of the reserve; this requires detailed knowledge of sources of imbalances, their probability distribution, and their correlation. Reserves can also be determined for long time periods such as one year (static) or more frequent periods depending on the current or expected status of the system (dynamic). Deterministic sizing is usually static; probabilistic sizing can be static or dynamic [1].

Wind plants are usually not large enough to constitute the worst contingency in a system and do not fail as a single unit; therefore they do not affect the contingency reserves requirements. However, it is recommended that studies should explicitly quantify the magnitude of low-probability ramp events for which reserves are needed, rather than basing the estimations on standard deviation [65].

BPA utilizes three types of reserves: regulation reserves cover differences between the supply and load within 10 minute intervals, following reserves apply from one 10 minute period to the next, while balancing reserves cover imbalances between forecast and supply at the 1 hour horizon, with a 99.5 percent reliability requirement [102]. BPA has an automated balancing reserves requirement tool which uses wind and load forecasts to estimate balancing reserve needs up to seven days out [13].

4.1.2 System reliability and flexibility:

Integrating new power plants can have a significant effect on the ability of the grid to survive low voltage conditions (voltage stability), oscillatory modes (small-signal stability), and short circuit faults (transient stability) [65]. System imbalances in the power grid can stem from different sources, such as unplanned outages and forecast errors. The probability of unplanned outages of power plants and transmission lines is a function of equipment age and type, plus operational decisions on maintenance, ramp rates, etc., while the size of forecast errors is a function of resource characteristics and operational decisions [1]. When a system has insufficient inertia, frequency control and handling of fault conditions becomes more difficult; the rate of change of frequency during a transient condition may trigger load shedding before primary response can stabilize the frequency [98].

The flexibility of a power system is important when incorporating variable renewable sources. Flexibility can be described as the capacity of the power system to respond to change, and ensures that demand balance, security and reliability constraints are met [8]. Conventional power plants and dispatchable renewable generators (biomass or geothermal) provide flexibility if they have the ability to rapidly ramp output up and down to follow net load, quickly shut down and start up, and operate efficiently at a lower minimum level during high VRE output periods [11]. Operational flexibility approaches include procedures and market practices such as real-time forecasting, faster scheduling, and ancillary services. In addition, coordination between BAs allows sharing of resources through reserve sharing, coordinated scheduling, and/or consolidated operation [7]. Without a sufficiently flexible grid, conventional plants cannot reduce output and VRE will need to be curtailed, which can add to system costs. As curtailment increases, VRE offsets less fossil fuel generation, decreasing its value [4].

A high penetration of renewable generation can be considered as the amount that begins to affect power-system operations. This level will differ for each system depending on operational practices, generation mix, inherent flexibility, and the market [61]. It is generally accepted that smaller percentages of renewable generation can be integrated into many electrical systems without significant operational changes [71]; possibly up to 30% of annual demand can be accommodated largely with flexibility options, but without energy storage and demand response [4]. The 30% level is viewed by another source as the level that will significantly increase flexibility requirements [10]; beyond 30%, integrating VRE becomes more challenging due to the limited alignment between wind and solar generation and electricity demand, as well as the inflexibility of conventional generators to ramp up and down to balance the system [4]. The flexibility of a power system can be enhanced by retrofitting only a portion of its conventional generators to improve the turndown level of gas and coal power plants. This type of system wide approach has a net benefit to the system, although there may not be a benefit at the plant level [103]. Sources of grid flexibility organized around domains of power markets that support balancing the grid at multiple timescales are shown in Figure 26.

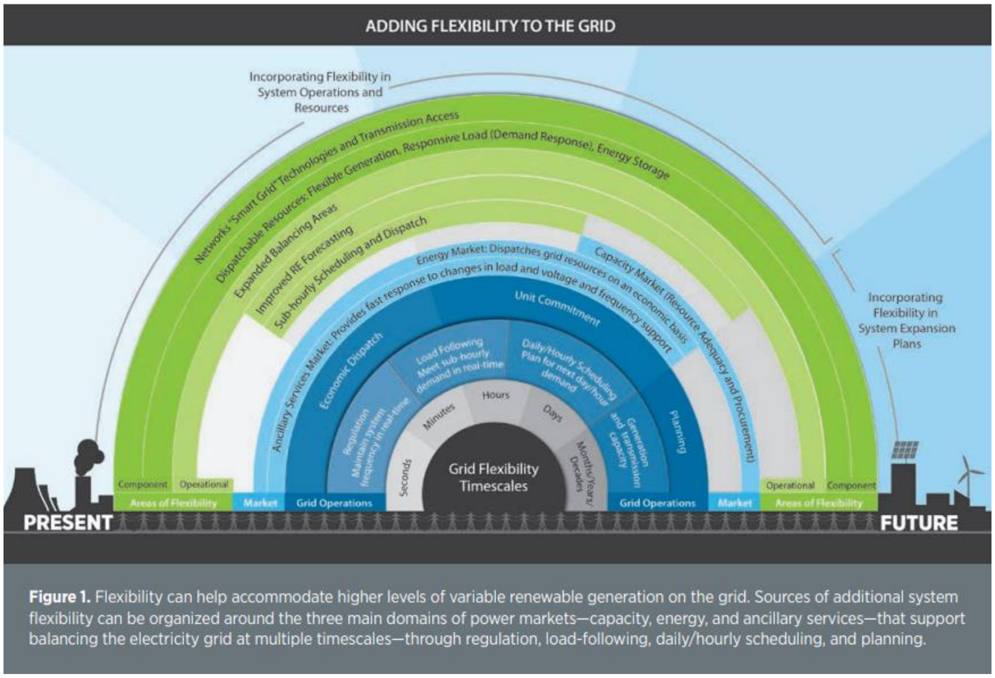

Figure 26 - Adding flexibility to the grid [101]

Numerous studies have identified two major ways to increase grid flexibility: methods that allow VRE to be used directly to offset demand and increase instantaneous VRE production, and methods that improve the alignment of VRE supply and demand, such as demand response and storage. Storage shifts the timing of supply, and demand response shifts the timing of demand [4]. The methods of obtaining grid flexibility are influenced by the regulatory structure - vertically integrated utilities typically use contractual requirements to obtain flexibility from generators, while system operators in restructured power markets use market designs with definitions of performance requirements to incentivize power system flexibility [104].

Wind and solar equipment characteristics determine how the generation facilities interact with the grid, and the extent to which they supply services such as voltage and frequency stability [9]. Modern wind and some solar plants now have the ability to provide active power control services including synthetic inertia, primary frequency response, and automatic generation control [105]. Distributed generators must meet interconnection standards and codes to interconnect with the grid, to support reliable distribution system operations. Traditionally, these standards require inverters to disconnect from the grid and interrupt energy production when certain grid disturbances are detected [42].

The overall question of how to design and operate a system with adequate flexibility, while limiting costs and ensuring reliability, has become a central focus rather than a secondary goal to traditional resource adequacy [16].

4.1.3 Transmission system:

It is important to determine the capacity of the existing transmission and generation infrastructure to support a proposed amount and configuration of VRE, while maintaining grid reliability. Robust transmission is important as it allows for aggregation of VRE and regulating units over large geographic areas; transmission expansion can be justified to both access high-quality resources and take advantage of resource diversity [93]. In addition to system structure, the actual requirement for transmission capacity can be influenced by correlations between demand and supply; some renewables may be better suited for implementation into a given transmission system [5].

When planning new transmission there are three key considerations: including system level interactions of transmission and generation, variation in generation/load conditions and long-range uncertainty of supply and demand, and the ability to adapt the system as unexpected changes occur. It is important to co-optimize investments in transmission and generation, and to consider system adaptability under different scenarios. Production cost modeling tools can be used to evaluate the economic performance of transmission and generation configurations. These tools optimize generation dispatch to simulate how energy markets utilize transmission, and can capture the constraints and costs in an actual system, but do not optimize network topology or suggest the most economic transmission investments [93].

It may be necessary to simplify the transmission network for simulation models, with buses being generalized to represent locations with significant load, power generation facilities, or interconnections between transmission lines, as there are limits to the complexity that can be modeled. This simplification makes it practical to optimize placement of transmission and generation investments, while considering numerous VRE and load conditions [93]. Power transmitted over interties can be represented as a single hypothetical generation station (including a constraint to prevent wheeling of power through the interties) equivalent to the total transmission capacity of the interties. When transmission line capacities are modeled with their winter conductor ratings it provides the maximum transmission potential. As other studies have done, the PNW's power grid represented by a purely resistive network, as this approximation is sufficient for long term planning purposes [5]. This simplification is represented by the DC power flow equation, shown in equation 8, based off equations 5 and 6.

$$P_k = \sum_{i=1}^{N} B_{ik}(\theta_k - \theta_i) \tag{8}$$

<u>4.1.4 Geographic diversity and combinations of renewable sources:</u>

Geographic diversity and/or combinations of renewable sources affect the impact of these renewables on the operation of the grid. The benefits of geographic diversity are well understood, as the variable output of multiple plants is smoothed when spread over large geographic areas and evaluated as an aggregate source. Studies have demonstrated that larger balancing authority areas are better suited to managing wind variability than smaller balancing authorities [65]. Solar and wind power are often highly complementary, especially on a seasonal basis, with spatial distribution less important between the sources than for the smoothing within the same resource. However, there is still a need for more studies of the smoothing effect and total variability for combinations of different renewable sources [29].

In many locations around the world, utilizing both wind and waves is viewed to be a good way to provide more constant production, with less risk of zero power, reduced peaks, and smoother changes from zero to peak values. The power distribution of waves shows a lower variability than wind power, because wind power is a function of the cube of the wind speed, while wave power is a function of the square of the wave height [29]. There is also discussion in the literature about the benefits of co-locating offshore wind turbines and WEC installations. Most windy areas are found in medium-high latitudes, with the best offshore wind resource at the west coast areas of the northern hemisphere and the east coast areas of the southern hemisphere. In addition to smoothed power output (for the same weather system the wave peaks trail the wind peaks), combined wave-wind systems could utilize common foundation systems and grid infrastructure, share Operating and Maintenance costs (O&M), and benefit from shadow effects (a milder wave climate inside the park). Wave-wind installations can be classified as co-located, hybrid or island systems. Co-located systems combine an offshore wind farm with a WEC array, with independent foundation systems but sharing the same marine area, grid connection, O&M etc. Hybrid systems combine an offshore wind turbine and a WEC on the same structure, while island systems are offshore multipurpose platforms [43].

4.2 Regulations, policies, operating practices and market considerations:

While there are significant regulations and policies affecting the electric utility industry, a few are of interest relative to increasing the penetration of renewable energy. Countries and some states in the US have adopted policies to derive specific percentages of electric energy from renewable sources, known within the US as Renewable Portfolio Standards (RPS). Denmark and Scotland have policies to derive 100% of their electricity from renewable sources, while Germany has a stated goal of 80% renewable electricity by 2050. Hawaii has the highest target of any state in the US requiring 100% renewable electricity by 2045 [98]. Oregon has the highest target within the Pacific NW, requiring the two large investor owned utilities to supply 50% of electricity from renewable energy sources by 2040, plus to phase out electricity from coal by 2030 [106] [107].

Determining RPS compliance costs is more complex in traditionally regulated states than in restructured states. Utilities in regulated states typically comply with RPS requirements through long-term power-purchase agreements with renewable generators or by ownership of renewable generation, and the expenses include both the cost of renewable energy certificates and the cost of the electricity [108]. Unbundled renewable energy credits (RECs) allow a utility to count the energy produced by a remote renewable energy facility even if the energy is not delivered to the utility's customers, bridging the difference between what a utility needs for RPS compliance and the renewable resources physically available for delivery to customers. Also, load is not the same as electricity sold to retail customers; most RPS requirements are based on retail sales rather than load, so if looking strictly at RPS compliance the load projections could be reduced slightly to account for line losses, wholesale power transactions, and other loads that are not retail sales [109]. Utilities and regulators have used varying approaches to estimate costs of avoided non-renewable generation, typically in three general categories - the cost of a generic conventional generator, wholesale electricity market prices, or production cost modeling. Rate impacts due to RPSs are estimated to be below 2% of average retail rates in most states [108].

FERC Order 764 (2012) is intended to remove barriers to the integration of renewables, requiring transmission providers to offer intra-hourly transmission scheduling. It also requires customers with large variable generators to provide meteorological and forced outage data to the transmission utility if the utility forecasts variable generation [13]. FERC Order 755 allows higher compensation for faster responding balancing resources such as batteries, flywheels and demand response, which may put storage technology at an advantage over other resources such as power plants. It should be noted that net metering tariffs can make storage unattractive, because electricity can be fed back into the grid at the retail price [83].

Increased cooperation between balancing areas can reduce fluctuations in supply and demand, and make it easier to maintain system balance. The benefits of sub-hourly scheduling between balancing areas are greater with higher levels of variable renewable generation. Especially where transmission constraints exist, faster scheduling across areas can allow variable generation to be more efficiently integrated through faster coordinated dispatch with neighboring markets [103]. Coordinated scheduling allows greater energy exchange, increases overall economic efficiency, and provides an increased ability to integrate VRE in the power system. However there are increased implementation costs, as energy exchange requires mechanisms to track energy purchases and flows. Transmission analysis is also essential in maintaining system reliability [15].

Dispatch below maximum output (curtailment) can be more of an issue for wind and solar generators than it is for fossil generation units because of differences in their cost structures. The economics of wind and solar generation depend on the ability to generate electricity whenever there is sufficient sunlight or wind to power their facilities. Because wind and solar generators have substantial capital costs but no fuel costs (i.e., minimal variable costs), maximizing output improves their ability to recover capital costs. In contrast, fossil generators have higher variable costs, such as fuel costs. Avoiding these costs can, to some degree, reduce the financial impact of curtailment, especially if the generator's capital costs are included in a utility's rate base [3].

Reserve sharing is one of the easiest methods to minimize the economic impact of uncertainty, as multiple balancing areas can reduce the total reserve requirements and lower system costs, while maintaining system reliability. Reserve sharing groups can share different types of reserves; from simplest to most complex, groups can share contingency reserves (in response to generator or transmission line failures), regulating reserves (secondary frequency response via automatic generation control), or flexibility reserves (to address variability and uncertainty on timescales longer than regulating reserves) [15]. Reserve sharing has relatively low implementation costs since many reserves have relatively small energy requirements, minimizing total energy exchanges that occur between balancing areas, and reducing the need to establish mechanisms to track energy flow and allocate costs (although transmission adequacy still needs to be ensured) [15]. Whether within or between balancing areas, ramping and reserve requirements are best addressed at the system level [105].

System flexibility can be motivated in restructured power markets through incentives and market design, such as sub-hourly dispatch, ancillary services markets, and price-responsive demand [7]. An energy imbalance market (EIM) is a bid-based centralized market - each system operator sends projected load and available capacity to the central market, where the EIM operator dispatches generators to produce electricity at least operating cost. Day ahead scheduling is still performed by the individual system operators [15]. The main objective for the introduction of EIMs is to reduce imbalances between demand and generation without ancillary services or additional reserves through the short-term energy trading between interconnected BAs. With increased geographical diversity of generation and load profiles, the main benefits are reduced operating reserves capacity, enhanced reliability, reduced costs and automatic dispatch, and real time visibility. The EIM in the Western Interconnection was opened in October 2014, interconnecting over 30 balancing authorities in the US and Canada. This allows for generation and demand balancing across the BAs on 15 minute and 5 minute time scales, with California Independent System Operator (CAISO) oversight [110].

The market structure can significantly impact investment decisions. For example, over 95% of PHS was developed under monopoly market conditions, aligned with periods of significant infrastructure growth. PHS is at a disadvantage in the US, with significant levels of fuel-based generation providing system flexibility, and a focus on interconnectors to increase the size of markets. In restructured markets, storage must specify its own charging/discharging windows and production costs in the day ahead market, then the ISO optimizes within that specified schedule. In liberalized markets, ancillary services can offer larger revenues to PHS operators than time-shifting energy, and market operators typically value regulation reserves the most, followed by spinning reserves. FERC 755's requirement that ISO's must compensate actual services provided for frequency response is beneficial to EES in the markets [71]. There are many potential policies and incentives to encourage VRE generators to provide grid-support services, including incentives for grid support capabilities, addressing congestion, aligning generation with demand, providing forecasting data, integration with dispatch optimization, and dispatchable renewable resources [111].

Regardless of technical capabilities or benefits, the cost of energy production is perhaps the single most important factor in determining whether an energy technology can reach commercialization [112]. Components that contribute to the cost of electricity from renewable technologies include resource quality, equipment cost and performance (including capacity factor), the balance of project costs, fuel (if any), operations and maintenance costs (and reliability), economic life of the project and the cost of capital [14]. Most storage technologies (except PHS) are not cost effective or mature enough for widespread implementation within the current energy markets [6].

4.3 Studies and recommendations:

Many studies have been completed on various aspects of VRE, from research focusing on one resource or technique to large national studies. With so many unique characteristics of regions and sites, the integration of high VRE penetration levels is changing electricity power planning from a centralized perspective to a regional and local perspective [99]. Due to the size and complexity of the electric grid and associated markets, all of the studies place simplifying limits on their analyses. Large studies include NREL’s Renewable Electricity Futures Study [35], the Western Wind and Solar Integration Study (WWSIS) [113] and the Eastern Renewable Generation Integration Study (ERGIS) [114]. Also, the Western Interconnection Flexibility Assessment contains significant information relevant to the Western Interconnection and the Pacific Northwest, including the interaction of the Northwest with neighboring regions [16]. In general, high levels of VRE penetration are technically feasible, but require modifications in the systems (generating mix, transmission capacity, balancing authority extent) or operating practices (scheduling frequency, curtailment, etc.). Integration costs may be reduced by larger balancing authority areas, increased transmission robustness and improved integration of VRE into market processes. Although the low inertia found in wind and solar plants could potentially create stability problems, many multi-region or national studies have not focused on power system stability issues [65].

It is prudent to cautiously evaluate the results of studies to validate their applicability and methods. The technologies are still developing, costs can be expected to change along with the technologies, and various studies model different features, with different methods, at different time scales, in different geographic areas. Simplifying assumptions in studies may or may not be technically, economically, socially or environmentally feasible. Overstating the results of a particular study beyond what its assumptions or methods may justify can cause debate about its validity. A recent example is a study proposing a low cost method of achieving 100% wind, water and solar generation [115], which was challenged by a group of researchers for significant shortcomings in the analysis [116]. Among other things, the challenging group of researchers emphasized industry consensus regarding the need for diverse portfolios of clean energy technologies, plus the importance of avoiding the presentation of "ideas" in a hypothetical analysis as feasible and reliable solutions.

4.3.1 Large renewable energy integration studies:

NREL's Renewable Electricity Futures Study analyzed the US electricity system's ability to meet customer demand until 2050, with high levels of renewable penetration. The key finding is that renewable generation from technologies commercially available today, in combination with a more flexible electric system, is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the country. The increased electric system flexibility could come from flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations. Additional operating reserves were required in high VRE systems and were accommodated through the availability of conventional power plants, storage technologies, and demand-side practices. A high renewable electricity future would reduce the energy-providing role of the conventional fleet and increase its reserve-providing role. (The existing conventional units would be more available to satisfy operating reserve requirements, as the dispatch of these plants would decline to accommodate additional VRE generation.) Improvement in the cost and performance of renewable technologies will have the most impact for reducing the direct incremental cost of high renewable generation [35].

During the first phase, the Western Wind and Solar Integration Study (WWSIS) investigated the benefits and challenges of integrating up to 35% wind and solar energy in the Western Interconnection in 2017. The study determined it is possible to accommodate 30% wind and 5% solar energy if utilities substantially increase their coordination of operations over wider geographic areas and schedule their generation and interchanges on an intra-hour basis. More specifically, this integration of wind and solar energy will not require extensive infrastructure if changes are made to operational practices. Wind and solar energy displace fossil fuels, and a 35% penetration would reduce fuel costs by 40% and carbon emissions by 25%-45%. The use of solar and wind forecasts is important, with their use in utility operations reducing operating costs by up to 14%. In addition, existing transmission capacity can be better used, and demand response programs can provide important flexibility [113].

In the WWSIS, all generators were assumed to be available for least-cost economic dispatch, and not limited by power purchase agreements. The recommended balancing reserve was three times the standard deviation of ten-minute net load, or 3% of load plus 5% of short-term forecast wind, with one standard deviation of the ten-minute net load variability available for regulation. If existing thermal units were dispatched less frequently, rather than de-committed, up-reserves could be provided from existing generation. If a large over-forecast caused spinning reserves to be required for regulation, the resulting shortfalls in the contingency reserves could be managed through increasing spinning reserves, storage, or demand side management [65]. The WWSIS also found that wind and solar variability has less of an impact on regulation requirements than hourly scheduling of generating units [103].

Phase 2 of the WWSIS evaluated the wear-and-tear costs and emissions impacts of cycling, and simulated grid operations to investigate impacts of wind and solar power on the fossil-fuel fleet. The study determined that the negative impact of cycling on overall plant emissions is relatively small. The increase in plant emissions from cycling was more than offset by the overall reduction in emissions, and in the high wind and solar scenario, net carbon emissions were reduced by one-third. The cycling costs varied depending on penetration level and wind/solar mix, with operating costs increased by roughly 2%-5% for fossil-fuel plants with the high penetration of variable renewables. From a system perspective, these increased costs were relatively small compared to the associated fuel savings [113].

Phase 3 of the WWSIS studied the dynamic performance of the Western Interconnection in fractions of 1 second to 1 minute following a large disturbance, with high penetrations of renewable energy. The study focused on large-scale frequency response and transient stability, which are critical to grid reliability. It was determined that, with good system planning, sound engineering practices, and commercially available technologies, the Western Interconnection can withstand the crucial first minute after severe grid disturbances with high penetrations of wind and solar on the grid. Frequency-responsive controls on wind and solar power plants and energy storage were also examined and could improve frequency response [113].

