RENEWABLES AND BATTERY OPTIONS

Supply Side Resource Plants

HDR Project #10108345

Portland General Electric

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RENEWABLES AND BATTERY SUPPLY SIDE OPTIONS

SUPPLY SIDE RESOURCE PLANTS

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APPENDICES

Executive Summary

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to assist with the overall 2019 IRP effort by characterizing the operational and cost attributes of various power generation technologies. HDR provides consulting, design, and Owner's engineering services for all aspects of power generation, including thermal, hydro, renewable, and energy storage projects. The parameters developed for each technology include estimated performance and operating characteristics, capital costs, operating costs, and implementation schedules. The range of technologies considered included wind generation, solar photovoltaic, and lithium-ion battery energy storage. The resulting parameters for the various technologies are summarized in Table E-1 for representative project sites within the PGE's service territory and surrounding regions. The following summarizes the basis for development of the parameters for each of the technologies:

1. Performance has been estimated for all options based on supplier feedback, performance estimating software, or Vaisala (a wind performance estimating sub-consultant).
2. Conceptual level project capital costs have been developed based on an overnight, turnkey engineer, procure, and construct (EPC) delivery in 2018$.
3. End of life decommissioning, net of salvage value, were estimated.
4. Technology maturity / cost forecasts were projected.
5. Conceptual level operations and maintenance (O&M) costs, including both fixed and variable O&M, were estimated and are presented in $/kW-yr and $/MWh, respectively.
6. Conceptual level project implementation schedules identifying key project milestones and duration of key project activities from EPC contractor notice to proceed (NTP) to the commercial operation date (COD) of the facility are presented.
7. Capital drawdown schedules were developed.
8. Input parameters for dispatch modeling were derived from the O&M costs and various operating characteristics developed for each option.

Additional details and results regarding the development of the generating resource characteristics are further summarized in this report. The information developed for the IRP activities are intended to represent the current energy industry landscape and are based on supplier-, site-, and project-generic technologies. Technology attributes are suitable for comparative purposes, should not be used for budget planning purposes, and are subject to refinement based on further evaluation and review.

Table E-1. Summary of Technology Attributes.

	Unit Type	100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana	25 MWa, Single-axis Tracking, Christmas Valley Oregon	Li-On Battery - 2 Hour	Li-On Battery - 4 Hour	Li-On Battery - 6 Hour
Plant Capacity	**MW**	306	245	234	234	95	100	100	100
Capital Cost	**$/kW**	$1,508	$1,539	$1,531	$1,520	$1,510	$916	$1,554	$1,902
Capital Cost (Batteries)	**$/kW-hr**	-	-	-	-	-	$458	$388	$317
Capacity Factor	**(%)**	32.7%	40.8%	42.9%	42.9%	24.8%	Daily Dispatch	Daily Dispatch	Daily Dispatch
Fixed O&M	**$/kW-yr**	$37.0	$37.0	$37.0	$37.0	$21.9	$23.5	$31.1	$42.6
Variable O&M	**$/MWH**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Land Lease[1]	**$/MWH**	1.70	1.70	1.70	1.70	4.22	-	-	-
Project Schedule	**months**	29	27	27	27	13	18	18	18

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[1] Battery options assume $2310/acre annual land lease cost and is included in the Owner's costs/Capital costs.

1 Introduction

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to characterize select renewable and battery energy storage system resources. The developed resource characteristics will be used by PGE for development of modeling inputs and assumptions to be used in its 2019 IRP development and dispatch models. These technology characteristics include estimated performance and operating attributes, capital costs, and operating costs for the various generating technologies. The technology options include several wind generation sites, a solar photovoltaic (PV) generation site, and lithium-ion battery energy storage systems (BESS). The following report summarizes the assumptions, calculations, and analyses to characterize the resource options and discusses current market conditions that may alter the accuracy of these inputs or the ability of PGE to implement the technologies considered in this study.

The following thermal and pumped hydro generating assets have been considered in this report:

1. Wind Generation – 100 MWa Annual Output
    a. Ione, Oregon
    b. Columbia River Gorge, Oregon
    c. Southeast Washington (Columbia County)
    d. Loco Mountain, Montana (near Colstrip Transmission Line in Meagher County)
2. Solar Photovoltaic (PV), Christmas Valley – 25 MWa Annual Output
3. Lithium-ion Battery Energy Storage System – 100 MW Capacity
    a. 2 hour storage duration
    b. 4 hour storage duration
    c. 6 hour storage duration

HDR has developed the following inputs for each of the generation options:

1. Plant Capacity and Performance
2. Operational Characterization
    a. Availability / Reliability
    b. Approximate Footprint
    c. Maintenance Cycle / Durations
    d. Technical Maturity
3. Plant Capital Costs
    a. Project Costs
    b. Owner's Costs
4. Project Schedule
5. Operations and Maintenance Costs
    a. Fixed Costs
    b. Variable Costs

The details and results of the plant characteristics developed by HDR are further discussed in the following sections of this report and are summarized in Appendix C.

2 Study Basis and Assumptions

The following basis was used for establishing performance, costs, and operating characteristics for the various generating resource options considered in this study.

2.1 Site Characteristics

The technology described in this report have been presented on the basis that installations are located in the Pacific Northwest at the following locations:

- Christmas Valley, Oregon (Solar PV)
- Ione, Oregon (Wind)
- Columbia River Gorge, Oregon (Wind)
- Southeastern Washington (Wind)
- Loco Mountain, Montana east of Rocky Mountains near Colstrip Transmission (Wind)

2.2 Plant Performance

2.2.1 Performance

Plant performance (i.e., output, efficiency, etc.) was estimated for all technologies based on performance estimating software, previous project developments, feedback from suppliers, and/or published performance information.

For the solar PV plant, performance was estimated using PVsyst software for a single axis tracking unit at the Christmas Valley, Oregon site.

Vaisala, a subconsultant to HDR, developed average annual wind energy production, historical wind resource, and generation profile data for all four wind sites. Historical wind data was obtained for a 38-year period and expected annual net generation was developed for a single wind turbine and then extrapolated to a 100 MW average (MWa) annual output.

Battery performance was estimated for expected round trip efficiencies for current lithium-ion battery technology based on recent project experience and industry and/or vendor specific data from similar projects.

2.3 Operations and Maintenance Cost Assumptions

For each technology considered, operating and maintenance (O&M) costs are presented and broken into fixed and variable costs as well as land lease/royalty costs. O&M costs are estimated based on a combination of previous HDR project experience and/or vendor information available.

While these costs vary from technology to technology, the fundamental breakdown between fixed and variable costs can be summarized as follows:

Fixed O&M: Fixed O&M costs are costs that are not generally dependent on the generation rate of the facility. These costs take into account plant operating and maintenance staff, fixed long term service agreement costs, and other fixed maintenance costs for equipment. Fixed staffing costs utilized in the analysis are defined below in Table 2.3-1. Typical plant staffing levels used for characterizing staffing costs are summarized in Table 2.3-2. No taxes, insurances, corporate general and administrative costs (G&A), or fixed transmission costs have been included.

Table 2.3-1. Fixed Staffing Costs.

Fixed Cost	Cost in 2018 $
Annual Cost for Salaried Staff	$140,000
Annual Cost for Hourly Staff	$100,000

Table 2.3-2. Plant Staffing Level Basis.

Staffing	Wind	Solar PV	BESS
Incremental Salaried Staff	3	1	0
Incremental Hourly Staff	2	2	0

Fixed costs developed for this evaluation are presented on a $/kW-yr basis computed by dividing the estimated fixed annual O&M costs by the net plant installed capacity or the average life of plant net degraded capacity where stated. Fixed O&M costs presented herein do not include costs associated with insurances, property taxes, or corporate general and administrative (G&A) costs.

Variable O&M: Variable O&M costs are those expenses that are dependent on electrical production/operation of a facility. Variable O&M costs include costs associated with consumption and disposal of materials associated with operation, as well as variable costs associated with operating facility equipment, such as major equipment maintenance and maintenance costs, including replacement material and components and outsourced labor to perform major equipment maintenance. Variable O&M costs are presented on a levelized annual $/MWh basis.

Land Lease/Royalty Costs: Land lease and royalty costs are those expenses associated with land leases and royalty payment fees that are often associated with renewable generation projects. Land lease payments go to the developer and are often based on a fixed annual cost or a variable cost based on the annual generation and presented in $/MWh. Royalty payments are based on the annual generation and also presented in a $/MWh basis.

2.4 Capital Cost Basis & Uncertainty Basis

Total project capital costs were developed assuming an engineer, procure and construct (EPC) contracting basis and are presented in this report based upon a project full notice to proceed (FNTP) in 2018. These costs assume that each of the technologies considered will be installed within the Pacific Northwest or Montana region, depending on the site location. General adjustments to account for wage rate and productivity factors have been applied to the different project site locations to account for regional differences.

Total capital cost estimates are broken down into project capital and Owner's costs. Project capital costs include the following:

- The costs associated with the procurement of major equipment (equipment costs)
- Costs associated with assembly and construction labor (construction costs)
- Costs associated with the procurement and installation of commodities such as electrical infrastructure and foundations (materials and supplies costs)
- Costs associated with site development, access, and staging
- Project indirects
- Construction management
- Engineering
- Contingency
- EPC fees and insurance

Owner's costs have been developed as 10 percent of the project capital costs and generally include the following (unless otherwise noted within the report):

- Project management
- Engineering support
- Construction management
- Owner contingency
- Plant operations during commissioning
- Insurance during construction
- Initial spares
- Construction utilities
- Project development

The following additional general site assumptions have been used:

- Project location on a site/land generally suitable for development
- General adjustments for labor and wage rates based on location in Oregon, Washington, or Montana.
- Electric scope of supply up to the high side of the GSU transformer (costs associated with grid interconnection and network upgrades excluded)
- Sufficient space is available at the site for construction activities, including lay-down.
- No costs have been included for land purchases, transmission interconnect costs, escalation, interest during construction, or sales tax.

