PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

October 14, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: UM 1794—Investigation into Schedule 37 Avoided Cost Prices – PacifiCorp's Opening Testimony

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing in the above-referenced docket the opening testimony and exhibits of Brian S. Dickman.

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

Oregon Dockets	Erin Apperson
PacifiCorp	Legal Counsel
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Portland, OR 97232	Portland, OR 97232
oregondockets@pacificorp.com	erin.apperson@pacificorp.com

Additionally, PacifiCorp requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Natasha Siores at (503) 813-6583.

Sincerely,

R. Bryce Dalley
Vice President, Regulation

Enclosures

Docket No. UM 1794
Exhibit PAC/100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

PACIFICORP

Opening Testimony of Brian S. Dickman

October 2016

OPENING TESTIMONY OF BRIAN S. DICKMAN
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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Valuation and Commercial Business.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Before joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003, including positions in revenue requirement, regulatory affairs, and energy supply management. I assumed my current role directing the Company's valuation and long-term origination groups in September 2016.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the public utility commissions in Oregon, California, Idaho, Utah, Washington, and Wyoming.

PURPOSE AND SUMMARY OF TESTIMONY

Q. Please describe the purpose of this testimony.

A. In my testimony I provide the background leading to the creation of this docket and describe the Company's proposed changes to the currently effective standard avoided cost prices. In Order No. 16-307, the Commission directed that "an expedited contested case proceeding shall be opened to allow a more thorough vetting of the issues raised in [docket UM 1729(1)] and possible revision to Schedule 37 avoided cost prices on a prospective basis." The outcome of this proceeding, as approved by the Commission, will be reflected in the Company's May 1, 2017, Schedule 37 update.

Q. Please summarize the issues addressed in your testimony in this docket.

A. The issues raised in the proceeding leading up to Order No. 16-307 centered around the demarcation of sufficiency and deficiency periods for both the renewable and non-renewable standard prices, and the appropriate cost and performance inputs used for the proxy resource during the deficiency period. I will discuss the Company's proposed treatment for these items below. At this time the Company is not proposing permanent changes to the Commission-approved policies and methodologies applicable to calculating Schedule 37 prices.

BACKGROUND

Q. Please describe the process leading to the creation of this docket.

A. On March 1, 2016, the Company submitted an update to its standard avoided cost prices (Schedule 37) in compliance with OAR 860-029-0080 and the requirements established in Order No. 14-058 to submit a complete avoided cost pricing update within 30 days of acknowledgement of an Integrated Resource Plan (IRP). In that filing, the Company requested an update to prices using inputs from its 2015 IRP, acknowledged by the Public Utility Commission of Oregon (Commission) on February 29, 2016, and its December 2015 official forward price curve (OFPC).

At the Commission's March 22, 2016 public meeting, the Commission expressed concerns about the impact of Senate Bill (SB) 1547 on the period of renewable resource deficiency relative to the 2015 IRP, which did not identify a need for a new renewable resource during the 20-year planning period. On March 23, 2016, the Commission issued Order No. 16-117, wherein it declined to approve the Company's March 1, 2016 filing and instead directed parties to work together to propose an expedited, non-contested case process to update the Company's avoided costs in light of the passage of SB 1547, which had been signed into law March 8, 2016. Among other things, the legislation increased Oregon's Renewable Portfolio Standard (RPS) target to 50 percent of electricity from renewable resources by 2040. The increased RPS requirements under SB 1547 are staged: 27 percent by 2025, 35 percent by 2030, 45 percent by 2035 and 50 percent by 2040.

On March 31, 2016, PacifiCorp filed its 2015 IRP Update, which concluded that PacifiCorp could meet its increased Oregon RPS obligations through the 20-year IRP planning horizon through a number of flexible alternatives including the purchase of unbundled renewable energy certificates (RECs). The 2015 IRP update also included updated cost and performance data applicable to a renewable resource proxy.