The Eastern Renewable Generation Integration Study found that integrating up to 30% variable wind and PV generation into the power system is technically feasible at a five-minute interval. The operation of thermal and hydro generation changes as wind and PV increase, and system operations at sunrise and sunset follow different patterns. Transmission flows will likely change more rapidly and more frequently with higher penetrations of wind and PV, and the operating practices of generators and transmission operators will be critical to realizing the total technical potential of the interconnection. The study also suggested that advanced visualization tools are helpful for understanding spatially and temporally rich models [114].

The Western Interconnection Flexibility Assessment reinforced conclusions reached by prior studies of high renewable penetrations: operating a system reliably is technically feasible; renewable curtailment plays a key role; regional coordination is an enabling strategy; and measures that increase a system's capability to serve loads during low net load conditions have the greatest potential to ease integration challenges. The nature of integration challenges with a high level of renewables vary from one region to the next and depend on the seasonality of load, the composition of the renewable portfolio, and the characteristics of non-renewable generators. Realizing a significant transformation of the electricity sector to greatly increase VRE penetration would require a coordinated approach: sustained build-up of many renewable resources in all regions; deployment of a renewable mix to accommodate constraints in transmission expansion, system flexibility, and resource accessibility; ensuring adequate contribution to planning and operating reserves from conventional generators, dispatchable renewable generators, storage, and demand-side technologies; increased flexibility of the electric system (through some combination of storage, demand-side options, ramping and more flexible dispatch of conventional generation, curtailment, and transmission); and transmission expansion for access to diverse and remote resources, and greater reserve sharing and balancing over larger geographic areas [35]. At high renewable penetrations, the need for flexibility reserves increases; at the same time, net load decreases. Therefore, the set points of the conventional resources must decrease to accept the additional renewable energy while the necessary operating range to meet the reserve requirements increases in size [16].

The EIA projects that onshore wind entering service in 2018 will be one of the technologies with the lowest total system levelized cost. But while wind power reduces electricity prices to a certain extent, electricity price volatility increases with wind power penetration. Over forecasting wind power increases electricity prices, while under forecasting wind power reduces electricity prices. For high wind penetrations, allowing wind power curtailment reduces electricity price volatility [117]. While the majority of integration studies focus on wind and/or solar resources, it has also been concluded that the integration of hypothetical wave energy farms would not pose any significant problems to the grid in the WECC system [46] [118].

For the US, NREL estimates grid investment costs to integrate 80% renewable electricity (half VRE) to be about $6 per MWh of VRE [119]. It has been recommended that future studies consider more broadly, and model more explicitly, the ways in which different types of balancing services can be purchased from different types of power plants. Storage and demand response could provide highly responsive balancing services, but will only be deployed if electricity markets reward power plants for their responsiveness [65].

4.3.2 Curtailment, net interchange and transmission system expansion:

As the concentration of intermittent resources becomes mismatched with the instantaneous demand for electricity, the share of renewable generation that must be curtailed to preserve reliability also increases. For day to day operations, strategies to avoid curtailment could include increased regional coordination, investments in energy storage, or adding flexible generation to the thermal fleet. The role of curtailment as an operational strategy to ensure reliability and efficient operations in high penetration renewable scenarios also has implications for policies aimed at increasing the penetration of renewables. The simplest strategy is to overbuild the renewable fleet so it has the capability to produce more on an annual basis than is required to meet policy goals, establishing an allowance for renewable curtailment. Other strategies may be to increase the downward flexibility of the existing generation fleet to accommodate more renewable production, or to find an alternative market for generation that would otherwise be curtailed (displacing fossil-fueled generators in other regions). Regional coordination can reduce, but not eliminate, renewable curtailment, as finding a market for surplus power may be difficult during periods when multiple regions experience curtailment simultaneously. The Western Interconnection Flexibility Assessment calculated an estimated curtailment cost of $100/MWh as a way of understanding the long-run cost of renewable curtailment [16].

NREL's Renewable Electricity Futures Study provided a similar list of potential strategies: additional transmission capacity in congested corridors would help reduce curtailment; increasing the size of reserve-sharing groups could help reduce the number of inflexible generators online to provide spinning reserves; the flexibility of the thermal fleet could be improved; additional energy storage and controllable loads could be used to improve system flexibility; and industry could take advantage of low-cost electricity available during times when curtailment would have occurred, with the increased demand consuming electricity that otherwise would have been curtailed [35].

Curtailments can occur in three ways: economic curtailment, self-scheduled cuts, and exceptional dispatch (the ISO orders generators to turn down output). Economic curtailments and self-scheduled cuts are considered "market-based," because the ISO's market optimization software automatically adjusts supply with demand. If market-based solutions haven't cleared the surplus of electricity that could be generated, the last resort is for the ISO to call on specific renewable plants to reduce output to prevent or relieve conditions that risk grid reliability [120].

Since reliability is a function of both generation and transmission, there is a need for creative thinking about how to most effectively utilize existing transmission resources, with possibly some level of transmission expansion, to facilitate high renewables scenarios. The siting of renewables and transmission can have a dramatic effect on the capacity value of a VRE plant. One study compared the levelized cost of energy from distant, high-capacity-factor wind sites to energy from near, lower-capacity-factor wind sites, and concluded that transmission investment costs could make the closer, lower-quality sites less expensive [65]. NREL's Renewable Electricity Futures Study lists assumptions for transmission and interconnection costs: inter-BA line $1,200–$5,340 /MW-mile; substation $10,700–$24,000 /MW; intertie (AC-DC-AC) $230,000 /MW; base grid interconnection $110,000 /MW; intra-BA line $2,400–$10,680/MW-mile; transmission losses 1% per 100 miles [35].

4.3.3 Storage:

Pumped hydro was determined in one study to be the most cost effective technology for generation applications, while CAES was the most cost effective for transmission and distribution applications [74]. The large scale use of pumped hydro in high-renewable penetration countries such as Germany and Ireland illustrate the type of operational changes that are likely to be needed as VRE penetration increases [65]. The addition of new downward flexibility (the ability to charge energy storage) provides substantially greater benefits than the addition of new upward flexibility (the ability to ramp from P_{min} to P_{max} very quickly), as it expands the net load range across which a system can operate [16].

NREL has developed a freely-available System Advisor Model (SAM) tool. SAM links a PV-coupled battery storage model to detailed financial models to predict the economic benefit of a system. The dispatch algorithm does not perform a cost-based optimization, but provides options for automated but suboptimal dispatch to achieve specified goals [121]. However, general conclusions are elusive because there is high sensitivity to the complex interplay among scenario parameters and location-specific information [122]. SAM assumes the battery is AC connected through a power converter, in parallel with the load, grid, and PV system. The power conversion is approximated by two efficiencies (charging and discharging). The manual dispatch controller allows a choice of how to charge and discharge the battery depending on the hour and month. The dispatch algorithm computes how much energy is needed to fully charge the battery and how much energy is currently in the battery based on information from the last time step. The energy from the PV system is compared against the energy required to meet the load, and decisions made based on the specified charging/discharging criteria. The user must input the minimum and maximum state-of-charge desired in the battery bank, and the minimum time allowed at each charge state before switching is also specified to prevent rapid charging/discharging [123]. There is also an automated dispatch controller that runs in a look-ahead mode, where perfect PV and load forecasting are performed over a period of 24 hours and the dispatch strategy is set to reduce peak grid purchases as much as possible [122].

An NREL study stated that modeling storage is significantly more complex than modeling conventional generation, and because its costs are currently typically higher than generation or demand response, value stacking is an important factor in its deployment. The study analyzed deployment of storage and interruptible load in the Western Interconnection through 2030. Two sets of assumptions were modeled: baseline conditions of about 32% renewable energy penetration by 2030, and higher renewable energy assumptions with penetrations reaching about 40% in 2030. Under scenarios with storage cost and performance from the DOE/EPRI 2013 Electricity Storage Handbook, new storage was not deployed in the Western Interconnection in the study timeframe. However, scenarios where capital costs for battery storage technologies were significantly below 2013 estimated values (down to about $100/kWh), more-significant storage capacity was predicted. The value of storage to the system varied greatly by region. While firm capacity needs were found to be an important driver for new storage development, the ability of storage to contribute to other system needs or lower system costs (such as operating reserves or energy shifting) can also drive new storage deployment. Storage enables increased renewable penetration in regions with a high need for flexibility reserves, which grow with renewable penetrations, plus energy shifting and curtailment reduction increase the value of energy storage in regions with already high penetrations of variable generation [124].

NREL compared battery storage when coupled to vs. independent from PV plants, and found that there are cost-benefit tradeoffs. Although independent systems have the highest cost (separate siting of PV and storage increases BOS costs compared with coupled systems), independent systems allow storage to be sited within congested urban areas. When storage is appropriately sized, co-locating and sharing components can be beneficial, however the results were for a specific case and the potentially significant benefits associated with deploying storage in congested areas were not included (such as deferring new investments in transmission/distribution capacity, and replacing peaking capacity in urban areas). Operating a PV plus storage system in a tightly coupled manner also decreases the overall efficiency of the power system and does not use grid assets to minimize overall system costs. The cost components used in this study were: battery module $304/kWh, battery BOS $612/KW, battery O&M $9/kW-yr (stated as 2016 costs but battery type not specified) [125].

Another energy storage study by NREL indicated that with technological advances, batteries can provide load shifting and operating reserves services now provided most often by highly flexible, natural-gas combustion turbines. Depending on battery life, batteries can enable a system with equal or lower overall life-cycle cost even if the capital cost of batteries is higher than the capital cost of a combustion turbine of equal capacity. The study also included information on one of the largest wind battery systems in the US, at Hawaii's Kahuku Wind Plant on Oahu. The 15-MW battery system (ten 1.5 MW/1-MWh battery packs) was designed to meet requirements for ramp rates and power fluctuations set by the Hawaiian Electric Company [73].

The primary focus of a 2010 study by the California Energy Commission was to determine the optimal use of grid-connected storage to provide ancillary services and meet NERC standards when renewable energy resources provide a significant portion of the energy used within the California ISO. Using dynamic modeling, the study estimated the need for regulation services and the role of storage in supporting these regulation requirements. Because of faster ramp rates and the ability to both generate and consume power, the study found that a 30 - 50 MW storage device could be as effective, in terms of regulating frequency to within limits, as a 100 MW combustion turbine used for regulation [65].

A study of high renewable scenarios for 2050 in western Europe determined that only fossil-fuel powered generators can supply inter-seasonal flexibility, as the storage technologies included lacked the necessary capacity. Power storage to provide inter-seasonal storage (such as hydrogen storage) was stated as being prohibitively expensive. High renewable scenarios led to some curtailment, but it was determined that it would be less expensive to curtail this power than to invest in storage. Higher curtailment levels may benefit the business case of electricity storage, but there is no consensus about the cost-effectiveness of this storage. Other studies suggest electricity storage as a cost-effective option for high renewable portfolios, or for systems with 100% renewables [126].

In solar-dominated regions, the renewable integration value of energy storage resources is driven largely by the ability to store excess renewable energy during midday and to discharge this energy to meet the evening peak. In contrast, over-generation in the Northwest is driven more by daily hydro energy constraints than by diurnal mismatches between load and renewable availability, and daily energy storage resources do not alleviate renewable curtailment. This suggests that managing imbalances in the Northwest may require longer duration energy storage [16].

Two technologies were chosen for this study based on the maturity of the technology, the literature search identifying the most widely utilized system types for the various applications, and the geography and specific needs of the Pacific Northwest. Li-ion batteries will be included for short to midrange applications, while pumped hydro storage will be modeled for longer scale applications.

4.3.4 Pacific Northwest and the Western Interconnection:

The Western Interconnection Flexibility Assessment identified no technical barriers to penetrations of renewable generation up to 40% in the Western Interconnection. However, it emphasized that routine, automated renewable curtailment is a fundamental necessity to electric systems at high renewable penetrations, although the magnitude of the curtailment can be reduced through efficient coordination of operations throughout the Western Interconnection. The interregional exchange was modeled based on historical values, but relaxing this constraint and allowing the use of the transmission system to its physical limits resulted in a reduction of renewable curtailment. This allowed regions facing oversupply to use the full capability of the transmission system to find an alternative market for their power [16].

The availability of imports and their contribution to the reliability of a region depends on a number of factors, including the physical limits of the transmission systems, long-term contracts or ownership of remote resources, the balance between loads and resources in different parts of the region, and the underlying economics of power markets. Aside from two deregulated power markets (California ISO and the Alberta Electric System Operator), the Western

Interconnection operates through bilateral contracts among a mix of vertically integrated utilities, public power utilities, and federal power marketing authorities. Interregional power exchange is largely based on longstanding contractual arrangements and well-established seasonal patterns. Overcoming this institutional barrier would have a large potential value by utilizing the diversity of loads and renewable resources in the Western Interconnection. If the limits on interregional power exchange increase from historically observed flows to the physical limits of the transmission paths, increased regional coordination can reduce renewable curtailment from 6.4% under historical limits to 3.0% under physical limits [16].

After analyzing the locations throughout the West of remaining prime quality utility scale renewable resources, one study suggests that by 2025 the largest surpluses will be wind power in Colorado, Montana, New Mexico, and Wyoming, geothermal power in Idaho, and geothermal and solar power in Nevada. The most likely importing states are projected to be California, Oregon, Utah, and Washington. The most likely paths are as follows: Montana and Wyoming wind power delivered to Arizona, California, Oregon, Utah, and Washington; Colorado and New Mexico wind power delivered to Arizona, California, and Utah; Idaho and Nevada geothermal power delivered to Arizona, California, Oregon, Utah, and Washington; and Arizona and Nevada solar power delivered to California, Oregon, Utah, and Washington. Power flows from Colorado and New Mexico to the Northwest were not included due to significant transmission limitations. The factors most likely to drive renewable energy procurement after 2025, such as switching to clean energy sources, replacing old capacity, and responding to consumer preferences, generally involve energy delivery [109].

The characteristics of the Northwest hydro system have important implications for renewable integration and energy storage. The modeled amount of curtailment experienced in high hydro conditions (60,000 MWh per day) is three times larger than that experienced in average hydro conditions (20,000 MWh per day). The value of energy storage in the Northwest may be limited by comparison to California and the Southwest. Since oversupply events during the spring runoff persist much longer, often throughout the day, there is a much more limited opportunity to shift generation within the day. Also, the Northwest already has significant intra-day energy storage capability through its existing system of hydroelectric resources; the hour-to-hour fluctuations can largely be managed by the hydro resource. Although the region-wide challenges in the Northwest suggest a limited role for daily energy storage, the inclusion of higher renewable portfolios may increase the benefits of energy storage. [16]

5. METHODS:

Understanding the interaction of generation types can be complex, due to seasonal variability and market forces. In the Pacific Northwest, there is significant hydroelectric capacity installed, 63% of nameplate capacity calculated from data downloaded from the EIA US Energy Mapping System based on years 2012 - 2015 [26] and 69% according to BPA [20]. In addition, a significant amount of power is exported from the BPA BAA. There are also known changes on the horizon, such as the planned phase-out of coal generation in Oregon by 2020 and in Washington by 2025. Therefore, a macro-level analysis was first performed to select combinations of renewables to analyze in more detail.

5.1 Initial Data collection:

There are many sources of publicly available data. A list of power plants in the US and the generating capacity of each is available at the Energy Information Administration (EIA) website [26]. The BPA Transmission website includes historical five-minute time series for aggregate wind forecasts, wind generation, hydro generation, thermal generation, total load, net interchange and available reserves [20]. The University of Oregon Solar Radiation Monitoring Laboratory has time series solar irradiance data for multiple locations in Oregon, shown in Figure 27 [69]. NOAA has historical meteorological information available through the National Centers for Environmental Information (formerly National Climatic Data Center) [127] and wave buoy time series data available from the National Data Buoy Center [44]. The BPA Transmission website also includes time series wind speed data for multiple locations, Figure 28 [20]. In addition, NREL publishes an Annual Technology Baseline with significant information, including capacity factors and costs, to provide consistency in their analyses [128].

Figure 27 - University of Oregon solar monitoring stations [69]

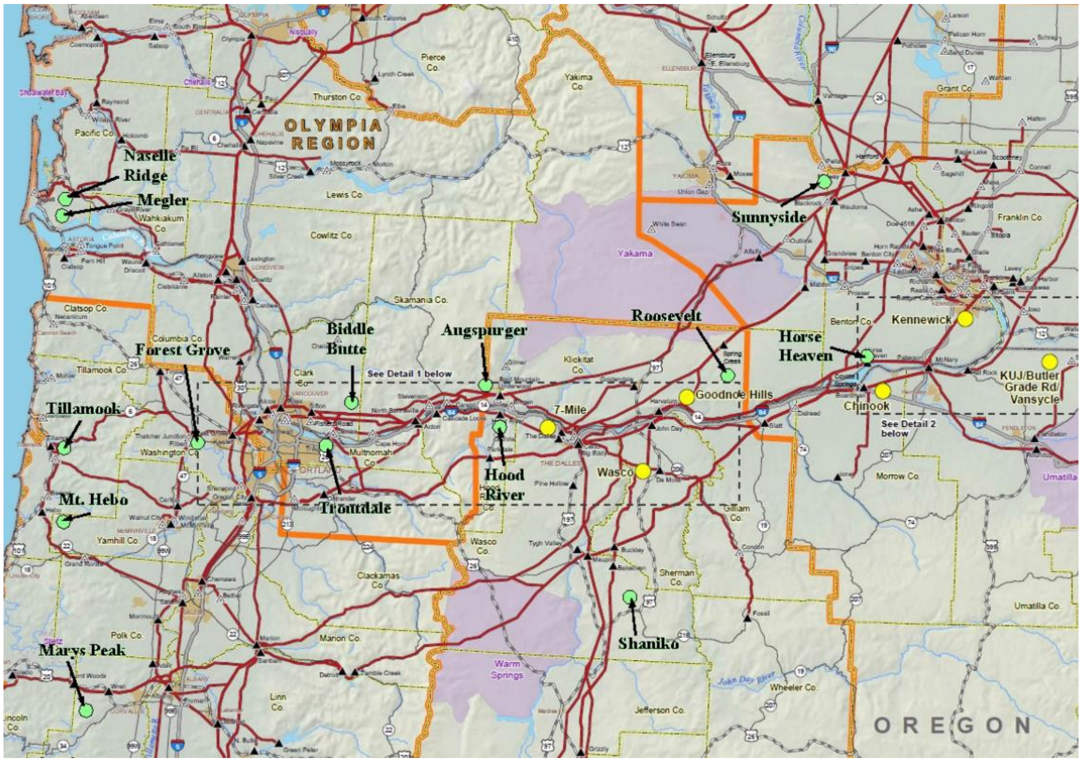

Figure 28 - BPA meteorological monitoring stations [20]

A list of all power plants in the US including the generating capacity of each was downloaded from EIA [26]. Since the states of Oregon, Washington and Idaho most closely match the BPA balancing authority area, all other states were excluded. The plants in the three states were sorted by primary fuel type and capacity within each state. Since the primary fuel types are hydro, wind and natural gas, these three categories were selected to evaluate the seasonal patterns of the generation mix. Coal was excluded due to its low penetration and future phase-out. Biomass was also excluded from the seasonal analysis due to its small contribution to the mix and its assumed current correlation to the forest products industry (based on the forest product owners of the majority of plants). The contribution of utility scale solar is negligible in all three states.

In each state, the top five plants of each type (hydro, wind, natural gas) were identified. In two cases, wind in Idaho and Washington, the top five plants totaled less than 50% of the total installed capacity. Therefore, a sixth wind plant was added in each of these two states. Also, in order to evaluate the seasonal interaction between hydro, wind and natural gas, the years 2012 - 2015 were selected, based on the reasonably constant amount of wind capacity since 2012 [20].

5.2 Plant size and location determination:

For each of the fifteen largest hydro facilities, five per state, the file containing net monthly generation was downloaded from EIA [26]. This data was then combined into a single Excel spreadsheet. Using the hydro capacities and the number of hours per month, the monthly capacity factor was calculated for each dam. Using the dam capacity as the weighting factor, the weighted average capacity factor was calculated for each month (for the four years), then averaged to a single capacity factor for each month of the year (January through December), as shown in equation 9. This process was repeated for the largest wind plants and natural gas facilities.

$$(Capacity\ factor) = \frac{\sum(Hourly\ generation)}{(Nameplate\ capacity)(Hours\ per\ month)} \qquad 9$$

The seasonal patterns of the three fuel types (hydro, wind and natural gas) are readily apparent when the capacity factors in the BPA BAA are graphed together (Figure 29). Over the course of the four years, the average capacity factor per month is shown. Hydro and wind output both peak in the spring; in late summer and early fall the natural gas capacity factor increases to compensate for the decrease in hydro and wind output.