All project total capital costs that are expressed as $/kW values in this report are derived by dividing the project costs by the total net plant installed capacity.

All costs presented herein are based upon current day cost expectations and actual project data and quotations where available. They are intended to reflect the current status of the industry with respect to recent materials and labor escalation; however, due to the volatility of the power generation marketplace, actual project costs should be expected to vary. Each project cost summary provides an indication of estimated accuracy of the total project cost values based on an American Association of Cost Engineering International (AACE) Class 4 estimate. The expected standard deviation of the cost has been calculated based on the accuracy of the cost estimate. Estimate uncertainty is characterized further in Table 2.4-1, where low corresponds to a low range of estimation (or underestimation) and high corresponds to a high range of estimation (or overestimation).

Table 2.4-1. Estimate Uncertainty

Estimate Class	Accuracy Range	
	Low	**High**
Class 4	-15 to -30%	+20 to +50%

Decommissioning costs have also been estimated, net of salvage value, and assume the site will be restored back to a brownfield condition, which removes all material and structures down to 2 to 3 ft. below grade. Decommissioning costs are presented in 2018 US dollars and reflect HDR's opinion of current market conditions and salvage values and do not include escalation to the end of project life. These costs have been estimated based on similar project experience or as a percentage of capital costs. It is anticipated that the Li-ion cells will have salvageable value at the end of project life, and is expected to result in zero additional costs to Owner for removal from site and recycling.

2.5 Technology Maturity

As more experience is gained through the application of a power generation technology, the capital costs would be expected to decrease as the design, fabrication, and installation of a technology becomes more mature. To estimate the effects of maturity on a generation technology, and the potential reductions in plant capital costs over time, cost trends were developed using data from the Energy Information Administration's (EIA) 2017 Annual Energy Outlook (AEO) National Energy Modeling System (NEMS). Cost forecasting data from NEMS was applied to the estimated capital costs as a basis for forecasting future costs for each technology option evaluated. All costs are referenced in 2018 US dollars and are forecasted from 2018 to 2050. In most cases, the NEMS forecasted cost projections did not start until 2020, so costs were estimated to be unchanged from 2018 until the start of the NEMS forecast. Figure 2.5-1 summarizes the results of the estimated future project costs. Further details are included in Appendix A (note that wind technology costs are similar, but small variations can be seen in Appendix A). It is also noted that lithium-ion battery technology cost forecasts are based on the renewable energy diurnal storage technology cost forecast provided from NEMS.

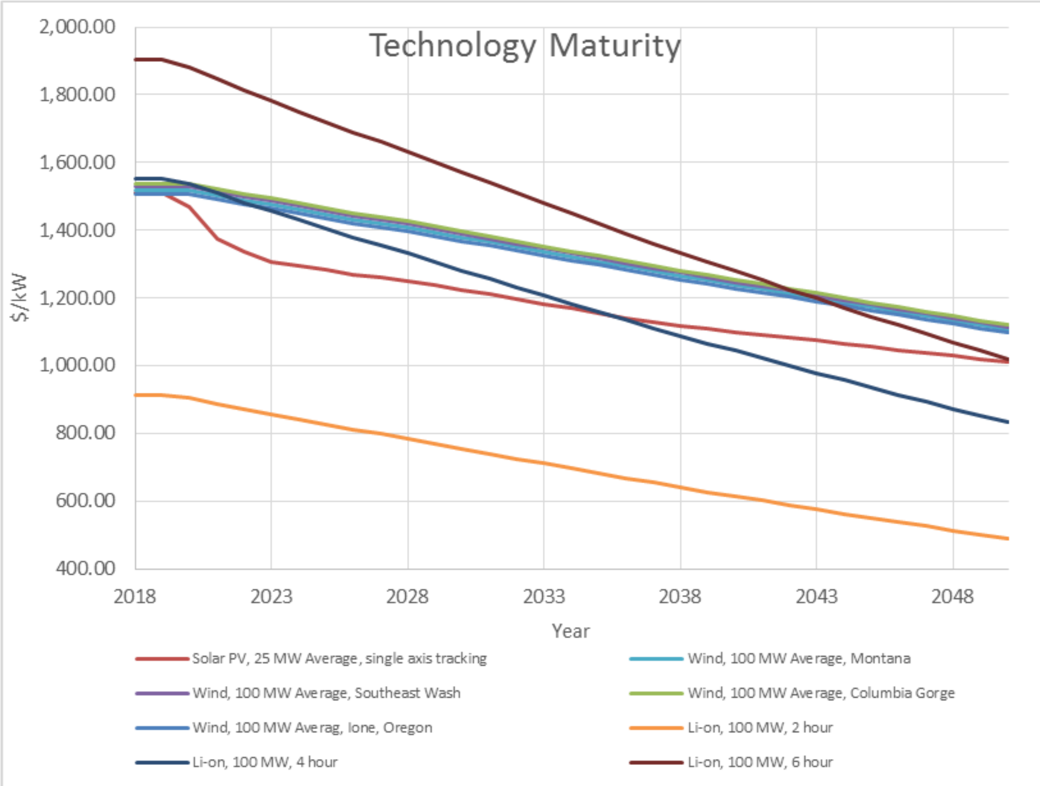


Figure 2.5-1. Technology Maturity Model

2.6 Project Schedule and Cash Flow Basis

The estimated project schedules presented herein are based upon current day EPC contracting approaches and methodologies. As such, it is expected that a portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. This will typically involve the procurement of the major equipment and the EPC contract assuming limited notice to proceed (LNTP) is awarded for these contracts prior to an FNTP.

While some project schedules estimated for this work include some developmental activities, the majority of the schedules and durations are generally presented from Full Notice to Proceed to the commercial operation date (COD) of the facility. It is expected that the permits will be received and project financing activities will be completed prior to the project FNTP.

For monthly cash flow determinations, a general project cash flow schedule has been utilized and adjusted as appropriate for each technology. A general representation of the curve is presented in Figure 2.6-1. Annual cash flow forecasts are provided for each technology from FNTP to the commercial operation date (COD) in Appendix B.

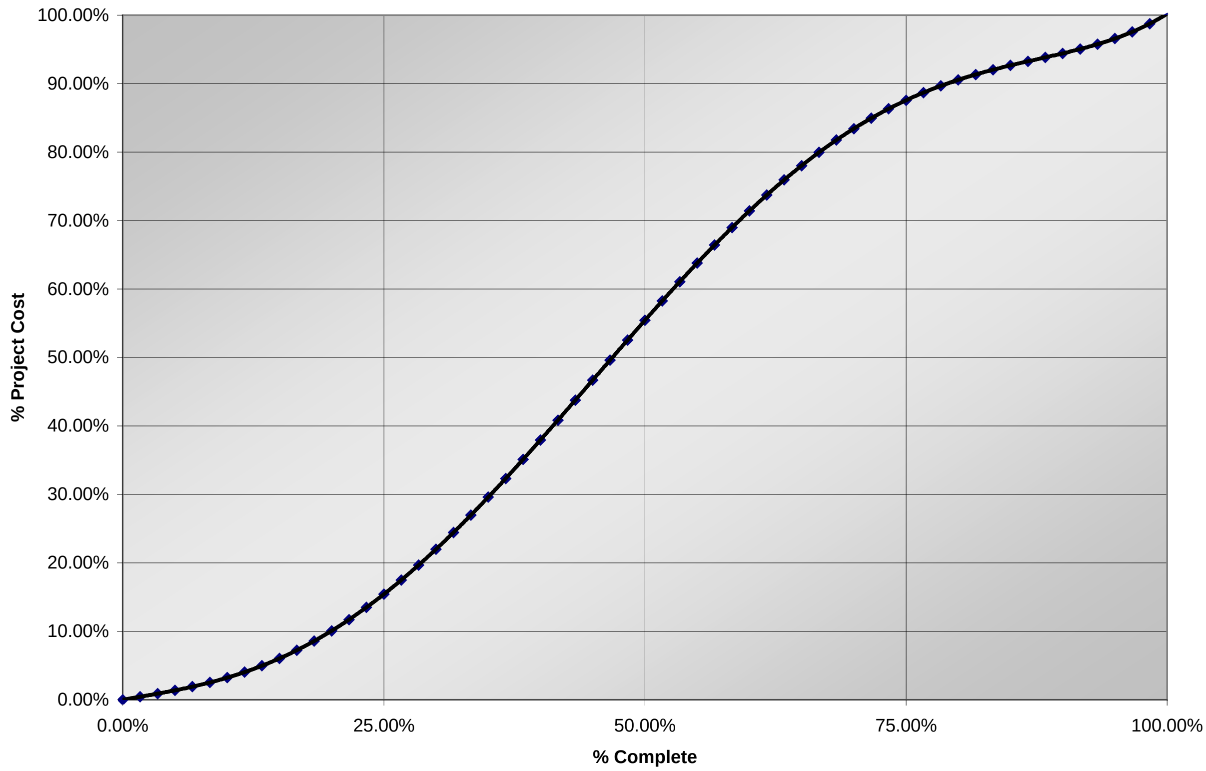


Figure 2.6-1. Representative Cash Flow Curve.