Following multiple settlement discussions, the Company, Staff, and interested stakeholders were unable to resolve issues regarding the Company's Schedule 37 update. On April 29, 2016, PacifiCorp filed a letter notifying the Commission that it would not make its annual May 1 avoided cost update given the ongoing efforts to resolve the Company's March 1, 2016 Schedule 37 filing.

On June 21, 2016, the Company filed revised Schedule 37 prices in UM 1729(1). The 2015 IRP and 2015 IRP Update concluded that the Company did not identify an immediate need to acquire new renewable resources because the Company could comply with its Oregon RPS requirements (including the increased obligations imposed by SB 1547) through the purchase of unbundled RECs. Nonetheless, PacifiCorp's June 21, 2016 avoided cost proposal identified a renewable resource deficiency period beginning in 2018 as a compromise position in light of concerns raised by the Commission in Order No. 16-117 and at the March 22, 2016 public meeting. Cost and performance assumptions for the renewable proxy resource used in the June 21, 2016 filing were also updated with cost and performance assumptions used in the Company's 2015 IRP Update. The Company's compromise position, in which it adopted a resource deficiency period beginning 2018, was explicitly linked to using updated cost and performance assumptions for the proxy renewable resource to ensure avoided cost prices reflect the most current assessment of renewable resource costs. Other inputs to the Schedule 37 calculation were taken from the acknowledged 2015 IRP, where applicable, including a non-renewable deficiency period beginning in 2028 coincident with the next major resource acquisition in the IRP preferred portfolio.

In the Company's 2015 IRP and 2015 IRP Update, the Company indicated that it would continue its strategy of acquiring RECs to satisfy future RPS compliance needs. Consistent with this strategy, the Company has acquired enough RECs to extend PacifiCorp's initial RPS compliance shortfall in Oregon to 2028, coincident with the anticipated retirement of the Dave Johnston plant in Wyoming.

On August 18, 2016, the Commission issued Order No. 16-307 directing the Company to file an amended Schedule 37, revising the renewable deficiency period to begin in 2028, and including cost and performance data from the acknowledged 2015 IRP. The Commission also directed the Company to continue using 2028 for the standard non-renewable deficiency period, and to update market prices for natural gas and electricity as required in an annual Schedule 37 update. The Company filed its revised Schedule 37 on August 22, 2016, which became effective August 24, 2016. In Order No. 16-307, the Commission directed that "an expedited contested case proceeding shall be opened to allow a more thorough vetting of the issues raised in this proceeding and possible revision to Schedule 37 avoided cost prices on a prospective basis." The outcome of this proceeding, as approved by the Commission, will be reflected in the Company's May 1, 2017, Schedule 37 update.[1]

Under the current Commission-approved process, avoided cost prices are to be based on the Company's most recently acknowledged IRP. In Order No. 10-488, the Commission ordered that resource deficiency is demarcated by the first major resource acquisition in the action plan of an acknowledged IRP. In Order No. 11-505, the Commission found that the IRP action plan should also be

[1] In addition to reflecting the resolution of issues addressed in this docket, the Company's May 1, 2017, Schedule 37 filing will update avoided cost prices for the items identified in Order No. 14-058, which established that annual updates must reflect: 1) updated natural gas prices, 2) on- and off-peak forward-looking electricity market prices, 3) changes to the status of the production tax credit, and 4) any other action or change in an acknowledged IRP update relevant to the calculation of avoided costs.

used to identify when a renewable resource acquisition could be avoided, and that a qualifying facility (QF) should be able to choose between standard non-renewable and standard renewable prices. In that order the Commission also determined that renewable resource deficiency is not triggered by procurement of unbundled RECs.

In this docket, the Company proposes to retain the assumptions included in the currently-effective Schedule 37 prices with the exception of the cost and performance of the renewable wind proxy used for standard renewable rates. Because of significant reductions in the cost of renewable resources since the 2015 IRP was prepared, and because the Company's RPS compliance strategy is to continue to rely on unbundled REC purchases, if Schedule 37 assumes a renewable resource is acquired in 2028 (a departure from the acknowledged 2015 IRP) it should also reflect the most current estimates of the costs to acquire such a resource if retail customers are to remain indifferent to purchasing the output of a renewable QF.