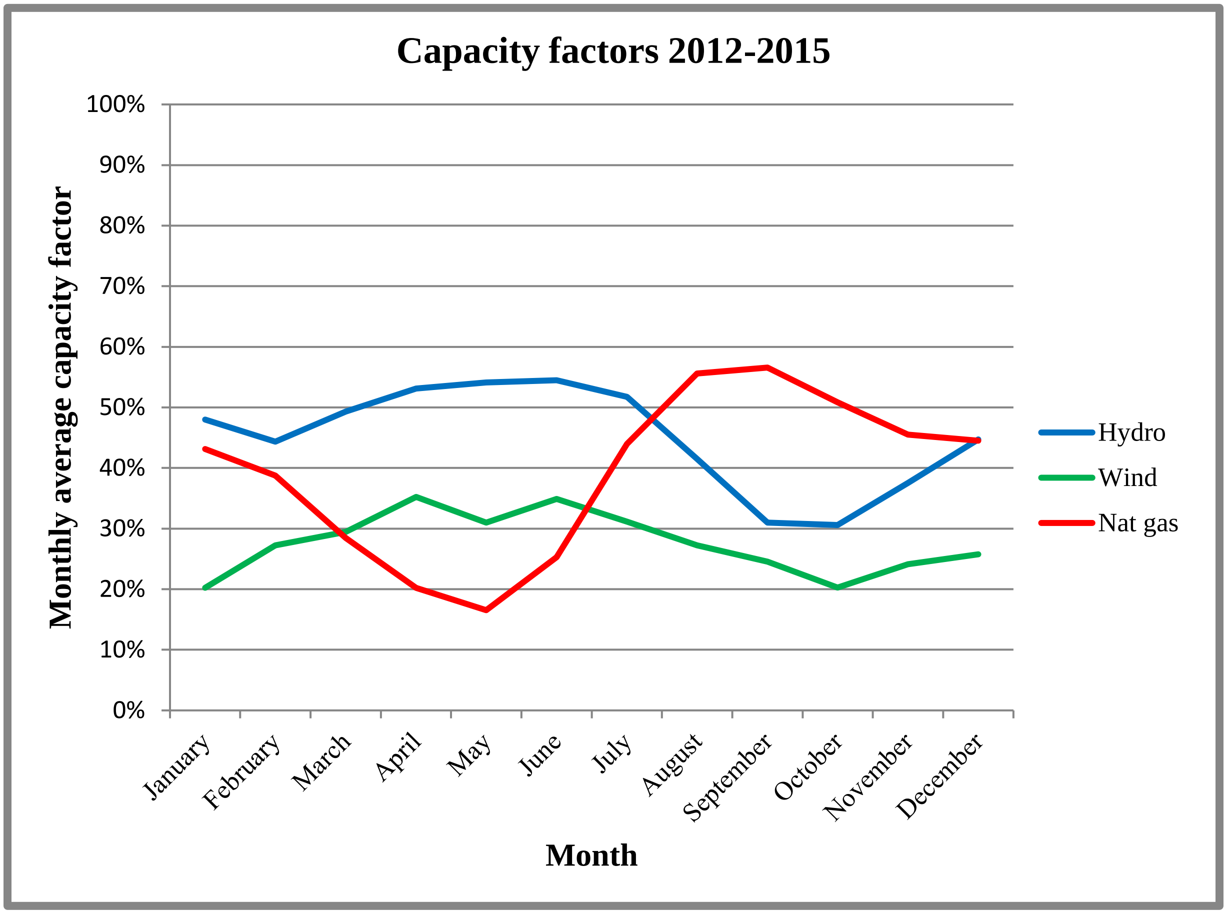

Figure 29 - Capacity factors of hydro, wind and natural gas, 2012-15. Data from [26].

As a visual representation of the relative installed capacities for the different fuel types, these capacities based on the EIA data were plotted in a pie chart (Figure 30).

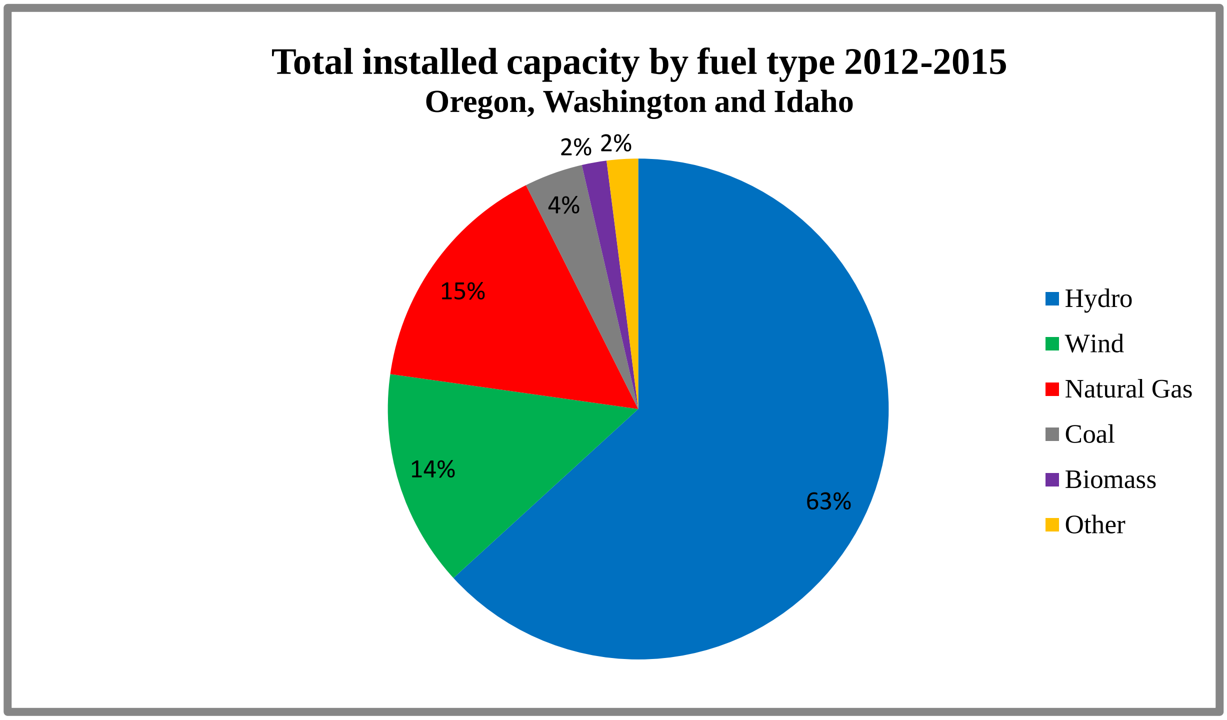

Figure 30 - Percentage of total installed capacity by fuel type, 2012-15

Next, actual generation and load data in five minute increments was downloaded to Excel from the BPA website for 2012 - 2015 [20]. This included aggregate wind forecast, wind generation, hydro generation, thermal generation, total load, and net interchange (all in MW). For each set of data, the average MW for each month was calculated, then converted to average MWh for the calendar months. The monthly generation based on the four year averages for each individual fuel source is graphed in Figure 31, and the contribution of the three sources to the total generation is shown in Figure 32.

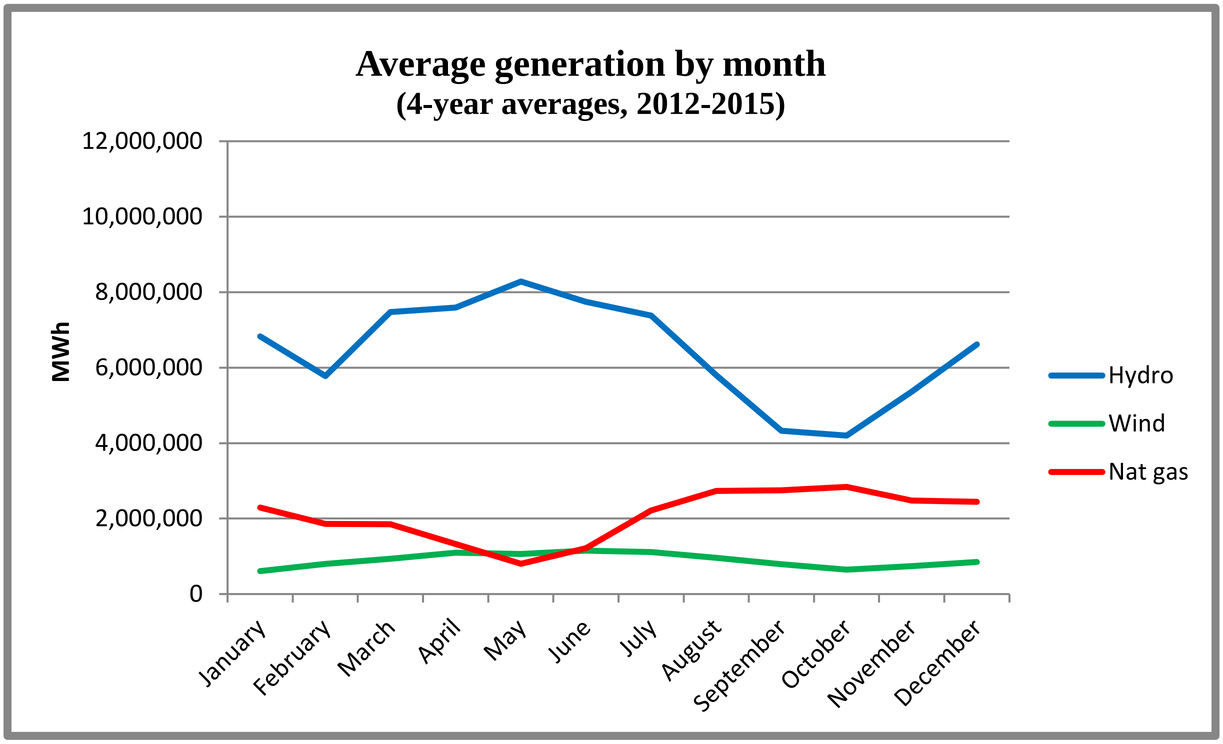

Figure 31 - Actual generation based on 4-year average, 2012-15

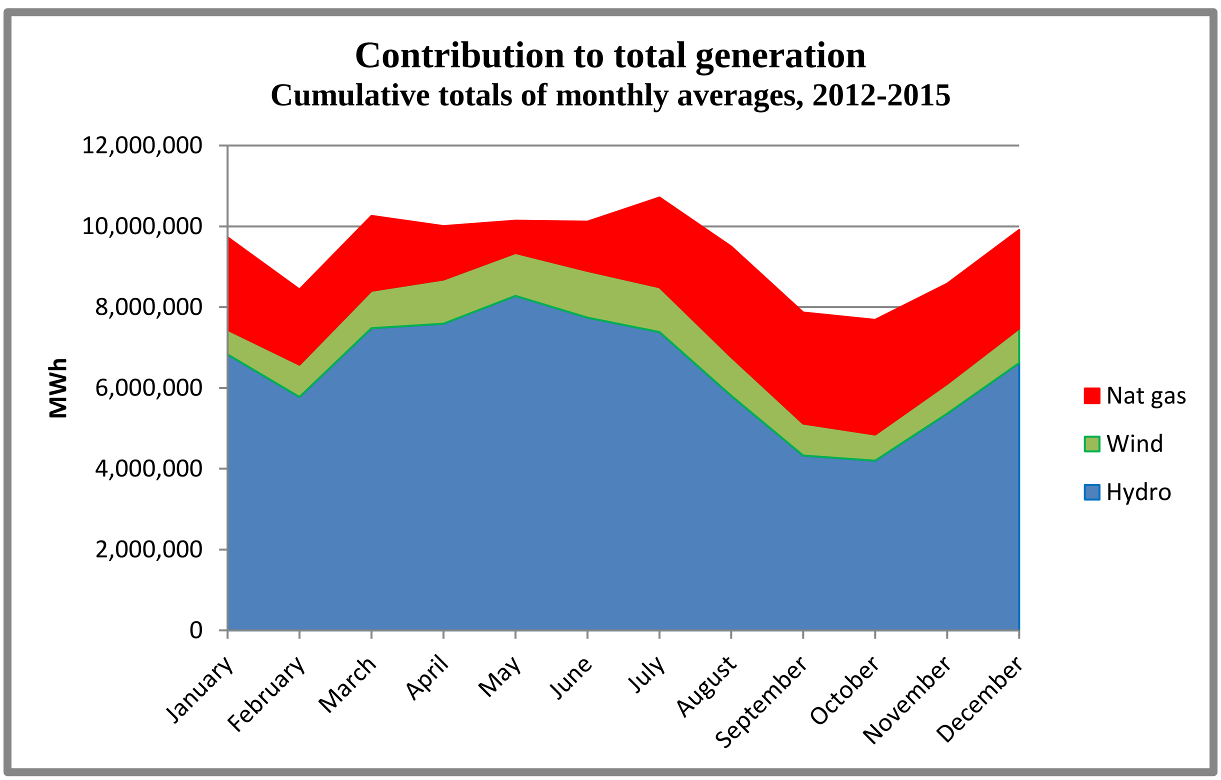

Figure 32 - Contribution to total generation of thermal, wind and hydro, 2012-15

Since a significant amount of power is exported from the BPA BAA, the load and net interchange averages are shown in Figure 33.

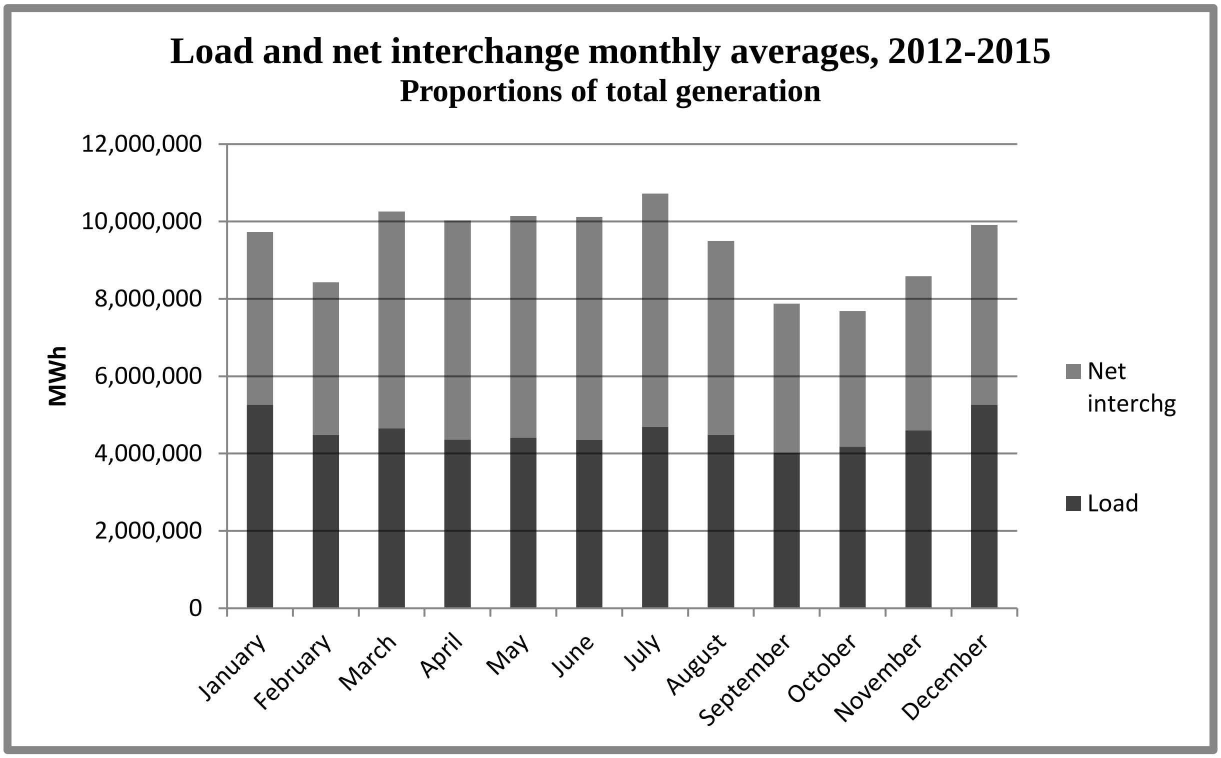

Figure 33 - Load and net interchange, 2012-15

5.3 Definition of study boundaries:

Of the three states completely within the BPA BAA, Oregon has the highest RPS requirement with 50% renewables by 2040. However, the RPS also states that replacing hydro resources is not the intent of the regulations [107]. In studying Figures 26 and 27, it can be seen that hydro makes up about 50% of generation during its low point in the calendar year. This generation is approximately 4,000,000 MWh/month. Although the load average is also roughly 4,000,000 MWh/month during the same period, a roughly equivalent amount is exported (Figure 28), and it is assumed that this historical level of exports will continue to exist.

Since a complete system model and optimization is very complex and computationally intensive, simplifying assumptions were made in defining the study boundaries. In order to focus on a broad analysis of storage benefits with high renewable portfolios, a copper-sheet analysis was used to simplify the limitations of the transmission system. The copper sheet analysis assumes zero resistance in all power grid elements, so the DC power flow equation simplifies even further, to equation 11.

$$P_k = P_i \qquad 11$$

The power available at bus k is equal to the power available at bus i. New renewable generation plants were assumed to be of a typical utility capacity and evenly sized between the geographic locations where data was available. Capital and annual O&M cost estimates were based on best available public data, but other market factors were excluded. Also, no grid balancing was implemented, as the differing curtailment and unserved load values were used to compare the impact of storage on high renewable portfolios.

Based on the above information, this study considered a 50% renewable requirement for Oregon to be the balance of the total generation not met by the 50% hydro contribution during its low point in the late summer and early fall, as seen in equation 12.

$$(Total\ pen) = (50\%\ hydro\ pen) + (50\%\ other\ renewable\ pen) \qquad 12$$

This 4,000,000 MWh/month equates to an average generation of roughly 5500 MW during this low hydro generation month, as shown in equation 13.

$$5500MW \approx \frac{4{,}000{,}000MWh}{(Hours\ per\ month)} \qquad 13$$

It should be noted that this definition of renewable penetration is different than typical definitions, and different than the definition used in the Oregon RPS. However, given that this study aims to find new knowledge in developing a fully renewable power grid in the PNW, new approaches need to be developed and analyzed.

5.4 Definition of portfolios:

The contributions of each renewable resource were evaluated in 5% increments of contribution to the 50% renewables requirement. The 14% contribution of wind to the total installed capacity means the current wind contribution was approximated at 15%. Biomass currently contributes 2% of the installed capacity and coal another 4%. Since the possibility of converting the Boardman coal facility to biomass is being considered by Portland General Electric [55], the existing biomass contribution was rounded up to 5%. Additional varying of hydro (decreased to 40%) was included in the initial set of scenarios to evaluate the impact, as well as the ability for incorporating greater than 100% renewable energy penetration (equation 14).

$$(90\%\, pen) \leq (Total\, pen) \leq (110\%\, pen) \qquad 14$$

To determine the initial set of combinations totaling 100% renewables, a matrix was set up to capture all combinations of the following generation sources:

- Hydro (40 - 50%)
- Wind (15 - 55%)
- Solar (0 - 40%)
- Wave (0 - 40%)
- Biomass (5 - 45%)

In order to identify renewable mixes to analyze, plant capacity factors (and plant nameplate capacities) were estimated. NREL publishes an Annual Technology Baseline (ATB) to be used for consistency in their analyses [128]. Table 1 shows the capacity factors used in the analysis, with most data from the NREL 2017 Annual Technology Baseline for the listed renewable resource. The wind plant capacity factor was based on the resource potential map and corresponding capacity factors in the ATB. Mid-range values were used for solar, and the 2016 ATB value was used for wave energy. Further break-down of the 50% renewables penetration of 5500 MW requires inclusion of these capacity factors. For each 5% increment, the required installed capacity of each renewable is also listed in Table 1 (guided by equation 15).

$$(Required\, nameplate\, capcity) = \frac{550MW}{(Capacity\, factor)} \qquad 15$$

For example, if solar PV is included at a 5% penetration level (split equally between centralized utility scale and distributed commercial installations), based on the listed capacity factors a total new nameplate capacity of roughly 1400 MW utility scale and 1800 MW distributed commercial is required.

Table 1 - Capacity factors and required new nameplate capacities for each 5% penetration of resource

	Required for each 5% (1/10 of 50% total) MW	Capacity factor %	Required installed nameplate capacity MW
Wind	550	25%	2200
Solar PV -centr.	275	20%	1400
& Solar PV - distr.	275	15%	1800
Biomass	550	52%	1100
Wave	550	25%	2200

In order to model the impact of additional renewable plants, sizes and locations were selected. The benefits of resource diversity and geographic diversity are well understood, and one assumption in this analysis was that new generation will be located within the geographic boundaries of the three states (plus the possible addition of offshore wave energy). To determine plant sizes, the list of plants previously downloaded from EIA was used. For both wind and utility scale solar, the low end of the size range of the largest plants was used, as a balance between economies of scale and some geographic diversity. Also, the prior development of the prime wind sites in the Columbia River Gorge implies moderately sized plants in other locations should be considered. Similarly, the difference in solar potential between the locations of the largest plants in California/Arizona and the best potential locations in the NW imply more moderately sized facilities.

Since the best data available for solar analysis is from the University of Oregon Solar Radiation Monitoring Laboratory [69], this places the potential new locations in Oregon (Figure 22). However, since the location in the Pacific Northwest with the largest promising area for good solar potential is in SE Oregon (Figure 6), this is a workable constraint in the analysis. It was assumed that solar is divided equally (output based on capacity factors applied to nameplate capacity) between large utility-scale plants in more remote locations and smaller distributed installations closer to population centers.

The assumed size of new biomass plants was based on the decision of PGE to test the Boardman coal plant with biomass, as this implies the Boardman plant size is a feasible scale of biomass. For wave energy, there is not much existing experience for reference, so a size slightly larger than wind and solar was used, as the overall wave state is reasonably constant over long shoreline distances, reducing the need for geographic diversity as compared to wind and solar.

Table 2 summarizes the required installed MW for each 5% increase in penetration, the assumed plant size for each type of fuel source, and the rounded number of plants required.

Table 2 - Plant requirements for each 5% increment of capacity. Sum of centralized and distributed PV equals a 5% solar penetration.

	Required installed, MW	Assumed plant size MW	Total plants required
Wind	2200	185	12
Solar PV - centralized	1400	110	13
& Solar PV- distributed	1800	17	110
Biomass	1100	550	2
Wave	2200	200	11

Evaluating the integration of additional renewables requires frequent data from sites. Locations with five minute observations for wind and/or solar data are very limited (located at BPA [20] and U of O [69]), although other generalized data and simulated datasets exist. In addition, the National Center for Environmental Information (formerly NCDC) maintains historical weather data, although the sites of interest for this analysis were at airports with usually hourly resolution [127]. It is obvious that there are not sufficient data sets to allow the use of one dataset per new site to be modeled. Therefore, it was necessary to determine how to reasonably group plants for analysis while maintaining as much realism as possible.