3 Wind Generation Technology

The U.S. is one of the largest and fastest-growing wind power generation markets in the world. In the last decade, there has been significant growth in wind capacity in the U.S. because of advancements in wind generation technology, federal tax incentives, and other policy incentives. Standalone wind is an intermittent power generation resource in that it is not fully dispatchable in the typical sense; however, output from wind installations can be curtailed when required.

Regional trends in the Pacific Northwest are consistent with trends across the U.S. According to the U.S. Department of Energy, wind energy production as a percentage of total electric generation is 11.2% for Oregon, 6.5% for Washington, and 7.6% in Montana[2]. For total wind installed capacity as of the end of 2017, Oregon has installed 3,213 MW, Washington has installed 3,075 MW and Montana has installed 695 MW[3]. During 2017, five wind projects totaling 50 MW achieved commercial operation in Oregon. No wind projects achieved commercial operation in 2017 in Washington and Montana. However, approximately 427 MW of wind power was under construction across the three states at the end of 2017.

For the purpose of this evaluation, a 100 MWa wind generation facility was evaluated in four regions of Oregon, Washington, and Montana: Columbia Gorge Oregon; Ione, Oregon; Southeast Washington (Columbia County); and East Central Montana (Loco Mountain region in Meagher County). It is noted that wind resources can vary regionally and the wind resources have been characterized to be representative of the surrounding areas centered at the location of interest and are inclusive of 38 years of historical weather and wind resource data.

3.1 Technology Overview

Wind power is generated by converting the kinetic energy of wind into electricity by rotating turbine blades that are connected to an electrical generator. Higher wind speeds (better wind resource) typically result in more efficient facilities and higher annual capacity factors. A map of wind speeds in the U.S. is shown below in Figure 3.1-1.

[2] U.S. Energy Information Administration. https://www.eia.gov/electricity/data.php
[3] American Wind Energy Association. U.S. Wind Industry Fourth Quarter 2017 Market Report. https://www.awea.org/gencontentv2.aspx?ItemNumber=11255

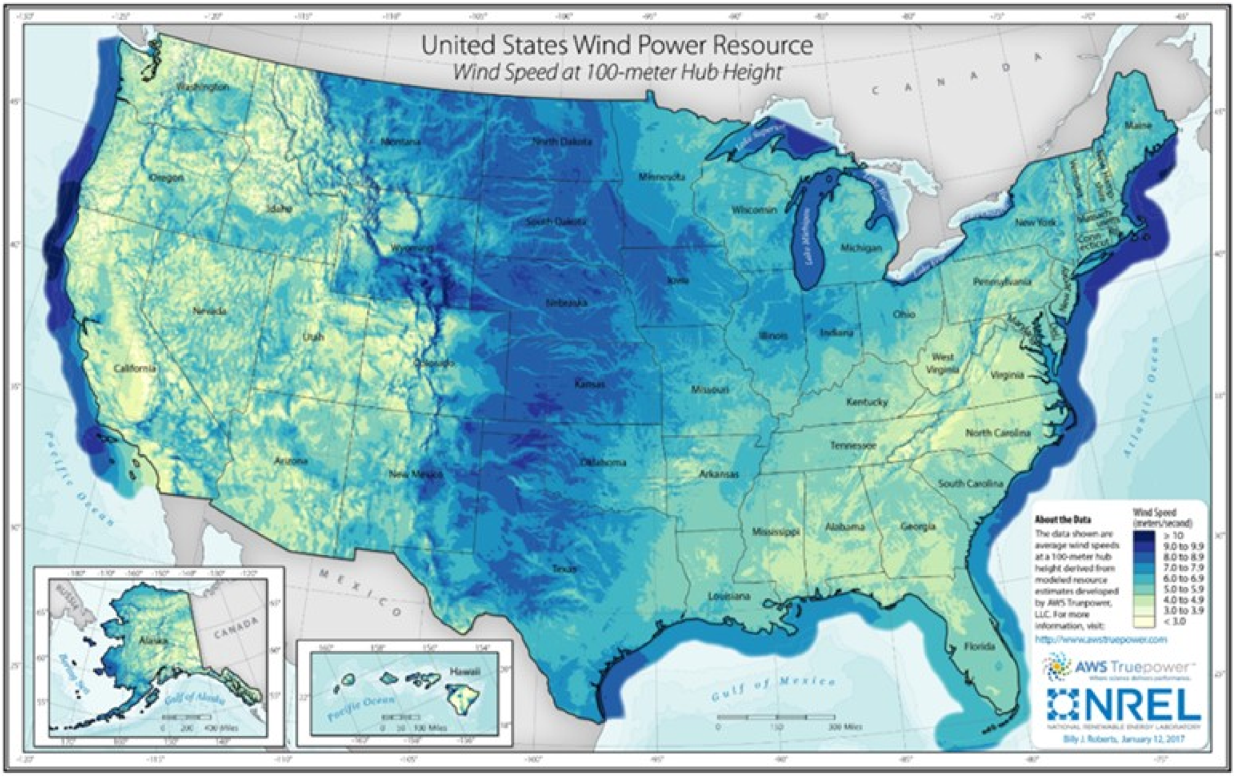


Figure 3.1-1. U.S. Wind Speeds at 100m Hub Height

A wind turbine ideally would be located where wind flow is non-turbulent and constant year round without excessive or extreme gusts. Wind speed typically increases with altitude and is higher over open areas without windbreaks such as trees or buildings. Favorable sites for wind turbines include the tops of smooth, rounded hills, open plains, and mountain gaps that funnel and intensify wind. Wind data is typically collected for a year or more via meteorological towers to determine general viability of a site.

Adequate spacing between the wind turbines must be maintained to reduce wind energy loss from interferences from nearby turbines. To minimize efficiency losses, wind turbines are commonly spaced three to five rotor diameters apart along an axis that is perpendicular to the prevailing wind direction and five to ten rotor diameters apart along an axis that is parallel to the prevailing wind direction.

3.2 Commercial Status

Wind power generation equipment, knowledge, and installation techniques have been adapted and implemented globally and is a well proven, commercially available technology for power generation. Advances in wind turbine designs have improved achievable plant efficiencies as compared to older wind power plants and increasingly allowing wind turbines to be more economically implemented in lower wind power class regions.

3.3 Operational Considerations

Wind farms are typically designed for a 25 year life, but well maintained turbines can last up to 30 years depending on the service conditions at the site and historical maintenance practices. Typical wind turbine sizes range from nominally 1.5 MW to 5 MW. For this analysis, a Vestas V136 3.6 MW with a hub height of 105 meter (m) was reviewed. The Vestas turbine model was considered because it was appropriate for the wind regimes in the Oregon, Washington, and Montana and it represents the recent industry trend of installing higher capacity turbines greater than 2 MW.

Note that the Federal Aviation Administration (FAA) does not have a height restriction on wind turbines. However, wind turbines with blade tip height that reaches greater than 500 feet would be within the FAA's altitude designation for general aviation aircraft and may require a longer permitting process for the FAA siting permit.

The characteristics of the wind generation technology considered are as follows:

- Vestas V136-3.6 wind turbines
- 105 m hub height for all sites
- 3.6 MW capacity per turbine
- 136 m rotor diameter

3.3.1 Plant Performance

Each wind site is sized to approximately 100 MWa. The actual nameplate capacity and estimated annual net capacity factor for each wind site location is provided below in Table 3.3-1.

Plant performance was estimated using a Vestas V136-3.6 power curve at a 105 m hub height. The net capacity factors were estimated from available wind resource data and include all losses up to the project busbar (i.e., transmission losses are not included). Wind resource data was gathered by Vaisala from meteorological towers across the region and corrected for long-term variability over a typical project lifetime by analyzing historical diurnal (daily), seasonal, and annual weather and atmospheric data from the last 38 years. Long-term data sources included information from the National Oceanic and Atmospheric Administration and the National Aeronautics and Space Administration.

Table 3.3-1. Wind Turbine Site Nameplate Capacities and NCFs

Wind Site	Nameplate Capacity (MW)	Annual NCF (%)
Ione, Oregon	306.0	32.7%
Columbia Gorge	244.8	40.8%
Southeast Washington	234.0	42.9%
Loco Mountain Montana	234.0	42.9%

3.4 Reliability, Availability, & Maintenance Intervals

Plant forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 3.4-2 on a per turbine base.

Table 3.4-2. Wind Plant Plant Availbility/Reliability (One Turbine)

Availability / Reliability		100 MWa Wind
Forced Outage Rate, per turbine	%	2.5%
Planned Outage Rate, per turbine	%	1.1%
Maintenance cycle and average maintenance duration	days/WTG/year	4

3.5 Land Requirements

The land required for a wind farm is divided between total overall footprint and direct, permanent footprint. The actual land use depends on many factors including wind resource, land ownership, terrain, land type (e.g., crop land, shrub land, forest), and wind turbine layout configuration. The four sites evaluated in this study would typically be located on grasslands or pasture. From site permits of actual operating and approved projects submitted to the Oregon Energy Facility Siting Council[4], the projects with turbines greater than or equal to 2.5 MW per turbine show an average total land area (i.e. the total area within overall site boundary) of approximately 48.2 acres (19.5 hectares) per installed MW and an average direct, permanent impact area (i.e. the land area directly impacted by turbine locations, access roads, and other site facilities) of 1.8 acres per installed wind turbine. HDR applied the average land use for total land area and direct, permanent impact area to all four sites. Table 3.5-1 summarizes land use requirements for each wind turbine site considered.