Q. How do the Schedule 37 prices currently in effect reflect the method for calculating standard avoided costs approved in previous Commission orders?

A. The Commission's ruling in Order No. 16-307 is consistent with past orders with the exception of selecting a renewable resource deficiency period that was not based on a renewable resource acquisition in the acknowledged 2015 IRP.

DEMARCATION OF SUFFICIENCY AND DEFICIENCY PERIODS

Q. What changes to the calculation of Schedule 37 avoided cost prices does the Company propose in this docket?

A. For purposes of its May 1, 2017 Schedule 37 update, the Company proposes to use renewable resource cost and performance assumptions from the 2015 IRP Update for the renewable proxy to capture noteworthy changes that have occurred since the 2015 IRP was prepared in 2014. Table 1 below illustrates the impact of the Company's proposal, using the currently-approved Schedule 37 as the baseline and changing only the cost of the renewable proxy, a Wyoming wind plant with an assumed online date in 2028.

Table 1

15 Year (2017-2031) Nominal Levelized Price - $/MWh

	Renewable Fixed Avoided Cost Prices						
	Base Load QF	Wind QF	Fixed Solar QF	Tracking Solar QF	Renewable Deficiency Start	OFPC	Renewable Proxy
Proposed Renewable Prices	$41.61	$35.59	$41.58	$41.79	2028	Mar 2016	2015 IRP Update WY Wind 43% CF
Current Commission Approved (August 21, 2016 Filing)	$43.46	$37.44	$43.53	$43.74	2028	Mar 2016	2015 IRP WY Wind 43% CF
Comparison to Comm. Approved Prices	($1.85)	($1.85)	($1.95)	($1.95)			

The Company does not intend to change the established process for determining Schedule 37 prices, but rather to align the renewable avoided cost prices with the assumed acquisition of a resource in 2028. Neither the 2015 IRP nor the 2015 IRP Update anticipates acquiring a new renewable resource during the IRP 20-year planning horizon. If renewable avoided costs are based on a renewable resource acquisition in 2028, despite the fact that the least-cost portfolio for planning purposes does not include such a resource, then the most current cost estimates for such a resource must be used. If not, retail customers cannot remain indifferent to the payments made to renewable QFs, particularly in an environment of rapidly declining costs.

After updated Schedule 37 prices from the May 1, 2017 filing are in place, the Company anticipates returning to the Commission's established process for updating its standard avoided cost prices (i.e., an update to all inputs 30 days after IRP acknowledgement, with the deficiency period marked by the next resource acquisition in the IRP, and a limited update every May 1).

Q. Why is the renewable resource deficiency period of 2028 reasonable?

A. For purposes of the May 1, 2017 avoided cost update, the Company is not opposed to continuing to use 2028 as the start of the renewable resource deficiency period. The Company's recent acquisition of RECs will push back the first RPS compliance shortfall to 2028, which reflects the RPS requirements of SB 1547. However, upon returning to the Commission's established process for updating its standard avoided cost prices tied to IRP acknowledgement, the Company does not support using the initial RPS compliance shortfall as the de facto criteria for establishing the deficiency period.

COST AND PERFORMANCE INPUTS

Q. Why is it appropriate to update the cost of the renewable proxy?

A. Avoided cost pricing approved by the Commission must conform with the standard that retail customers should be indifferent to the Company's purchase of QF power. Prices paid to QFs may not exceed "the incremental cost to the electric utility of alternative electric energy."[2] The incremental cost standard is

[2] 16 U.S.C. § 824a-3.

intended to leave customers economically indifferent to the source of a utility's energy by ensuring that the cost to the utility purchasing power from a QF does not exceed the cost the utility would have otherwise incurred without the QF purchase.[3] The Commission has repeatedly acknowledged the importance of the customer indifference standard and has identified the ratepayer indifference standard as its "primary aim." Using the most accurate and updated information available ensures that customers remain economically indifferent.