Based on the overall solar potential of the sites, and particularly data availability, the following locations were used for new centralized solar groupings - Bend/Redmond, Burns, Ashland/Medford, and Hermiston. For this utility scale solar (good solar potential but remote from the largest population centers), it was decided to place one-fourth of the capacity at each of the above named locations (1/4 of 1400 MW = 350 MW for each 5% penetration). For distributed solar, a different approach was used. One of the advantages of distributed solar is the use of smaller footprints or rooftop installations near population centers to minimize transmission requirements. The main population center in Oregon is the Portland to Eugene area, therefore a linear approach to siting plants was assumed. The approximate distance from Portland to Eugene is 110 miles, with a distributed solar facility assumed to be spaced every mile along this imaginary line. Since this portion of the state has little truly vacant land, the capacity could be on rooftops, in farmland, over parking lots, etc. With solar radiation and wind speed available for Portland, Salem and Eugene, it was assumed the average irradiance of the three locations (at each 5 minutes) applied to the distributed facilities would provide a reasonable approximation of conditions and output (using the average conditions to smooth output over the line of plants, seen in equation 16). If options required additional new distributed capacity, additional "lines" from Portland to Eugene were added to keep the capacity near the population centers.

$$(Distributed\ solar\ gen) = \frac{(Portland\ gen) + (Salem\ gen) + (Eugene\ gen)}{3} \qquad 16$$

Modeling new locations for wind generation was also significantly limited by lack of detailed time series data, with most historical data in the Columbia Gorge area. Excluding the Gorge and the Portland to Eugene population area, six sites with wind speed time series data were identified: Megler, Tillamook, Mary's Peak, Shaniko, Bend/Redmond and Ashland. With twelve new 185 MW plants needed for each 5% increase in penetration, two of these new plants were sited at each of the six locations for each 5%. Although not ideal, as this does not optimize the wind power potential of new sites, it does model the best geographic diversity possible within constraints of available data. Also, coastal locations such as Megler and Tillamook have moderately good wind power potential based on wind resource maps.

Wave data was obtained from NOAA's National Data Buoy Center [44]; three buoys were chosen based on geographical spread and approximate distance from shore (5 - 15 mile range) - 46015 Port Orford, 46050 Stonewall Bank, and 46211 Grays Harbor. It has been shown that the overall sea state is relatively constant at any given time over moderate distances [118], so these three buoys provide a representative picture of the Oregon/Washington sea state. Buoy data is only available in 30 minute or 1 hour increments, so data was filled in to 5 minute increments for a total of 11 wave farms (for the first 5% increment of wave energy) spread out between Port Orford and Grays Harbor. More specifically, to fill in the data to the five-minute intervals, the most recent point was extended until the next actual reading was reached. The average readings of the three buoy sites were used to model output for the entire set of plants (with relatively constant sea state over this distance, and the averages used for smoothing). For options with a higher wave energy penetration, additional rows of 11 wave farms were added. The geographic range of wave farms selected did not extend north of Grays Harbor due to the presence of the Olympic Mountains with the resulting lower population density and increased difficulty and expense of adding transmission lines.

5.5 Portfolio costs and selection for seasonality/storage analysis:

Simplifying assumptions were required to select options for further analysis, including maintaining the current level of net interchange, and determining the range of variability/reserves accommodated within the hydro system and/or EIM. With the recent addition of the EIM in the BA, and the current use of natural gas plants for flexibility, no actual data on reserves served by the combination of hydro and EIM is available. Therefore, the historical time series data for the relevant years was downloaded from BPA for reserves deployed, max inc reserves, and max dec reserves. The time series data implicitly includes seasonal limitations of the hydro system, and it is assumed that the EIM could provide reserves historically supplied by flexible thermal plants. Beyond this range (max inc to max dec at each 5 minutes), the impact of each portfolio was quantified utilizing unserved load and curtailment costs. Therefore, the overall cost considerations include unserved load or curtailment (beyond assumed system capabilities), capital costs, fixed and variable operating costs, fuel costs, and any new transmission capacity required. The relevant costs used in the analysis are listed in Table 3 and 4.

Table 3 - Capital & O&M costs for new generation
(NREL 2017 ATB mid range values - offshore wind data used for wave costs.)

	Capital $/kW	Fixed O&M $/kW-yr	Var. O&M $/MWh	Fuel $/MWh	Tech. life Years	Econ. life Years
Wind	$1643	$51	$0	$0	25 years	20 years
Utility PV	$2014	$13	$0	$0	30 years	20 years
Commercial PV	$2465	$18	$0	$0	30 years	20 years
Biomass	$3889	$108	$5	$3	45 years	20 years
Wave	$6000	$131	$0	$0	25 years	20 years

Table 4 - Misc. system costs

	Cost	Source
Inter BA transmission line	$1,200 - $5,340 per MW-mile	[35]
Intra BA transmission line	$2,400 - $10,680 per MW-mile (mid-range $6,500)	[35]
Substation	$10,700 - $24,000 per MW (mid-range $17,300)	[35]
Cost of curtailment	$100/MWh	[16]
Cost of unserved load	$50,000/MWh	[16]

The assumed new transmission line costs for each of the selected locations was based on the approximate distance from existing large transmission lines or population centers (Table 5). Other transmission capacity impacts and grid stability were not included; a copper sheet analysis was assumed to keep the focus on the tradeoffs of renewable type, seasonality and storage.

Table 5 - Distance and estimated costs per 5% penetration of new transmission by generation location. Sum of centralized and distributed PV equals a 5% solar penetration.

Plant	New transmission (miles)	Nameplate Capacity (MW)	Transmission line cost ($M) at $6,500/ MW mile	New substations required?	New substation cost ($M) at $17,300/MW)	Transmission cost per 5% penetration ($M)	Transmission cost per 5% by resource ($M)
Wind - Megler	20	370	48.1	1	6.4	54.5	266.1
Wind - Tillamook	0	370	0	0	0	0	
Wind - Mary's Peak	40	370	96.2	1	6.4	102.6	
Wind - Shaniko	30	370	72.2	1	6.4	78.6	
Wind - Bend	0	370	0	0	0	0	
Wind - Ashland	10	370	24	1	6.4	30.4	
Solar - Bend	0	350	0	0	0	0	28.9
Solar - Burns	0	350	0	0	0	0	
Solar - Ashland	10	350	22.8	1	6.1	28.9	
Solar - Hermiston	0	350	0	0	0	0	
Solar - distributed	0	1800	0	0	0	0	0
Biomass - plant #1	10	550	35.8	1	9.5	45.3	90.6
Biomass - plant #2	10	550	35.8	1	9.5	45.3	
Wave - 11 plants	110 total	200 each	143	11	38	181	181

The total estimated cost for each 5% penetration was estimated using the nameplate capacities for each resource from Table 1, and using the costs in Tables 3, 4 and 5. The resulting costs are shown in Table 6.

Table 6 - Total estimated costs for 20 year economic life for each new 5% penetration of each resource. Sum of centralized and distributed PV equals a 5% solar penetration. Annual costs are assumed to be the same each year of the 20 year economic life.

	Installed nameplate (MW)	Capital ($M)	New Transmission ($M)	Fixed O&M for 20 yrs. ($M)	Variable O&M for 20 yrs ($M)	Fuel for 20 yrs ($M)	Total cost for 20 yrs ($M)
Wind	2200	3615	266	561	0	0	4442
Solar PV - centralized	1400	2820	29	72	0	0	2920
& Solar PV - distributed	1800	4437	0	99	0	0	4536
Biomass	1100	4278	91	1188	482	289	6328
Wave	2200	13200	181	1441	0	0	14822

The last step before utilizing a cost function to determine which portfolios are stronger cases than others, the curtailment and unserved load must be calculated. As stated previously, this study did not implement grid balancing, so that the unique seasonal patterns of the PNW could be studied. As such, the mismatch between the 100% renewable generation portfolio and the load was used in the cost function. Specifically, if generation was greater than load at a given point, this was labeled as curtailment (or, positive mismatch), as a renewable plant would need to be curtailed. If renewable generation was less than load, this was labeled as unserved load (or, negative mismatch). To calculate the mismatch at each five minute data point, equation 17 was used.

$$(Mismatch) = (Hydro) + (Wind) + (Wave) + (Solar) + (Biomass) - (Load) \qquad 17$$

Curtailment and unserved load data series were then separated, such that positive mismatch values went into the curtailment series, and negative mismatch values went into the unserved load series.

To determine which portfolios are the best or most interesting candidates, a cost function was developed, as shown in equation 18:

$$C_{port} = C_{cap} + C_{ann} + C_{curt} \sum_{i=1}^{end} \frac{curt_i}{12} + C_{uload} \sum_{i=1}^{end} \frac{uload_i}{12} \qquad 18$$

where C_{port} is the total cost of the portfolio, C_{cap} is the capital cost of the portfolio, C_{ann} is the annual cost of the portfolio, C_{curt} is the cost of curtailment ($/MWh), $curt_i$ is the average curtailment in MW at each five minutes during the study years, C_{uload} is the cost of unserved load

($/MWh), and $uload_i$ is the average unserved load in MW at each five minutes during the study years. Specifically, both the capital and annual costs associated with a portfolio are only the costs associated with new renewable energy plants; the cost of operating or retiring current plants as necessary was not included.

The calculation represented by equation 6 was applied to each resource combination in the matrix described in section 5.4. This application resulted in 19,683 unique renewable energy portfolios, each with an associated list of costs (total, capital, annual, curtailment, and unserved load). These cost matrices were then iterated through to extract different portfolios of interest.

5.6 Selecting Portfolios

In order to select the portfolios for further analysis, a list of criteria was generated to identify interesting portfolios to analyze. The identified criteria are not all desirable characteristics, but rather an attempt to identify interesting yet reasonable portfolios to evaluate relative to seasonality, daily patterns, and energy storage. Table 7 lists these criteria, plus the portfolio which best meets each one. Each row lists the specific portfolio percentages that best meet the specific listed criteria. For example, the portfolio listed for the lowest capital cost (i.e. Hydro 50%, Wind 35%, Solar 0%, Wave 0%, and Biomass 5%) does not consider the other cost factors, such as annual costs or the cost of unserved load or curtailment. Note that capital costs include new transmission assumed to be required.

Table 7 - Portfolio selection criteria. All costs and other values summed/extrapolated for 20 year economic life. Calendar quarters are considered to be winter (January, February, March), spring (April, May, June), summer (July, August, September) and fall (October, November, December). *Abbreviations: cap (capital cost of new investment plus any new transmission assumed required); annual (operations and maintenance costs, fixed and variable, plus annual fuel costs, totaled for 20 years); uload (unserved load or cost of unserved load, totaled for 4 study years then multiplied by 5), curtail (curtailment or cost of curtailment, totaled for 4 study years then multiplied by 5).*

	Criteria	Portfolio					Criteria	Total Cost
		Hydro %	Wind %	Solar %	Wave %	Biomass %	$M or MWh	$M
	Lowest total $ (cap+annual+uload+curtail)	50	15	0	0	40	$106,945	$106,945
Hydro ≤ 50% & Biomass ≤ 15%	Lowest total $ (cap+annual+uload+curtail)	50	20	5	20	15	$945,149	$945,149
	Lowest cap cost	50	35	0	0	5	$15,524	$6,142,861
	Lowest annual costs	50	15	20	0	5	$4,322	$6,982,447
	Lowest cap + annual cost	50	35	0	0	5	$21,410	$6,142,861
	Lowest uload costs	50	15	5	25	15	$783,259	$949,551
	Lowest curtail costs	50	15	5	5	15	$32,027	$2,034,433
	Lowest uload + curtail costs	50	15	5	25	15	$851,687	$949,551
	Lowest total cost w/ new solar & wave	50	20	5	20	15	$945,149	$945,149
	Lowest total cost w/ new solar	50	20	5	20	15	$945,149	$945,149
	Lowest total cost w/ new wave	50	20	5	20	15	$945,149	$945,149
	Lowest total spring curtail (MWh)	50	15	0	20	5	15,276,791	$4,508,305
	Lowest total fall uload (MWh)	50	15	5	25	15	1,186,371	$949,551
	Lowest total winter uload (MWh)	50	15	0	30	15	306,044	$1,270,590
	Lowest total fall +winter uload (MWh)	50	15	5	25	15	1,498,480	$949,551
	Lowest spr. curtail + fall/win. uload (MWh)	50	15	0	20	5	22,462,284	$4,508,305
	Lowest spr. curtail + fall/win. uload cost	50	15	5	25	15	$78,514	$949,551
If wave $ @10%	Lowest total $ (cap+annual+uload+curtail)	50	15	5	25	15	$882,852	$882,852
	Lowest uload costs	50	15	5	25	15	$783,259	$882,852
	Lowest curtail costs	50	15	5	5	15	$32,027	$2,021,093
	Lowest total spring curtail (MWh)	50	15	0	20	5	15,267,791	$4,454,946
	Lowest total fall uload (MWh)	50	15	5	25	15	1,186,371	$882,852
	Lowest total winter uload (MWh)	50	15	0	30	15	306,044	$1,190,551
	Lowest total fall +winter uload (MWh)	50	15	5	25	15	1,498,480	$882,852
	Lowest spr. curtail + fall/win. uload (MWh)	50	15	0	20	5	22,462,284	$4,454,946
	Lowest spr. curtail + fall/win. uload cost	50	15	5	25	15	$78,514	$882,852

The portfolios in Table 7 have many expected characteristics. The least expensive option overall adds only baseline biomass to the existing sources. With the high cost penalty for unserved load (Table 4), the dispatchable biomass resource minimizes the total cost. In order to have variable renewable sources for analysis of seasonality and storage, biomass was then limited to 15% for the remaining portfolios. Portfolios which minimize unserved load tend to have higher wave penetrations, as wave energy shows less variability than either wind or solar. Wind energy is the most established variable source, with the costs furthest along the learning curve, therefore high wind penetration leads to lowest capital costs. However, the variability has a significant impact on the total portfolio costs. A similar situation exists for solar energy with its low annual costs. There are eight unique portfolios in Table 7, summarized in Table 8. The total costs include wave at its current cost - the potential reduction in capital costs was included later as a sensitivity analysis.

Table 8 - Portfolios selected for further analysis

Portfolio #	Portfolio name	Primary Characteristic	Hydro %	Wind %	Solar %	Wave %	Biomass %	Total %	Total cost $M
1	H50/W15/S0/V0/B40	High biomass baseline	50	15	0	0	40	105	$106,945
2	H50/W15/S0/V20/B5	Low seas. uload/curt	50	15	0	20	5	90	$4,508,305
3	H50/W15/S0/V30/B15	Low winter uload	50	15	0	30	15	110	$1,270,590
4	H50/W15/S5/V5/B15	Low curtailment	50	15	5	5	15	90	$2,034,433
5	H50/W15/S5/V25/B15	Low unserved load	50	15	5	25	15	110	$949,551
6	H50/W15/S20/V0/B5	Low annual costs	50	15	20	0	5	90	$6,982,447
7	H50/W20/S5/V20/B15	Low total cost	50	20	5	20	15	110	$945,149
8	H50/W35/S0/V0/B5	Low capital costs	50	35	0	0	5	90	$6,142,861

5.7 Seasonality/storage assumptions and modeling:

Since different calendar years may have significant variation in snow pack and water runoff, a comparison of river flow during the study years to the 30-year average is shown in Figure 34. Of the four years, runoff during one year is high (2012), one year is low (2015), and the others are relatively typical; therefore, the study years should accurately represent hydro seasonality in the region.

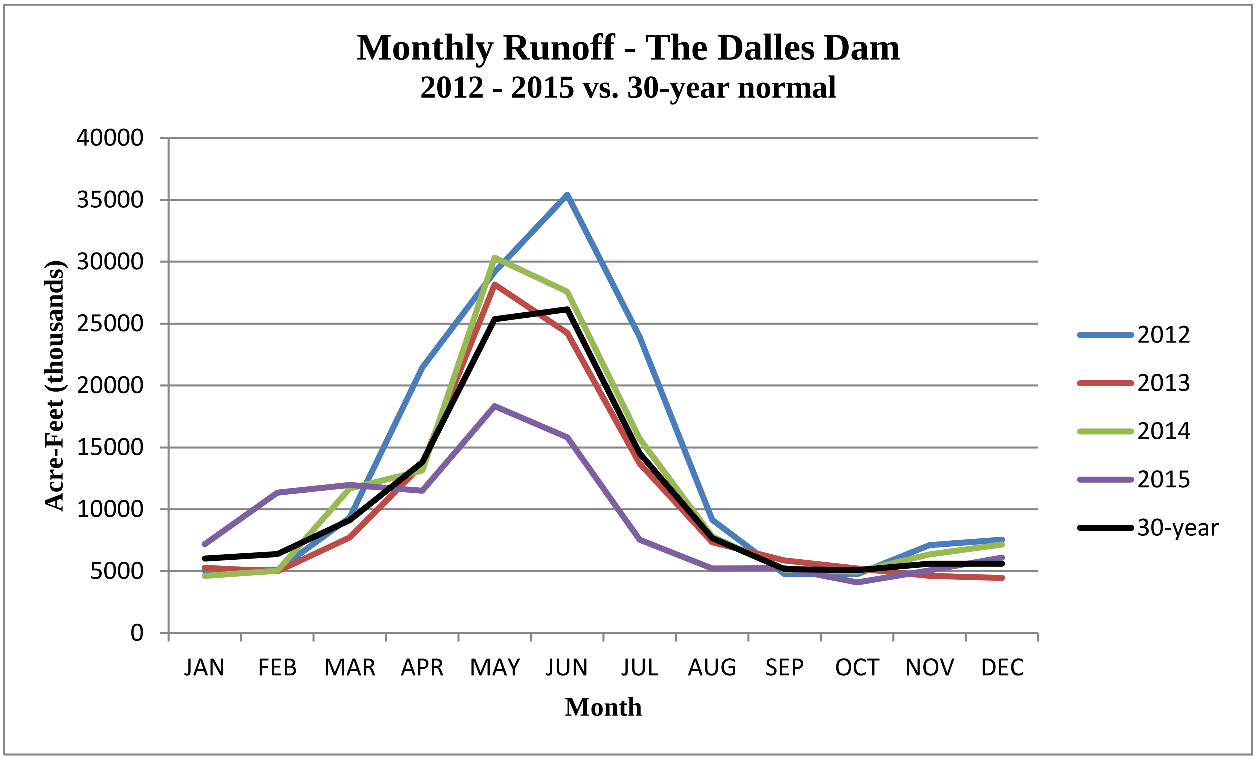

Figure 34 - Monthly runoff - The Dalles dam [129]

With a very complex hydro system, and the lack of publically available data on water levels, river flows and discharge rates at the specific dams, it would be extremely difficult to model PHS at the dams themselves. It is assumed that the hydro system is already optimized as much as possible, given the often conflicting requirements. Along with other potential issues, it does not seem feasible to assume reservoir capacity would be available for PHS during many times of wind curtailment (such as spring high runoff and high wind). The water flow could also be needed to maintain water levels and quality during the low flow season. As a result, the only PHS modeled in the study is the addition of the proposed, closed loop system at JD Pool.

The proposed JD Pool system would be located in Klickitat County (Washington) on the site of the former Golden Northwest Aluminum smelter, close to BPA's John Day substation (the north end of a major transmission line to California). There would be two 65 acre ponds, one at the previous site of the smelter, and one at the top of the cliff, each holding 7000 acre-feet of water. The topography is excellent, with a 2000' rise over approximately a mile horizontally. The facility would have 1,200 MW capacity (4 x 300 MW reversible pump/turbine motor/generators), with storage of 14,745 MWh [130]. The cost has been estimated at $2+B

[131]. A different source estimates the cost range for PHS as $1800/kW to $3500/kW of installed capacity, with the cost drivers the overall head height, the tunnel lengths, amount of reservoir construction required, and the use of variable speed technology. At that cost range, the estimate for a 1200 MW facility becomes $2.16B to $4.2B. Given the stated excellent topography of the JD Pool site, it is assumed that $2.2B is a reasonable cost estimate to use. The efficiency is assumed to be 80% [91], with negligible self-discharge, and annual O&M costs at 1% of construction costs [132].

The use of battery storage in the Pacific Northwest is expected to match California (smaller power capacities, with longer discharge durations) more closely than the PJM (larger power capacities, with shorter discharge durations). According to the EIA, California in 2016 had storage averaging 5.7 MW capacities with approximately 4 hour discharge durations [80]. This is consistent with PGE's view of "large scale" storage being in the range of 4 - 6 MW capacities. An estimate of best-in-class utility scale Li-ion storage is $764/kWh installed, with approximately $250/kWh for the battery pack, and $514/kWh for the balance of system. The battery pack is expected to last only 10 years (3000-4000 cycles with an average of one full cycle per day). An annual fixed cost (2016) is listed as $167 - $371 per kW/yr by PGE, depending on the length of the discharge duration [56]. The batteries used at the PGE Salem Smart Power Center are EnerDel SP90-590, with a specified efficiency of 95% [133].

No storage was modeled for existing wind or hydro, biomass (considered baseline), or distributed solar. For the remaining new sources (wind, wave and centralized solar), it was assumed that any battery storage for a given type of resource would be equal sized installations at each plant (copper sheet analysis, all charging or discharging equally and simultaneously). For battery storage only, a range of sizes was initially modeled for each resource and combination of resources, from zero to resource nameplate capacities in 5% increments. In contrast, PHS was modeled as a single, centralized storage resource (up to the maximum charge/discharge rate and within the physical storage limits of the closed loop system). These modeled technical details and costs are summarized in Table 9.