Table 3.5-1. Wind Turbine Site Land Requirements

		100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana
Number of Turbines		85	68	65	65
Total Land Area	acres	14,700	11,800	11,300	11,300
Approx. direct footprint* (permanent), per turbine	acres/turbine	1.8	1.8	1.8	1.8

3.6 Project Cost

Table 3.6-1 summarizes the estimated total project costs for each of the wind resource sites considered for a 2018 notice to proceed. The breakdown of estimated EPC costs and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the end of plant life decommissioning costs are also referenced. It is noted that project capital costs are based on a turnkey EPC contracting and approach methodology, which assumes the EPC contractor procures the major equipment, including the wind turbines. The wind turbines typically represent a large portion of the project

[4] https://www.oregon.gov/energy/facilities-safety/facilities/Pages/Facilities-Under-EFSC.aspx

cost ranging approximately $800/kW to $1,000/kW. EPC contingency costs, fees, and markups can increase project costs as compared to a project with Owner/developer procured turbines.

The turbines are assumed to be installed on land not owned by the project developer resulting in an assumed land lease cost, which is not included in the capital costs (but is provided in O&M costs).

Decommissioning costs include removal of the turbine from the foundation, partial removal of concrete foundation pedestal, extracting salvageable material, and reclaiming of disturbed areas (except for access roads, which are left in place for land owner use). The estimated salvage values for steel and copper are based on surveys published by the United States Geological Survey. Based on similar project experience and industry data available, HDR used an overall net cost of $35/kW for wind project decommissioning.

Table 3.6-1. Wind Plant Project EPC and Owner's Costs (Total Plant)

Project Costs, 2018$		100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana
Total Plant Cost	$1,000	461,400	376,700	358,300	355,700
Total Plant Cost	$/kW	1,508	1,539	1,531	1,520
EPC Cost	$1,000	415,300	339,000	322,500	320,100
Owner's Cost	$1,000	46,100	37,700	35,800	35,600
Std Deviation from Total Plant Costs	$/kW	424	432	430	427
End of Life Decomissioning Costs	$1,000	10,700	8,600	8,200	8,200

3.7 Implementation (Schedule)

Project schedules for a 100 MWa generation resource have been estimated and are based upon current day EPC contracting approaches and methodologies. The schedule assumes that the procurement of the major equipment including the wind turbines are the responsibility of the EPC contractor.

Wind power plants have a timeline ranging from 18 to 36 months for the EPC period (i.e. EPC contractor NTP through COD) depending on many different factors. A wind power generating facility with an output of 230MW similar to the SE Washington and Loco Mountain Montana sites will have an overall duration of approximately 26 months for the EPC period while a larger facility similar to the Ione North site with an output of 306 MW will have a duration of 28 months. The schedule duration varies based on the number of wind turbine at each location. A typical, 28 month project schedule is depicted in Figure 3.7-1. The estimated variation in overall EPC period and construction period for each of the selected sites, based on plant site and other site factors, are further shown below in Table 3.7-1. The construction period is from on-site EPC contractor mobilization through COD.

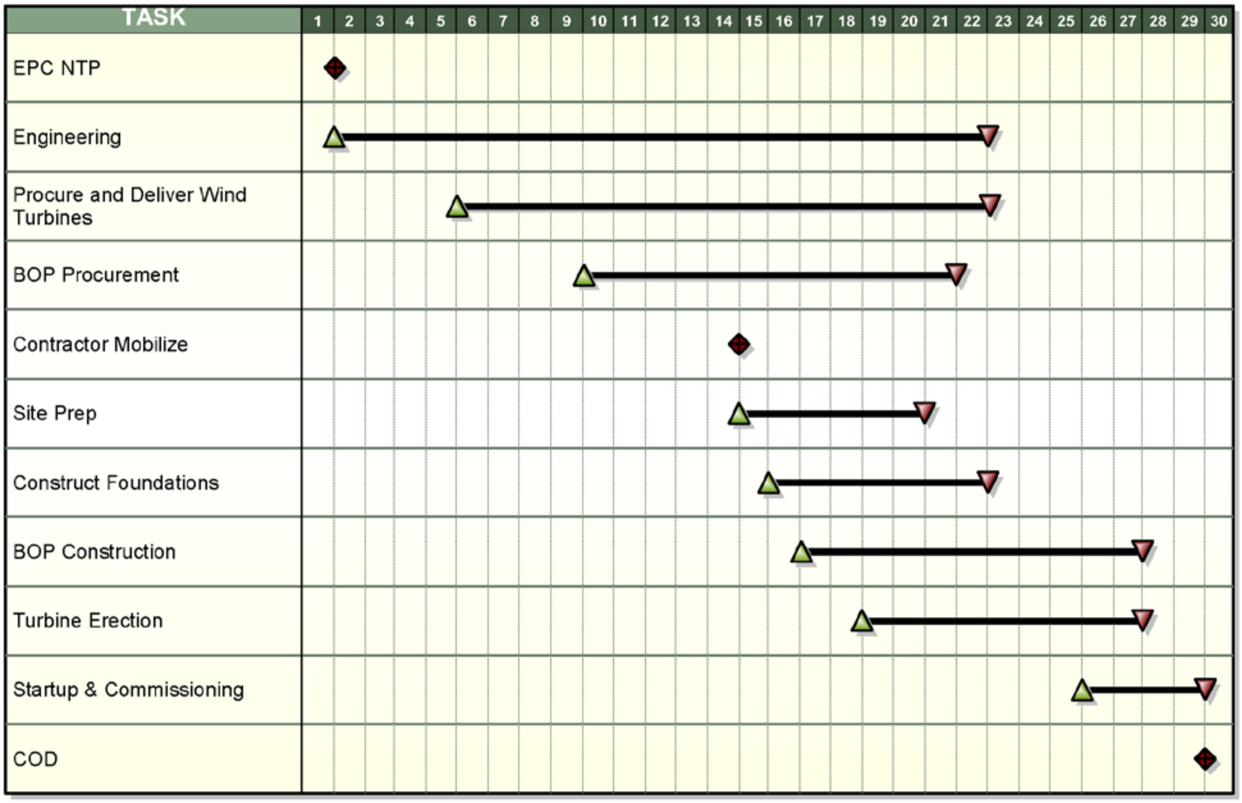


Figure 3.7-1. 100 MWa Wind Conceptual Project Schedule (Typical)

Table 3.7-1. Site Wind Plant Project Schedule Variation

Wind Site	EPC Period (months)	Construction Period (months)
Ione, Oregon	28	15
Columbia Gorge	26	13
Southeast Washington	26	13
Loco Mountain Montana	26	13

3.8 Operating Costs

The estimated fixed and variable O&M costs for each wind site are presented in Table 3.8-1. Operation and maintenance costs are inclusive of plant staffing and major turbine parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance. The O&M costs for wind projects are generally presented as a combined fixed and variable O&M component as shown in Table 3.8-1.

Plant staffing has been included as defined in Table 2-1 and 2-2. Staffing for the proposed wind power plants often utilize a remote monitoring/operating system with minimal on-site staff. Wind turbine maintenance labor is typically contracted in an O&M services contract.

Land lease costs have also been estimated and are typically paid to land owners as compensation for using their land. Royalties may also be paid to land owners as a small percentage of the project revenue. Based on HDR's project experience, the land lease and royalty costs for all four wind sites are estimated to be $1.70/MWh at the plant busbar.

Table 3.8-1. Wind Plant Fixed and Variable Operating Costs

Operating Costs, 2018$		100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana
Fixed O&M	$/kW-yr	37.0	37.0	37.0	37.0
Variable O&M	$/MWH	0	0	0	0
Land Lease/Royalties	$/MWH	1.7	1.7	1.7	1.7

4 Solar PV Technology

Solar PV technology uses solar cells or photovoltaic arrays to convert light from the sun directly into electricity. Utility-scale solar PV systems made up 1.3% of the total net generation in the U.S. in 2017[5].

For the purpose of this study, a 25 MWa AC solar plant was analyzed in Christmas Valley, Oregon, with the following characteristics:

- Single-axis tracking
- Inverter DC/AC ratio is 1.30
- 18% efficient solar panels from a representative vendor such as Hanwha
- Total installed nameplate capacity of 95 MW AC

4.1 Technology Overview

PV cells are made of different semiconductor materials and come in many sizes, shapes, and ratings. Utility scale PV technologies are generally mono/poly silicon or thin film. Solar cells produce direct current (DC) electricity and therefore require a DC to alternating current (AC) converter to allow for grid connected installations.

The PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by the local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west and dual-axis trackers allow for modules to remain pointed directly at the sun throughout the day. This evaluation considers a single-axis tracking configuration.

The amount of electricity produced from PV cells depends on the quantity and quality of the light available and performance characteristics of the PV cell. The largest PV systems in the country are located in the Southwestern regions where, as shown in Figure 4.1-1, where the strongest solar resources are available.