The Company's acknowledged 2015 IRP did not indicate a need to acquire a renewable resource; rather, the 2015 IRP action plan demonstrated that using unbundled RECs to meet its state RPS compliance requirements resulted in lower costs and lower risk to customers. In addition, the Company's 2015 IRP Update continues to call for an RPS compliance strategy that includes procuring unbundled RECs as a cost effective means for meeting RPS requirements.

The 2015 IRP includes an analysis illustrating that when Oregon situs RPS wind resources were assumed to be brought online in 2028, costs increased relative to the least-cost portfolio. The 2015 IRP Update also did not include acquisition of a renewable resource despite significant declines in the cost of such resources. Administratively determining that renewable avoided costs should be based on a renewable resource acquisition in 2028, despite the fact that the least-cost portfolio for planning purposes does not include such a resource, dictates that

[3] *Indep. Energy Producers Ass'n, Inc. v. Ca. Pub. Util. Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994) ("If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize QFs because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere.")

the most current cost estimates for such a resource be used. Given that renewable resource costs have declined significantly since the inputs to the acknowledged 2015 IRP were prepared, customer indifference cannot be maintained if renewable avoided cost prices are calculated assuming a high-cost renewable resource acquisition in 2028 despite having an IRP analysis demonstrating that such an approach increases customer costs.

Q. Please describe the difference in renewable resource capital cost and performance assumptions used in the 2015 IRP Update compared to prior IRPs.

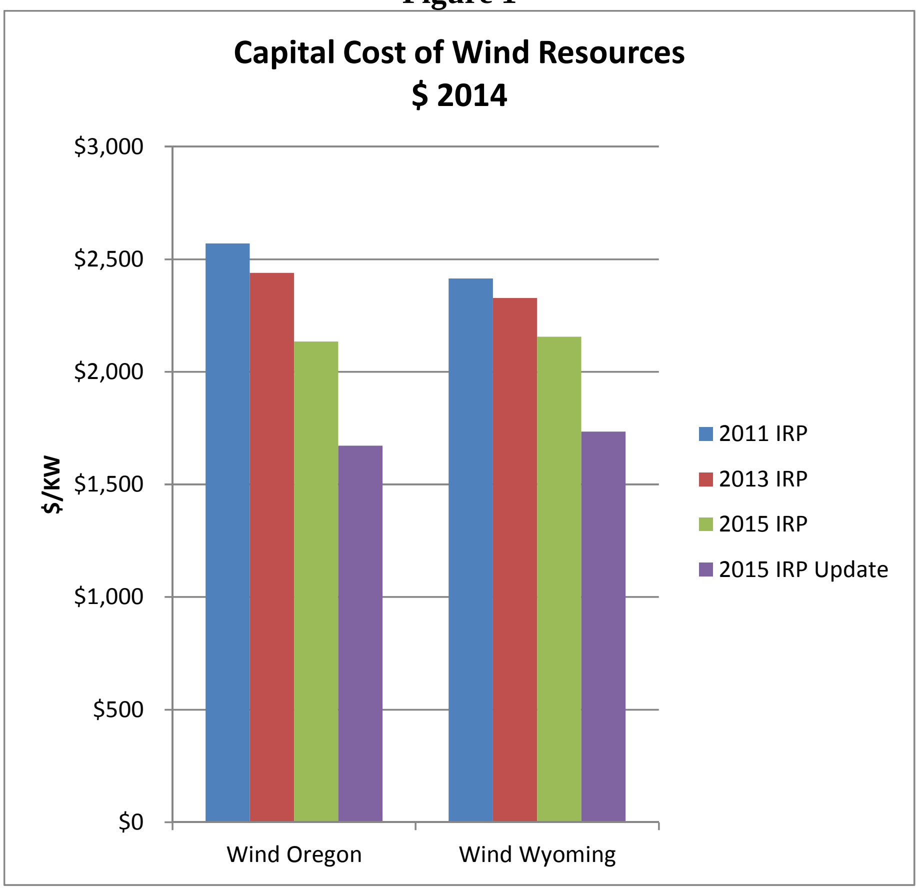
A. The capital cost of renewable resources has declined considerably over the course of the last several IRPs. Compared to the 2011 IRP, inflation adjusted capital costs for a solar resource located in Oregon have declined over 38 percent, while the capital costs for wind resources located in Oregon and Wyoming have declined 35 percent and 28 percent, respectively.[4] Over the same period of time, the expected output from renewable projects has steadily increased. Capacity factors included in the Company's IRPs for a single-axis tracking solar project in Oregon have increased from 25 percent to over 29 percent. Similarly, capacity factors for wind projects in the Company's IRPs have increased from 29 percent to 35 percent in Oregon and from 35 percent to 43 percent in Wyoming.