Table 9 - Modeled storage - technical and cost assumptions

	Pumped Hydro Storage	Li-ion Batteries
Power (MW)	1,200 MW	Range modeled
Storage capacity (MWh)	14,745 MWh	Range modeled
Capital costs	$2.2 billion	$764 per kWh
Battery replacement cost (10 yr)	N/A	$250 per kWh
Annual O&M	$22M (1% of constr.)	$270 per kW/yr
Efficiency	80%	90%
State of charge range	0 - 100%	5 - 95%

For each portfolio, the impacts of storage were evaluated separately for each resource, then in combinations of resources (i.e., wind only, solar only, wave only, wind and solar, wind and wave, solar and wave, and wind/solar/wave). When storage was modeled at two or three types of resources, it was assumed that storage would operate consistently within a resource, but could potentially operate in a different manner at a different resource (although not charging and discharging simultaneously). The storage decisions were based on available data at each five minutes (current generation and load, month/day/time, state of charge, unserved load, and curtailment.), and no forecasting was performed.

A set of rules was created to determine this storage charge/discharge decision at each five minute data set, including the storage efficiency. The overall approach was based on storage charge/discharge methods/equations utilized in an NREL analysis [124], and shown in Figure 35.

$$L_{d,1} = L_d^{start} - P_{d,1}^{gen} + P_{d,1}^{chg} \cdot \eta - 0.25\left(R_{d,1}^{flex} + R_{d,1}^{reg}\right)(1-\eta)$$
$$L_{d,h} = L_{d,h-1} - P_{d,h}^{gen} + P_{d,h}^{chg} \cdot \eta - 0.25\left(R_{d,h}^{flex} + R_{d,h}^{reg}\right)(1-\eta), \qquad \forall h > 1$$

Figure 35 - NREL charge/discharge equations for battery energy storage [124]

For batteries, the two extremes are a grid-focused approach and a storage-focused approach. In a grid-focused approach, the first priority is to charge the storage if curtailment exists (up to the maximum SoC) and to discharge storage if unserved load exists (to the minimum SoC); this approach creates significant cycling of the storage resource. The explicit rules for a grid-focused approach are shown below:

1. IF curtailment exists
    a. IF battery SoC < SoC maximum
        i. Sink power into battery
    b. ELSE IF battery SoC >= SoC maximum
        i. Do nothing
2. ELSE IF unserved load exists
    a. IF battery SoC >= SoC minimum
        i. Source power from battery
    b. ELSE IF battery SoC < SoC minimum
        i. Do nothing

In contrast, a storage-focused approach attempts to minimize cycling. Once the storage starts to charge, it charges (during curtailment) until maximum SoC; when it starts to discharge, the storage discharges (to meet unserved load) until minimum SoC. There are different economic impacts with these two approaches - higher storage costs (increased cycling and reduced life) vs. more unserved load and curtailment. The explicit rules for a storage focused approach (based on the grid-focused approach) are shown below:

1. IF battery is in charge mode
    a. IF curtailment exists
        i. IF battery SoC < SoC maximum
            1. Sink power into battery
        ii. ELSE IF battery SoC >= SoC maximum
            1. Turn battery to discharge mode
    b. ELSE IF unserved load exists
        i. Do nothing
2. If battery is in discharge mode
    a. IF curtailment exists
        i. Do nothing
    b. ELSE IF unserved load exists

        i. IF battery SoC >= SoC minimum
            1. Source power from battery
        ii. ELSE IF battery SoC < SoC minimum
            1. Turn battery to charge mode

Since both extremes have cost penalties associated with them, a balanced approach was modeled and used in the analysis of energy storage cases. The batteries were prevented from cycling excessively by limiting them to five charge/discharge cycles per day; max and min SoC levels were also defined. When excess generation exists, the batteries accept this energy up to their capacities, at their maximum rates up to the grid requirements. Conversely, when insufficient generation exists, the batteries provide energy to the grid, up to the maximum rate and energy stored. The explicit rules for the balanced approach are shown below:

1. IF battery cycle count < 10
    a. IF battery is in charge mode
        i. IF curtailment exists
            1. IF battery SoC < SoC maximum
                a. Sink power into battery
            2. ELSE IF battery SoC >= SoC maximum
                a. Turn battery to discharge mode
                b. Increment cycle count
        ii. ELSE IF unserved load exists
            1. Do nothing
    b. If battery is in discharge mode
        i. IF curtailment exists
            1. Do nothing
        ii. ELSE IF unserved load exists
            1. IF battery SoC >= SoC minimum
                a. Source power from battery
            2. ELSE IF battery SoC < SoC minimum
                a. Turn battery to charge mode
                b. Increment cycle count

2. ELSE IF battery cycle count >= 10
    a. IF new day
        i. Reset cycle count to 0
    b. ELSE IF not new day
        i. Do nothing

With eight portfolios, seven different resource combinations for application of storage, and ranges of battery power/capacities, a significant number of combinations exist. Battery power and capacity were initially modeled in 5% increments from zero to resource nameplate, while PHS modeling just included limits on the maximum power and capacity. In addition to battery storage only and PHS only, each combination of batteries and PHS was modeled as well.

Since each portfolio already had the curtailment and unserved load time series calculated and saved in the associated file, these series were able to be used when applying energy storage. Generally, if curtailment existed, and the energy storage was not at full state of charge, the state of charge was increased, and curtailment was decreased by the amount of generation stored. This same logic applied to the unserved load time series. These modifications are shown in equations 19 and 20.

$$(Modified\ curtailment) = (Curtailment) - (Generation\ stored) \tag{19}$$

$$(Modified\ unserved\ load) = (Unserved\ load) - (Generation\ sourced) \tag{20}$$

To determine the cost of a portfolio after storage was added, a revised version of equation 18 was used, and is shown in equation 21

$$C_{port} = C_{cap} + C_{ann} + C_{cap,s} + C_{ann,s} + C_{curt}\sum_{i=1}^{end}\frac{curt_i}{12} + C_{uload}\sum_{i=1}^{end}\frac{uload_i}{12} \tag{21}$$

where all of the variable definitions remain the same, and $C_{cap,s}$ and $C_{ann,s}$ are the capital and annual costs, respectively, of the energy storage added. The curtailment and unserved load power time series ($curt_i$ and $uload_i$, respectively) are modified based on the power flow into / out of the energy storage present. This allowed comparisons to be made between generation type, storage type, storage capacity, and storage power rating. In addition, the changes in seasonal curtailment and unserved load were analyzed.

6. RESULTS AND DISCUSSION:

Figure 36 shows increasing amounts of energy storage (up to name plate capacities of resources) for each of the eight portfolios as listed in Table 8. (Portfolios 5 and 7 overlap on the graph.) As the storage increases, the increase in this storage cost offsets some decrease in unserved load and curtailment costs, but the cost changes are not visible at this scale. It is interesting to note that increasing amounts of storage do not change the relative cost effectiveness of the different portfolios. The three highest cost portfolios include primarily a high variable generation source and do not have the advantages of resource diversity. In addition, the primary characteristic used to select these three highest cost portfolios (lowest annual costs, lowest capital costs, and lowest seasonal unserved load and curtailment, respectively) drove the total penetration to the minimum allowable total, which resulted in higher portfolio costs. The lowest cost portfolio includes high biomass penetration, which is to be expected as baseline generation is regarded as the cheapest option. The next three lowest cost portfolios include a diverse mix of generation resources and weighted towards the maximum allowable total penetration.

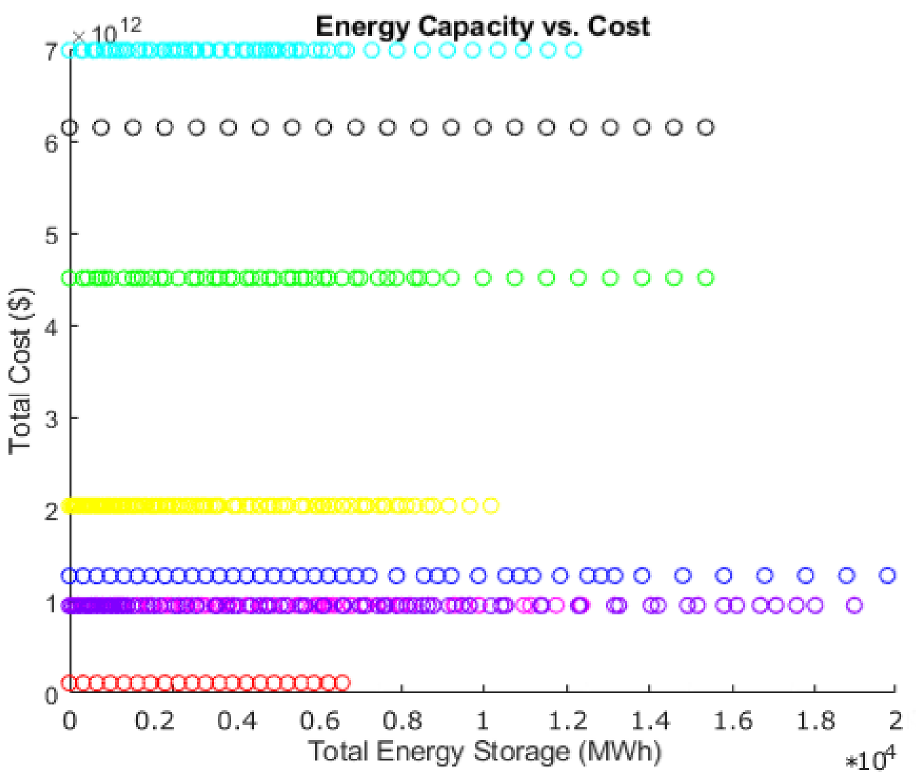

Figure 36 - Energy Capacity vs. Cost

The 500 lowest cost points (combinations of PHS and/or different levels of battery storage) for each of the three lowest cost portfolios (3, 5 and 7) are plotted in Figure 32. This narrows down the information in Figure 31 to the most cost effective ranges. Comparing Figures 36 and 37, the lowest cost storage options are concentrated towards lower total storage capacity.

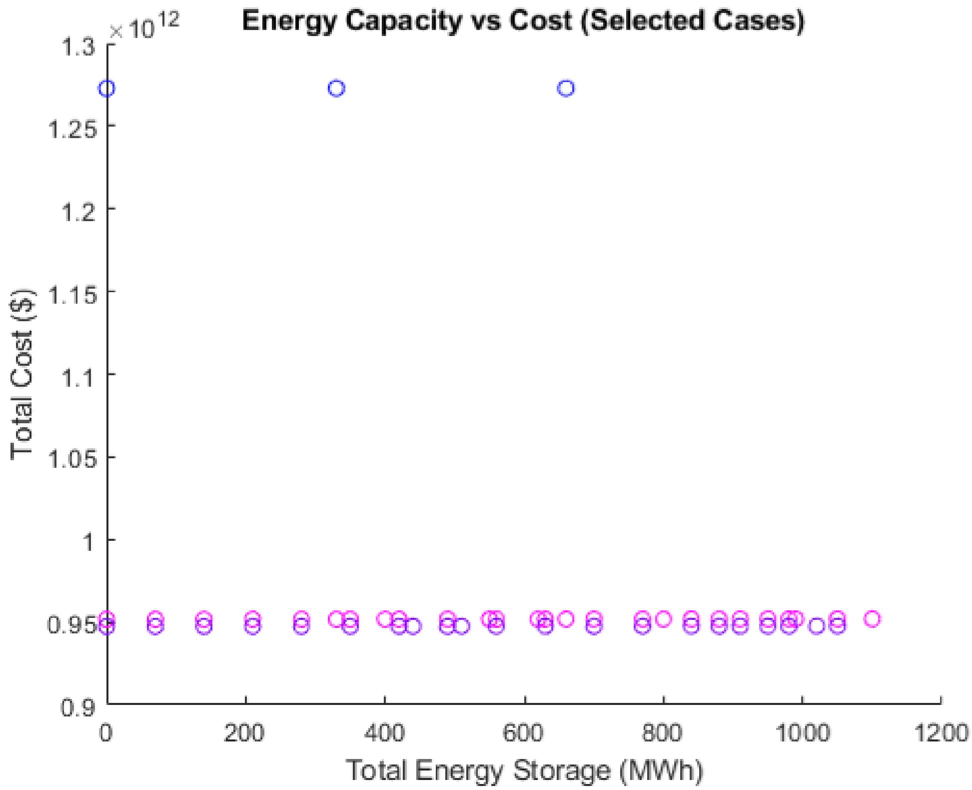

Figure 37 - Energy Capacity vs. Cost (Selected Cases)

As a rough sensitivity analysis, the calculations were repeated with wave costs reduced to 10% of the original amount (as WEC technology is in the early part of the learning curve). The results are shown in Figures 38 and 39. Although the total cost is reduced, this does not change the relative positions of the portfolios. Also, the lowest cost portfolios are already heavily weighted towards wave energy, as the lower variability of the resource decreases the amount (and therefore the cost penalty) of unserved load. Therefore, the storage analysis is based off the current wave costs, as all storage cases within a given portfolio are equally changed by decreased wave costs.

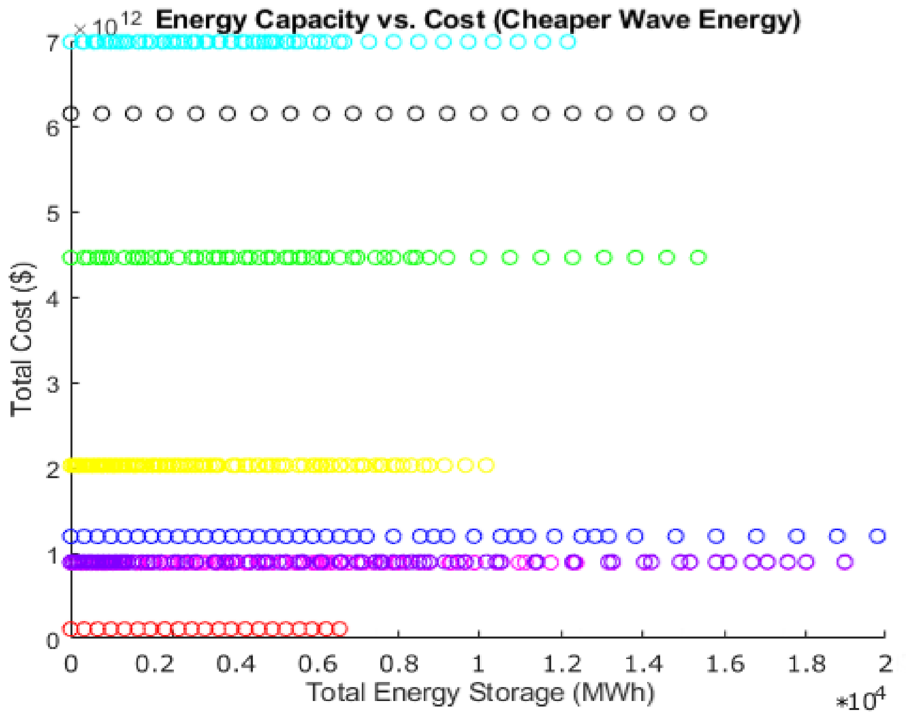

Figure 38 - Energy Capacity vs. Cost (Cheaper Wave Energy)

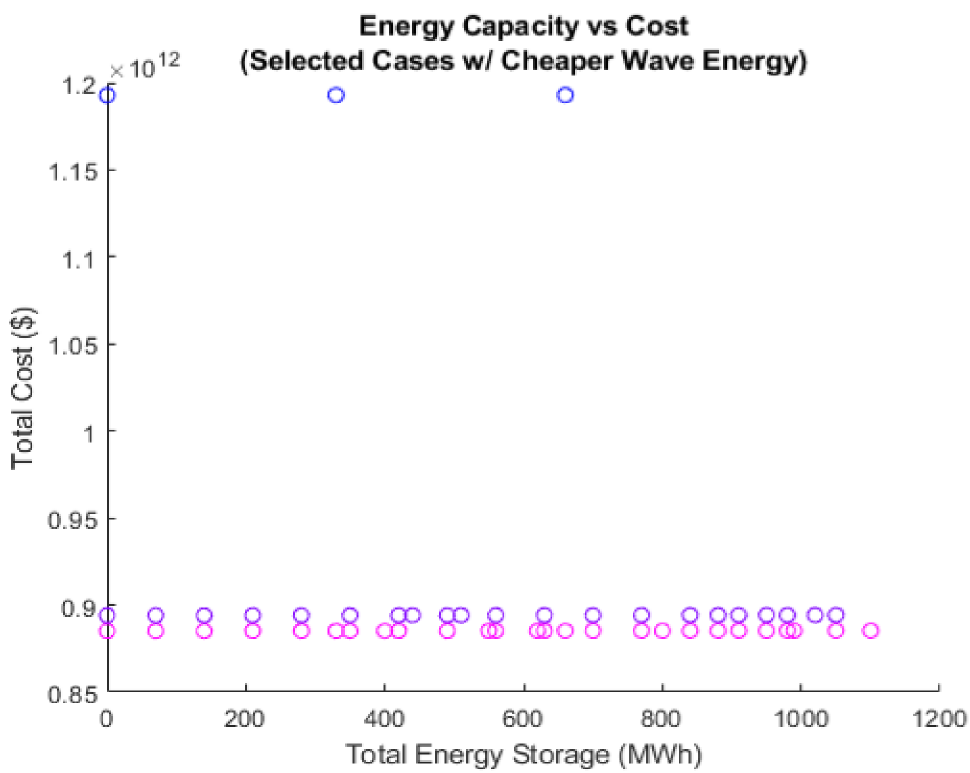

Figure 39 - Energy Capacity vs. Cost (Selected Cases w/ Cheaper Wave Energy)

As a different way of looking at the information, the lowest 500 cost points (per portfolio for portfolios 3, 5 and 7) were plotted against the storage applications in Figure 40. In most cases, one or more of the lowest cost points exists for each storage application. All three portfolios include significant wave energy, and option 3 does not include any solar generation.

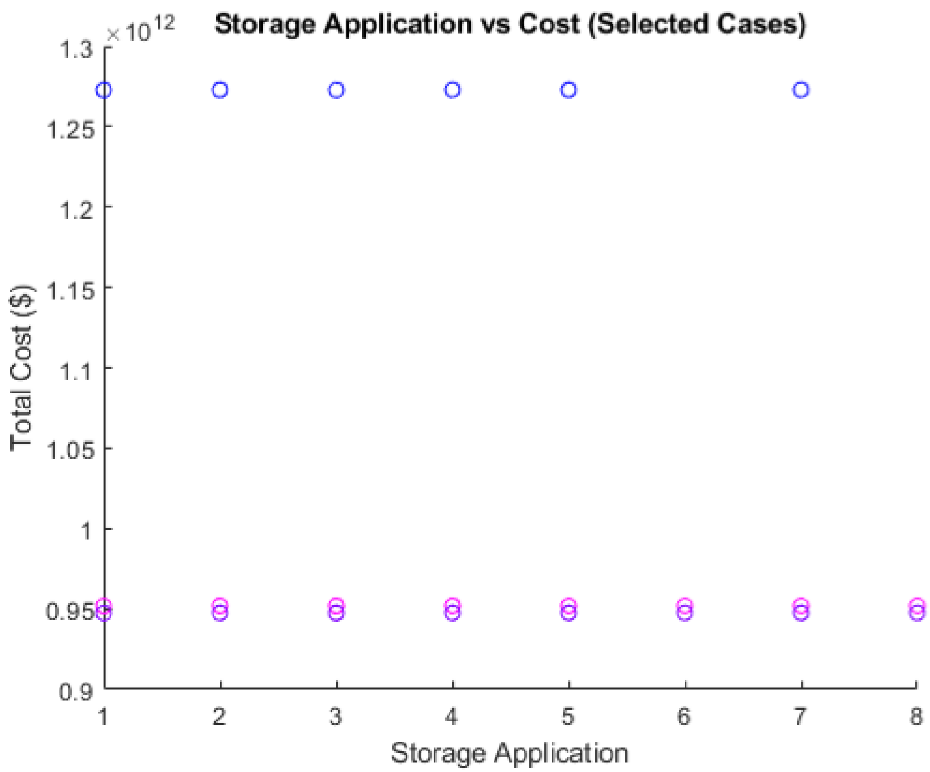

Figure 40 - Storage Application vs. Cost (Selected Cases)
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave, 8=wind/solar/wave

In order to zoom in on the information, two more graphs were created, Figure 41 for portfolios 5 and 7 and Figure 42 for portfolio 3. It is interesting that the total cost of the portfolio with storage never significantly drops below the cost without storage. Also, the increases in cost ranges (for a given resource application) with added storage may reflect the benefits of storage to that resource. For example, increases in storage applied to solar would benefit the diurnal patterns, while storage applied to wave would increase the cost with fewer benefits.