[5] U.S. Energy Information Administration (EIA)

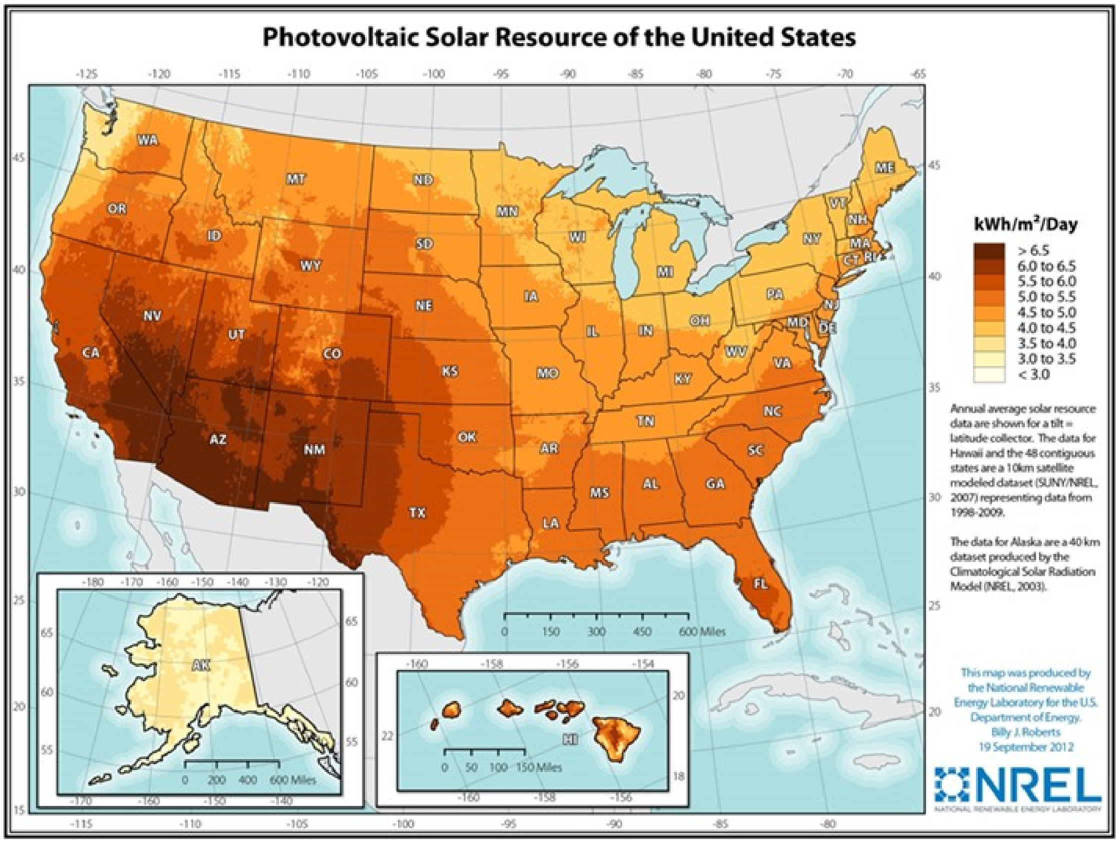


Figure 4.1-1. United States Photovoltaic Solar Resource

4.2 Commercial Status and Current Market

PV cells are commercially available with a significant installed operating base. There currently is over 50 GW of installed solar PV capacity in the U.S.[6] In 2017, approximately 10 GW of solar PV was installed, which represented 30 percent of the new electric generating capacity installed within the U.S.

The Federal Investment Tax Credit (ITC) has been instrumental in supporting the deployment and growth of solar energy in the U.S. The ITC currently offers a 30% tax credit towards the investment cost of solar systems. For a solar project to get the 30% ITC, it must begin construction by December 31, 2019, but it does not have to go into service until December 31, 2023. The percentage steps down to 26% and 22% for projects that start construction in 2020 in 2021, respectively. The project costs presented in Section 4.6 do not account for impacts associated with ITC credits.

[6] 2017 Solar Market Insight Report, Solar Energy Industries Association (SEIA)

Recently, the U.S. imposed a 30% tariff on imported crystalline-silicon solar cells and modules that went into effect February 7, 2018. The tariffs start at 30% of the cell price in 2018 and then gradually drop to 15% by February 7, 2021. Per SEIA, the 30% tariff can be expected to increase year 1 PV module prices by roughly $0.10/W or $100/kW. The technology forecast curve in Appendix A does not include pricing impacts that may be associated with the tariff.

4.3 Operational Considerations

4.3.1 Plant Performance

A 25 MWa solar facility site was selected in Christmas Valley, Oregon. The nameplate capacity of the facility is 95 MW as shown in Table 4.3-1 below. The power of a panel degrades over time at an estimated annual rate of 0.5%. The NCF shown below in Table 4.3-1 represents the degraded annual capacity factor over the life of the plant. 1.

Table 4.3-1. Solar Site Nameplate Capacity and Net Annual Averaged Degraded Capacity Factor

Solar PV Site	Nameplate Capacity (MW)	Annual NCFs (%)
Christmas Valley	95	24.8%

4.4 Reliability, Availability, & Maintenance Intervals

Plant forced outage rates, planned outage rates, and mean average outage duration are summarized in Table 4.4-2.

Table 4.4-2. Solar Plant Plant Availbility/Reliability

Availability / Reliability		Solar PV 25 MWa
Forced Outage Rate	%	0%
Planned Outage Rate	%	2%
Mean Annual Outage Duration	Days/year	7.3

4.5 Land Requirements

The land area required for Solar PV applications can be extensive depending on a variety of factors including the land and design. It is envisioned that approximately 38 arrays of 2.5 MW each would be installed. Each array would consist of about 8,764 modules of 370 Wp capacity each. An approximate land requirement of 475 acres was estimated for a 25 MWa Solar PV installation. This estimate is based on HDR project experience and is derived based on ground cover ratio and panel energy densities from a variety of HDR projects.

4.6 Project Cost

Table 4.6-1 summarizes the estimated total project costs for a 25 MWa Solar PV Site. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

The estimated solar project cost includes the modules, structures, inverters, the balance of the system, and engineering and management services.

Solar PV project decommissioning costs are estimated based on recent, similar project experience and industry data. Decommissioning costs include removal of PV panels, removal of above ground panel racking, removal of below ground cables and racking foundations (piles), extraction of salvageable material, removal of access roads, and reclamation of disturbed areas. The estimated salvage values for steel, copper, and aluminum are based on surveys published by the United States Geological Survey. Based on recent studies, HDR assumed an overall net cost of $20/kW for solar PV project decommissioning.

Table 4.6-1. Solar PV Plant EPC and Owner's Costs

Project Costs, 2018$		25 MWa, Single-axis Tracking, Christmas Valley Oregon
Total Plant Cost	$1,000	143,450
Total Plant Cost	$/kW	1,510
EPC Cost	$1,000	130,409
Owner's Cost	$1,000	13,041
Std Deviation from Total Plant Costs	$/kW	424
End of Life Decomissioning Costs	$1,000	1,900

4.7 Implementation (Schedule)

Project schedules for a 25 MWa generation solar PV resource have been estimated and are based upon current day EPC contracting approaches and methodologies. As such, it is expected that a portion of the preliminary engineering and equipment sourcing activities, site acquisition, and project permitting activities are completed prior to FNTP of the project. This will typically also involve the procurement of major equipment and of the EPC contract with some level of LNTP awarded for these contracts prior to FNTP.

Currently, solar PV installations have a timeline of approximately 1 to 2 years from EPC NTP through COD. A conceptual project implementation schedule is provided below in Figure 4.7-1.

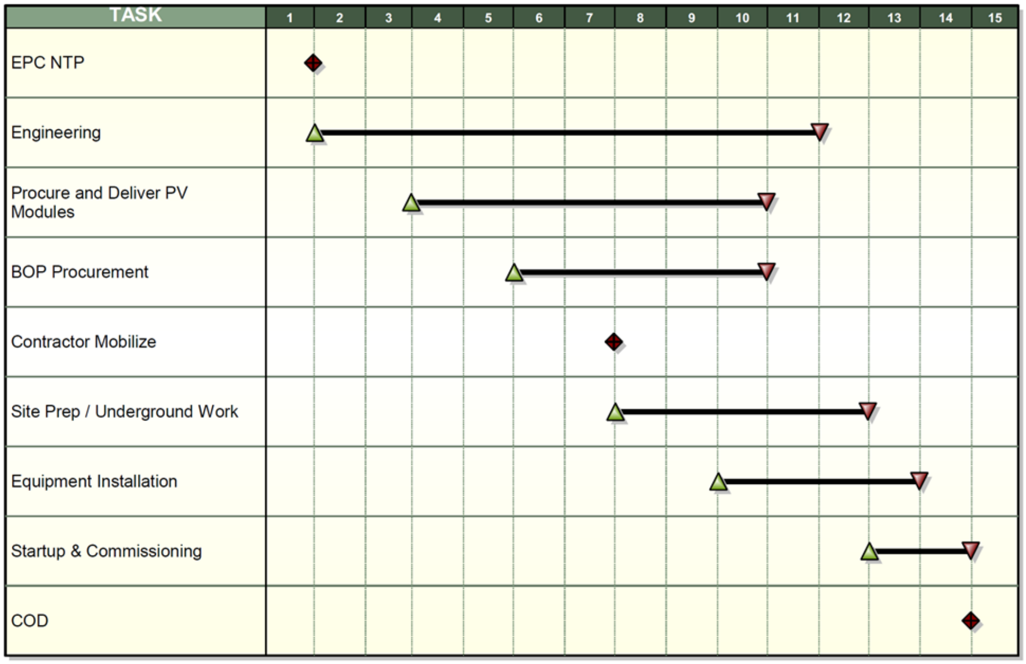


Figure 4.7-1. 25 MWa Solar PV Conceptual Project Schedule

4.8 Operating Costs

The estimated fixed and variable O&M costs for a 25 MWa solar PV site are presented in Table 4.8-1. Operation and maintenance costs are inclusive of plant staffing and major equipment parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance.