For a wind project, the decline in capital costs included in the Company's IRPs is most pronounced in the 2015 IRP Update. In its 2015 IRP, prepared in

[4] This is based on costs in 2014 dollars to be consistent with figures published in the 2015 IRP and 2015 IRP Update.

2014, the Company estimated that a wind resource located in Oregon would have a capital cost of $2,135/kW in 2014 dollars. In its 2015 IRP Update, prepared in late 2015, the Company estimated that the costs would be $1,672/kW in 2014 dollars, a 22 percent reduction. For a wind resource located in Wyoming, capital costs declined from $2,156/kW in the 2015 IRP to $1,735/kW in the 2015 IRP Update, a 20 percent reduction. Figure 1 below shows the change in costs for Oregon and Wyoming wind resources included in each of the Company's IRPs since 2011 and in the latest 2015 IRP Update.

Figure 1



If wind resource cost and performance assumptions are included in the Company's avoided costs at the level previously assumed in the 2015 IRP, it is clear they would not be representative of the current cost and performance of an avoidable proxy renewable resource and would not be indicative of the cost of an alternative renewable resource.

Q. What caused the sharp drop in capital costs between the 2015 IRP and 2015 IRP Update?

A. The Company developed the cost estimates for wind resources in past IRPs based on its experience developing several wind projects in Wyoming and the Columbia River gorge. Capital costs for wind plants in the 2015 IRP were based on the Company's development of the Dunlap facility in 2010, updated to bring costs current in 2014 when the IRP was prepared. In fall 2015, the Company reviewed the cost of renewable resources and found that the cost of development had declined significantly from previous estimates. Based on input from a wind turbine manufacturer regarding the cost of turbines and plant construction, the Company updated the cost of renewable resources in the 2015 IRP Update.

Q. Are there publicly available sources that corroborate the cost and performance estimates included in the Company's 2015 IRP Update?

A. Yes. Several relatively recent wind resource projects constructed in the Pacific Northwest support the data included in the Company's 2015 IRP Update. For example, Portland General Electric Company (PGE) reports a 36.8 percent capacity factor for its 267 MW Tucannon Wind facility that came online in 2015.[5] Similarly, PGE reports higher capacity factors for older vintage projects,

[5] *In the Matter of Portland General Electric Company, 2013 Integrated Resource Plan,* Docket No. LC 56, Integrated Resource Plan at 21 (Mar 27, 2014).

including a 34.7 percent capacity factor for its 75 MW Klondike II wind project that came online in 2005, and a 31.8 percent capacity factor for the 450 MW Biglow Canyon wind project that come online in phases between 2007 and 2011.[6]

In preparation for its 2016 IRP, PGE commissioned a study by DNV GL to evaluate several different renewable supply options. The report was completed in November 2015 and included an estimate of the cost and performance of new utility-scale on shore wind projects located in Ione, Oregon and central Montana. That study, included as Exhibit PAC/101, estimated that the Oregon project would have a capacity factor of 34 percent and capital costs of $1,680/kW in 2015 dollars, and that the Montana project would have a capacity factor of 42 percent and capital costs of $1,700/kW in 2015 dollars.[7]