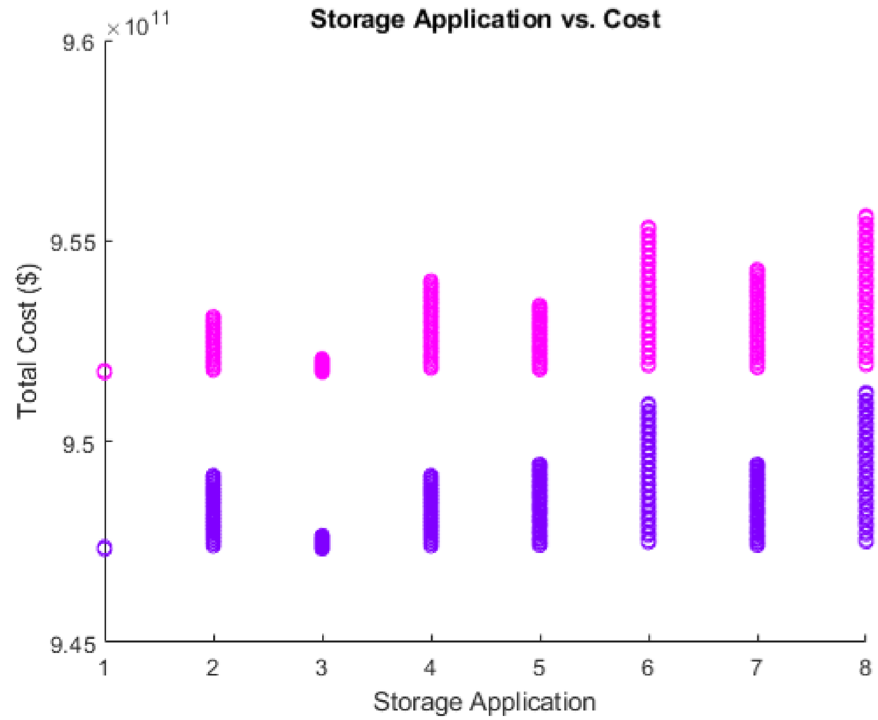

Figure 41 - Storage Application vs. Cost (Portfolios 5 and 7)
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave, 8=wind/solar/wave

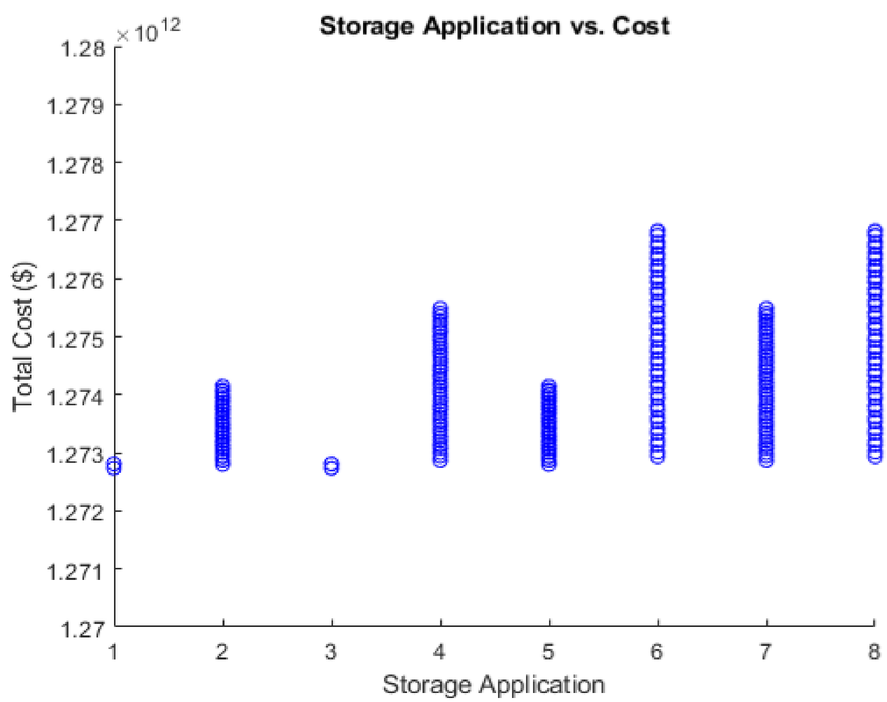

Figure 42 - Storage Application vs. Cost (Portfolio 3)
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave, 8=wind/solar/wave

It is also of interest to compare the battery storage capacity vs. power rate for the lowest cost points of portfolios 3, 5 and 7. These points are plotted in Figure 43. Since the points are spread out over a variety of combinations, battery specifics can reasonably be selected to meet other criteria as well.

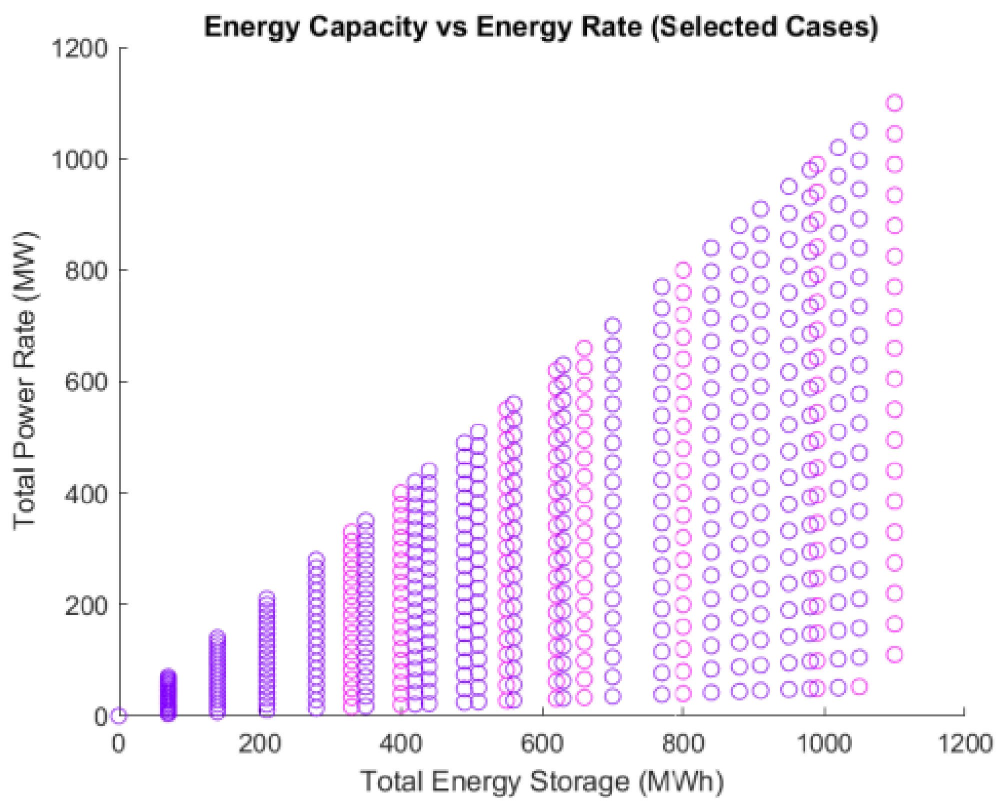

Figure 43 - Energy Capacity vs. Energy Rate (Selected Cases)

Another interesting comparison is plotting the storage application vs. the total energy storage. This is shown in Figures 44 (portfolio 3), 45 (portfolio 5), and 46 (portfolio 7). Although the graphs do not show the concentration of points at any given location, they do illustrate again that a variety of combinations exist in the collection of lowest cost scenarios.

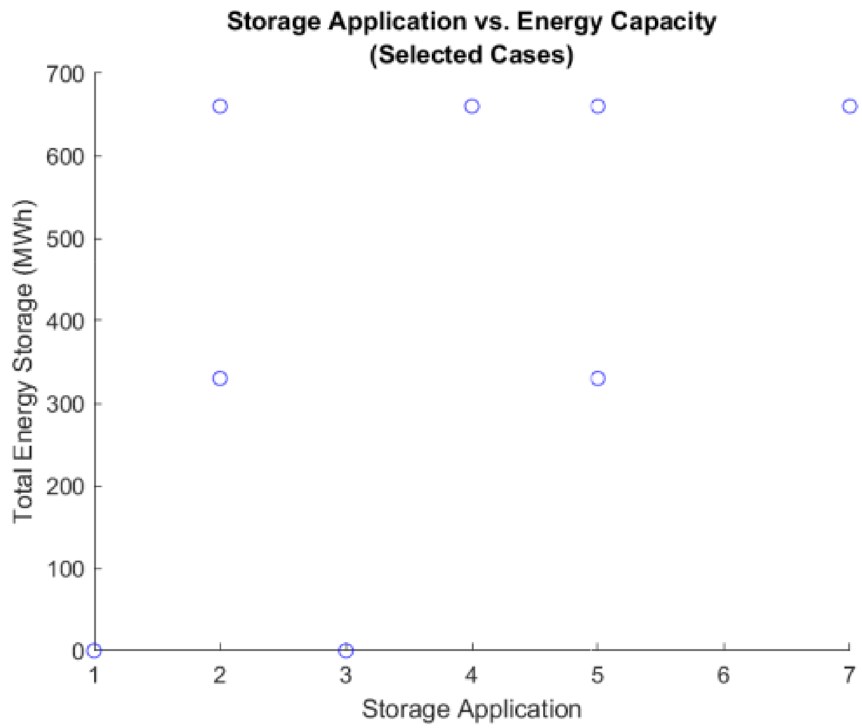

Figure 44 - Storage Application vs. Energy Capacity (Selected Cases) - Portfolio 3
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave

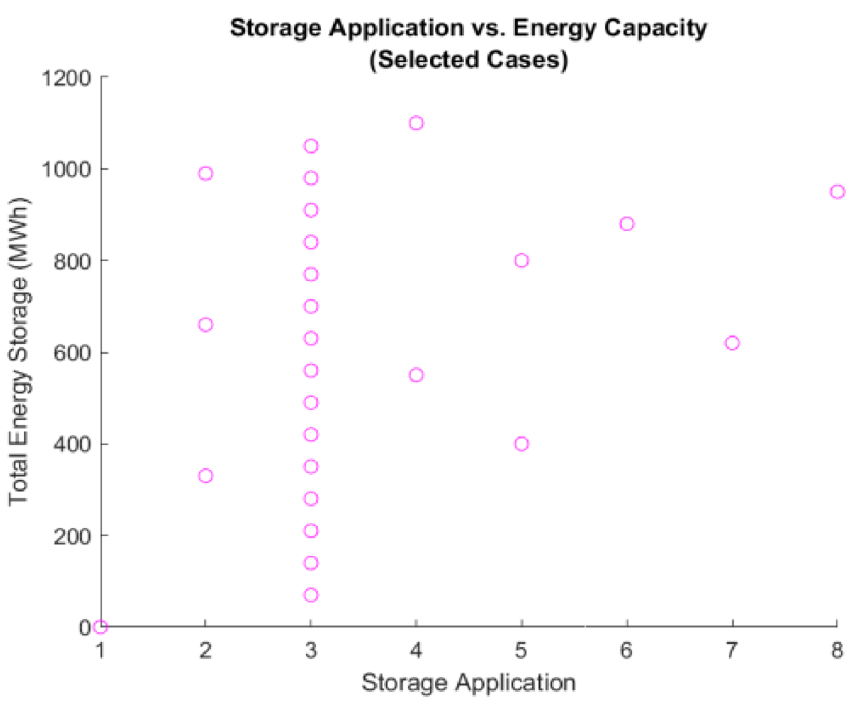

Figure 45 - Storage Application vs. Energy Capacity (Selected Cases) - Portfolio 5
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave, 8=wind/solar/wave

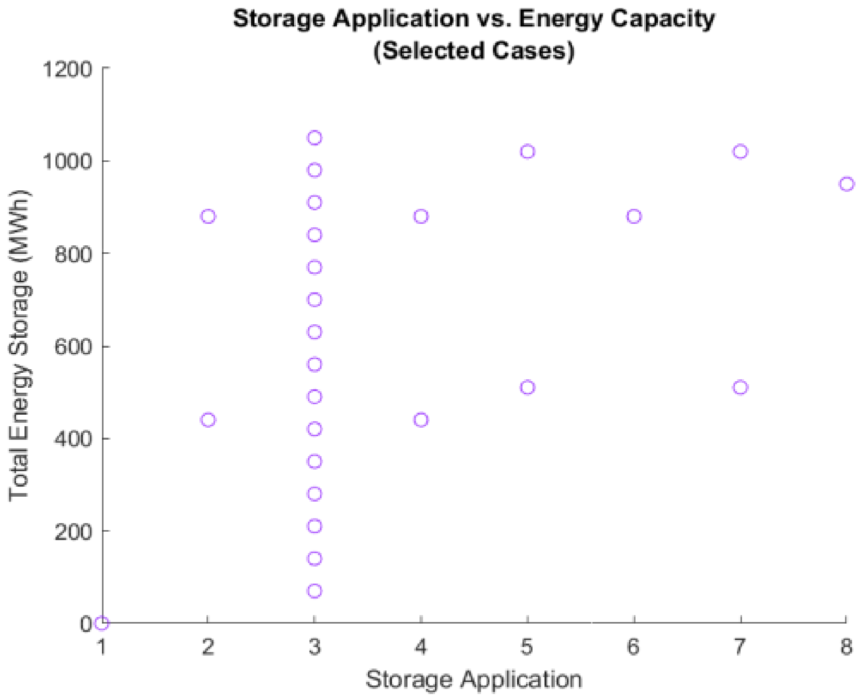

Figure 46 - Storage Application vs. Energy Capacity (Selected Cases) - Portfolio 7
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave, 8=wind/solar/wave

Similarly, it is interesting to compare the storage application to the total power rate. This is illustrated in Figures 47 (portfolio 3), 48 (portfolio 5) and 49 (portfolio 7). As with the energy capacity, there is a range of combinations within the lowest cost scenarios.

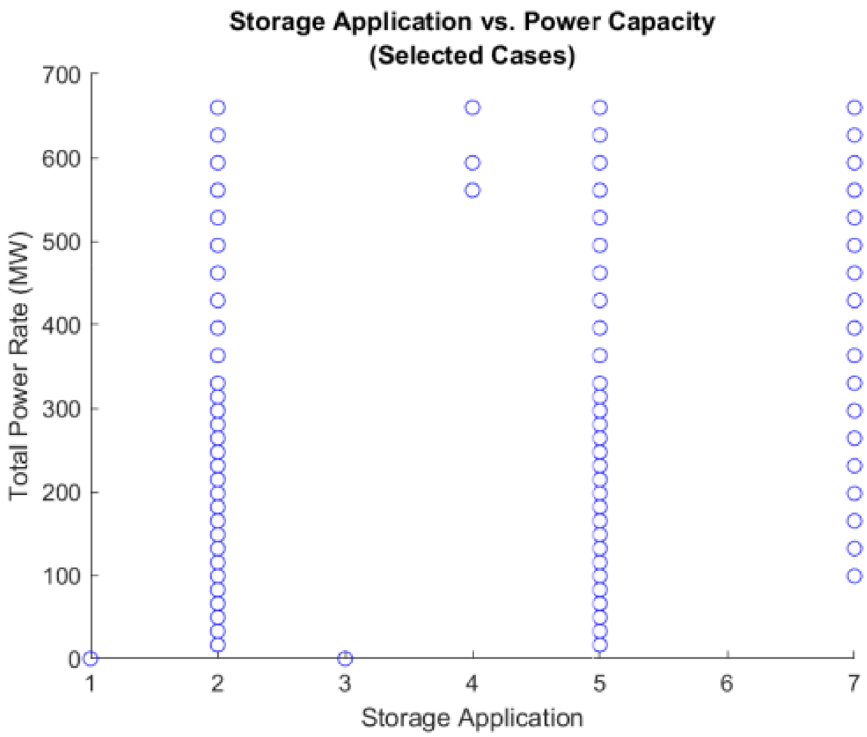

Figure 47 - Storage Application vs. Power Capacity (Selected Cases) - Portfolio 3
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave

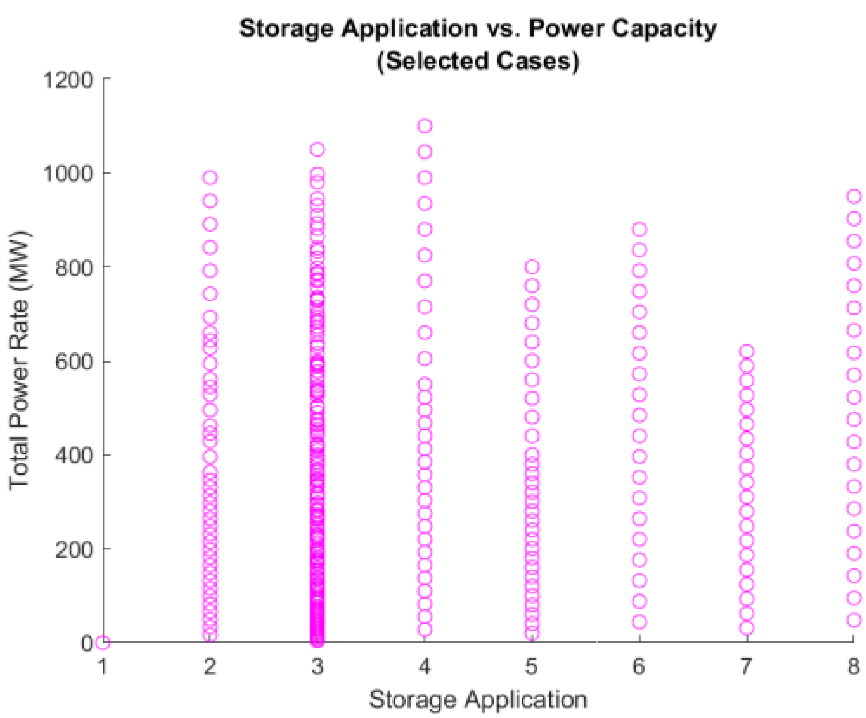

Figure 48 - Storage Application vs. Power Capacity (Selected Cases) - Portfolio 5
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave, 8=wind/solar/wave

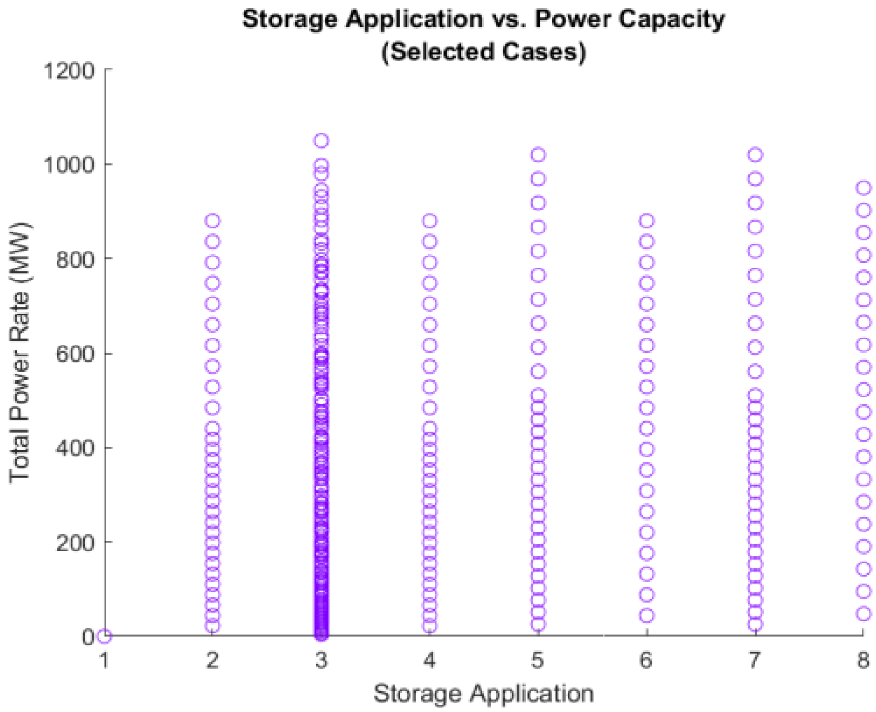

Figure 49 - Storage Application vs. Power Capacity (Selected Cases) - Portfolio 7
1=none, 2=wind, 3=solar, 4=wave, 5=wind/solar, 6=wind/wave, 7=solar/wave, 8=wind/solar/wave

Next, several time series were compared to evaluate seasonal impacts. Portfolio 7 includes all the variable renewables and is the lowest total cost, other than the biomass baseline, so it was used for the comparisons. The time series compared were the portfolio without storage, with PHS only, and with the least cost battery storage option (no PHS). This least cost battery option had batteries applied to solar only, at 5% of the centralized solar nameplate capacity, and the ability to charge or discharge fully within an hour. Curtailment and unserved load monthly averages were determined and used for comparison (MWh summed per month, then averaged over the four years for each calendar month, shown in equation 22). This comparison is shown in Figure 50.

$$MWh_{avg} = \frac{\frac{\sum_{i=1}^{end} MW_i}{12}}{4} \qquad 22$$

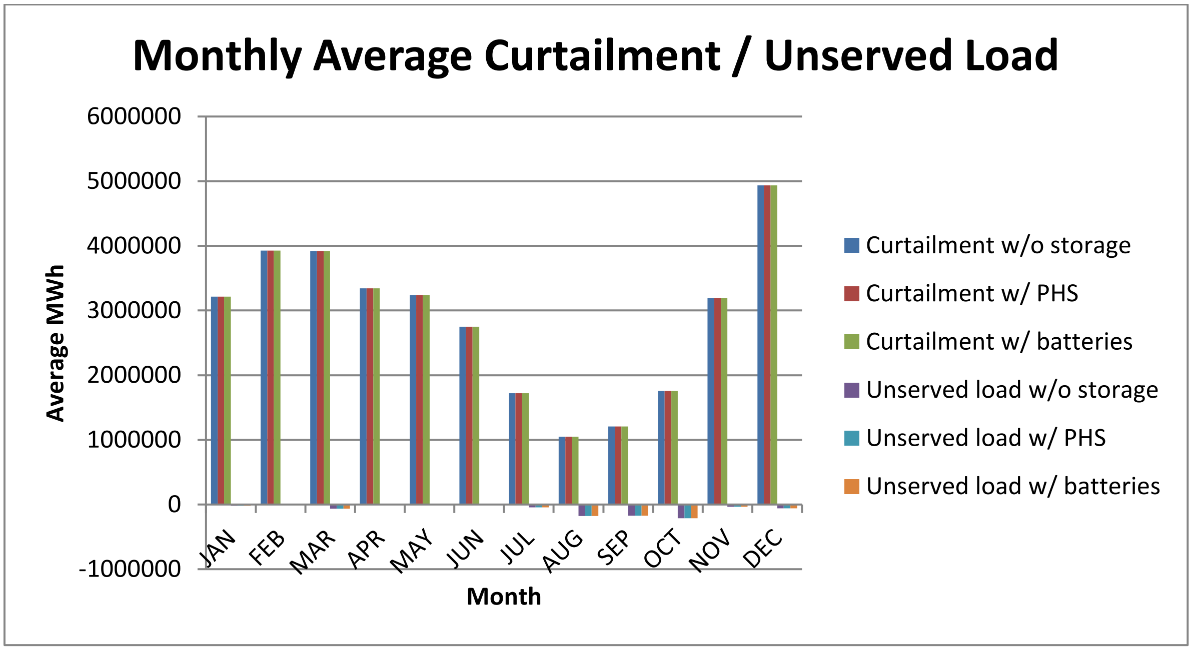

Figure 50 - Monthly Average Curtailment / Unserved Load

In addition to the expected seasonal pattern, it is obvious that the lowest cost portfolio has significantly more curtailment than unserved load; this is due to the higher cost penalty placed on unserved load ($50,000/MWh) than on curtailment ($100/MWh). The monthly data was then consolidated into seasons, with the resulting graph as Figure 51.