Plant staffing has been included as defined in Table 2-1 and 2-2. Staffing for the proposed solar PV power plant often utilizes a remote monitoring/operating system with minimal on-site staff. The majority of the staff is typically associated with maintenance and cleaning of the solar fields.

Land lease costs have also been estimated and are typically paid to land owners as compensation for using their land. Based on HDR's project experience, the land lease costs for a solar PV site is estimated to be $4.22/MWh.

Table 4.8-1. Solar PV Fixed and Variable Operating Costs

Operating Costs, 2018$		25 MWa, Single-axis Tracking, Christmas Valley Oregon
Fixed O&M	$/kW-yr	21.9
Variable O&M	$/MWH	0
Land Lease/Royalties	$/MWH	4.22

5 Battery Energy Storage System

Grid-connected battery energy storage systems (BESS) are maturing and have steadily increased in commercial deployment in the electric industry. For this resource option, a lithium-ion battery energy storage system was considered with the following characteristics:

- 100 MW installed capacity
- 2-hour, 4-hour, and 6-hour storage capacity evaluated
- A typical container/module size of 5 MWh was assumed.

5.1 Technology Overview

Lithium Ion (Li-ion) batteries utilize the exchange of lithium ions between electrodes to charge and discharge the battery. When the battery is in use (discharging) the charged electrons move from the anode to the cathode and in the process, energize the circuit that it is connected to. Electrons flow in the reverse direction during a charge cycle when energy is drawn from the grid. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve applications. Additionally, compared to other BESS, the Li-ion technology provides the highest energy storage density resulting in its adoption in several different markets ranging from consumer electronics to transportation (electric vehicles).

5.2 Commercial Status and Current Market

The market for utility-scale energy storage systems such as batteries is relatively early in development, but it is growing and evolving at a very rapid pace. The global energy storage market is expected to exceed 40 GW by 2022 from currently installed estimates of about 6 GW[7].

The increasing demand for battery storage in consumer electronics and the transportation sector as well as the emerging demand from the energy sector is propelling advances in the technology and manufacturing capacity for Li-ion. This is also aiding the trend of declining initial capital cost for this technology. Li-ion battery technology is a relatively mature technology, having been first proposed in 1970 and released commercially in 1991.

Other battery storage technologies include sodium sulfur, lead-acid, zinc iron and zinc bromine flow technologies; however, Li-ion is the most prominent and widely used for utility scale BESS. This is primarily due to technology maturity and risks that are better understood, the number of established and credit worthy Li-ion battery manufacturers in the market place, their ability to provide long term performance guarantees and warranties typically required by the electric utility industry, and the existence of reliable integrators that have a successful track record of installing turnkey EPC BESS projects for several years.

[7] Energy Storage Association

5.3 Operational Considerations

A 100 MW BESS \resource with one discharge cycle per day was considered with various hours of dispatch. Major components of a BESS station include the battery containers, battery management system (BMS), power conversion system (PCS) enclosures, plant control systems, and balance of plant systems including the cooling system, station load transformers, pad mounted medium/high voltage transformers, and grid interconnection gear with metering, site utilities, foundations and plant fencing. It is noted that the certain vendors may design the BESS in a multistory building with appropriate HVAC, lighting and security. While such a configuration may result in a slightly smaller footprint the overall EPC costs are anticipated to be similar.

The BESS plant consists of a number of containers that house the storage cells. The specific capacity of a container varies from manufacturer to manufacturer, but typical size of 5 MWh was used for this analysis.

5.3.1 Performance Data

Table 5.3-1 summarizes the estimated performance data for a typical 100 MW Li-ion BESS with 2 hours, 4 hours, and 6 hours of dispatch capability. As shown, battery efficiency improves with larger systems.

Table 5.3-1. BESS Performance

Lithium Ion BESS			
Capacity (MW)	100	100	100
Max Storage Limit (MWh)	200	400	600
Discharge Duration (hours)	2	4	6
Round Trip Efficiency	82%	87%	89%

5.4 Reliability, Availability, & Maintenance Intervals

Plant forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 5.4-1. Forced and Planned outage rates are based on a single container/module. Plant capacity is therefore only reduced by 5 MWh's during scheduled or unscheduled outages per container, dependent on the number containers out. Partial outage rates for mutliple containers can be estimated by multiplying the number of containers out by the single container forced outage rate to determine the forced outage rate for a specific capacity level.

Table 5.4-1. BESS Availbility/Reliability

Availability / Reliability		BESS
Forced and Planned Outage Rate	%	<2

Availability / Reliability		BESS
Mean Annual Outage Duration	Days/year	3-5 Days

5.5 Land Requirement

An outdoor battery storage configuration was considered for this resource option. The approximate land requirement was estimated based on manufacturer and industry data and is expected to be about 2.17 acres for the 200 MWh BESS, 3.3 acres at 400 MWh, and about 5 acres for the 600 MWh BESS system.

5.6 Project Cost

Table 5.6-1 summarizes the estimated total project costs for each BESS resource evaluated. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference. Owners cost also includes an allocation of costs for leasing a project site at 2,310 $/acre according to the average 2017 Farm Real Estate values in Oregon reported by the U.S. Department of Agriculture[8]. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

The EPC cost for an installed BESS includes the costs of the energy storage equipment, power conversion equipment, power control system, balance of system including site utilities, grid interconnection and installation costs.

For Li-ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system includes internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system.

Decommissioning costs are presented as net salvage value and assume the site will be taken back to a brownfield site, which removes all material and structures down to 2 to 3 ft. below grade. Per market sources it is anticipated that the Li-ion cells will have salvageable value at end of project life, and is expected to result in zero additional costs for removal and recycling. Net decommissioning costs to owner for remaining balance of plant is indicated in Table 5.6-1.

[8] United States Department of Agriculture. Land Values 2017 Summary. https://www.usda.gov/nass/PUBS/TODAYRPT/land0817.pdf. August 2017.

Table 5.6-1. BESS Plant Project Costs

Project Costs, 2018$		Li-On Battery - 2 Hour	Li-On Battery - 4 Hour	Li-On Battery - 6 Hour
Total Plant Cost	$1,000	91,600	155,400	190,200
Total Plant Cost	$/kW	916	1,554	1,902
Total Plant Cost	$/kWhr	458	388	317
EPC Cost	$1,000	82,400	139,900	171,200
Owner's Cost	$1,000	9,200	15,500	19,000
Std Deviation from Total Plant Costs	$/kW	267	462	567
End of Life Decomissioning Costs	$1,000	500	750	1,000

5.7 Implementation (Schedule)

Project schedules for a 100 MW BESS resource have been estimated and are based upon current day EPC contracting approaches and methodologies. As such, it is expected that a portion of the preliminary engineering and equipment sourcing activities, site acquisition, and project permitting activities are completed prior to FNTP of the project. This will typically also involve the procurement of major equipment and of the EPC contract with some level of LNTP awarded for these contracts prior to FNTP.

The BESS integrator's scope of supply typically includes most of the systems up to the inverter terminal where AC power is available to the GSU transformer. Accordingly, the BESS integrator can deliver the major systems within approximately 12 months from NTP. Additional site engineering, foundation and substructure work, permitting, site utilities and utility interconnection work is generally completed by a general/EPC contractor. A typical 100 MW BESS project can be commissioned and estimated to be in commercial operation within 20 months from NTP. A typical project implementation schedule for a 100 MW BESS installation is provided in Figure 5.7-1. Schedule differences for the different storage capacity options are expected to be minimal.