Q. Has the Company also had a similar market study prepared?

A. Yes. After observing the changes in market conditions during 2015, the Company engaged a third-party consultant, Black & Veatch, in 2016 to prepare a wind market study to inform its upcoming 2017 IRP. This study is included as Exhibit PAC/102. The Black & Veatch study estimates the capital costs of a wind plant in 2016 dollars to be $1,784/kW in Wyoming and $1,769/kW in Oregon. For comparison to the Company's 2015 IRP Update, expressing the Black & Veatch estimates in 2014 dollars results in capital costs of approximately $1,718/kW in Wyoming and $1,703/kW in Oregon.

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[6] *Id* at 27.
[7] Appendix M of PGE's Draft 2016 IRP: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning

Q. Why did the Company use a Wyoming wind plant as the renewable proxy in its current standard renewable avoided costs?

A. Establishing a renewable resource deficiency period of 2028 aligns the assumed acquisition of a renewable resource with the anticipated retirement of the 762 MW Dave Johnston coal plant in eastern Wyoming. Retiring this plant will free up transmission capacity and provide access to more cost effective wind resources in eastern Wyoming for the benefit of customers.

Q. Is the Company proposing any changes to the standard non-renewable resource avoided costs?

A. No. Current standard non-renewable avoided costs are tied to the acknowledged 2015 IRP, including demarcation of the resource deficiency period and the cost and performance of the proxy resource.

Q. Is a deficiency period of 2028 reasonable for standard non-renewable resources given the fact that the Company anticipates retiring several coal-fired units prior to that year?

A. Yes. A resource deficiency period of 2028 is based on the next major resource acquisition in the preferred portfolio in the acknowledged 2015 IRP. The preferred portfolio is calculated to the be lowest-cost, least-risk approach to serve customers, and the evaluation of new resource additions takes into account all known retirements of existing units. In the 2015 IRP it was anticipated that two major coal units would be re-fueled to burn natural gas. In the 2015 IRP Update those units were no longer assumed to be converted to natural gas, but would instead be retired. Despite that change, acquisition of the next major resource remained in 2028.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UM 1794
Exhibit PAC/101
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

PACIFICORP

Exhibit Accompanying Opening Testimony of Brian S. Dickman

DNV GL Study of Renewable Supply Options for PGE

October 2016

APPENDIX M. Evaluation of Five Renewable Supply Options (DNV GL)

DNV·GL

INTEGRATED RESOURCE PLANNING

Evaluation of Five Renewable Supply Options

Portland General Electric Company

Document No.: 703337-USPO-T-01-C
Date: 25 November 2015

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Task and objective:

Prepared by:	Verified by:	Approved by:
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Keywords:
Offshore wind, onshore wind, solar, integrated resource planning

Issue	Date	Reason for Issue	Prepared by	Verified by	Approved by
A	6 November 2015	DRAFT	C. Elkinton	C. Johnson	C. Johnson
B	24 November 2015	DRAFT	C. Elkinton	C. Johnson	C. Johnson
C	25 November 2015	FINAL	C. Elkinton	C. Johnson	C. Johnson

1 INTRODUCTION

Portland General Electric Company ("PGE" or the "Customer") has requested Garrad Hassan America, Inc., (hereafter DNV GL), to provide technical and financial information related to five potential renewable electricity generation projects in support of the Customer's Integrated Resource Planning ("IRP" or "Project").

The information provided in this Technical Note summarizes the results of DNV GL's analyses of these five projects along with the methodologies employed and assumptions made.