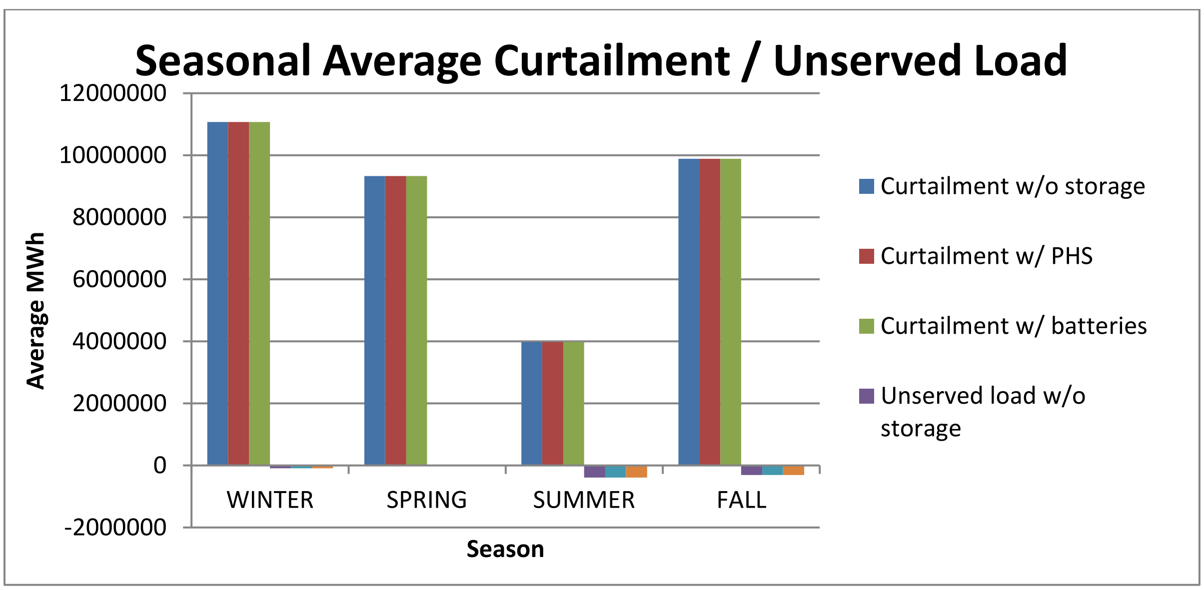

Figure 51 - Seasonal Average Curtailment / Unserved Load

In both Figure 50 and Figure 51 the scale makes it difficult to see the benefits of the energy storage, so the seasonal reductions of the PHS and battery scenarios are shown in Figure 52 (curtailment) and Figure 53 (unserved load). The reductions with battery storage are again minimal compared to the scale of the PHS reductions. The two graphs are at different scales, again due to the higher cost penalty of unserved load.

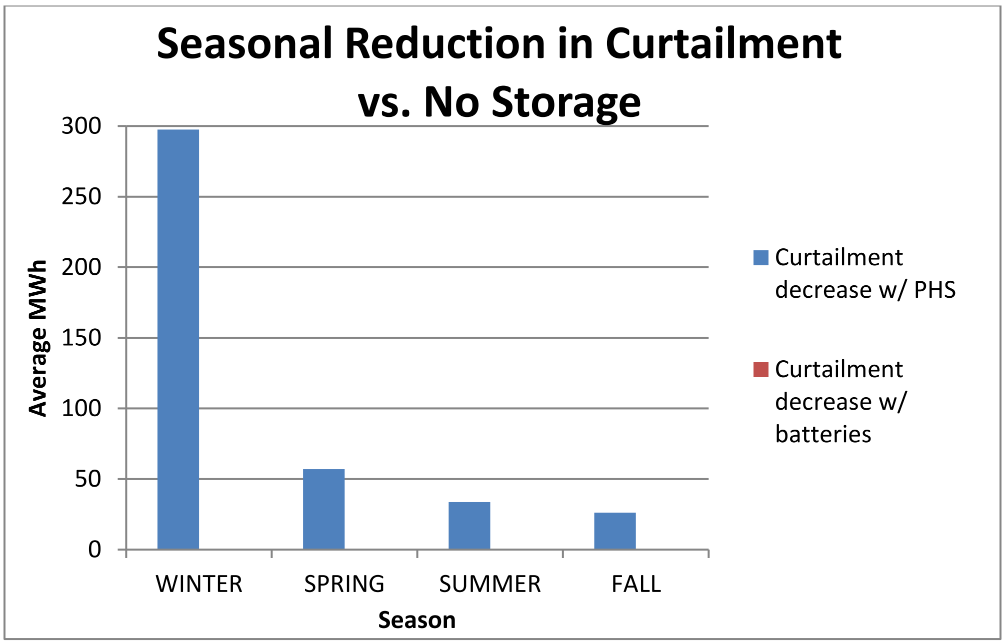

Figure 52 - Seasonal Reduction in Curtailment vs. No Storage

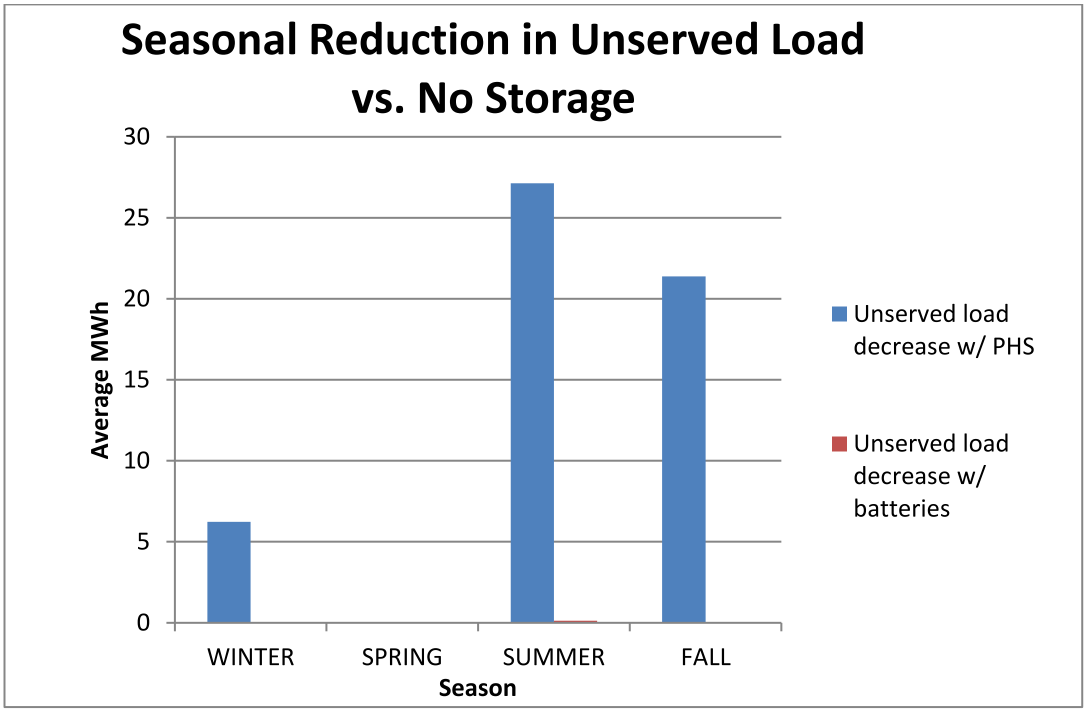

Figure 53 - Seasonal Reduction in Unserved Load vs. No Storage

It is also interesting to look at the same information translated to cost savings. This is shown in Figure 54.

	WINTER	SPRING	SUMMER	FALL
PHS Curtailment	$29,748	$5,695	$3,353	$2,612
Battery Curtailment	$3	$0	$14	$5
PHS Unserved Load	$311,678	$2,176	$1,356,549	$1,069,644
Battery Unserved Load	$1,298	$91	$6,949	$2,387

Figure 54 – Seasonal Curtailment and Unserved Load Savings

7. CONCLUSIONS:

The important contribution of this study is the modeled importance of wave energy and pumped hydro storage when integrating high penetrations of variable renewable energy in the Pacific Northwest. With integration studies very location specific, a detailed study based on actual four-year time series of load, generation and weather provides valuable information.

It is well understood that the existing hydro system is an important part of high renewable portfolios, not only for the power generated, but also for the significant balancing capability. The seasonal patterns of hydro and wind, and the resulting issues, are also well understood. This study evaluated different 100% renewable portfolios (i.e., the elimination of traditional thermal generation). The penetration of new biomass was limited to 15% in order to compare the resulting interaction of new variable renewables (wind, solar and wave).

With this constraint of biomass limited to 15%, the lowest cost portfolios include significant wave generation, ranging from 20 – 30% and distributed along Oregon's and Washington's coastline. Even with the current cost of wave energy, early on the learning curve, the less variable nature of wave generation provides significant benefits, resulting in the lowest total cost portfolios. In addition, the portfolio with the lowest unserved load cost also includes 25% wave energy penetration.

The lowest cost portfolio, limiting biomass to 15%, is a slight overbuild of generation capacity, yet still suffers from significant summer/fall unserved load in addition to winter/spring curtailment. The time series data from this lowest cost portfolio was used to evaluate the expected impact of energy storage on it. Justification of storage depends highly on its cost, as well as the opportunity to combine other benefits (value stacking).

Batteries are well suited for diurnal patterns and short term variations. When evaluating the four-year time series of the lowest-cost portfolio, the use of batteries shows some reduction in unserved load and curtailment, but the low financial benefit when compared with the required costs make it an impractical solution given the current cost of battery energy storage. In the PNW, the patterns of curtailment and unserved load typically span multiple days or weeks, which would require cost-prohibitively large battery energy storage facilities.

Although a single pumped hydro storage facility as modeled also has insufficient capacity to store energy between seasons, it shows a significant benefit for the issues within seasons. It reduces unserved load during the low hydro, low wind and lower wave generation season (summer/fall), and reduces curtailment during winter. In the spring, the high hydro and wind generation occurs often enough to exceed the capability of energy storage to shift much capacity. With the high cost penalty for unserved load, the addition of pumped hydro storage shows significant savings. Over the four years this study investigated, PHS reduced the annual cost of curtailment by $41,409 and the annual cost of unserved load by $2,740,047. Expanding these values out to the 20 year economic life used in this study, this equates to a cost reduction of curtailment of $828,180, and a cost reduction of unserved load of $54,800,940.

Given the level of investment needed based on the economic model used in this study, these savings seem almost negligible, as the investment in Portfolio 7 is approximately $950,000,000,000. However, the actual life of a PHS facility will significantly exceed the economic life in the analysis, the economic model does not include income from selling electricity, and the value of ancillary services is not included. Including these factors (as described in the future work section) would allow more accurate estimates for analysis. It should also be noted that, although not included in this study, other less variable generation such as geothermal or tidal would be beneficial, as well as alternative longer-term storage options comparable in capacity to pumped hydro.

Some level of variable renewables over-build, and thus curtailment, is viewed as necessary to achieve high penetration while maintaining the desired level of system reliability. This was modeled to some degree by allowing a small range of variable renewable totals (90 – 110%); this range was limited to allow analysis of potential energy storage. Also, no comparison was made regarding the relative benefits of increased interstate transmission for renewables vs. utilizing energy storage. Although greater interstate coordination would certainly provide some benefits, it seems likely that other solutions such as energy storage will still be required.

Other ideas to address seasonality issues are solutions such as operating a biomass facility only during the seasons with higher loads and lower hydro and variable renewable generation (late summer through early winter). It may also be possible to utilize electricity for fuel production (such as electrolysis of water to produce hydrogen) during peak renewable generation periods, then utilize this fuel during the peak load/lower generation seasons. Although these ideas are likely to be impractical economically at the present time, as technology develops, and costs change, they may become worth evaluating. Increasing the penetration of renewable energy generation will have many benefits, yet will also be extremely complex to accomplish while maintaining necessary levels of reliability.

7.1 Future Work

The scope of this study was constrained by underlying assumptions made to reduce the computational runtime to a reasonable scale. Therefore, there are a number of avenues that future work can include. A significant avenue would be to incorporate the hydroelectric generation system for system balancing. Since this study used historical hydro and load data, the balancing that the hydro system has already done for currently installed renewable energy is accounted for, however, there is no balancing done for the new renewable energy added. Although the hydro system has historically hit its balancing limits, it would be very interesting to see if (and how much) the ultimate cost of portfolios and energy storage cases changes with large-scale grid balancing included.

Another piece of future work is changing the way renewable energy is scaled for the different portfolios. In this study, for example, if less solar energy was needed, all of the solar generation plants had their output scaled down linearly. An alternative method of reducing the amount of solar energy is by taking one of the solar plants offline, as if disconnecting the switch that leads from the plant to the power grid. While this may be a more realistic approach to reducing generation from a renewable resource, it also reduces the geographic diversity of that resource, so the potential impacts would be interesting to investigate. The economic implication of ordering plant shutdowns would also need to be included.

Additionally, alternative energy storage algorithms can be used. A promising potential algorithm will look to specifically minimize unserved load. Since the cost of unserved load is the largest cost used in the economic portion of this study, specifically aiming to minimizing it should produce modified results. It should be noted, however, that utilizing an alternative energy storage algorithm will only affect the results of the energy storage analysis portion if the same methodologies are used. To achieve the desired results from this specific portion of future work, the energy storage analysis will need to be incorporated into the first round of portfolio selection analysis.

On the economic side, there is room for improved models. This study utilized a simple economic analysis to compare between different renewable portfolios and energy storage cases. Cost estimates were obtained from NREL, EIA, and WECC reports, and are mid-range average costs. Therefore, specific cost adjustments could be made for each resource and/or location. Actual (versus modeled) output from existing renewable resources would also be beneficial for correlation and refinement of the data. With more refined cost estimates and the value of the electricity generated, alternative types of economic analysis could be performed, such as Net Present Value (NPV) or Levelized Cost of Electricity (LCOE).

Lastly, an optimization problem could be fully defined and solved. The issue, however, is that much of the needed information for turning this study into an optimization problem is not publicly available. Additionally, by incorporating more technical and economic factors into the optimization problem, the computational time will increase.

8. REFERENCES:

[1] L. Hirth, I. Ziegenhagen, "Balancing power and variable renewables: Three links," Renewable and Sustainable Energy Reviews, vol. 50, pp 1035 - 1051

[2] "Using Wind and Solar to Reliably Meet Electricity Demand," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63038, May 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[3] "Wind and Solar Energy Curtailment: Experience and Practices in the United States," National Renewable Energy Laboratory, Golden, CO., Technical Report NREL/TP-6A20-60983, March 2014, [online] Available: https://www.nrel.gov/docs/fy14osti/60983.pdf Accessed on April 16, 2018.

[4] "The Role of Storage and Demand Response," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63041, September 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[5] I. Moazzen, B. Robertson, P. Wild, A. Rowe, B. Buckham, "Impacts of large-scale wave integration into a transmission constrained grid," Renewable Energy, vol. 88, pp 408 - 417

[6] X.Luo, J. Wang, M. Dooner, J. Clarke, "Overview of current development in electrical energy storage technologies and the application potential in power system operation," Applied Energy, vol. 137, pp 511 - 536

[7] "Integrating Variable Renewable Energy Into The Grid: Key Issues," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63033, May 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[8] H. Holttinen, M. O'Malley, J. Dillon, D. Flynn, A. Keane, H. Abildgaard, L. Soder, "Steps for a Complete Wind Integration Study," 2013 46th Hawaii International Conference on System Sciences, IEEE Computer Society

[9] "Grid Integration Studies: Data Requirements," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63043, June 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[10] H. Shaker, H. Zareipour, D. Wood, "Impacts of large-scale wind and solar power integration on California's net electric load," Renewable and Sustainable Energy Reviews, vol. 58, pp 761 - 774

[11] "Sources of Operational Flexibility," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63039, May 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[12] L. Jones, *Renewable Energy Integration: Practical Management of Variability, Uncertainty and Flexibility in Power Grids*, Waltham, MA., Elsevier, 2014.

[13] "A Review of Variable Generation Forecasting in the West, July 2013 - March 2014," National Renewable Energy Laboratory, Golden, CO., Subcontractor Report NREL/SR-6A20-61035, March 2014. [Online] Available: http://www.nrel.gov/docs/fy14osti/61035.pdf Accessed on May 7, 2016.

[14] M. Bilgilia, A. Ozbeka, B. Sahinb, A. Kahramanc "An overview of renewable electric power capacity and progress in new technologies in the world," Renewable and Sustainable Energy Reviews,
Volume 49, September 2015, Pages 323–334

[15] "Balancing Area Coordination: Efficiently Integrating Renewable Energy into the Grid," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63037, June 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[16] "Western Interconnection Flexibility Assessment," Energy and Environmental Economics, Inc., San Francisco, CA and National Renewable Energy Laboratory, Golden, CO., December 2015 [online] Available:
https://www.wecc.biz/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf Accessed on December 1, 2016.

[17] "Oregon State Energy Profile," US Energy Information Administration, US Department of Energy, Washington, DC. [online] Available: http://www.eia.gov/state/print.cfm?sid=OR Accessed on January 5, 2017.

[18] Map of power generation in the Northwest, Northwest Power and Conservation Council [online] Available: https://www.nwcouncil.org/energy/energy-topics/power-supply/map-of-power-generation-in-the-northwest Accessed on September 5, 2018

[19] 2010 Census: United States Profile, US Census Bureau [online] Available: https://www2.census.gov/geo/maps/dc10_thematic/2010_Profile/2010_Profile_Map_United_States.pdf Accessed on September 5, 2018

[20] "Wind Generation & Total Load in the BPA Balancing Authority," Bonneville Power Adminstration, Bonneville Power Administration, Portland, Oregon. [online] Available: https://transmission.bpa.gov/Business/Operations/Wind/default.aspx Accessed on October 1, 2016.

[21] "NREL Biopower Atlas," National Renewable Energy Laboratory, Boulder Co. [online] Available: https://maps.nrel.gov/biopower-atlas/#/?aL=TjhcqB%255Bv%255D%3Dt%26dvtS49%255Bv%255D%3Dt%26dvtS49%255Bd

%255D%3D1&bL=groad&cE=0&lR=0&mC=40.613952441166596%2C-81.474609375&zL=4 Accessed on October 1, 2016.

[22] "Renewable Portfolio Standard," US Department of Energy, Washington DC. [online] Available: http://energy.gov/savings/renewable-portfolio-standard-8 Accessed on January 5, 2017.

[23] "Washington State Energy Profile," US Energy Information Administration, US Department of Energy, Washington, DC. [online] Available: http://www.eia.gov/state/print.cfm?sid=WA Accessed on January 5, 2017.

[24] "Idaho State Energy Profile," US Energy Information Administration, US Department of Energy, Washington, DC. [online] Available: http://www.eia.gov/state/print.cfm?sid=ID Accessed on January 5, 2017.

[25] Starrett, Michael A., "Development and Experimental Hardware Validation of Novel Variable Speed Hydropower Control Schemes for Emerging Applications and Water Resource Paradigms," Oregon State University Scholar's Archive

[26] "US Energy Mapping System," US Energy Information Administration, US Department of Energy, Washington, DC. [online] Available: http://www.eia.gov/state/maps.cfm?src=home-f3 Accessed on October 1, 2016.

[27] J. Song, T.K.A. Brekken, E. Cotilla-Sanchez, A. von Jouanne, "Optimal Placement of Energy Storage and Demand Response in the Pacific Northwest," Power and Energy Society General Meeting (PES), 2013 IEEE.

[28] O. Ellabban, H. Abu-Rub, F. Blaabjerg, "Renewable energy resources: Current status, future prospects and their enabling technology," Renewable and Sustainable Energy Reviews 39 (2014) pp 748–764

[29] J. Widen, et al, "Variability assessment and forecasting of renewables: A review for solar, wind, wave and tidal resources," Renewable and Sustainable Energy Review, vol. 44, pp 356 - 375

[30] "Utility Scale Renewable Energy," California Energy Commission [online] Available: http://www.energy.ca.gov/research/renewable/utility.html Accessed on January 5, 2017.

[31] Y. Ren, P.N. Suganthan, N. Srikanth, "Ensemble methods for wind and solar power forecasting - A state-of-the-art review," Renewable and Sustainable Energy Reviews, vol. 50, pp 82 - 91

[32] J. Jung, R. Broadwater, "Current status and future advances for wind speed and power forecasting," Renewable and Sustainable Energy Reviews, vol. 31, pp 762 - 777

[33] Y. Aliari, A. Haghani, "Planning for integration of wind power capacity in power generation using stochastic optimization," Renewable and Sustainable Energy Reviews, vol. 59, pp 907 - 919

[34] "Utility-Scale Wind," WINDExchange, Wind Program, Energy Efficiency and Renewable Energy, US Department of Energy, Washington, DC. [Online] Available: http://apps2.eere.energy.gov/wind/windexchange/utility-scale-wind.asp Accessed on January 5, 2017.

[35] "Renewable Electricity Futures Study," National Renewable Energy Laboratory, Golden, CO, [online] Available: http://www.nrel.gov/analysis/re_futures/ Accessed on January 5, 2017.