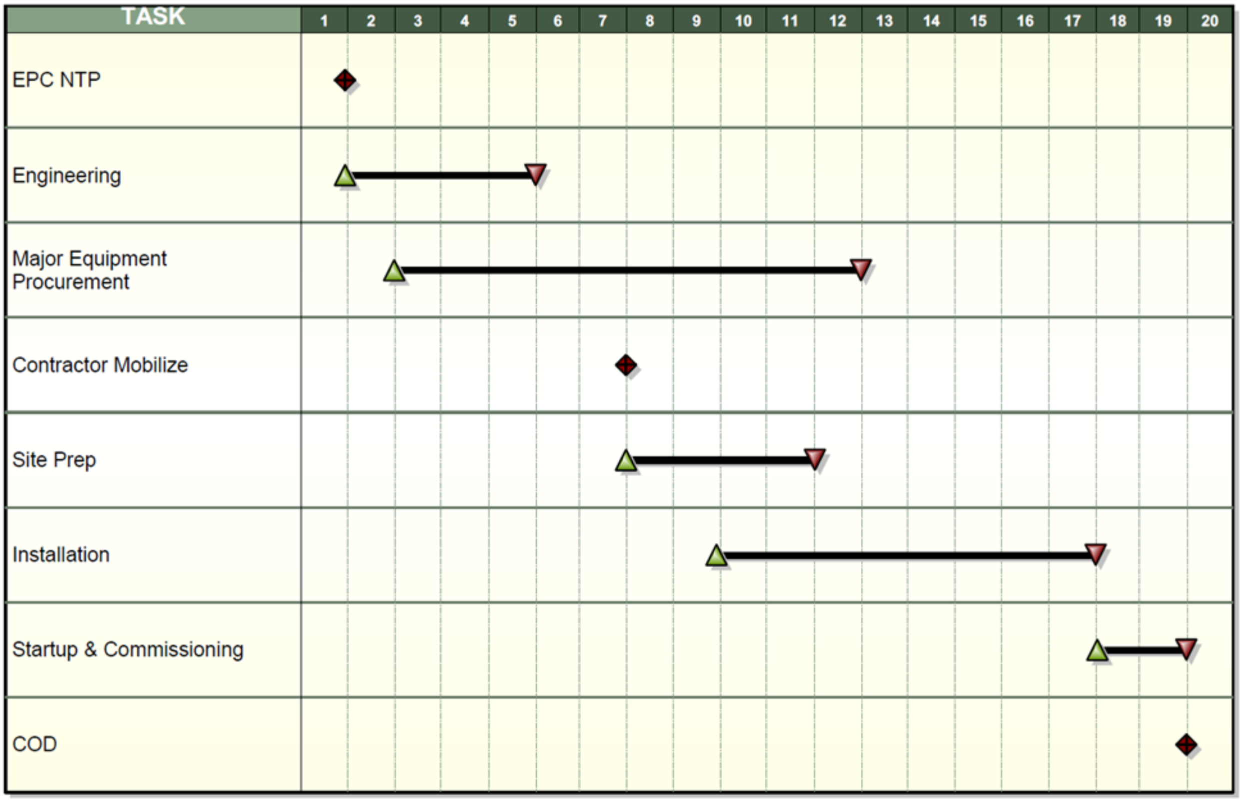


Figure 5.7-1. 100 MW BESS Conceptual Project Schedule

5.8 Operating Costs

The estimated fixed and variable O&M costs for each BESS resource option are presented in Table 5.8-1. Operation and maintenance costs are inclusive of plant staffing and major equipment parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance.

Plant staffing has been included as defined in Table 2-1 and 2-2. Staffing for the proposed BESS plant often utilizes a remote monitoring/operating system with minimal on-site staff. Maintenance labor is assumed to be contracted in an O&M services contract.

As indicated in Section 5.6 above, an allocation of 2,310 $/acre/yr has been included in the Owners Cost for a leasing the project site.

The major component of the O&M cost for a Li-ion BESS system is related to energy and capacity augmentation. Augmentation maintains the BESS capability to serve the Owner's requirement for the term of the agreement. These costs are typically covered in the fixed O&M costs. Additional fixed O&M costs include 24x7 remote monitoring, remote troubleshooting, performing scheduled maintenance activities, inverter replacements, emergency and unscheduled maintenance support, periodic reporting, training and continuous improvement, software licensing and updates, HVAC maintenance, auxiliary electrical loads, landscaping, and mechanical/electrical inspections and updates. No additional staffing costs are included as it is assumed that the BESS will be completely unmanned.

For Li-ion BESS, the Fixed O&M costs indicated below includes both the fixed and variable O&M costs associated with maintaining the electrical output of BESS for the life of the system, and the augmentation service agreement. The total annual augmentation agreement is estimated based on the 1 full cycle/day discharge rate. Utility energy costs for charging the battery is not included in the O&M costs.

For the Li-ion BESS, levelized fixed and variable O&M costs are estimated below in Table 5.9-1.

Table 5.9-1. BESS Plant O&M Costs

Operating Costs, 2018$		Li-On Battery - 2 Hour	Li-On Battery - 4 Hour	Li-On Battery - 6 Hour
Fixed O&M	$/kW-yr	23.5	31.1	42.6
Variable O&M	$/MWH	0	0	0
Land Lease/Royalties	$/MWH	0	0	0

Appendices

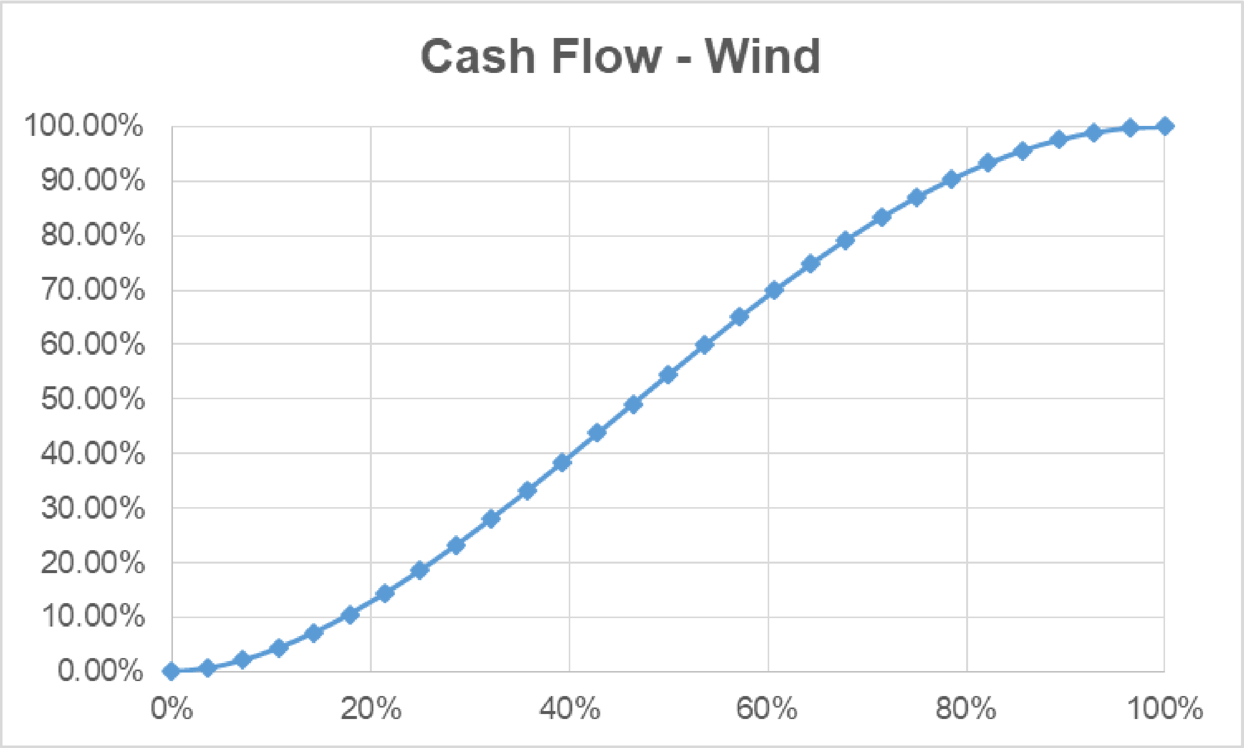
Appendix A – Technology Maturity / Cost Forecast