[36] S. Kota, S. Bayne, S. Nimmagadda, "Offshore wind energy: A comparative analysis of UK, USA and India," Renewable and Sustainable Energy Reviews, vol. 41, pp 685 - 694

[37] E. Akarslan, F.O. Hocaoglu , "A novel adaptive approach for hourly solar radiation forecasting," Renewable Energy, vol. 87, pp 628 - 633

[38] R. Inman, H. Pedro, C. Coimbra, "Solar forecasting methods for renewable energy integration," Progress in Energy and Combustion Science, vol. 39, pp 535 - 576

[39] "Solar Forecasting," IEEE Power and Energy Magazine, November/December 2015, p 50 - 59

[40] T.C. McCandless, S.E. Haupt, G.S. Young, "A regime-dependent artificial neural network technique for short-range solar irradiance forecasting," Renewable Energy, vol. 89. pp 351 - 359

[41] "Land-Use Requirements for Solar Power Plants in the United States," National Renewable Energy Laboratory, Golden, CO., Technical Report NREL/TP-6A20-56290 June 2013 [Online] Available:
http://www.nrel.gov/docs/fy13osti/56290.pdf Accessed on January 5, 2017.

[42] "Grid Integration Distributed Solar: Addressing Challenges for Operations and Planning," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63042, March 2016. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[43] C. Perez-Collazo, D. Greaves, G. Iglesias, "A review of combined wave and offshore wind energy," Renewable and Sustainable Energy Reviews, vol. 42, pp 141 - 153

[44] "Nationial Data Buoy Center," National Oceanic and Atmospheric Administration, National Weather Service [online] Available: http://www.ndbc.noaa.gov/ Accessed on October 1, 2016.

[45] G. Reichard, B. Robertson, B. Buckham, J.R. Bidlot, C. Hiles, "Simulating and forecasting ocean wave energy in western Canada," Ocean Engineering, vol. 103, pp 223 - 236

[46] A. Uihlein, D. Magagna, "Wave and tidal current energy - A review of the current state of research beyond technology," Renewable and Sustainable Energy Reviews, vol. 58, pp 1070 - 1081

[47] S. Armstrong, E. Cotilla-Sanchez, T. Kovaltchouk, "Assessing the impact of the grid connected Pacific Marine Energy Center wave farm," IEEE Journal of Emerging and Selected Topics in Power Electronics, vol. 3, no. 4, December 2015

[48] S. Astariz, C. Perez-Collazo, J. Abanades, G. Iglesias, "Co-located wave-wind farms: Economic assessment as a function of layout," Renewable Energy, vol. 83, pp 837 - 849

[49] R. Tiron, F. Mallon, R. Dias, E. Reynaud, "The challenging life of wave energy devices at sea: A few points to consider," Renewable and Sustainable Energy Reviews, vol. 43. pp 1263 - 1272

[50] " Biopower Program, Activities Overview," US Department of Energy, Washington, DC. DOE/GO-102000-1049 [online] Available: http://www.nrel.gov/docs/fy00osti/27980.pdf Accessed on January 5, 2017

[51] "Biopower," US Department of Energy, Energy Efficiency and Renewable Energy, Biomass Program, March 2010 [online] Available: https://www.energy.gov/sites/prod/files/2014/04/f14/biopower_factsheet.pdf Accessed on January 5, 2017.

[52] J. Dolginow, R. Massey, "Switchgrass and Miscanthus: Economics of Perennial Grasses Grown for Bioenergy," University of Missouri Extension, Columbia, MO. [online] Available: http://extension.missouri.edu/p/G4980 Accessed on January 5, 2017.

[53] A. Milbrandt, D. Heimiller, A. Perry, C. Field, "Renewable energy potential on marginal lands in the United States," Renewable and Sustainable Energy Reviews, vol. 29, January 2014, pp 473–481

[54] D. Nderitu, P. Preckel, D. Gotham, E. Dobis, "Assessment of the National Prospects for Electricity Generation from Biomass," US Department of Agriculture, April 2014, State Utility Forecasting Group, Energy Center at Discovery Park, Purdue University, West Lafayette, Indiana. [online] Available: https://www.purdue.edu/discoverypark/energy/assets/pdfs/SUFG/publications/USbiopower_04_2014.pdf Accessed on January 5, 2017

[55] "Could biomass fuel Boardman?" Portland General Electric, September 2016 [online] Available: pge-biomass-boardman-giant-cane-fact-sheet%20(2).pdf Accessed on January 5, 2017

[56] "Portland General Electric - 2016 Integrated Resource Plan," Portland General Electric [online] Available: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning# Accessed on March 7, 2018

[57] "Biopower Basics," US Department of Energy, Washington, DC. [online] Available: https://energy.gov/eere/bioenergy/biopower-basics Accessed on January 5, 2017

[58] "LFG Energy Project Development Handbook, Chapter 1: Landfill Gas Energy Basics," US Environmental Protection Agency [online] Available: http://www.nswaienvis.nic.in/Waste_Portal/Technologies/landfil_gas_recovery/landfill%20gas%20Energy%20Basics.pdf Accessed on January 5, 2017

[59] "LFG Energy Project Development Handbook, Chapter 3: Project Technology Options," US Environmental Protection Agency [online] Available: https://www.epa.gov/sites/production/files/2016-09/documents/pdh_chapter3.pdf Accessed on January 5, 2017

[60] "Forecasting Wind and Solar Generation: Improving System Operations," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-65728, May 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[61] K. Orwig, et al, "Recent Trends in Variable Generation Forecasting and Its Value to the Power System," IEEE Transactions on Sustainable Energy, vol. 6, no. 3, July 2015

[62] R. Zavadil, "Renewable Generation Forecasting: The Science, Applications and Outlook," 2013 46th Hawaii International Conference on System Sciences, IEEE Computer Society, pp 2252 - 2260

[63] S. Armstrong, E. Cotilla-Sanchez, T. Kovaltchouk, "Assessing the impact of the grid-connected pacific marine energy center wave farm," IEEE Journal of Emerging and Selected Topics in Power Electronics, vol. 3, pp 1011 - 1020

[64] A. Foley, P. Leahy, A. Marvuglia, E. McKeogh, "Current methods and advances in forecasting of wind power generation," Renewable Energy, vol. 37, pp. 1 - 8

[65] J. Dowds, et.al., "A review of large-scale wind integration studies," Renewable and Sustainable Energy Reviews, vol. 49, pp 768 - 794

[66] "Final Report on the Creation of the Wind Integration National Dataset (WIND) Toolkit and API, October 1, 2013 - September 30, 2015," National Renewable Energy Laboratory, Golden, CO., Subcontractor Report NREL/SR-5D00-66189, April 2016. [Online] Available: http://www.nrel.gov/docs/fy16osti/66189.pdf Accessed on May 7, 2016.

[67] D. Larson, L. Nonnenmacher, C. F.M. Coimbra, "Day-ahead forecasting of solar power output from photovoltaic plants in the American Southwest," Renewable Energy, vol. 91, pp 11 - 20

[68] A. Kaur, L. Nonnenmacher, H. Pedro, C. Coimbra, "Benefits of solar forecasting for energy imbalance markets," Renewable Energy, vol. 86, pp 819-830

[69] "University of Oregon Solar Radiation Monitoring Laboratory," University of Oregon, Eugene, Oregon. [online] Available: http://solardat.uoregon.edu/ Accessed on January 26, 2017.

[70] R. Shah, N. Mithulananthan, R.C. Bansal, V.K. Ramachandaramurthy, "A review of key power system stability challenges for large-scale PV integration," Renewable and Sustainable Energy Reviews, vol. 41, pp 1423 - 1436

[71] E. Barbour, L.A. Grant Wilson, J. Radcliffe, Y. Ding, Y. Li, "A review of pumped hydro energy storage development in significant international electricity markets," Renewable and Sustainable Energy Reviews, vol. 61, pp 421 - 432

[72] “The Role of Storage and Demand Response,” Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63041, September 2015. [online] Available:http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016

[73] "Energy Storage - Possibilities for Expanding Grid Flexibility," National Renewable Energy Laboratory, Golden, CO. [online] Available: https://www.nrel.gov/docs/fy16osti/64764.pdf Accessed on April 13, 2018.

[74] A. Berrada, K. Loudiyi, "Operation, sizing, and economic evaluation of storage for solar and wind power plants," Renewable and Sustainable Energy Reviews, vol. 59, pp 1117 - 1129

[75] “Energy Storage Study 2014,” Turlock Irrigation District, [online] Available: http://www.energy.ca.gov/assessments/ab2514_reports/Turlock_Irrigation_District/2014-10-28_Turlock_Irrigation_District_Energy_Storage_Study.pdf Accessed on April 12, 2018.

[76] B. Zakeri, S. Syri, "Electrical energy storage systems: A comparative life cycle cost analysis," Renewable and Sustainable Energy Reviews, vol. 42, pp 569 - 596

[77] N. Li, K. Hedman, "Economic Assessment of Energy Storage in Systems With High Levels of Renewable Resources," IEEE Transactions on Sustainable Energy, vol. 6, no. 3, July 2015, pp 1103 - 1111

[78] House Bill 2193, 78th Oregon Legislative Assembly - 2015 Regular Session [online] Available: https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193 Accessed on May 8, 2018.

[79] "PGE submits storage plan to Oregon Public Utilities Commission" Press Release Nov. 1, 2017, Portland General Electric [online] Available: https://www.portlandgeneral.com/our-company/news-room/news-releases/2017/11-01-2017-pge-submits-storage-plan-to-opuc Accessed on June 11, 2018

[80] “The design and application of utility-scale battery storage varies by region,” US Energy Information Administration [online] Available: https://www.eia.gov/todayinenergy/detail.php?id=35132 Accessed on April 12, 2018

[81] F.J. deSisterns, J.D. Jenkins, A. Botterud, "The value of energy storage in decarbonizing the electricity sector," Applied Energy, vol. 175, pp 368 - 379

[82] "Maintaining Balance," D. Stenclik, P. Denholm, B. Chalamala, IEEE Power and Energy Magazine, vol. 15, number 6, November/December 2017. p31

[83] A. Malhotra, B. Battke, M. Beuse, A. Stephan, "Use cases for stationary battery technologies: A review of the literature and existing projects," Renewable and Sustainable Energy Reviews, vol. 56, pp 705 - 721

[84] A. Subburaj, B. Pushpakaran, S. Bayne, "Overview of grid connected renewable energy based battery projects in USA," Renewable and Sustainable Energy Reviews, vol. 45, pp 219 - 234

[85] A. Mahesh, K.S. Sandhu, "Hybrid wind/photovoltaic energy system developments: Critical review and findings," Renewable and Sustainable Energy Reviews, vol. 52, pp 1135 - 1147

[86] Energy Storage Systems Overview of the Technology, Safety Related Issues and Codes/Standards, Sandia National Laboratories [online] Available: https://www.sandia.gov/energystoragesafety-ssl/wp-content/uploads/2017/08/ESS-Fundamentals-Presentation.pdf Accessed on September 5, 2018

[87] T.R. Ayodele, A.S.O. Ogunjuyigbe, "Mitigation of wind power intermittency: Storage technology approach," Renewable and Sustainable Energy Reviews, vol. 44, pp 447 - 456

[88] "Modeling and Analysis of Value of Advanced Pumped Storage Hydropower in the US," Argonne National Laboratory, Chicago, IL., ANL/DIS-14/7, 2014 [online] Available: https://anl.app.box.com/s/timqpu2moj7zw4t8t5ta9xpck14tta63 Accessed on April 16, 2018.

[89] Regional Hydropower Potential Scoping Study, Prepared for the Northwest Power & Conservation Council November 2014 [online] Available: http://www.nwhydro.org/wp-content/uploads/docs/Hydropower_Report.pdf Accessed on September 5, 2018

[90] S. Rehman, L.M. Al-Hadhrami, Md. M. Alam, "Pumped hydro energy storage system: A technological review," Renewable and Sustainable Energy Reviews, vol. 44, pp 586 - 598

[91] "DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA," Sandia Report SAND2015-XXX, Sandia National Laboratories, January 2015 [online] Available: http://prod.sandia.gov/techlib/access-control.cgi/2015/151002.pdf Accessed on June 11, 2018.

[92] "DOE/EPRI Electricity Storage Handbook," US Department of Energy, Electric Power Research Institute, and NRECA. [online] Available: http://www.sandia.gov/ess/publication/doeepri-electricity-storage-handbook/ Accessed on October 1, 2016.

[93] B. F. Hobbs, et al, "Adaptive Transmission Planning," IEEE power and energy magazine, July/August 2016, pp 30 - 40

[94] H. Holttinen, M. O'Malley, M. Milligan, J.C. Smith, "Recommended Practices for Wind Integration Studies," 2014 IEEE PES General Meeting, July 2014

[95] A. Malheiro, P. Castro, R. Lima, A. Estanqueiro, "Integrated Sizing and scheduling of wind/PV/diesel/battery isolated systems," Renewable Energy, vol. 83, pp 646 - 657

[96] "Calliope: a multi-scale energy systems (MUSES) modelling framework," [online] Available: https://calliope.readthedocs.io/en/stable/ Accessed on September 11, 2018

[97] " Modeling Capabilities and Projects at NREL Related to Transmission Planning and Operation," September 29, 2016, National Renewable Energy Laboratory, Golden, CO., [online] Available: https://arpa-e.energy.gov/sites/default/files/ARPA-E%20Paul%20Denholm.pdf Accessed on September 11, 2018.

[98] B. Elliston, J. Riesz, I. MacGill, "What cost for more renewables? The incremental cost of renewable generation - An Australian National Electricity Market case study," Renewable Energy, vol. 95, pp 127 - 139

[99] S. Pereira, P. Ferreira, A.I.F. Vaz, "Optimization modeling to support renewables integration in power systems," Renewable and Sustainable Energy Reviews, vol. 55, pp 316 - 325

[100] M. Iqbal, M. Azam, M. Naeem, A.S. Khwaja, A. Anpalagan, "Optimization classification, algorithms and tools for renewable energy: A review," Renewable and Sustainable Energy Reviews, vol. 39, pp 640 - 654

[101] T. Simpkins, D. Cutler, K. Anderson, D. Olis, E. Elgqvist, M. Callahan, A. Walker, "REopt: A Platform for Energy System Integration and Optimization," National Renewable Energy Laboratory, Boulder Co., Conference Paper NREL/CP-7A40-61783, August 2014.

[102] G. Reikard, B. Robertson and J-R. Bidlot, "Combining wave energy with wind and solar: Short-term forecasting," Renewable Energy, vol. 81, pp 442-456

[103] "Renewable Energy on the Grid - Redefining What's Possible," National Renewable Energy Laboratory, Golden, CO., NREL/BR-6A20-63367, April 2015, [Online] Available: http://www.nrel.gov/docs/fy15osti/63367.pdf Accessed on August 9, 2016

[104] "Methods for Procuring Power System Flexibility," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63040, May 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[105] "Wind and Solar on the Power Grid: Myths and Misperceptions," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63045, May 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[106] "Higher Oregon renewable portfolio standard targets likely to boost wind power," US Energy Information Administration, April 22, 2016. [online] Available: http://www.eia.gov/todayinenergy/detail.cfm?id=25932#. Accessed on May 7, 2016

[107] Senate Bill 1547, 78th Oregon Legislative Assembly - 2016 Regular Session [online] Available: https://olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled Accessed on January 26, 2017.

[108] G. Barbose, L. Bird, J. Heeter, F. Flores-Espino, R. Wiser, "Costs and benefits of renewable portfolio standards in the United States," Renewable and Sustainable Energy Reviews, vol. 52, pp 523 - 533

[109] "Beyond Renewable Portfolio Standards, An Assessment of Regional Supply and Demand Conditions Affecting the Future of Renewable Energy in the West," National Renewable Energy Laboratory, Golden, CO., Technical Report NREL/TP-6A20-57830, August 2013. [online] Available: http://www.nrel.gov/docs/fy13osti/57830-1.pdf Accessed on January 5, 2017.

[110] A. Kaur, L. Nonnenmacher, H. Pedro, C. Coimbra, "Benefits of solar forecasting for energy imbalance markets," Renewable Energy, vol. 86, pp 819-830

[111] "Scaling Up Renewable Energy Generation: Aligning Targets and Incentives with Grid Integration Considerations," Greening The Grid, National Renewable Energy Laboratory, Golden, CO., Fact Sheet NREL/FS-6A20-63034, May 2015. [Online] Available: http://greeningthegrid.org/resources/fact-sheets Accessed on May 12, 2016.

[112] S. Astariz, G. Iglesias, "The economics of wave energy: A review," Renewable and Sustainable Energy Reviews, vol. 45, pp 397 - 408

[113] "Grid Modernization, Western Wind and Solar Integration Study," National Renewable Energy Laboratory, Golden, CO. [online] Available: https://www.nrel.gov/grid/wwsis.html Accessed on January 26, 2017.

[114] "Eastern Renewable Generation Integration Study," National Renewable Energy Laboratory, Golden, CO., NREL/TP-6A20-64472, August 2016, [Online] Available: http://www.nrel.gov/docs/fy16osti/64472.pdf Accessed on January 26, 2017

[115] M. Jacobson, M. Delucchi, M. Cameron, B. Frew, "Low-cost solution to the grid reliability problem with 100% penetration of intermittent wind, water, and solar for all purposes," PNAS, December 8, 2015, vol. 112, no. 49

[116] C. Clack, et al, "Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar," PNAS, June 27, 2017, vol. 114. no. 26.

[117] C. B. Martinez-Anido, G. Brinkman, B-M. Hodge, "The impact of wind power on electricity prices," Renewable Energy, vol. 94, pp 474 - 487

[118] S. Parkinson, K. Dragoon, G. Reikard, G. Garcia-Medina, H. Ozkan-Haller, T.K.A. Brekken, "Integrating ocean wave energy at large-scales: A study of the US Pacific Northwest," Renewable Energy, vol. 76, pp 551-559.

[119] F. Ueckerdt, R. Brecha, G. Luderer, "Analyzing major challenges of wind and solar variability in power systems," Renewable Energy, vol. 81, pp 1 - 10

[120] “Impacts of renewable energy on grid operations,” California ISO [online] Available: https://www.caisohttps://www.caiso.com/Documents/CurtailmentFastFacts.pdf.com/Documents/CurtailmentFastFacts.pdf Accessed on April 12, 2018.

[121] "An Overview of the Automated Dispatch Controller Algorithms in the System Advisor Model (SAM)," National Renewable Energy Laboratory, Golden, CO., Technical Report NREL/TP-6A20-68614, November 2017. [online] Available: https://www.nrel.gov/docs/fy18osti/68614.pdf Accessed on May 9, 2018.

[122] "Economic Analysis Case Studies of Battery Energy Storage with SAM," National Renewable Energy Laboratory, Golden, CO., Technical Report NREL/TP-6A20-64987, November 2015. [online] Available: https://www.nrel.gov/docs/fy16osti/64987.pdf Accessed on May 9, 2018.

[123] "Technoeconomic Modeling of Battery Energy Storage in SAM," National Renewable Energy Laboratory, Golden, CO., Technical Report NREL/TP-6A20-64641, September 2015. [online] Available: https://www.nrel.gov/docs/fy15osti/64641.pdf Accessed on May 9, 2018.

[124] "Capturing the Impact of Storage and Other Flexible Technologies on Electric System Planning" National Renewable Energy Laboratory, Golden, CO. Technical Report NREL/TP-6A20-65726, May 2016 [online] Available: https://www.nrel.gov/docs/fy16osti/65726.pdf Accessed on June 12, 2018

[125] "Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants," National Renewable Energy Laboratory, Golden, CO. NREL/TP-6A20-68737 [online] Available: https://www.nrel.gov/docs/fy17osti/68737.pdf Accessed on April 13, 2018.

[126] Brouwer, M. van der Broek, W. Zappa, W. Turkenburg, A. Faaij, "Least-cost options for integrating intermittent renewables in low-carbon power systems," Applied Energy, vol 161, pp 48-74

[127] National Centers for Environmental Information, National Oceanic and Atmospheric Administration [online] Available: https://www.ncdc.noaa.gov/ Accessed on January 15, 2017.

[128] "Annual Technology Baseline and Standard Scenarios," National Renewable Energy Laboratory, Golden, CO. [online] Available: http://www.nrel.gov/analysis/data_tech_baseline.html Accessed on October 15, 2016.

[129] NOAA Northwest River Forecast Center, Monthly Runoff Information (Columbia, The Dalles Dam) National Oceanic and Atmospheric Administration, US Department of Commerce [online] Available: https://www.nwrfc.noaa.gov/water_supply/ws_normals.cgi?id=TDAO3 Accessed on June 1, 2018

[130] "Group meets to examine planned pumped storage project," Rodger Nichols, The Goldendale Sentinel, Goldendale, WA., May 23, 2018. [online] Available: http://www.goldendalesentinel.com/story/2018/05/23/news/group-meets-to-examine-planned-pumped-storage-project/10349.html Accessed on July 9, 2018

[131] "JD Pool Pumped Storage – A Case Study of the Challenges Facing Pumped Storage in the PNW NWHA February 2016," Klickitat PUD, White Salmon, WA. [online] Available: http://www.nwhydro.org/wp-content/uploads/events_committees/Docs/2016_Pumped_Storage_Workshop_Presentations/8%20-%20Brian%20Skeahan.pdf Accessed on July 9, 2018

[132] "Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest," Prepared for US Army Corps of Engineers, Northwest Division, Hydroelectric Design Center by MWH, August 2009. [online] Available: https://www.hydro.org/wp-content/uploads/2017/08/PS-Wind-Integration-Final-Report-without-Exhibits-MWH-3.pdf Accessed on July 10, 2018

[133] "The Salem Smart Power Center - An Assessment of Battery Performance and Economic Potential," Pacific Northwest National Laboratory, Richland, WA. September 2017 [online] Available: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-26858.pdf Accessed on July 2, 2018