2018 US $/kW, FNTP Year

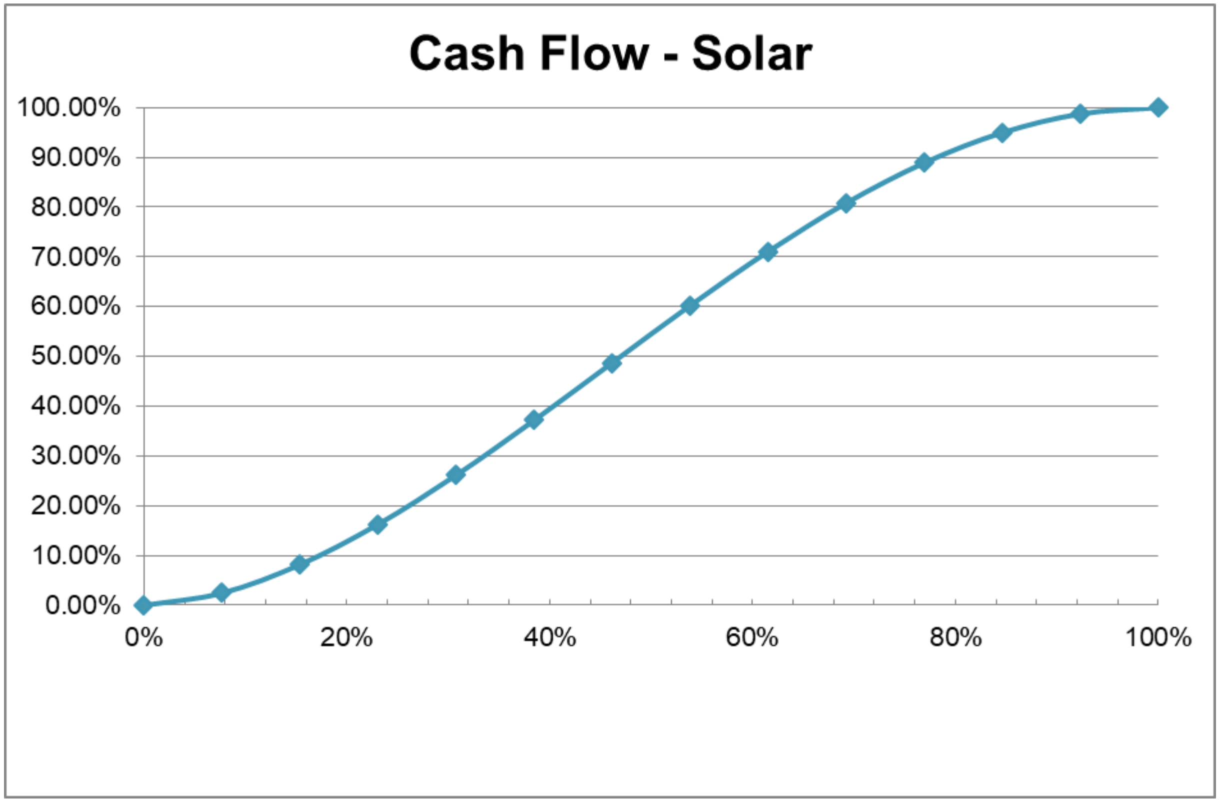
Technology	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Solar PV, 25 MW Average, single axis	1,510	1,510	1,469	1,374	1,335	1,307	1,294	1,282	1,271	1,261	1,250	1,237	1,225	1,212	1,198	1,183	1,169	1,155	1,141	1,128	1,119	1,110	1,101	1,092	1,084	1,075	1,065	1,056	1,047	1,038	1,029	1,020	1,011
Wind, 100 MW Averag, Ione, Oregon	1,508	1,508	1,508	1,493	1,478	1,464	1,449	1,436	1,422	1,410	1,397	1,383	1,369	1,355	1,341	1,326	1,312	1,298	1,284	1,269	1,256	1,242	1,229	1,217	1,203	1,191	1,177	1,164	1,151	1,138	1,125	1,112	1,099
Wind, 100 MW Average, Columbia Gorge	1,539	1,539	1,539	1,523	1,508	1,494	1,479	1,465	1,451	1,439	1,426	1,411	1,397	1,383	1,368	1,354	1,339	1,324	1,310	1,295	1,281	1,268	1,255	1,242	1,228	1,215	1,201	1,188	1,174	1,161	1,148	1,135	1,122
Wind, 100 MW Average, Southeast Wash	1,531	1,531	1,531	1,515	1,500	1,487	1,472	1,457	1,443	1,432	1,419	1,404	1,390	1,376	1,361	1,346	1,332	1,317	1,303	1,289	1,275	1,261	1,248	1,235	1,222	1,209	1,195	1,182	1,168	1,155	1,142	1,129	1,116
Wind, 100 MW Average, Montana	1,520	1,520	1,520	1,504	1,490	1,476	1,461	1,447	1,433	1,421	1,408	1,394	1,380	1,366	1,351	1,337	1,322	1,308	1,294	1,279	1,266	1,252	1,239	1,226	1,213	1,200	1,187	1,173	1,160	1,147	1,134	1,121	1,108
Li-on, 100 MW, 2 hour	915	915	905	889	873	858	842	827	812	799	784	770	755	741	726	711	697	683	669	655	641	628	615	602	589	577	564	551	539	527	515	502	491
Li-on, 100 MW, 4 hour	1,554	1,554	1,537	1,509	1,482	1,457	1,430	1,405	1,379	1,356	1,332	1,307	1,282	1,258	1,233	1,208	1,184	1,160	1,136	1,112	1,089	1,067	1,045	1,023	1,001	980	958	936	915	895	874	853	833
Li-on, 100 MW, 6 hour	1,902	1,902	1,881	1,847	1,814	1,783	1,750	1,719	1,688	1,660	1,631	1,600	1,569	1,540	1,509	1,479	1,449	1,420	1,391	1,361	1,333	1,306	1,279	1,252	1,225	1,199	1,172	1,146	1,120	1,095	1,070	1,044	1,020

Appendix B – Drawdown Schedules

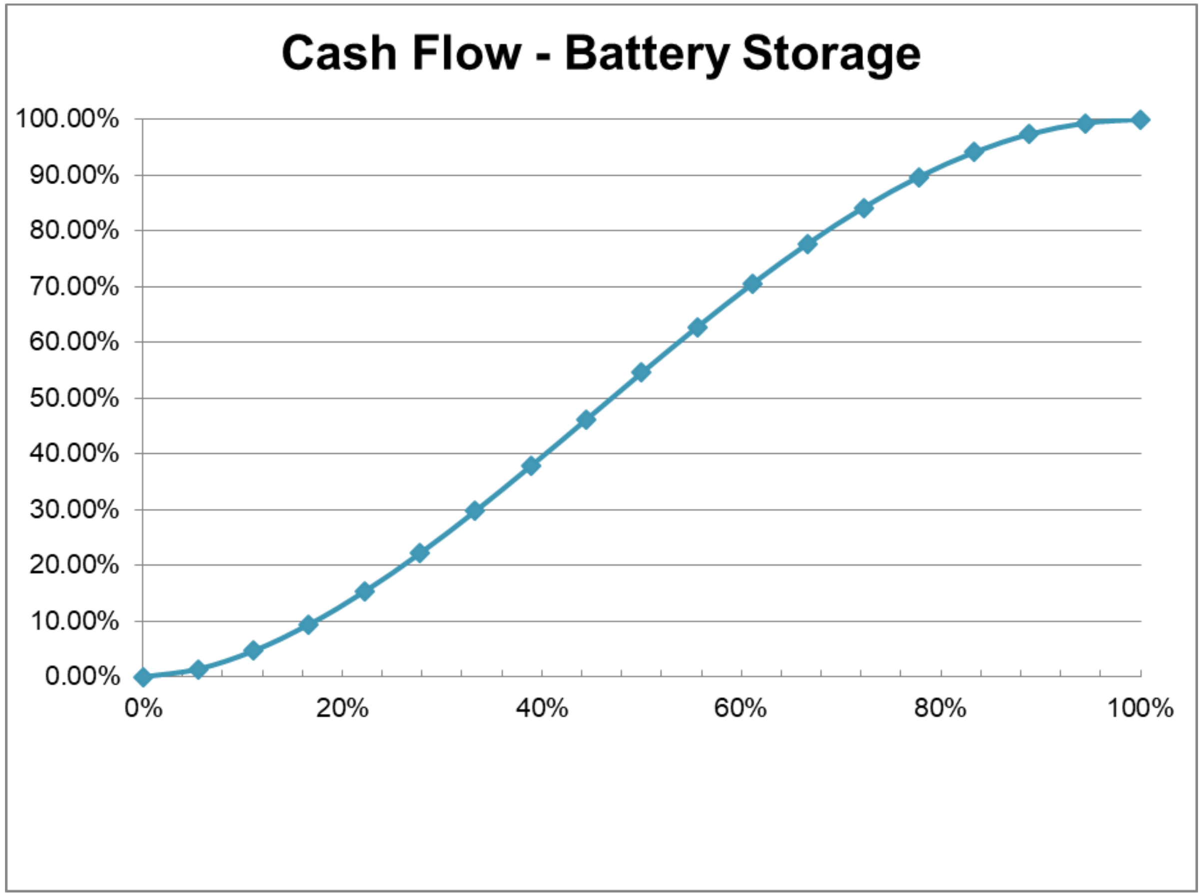
Month	% Complete	0.00%	Cumulative Accrual
0	0%	0.00%	0.00%
1	4%	0.65%	0.65%
2	7%	1.52%	2.17%
3	11%	2.22%	4.39%
4	14%	2.82%	7.21%
5	18%	3.36%	10.57%
6	21%	3.82%	14.39%
7	25%	4.23%	18.62%
8	29%	4.58%	23.20%
9	32%	4.86%	28.06%
10	36%	5.09%	33.14%
11	39%	5.25%	38.39%
12	43%	5.35%	43.75%
13	46%	5.40%	49.14%
14	50%	5.38%	54.53%
15	54%	5.31%	59.83%
16	57%	5.17%	65.01%
17	61%	4.99%	69.99%
18	64%	4.75%	74.74%
19	68%	4.46%	79.20%
20	71%	4.12%	83.32%
21	75%	3.74%	87.06%
22	79%	3.33%	90.39%
23	82%	2.87%	93.26%
24	86%	2.39%	95.65%
25	89%	1.89%	97.54%
26	93%	1.36%	98.90%
27	96%	0.82%	99.72%
28	100%	0.28%	100.00%



Month	% Complete	0.00%	Cumulative Accrual
0	0%	0.00%	0.00%
1	8%	2.47%	2.47%
2	15%	5.72%	8.19%
3	23%	8.11%	16.29%
4	31%	9.86%	26.16%
5	38%	11.01%	37.17%
6	46%	11.56%	48.73%
7	54%	11.51%	60.23%
8	62%	10.88%	71.11%
9	69%	9.71%	80.82%
10	77%	8.08%	88.91%
11	85%	6.06%	94.97%
12	92%	3.76%	98.73%
13	100%	1.27%	100.00%



Month	% Complete	0.00%	Cumulative Accrual
0	0%	0.00%	0.00%
1	6%	1.40%	1.40%
2	11%	3.27%	4.67%
3	17%	4.72%	9.39%
4	22%	5.90%	15.30%
5	28%	6.86%	22.15%
6	33%	7.58%	29.73%
7	39%	8.07%	37.80%
8	44%	8.34%	46.14%
9	50%	8.38%	54.53%
10	56%	8.20%	62.73%
11	61%	7.81%	70.53%
12	67%	7.21%	77.75%
13	72%	6.44%	84.18%
14	78%	5.50%	89.69%
15	83%	4.43%	94.11%
16	89%	3.24%	97.36%
17	94%	1.98%	99.34%
18	100%	0.66%	100.00%



Appendix C – Modeling Inputs Summary Tables (See Excel File)