2 ABBREVIATIONS AND TERMINOLOGY

The following abbreviations are used in this document:

Abbreviation	Meaning
AC	Alternating Current
aMW	Average Megawatts – the total annual production divided by the number of hours per year
BOP	Balance of Plant
DC	Direct Current
EPC	Engineering, Procurement, Construction
IEA	International Energy Agency
IRP	Integrated Resource Planning
O&M	Operations and Maintenance
PGE	Portland General Electric
PTC	Production Tax Credit
PV	Photovoltaic
Wp	Watts Peak – the measure of DC output under full solar radiation

The Average Capacity of the energy projects discussed herein is given in average megawatts (aMW), which is calculated by dividing the total production for a year by the number of hours in a year. This is different than the project's Nameplate Capacity, which is discussed below in units of megawatts (MW).

The solar industry tends to base its calculations on DC electricity, whereas utilities tend to prefer to work in AC electricity. In order to convert the requested solar parameters into AC units, a DC-to-AC conversion factor of 1.2 was used. This value is commonly seen in the industry; however, for a more accurate value for a given project, a site-specific and technology-specific evaluation is required.

Within this report, solar cost results referenced to watts peak (e.g. $/Wp) are based on DC power, whereas cost results referenced to watts (e.g. $/MW) have been converted to AC power.

3 SUMMARY OF THE WORK

DNV GL was asked to provide numerical values for specific technical and financial parameters that specify five renewable energy projects under consideration by PGE in its IRP. This section describes the methodology and assumptions DNV GL used to determine these numerical values.

The five renewable energy projects under consideration are defined as follows:

Project Name	Location	Average Capacity	Generation Technology
Coos Bay Offshore Wind	Offshore from Coos Bay, Oregon	30 aMW	Wind (Offshore)
Ione Wind	Ione, Oregon	116 aMW	Wind
Central MT Wind	Montana East of Rockies Along Colstrip Line	100 aMW	Wind
Christmas Valley Solar 1	Christmas Valley, Oregon	25 aMW	Solar (fixed tilt)
Christmas Valley Solar 2	Christmas Valley, Oregon	25 aMW	Solar (single axis tracking)

It is noted that the Coos Bay Offshore Wind project is a real project under development by Principle Power. This project is still in the early stages of development, but where possible, actual project specifications have been used herein.

To DNV GL's knowledge, the remaining 4 projects are not currently under development. As such, DNV GL has developed a set of specifications for these projects considered to represent the technologies and practices currently in use today.

3.1 Technical Parameters

3.1.1 Capacity

The Nameplate Capacity is the name-plate generation capacity of the project (in megawatts) needed to meet the required Average Capacity.

3.1.1.1 Results

- Coos Bay Offshore Wind: 72 MW
- Ione Wind: 338 MW
- Central MT Wind: 236 MW
- Christmas Valley Solar 1: 115 MW
- Christmas Valley Solar 2: 103 MW

3.1.1.2 Methodology

For all projects, the Nameplate Capacity is calculated by dividing the Average Capacity by the Capacity Factor.

3.1.1.3 Assumptions

Assumes Average Capacities provided by the Customer (see table above).

3.1.2 Capacity Factor

3.1.2.1 Results

- Coos Bay Offshore Wind: 42%
- Ione Wind: 34%
- Central MT Wind: 42%
- Christmas Valley Solar 1: 21.7%
- Christmas Valley Solar 2: 24.2%

3.1.2.2 Methodology

- Wind projects: Gross energy is based on the power curve noted below and assumed mean wind speed (see assumptions below). Net energy includes typical energy loss factors for an offshore wind farm. The net Capacity Factor was calculated as the ratio of the net energy to the product of the Average Capacity and 8760 hours per year.
- Solar projects: Meteorological data were obtained from SolarAnywhere for the requested project area. The PVsyst software was used to calculate net energy, assuming spacing and loss factors considered reasonable for the region and type of technology. The DC net capacity factor was calculated as the ratio of the net energy to the product of the Average Capacity and 8760 hour per year. The reported AC net Capacity Factor was calculated by applying a DC/AC ratio of 1.2, which is considered reasonable for this region.

3.1.2.3 Other Assumptions

- Coos Bay Offshore Wind: Mean wind speed of approximately 9 m/s, which is based on preliminary mesoscale mapping
- Ione Wind: Mean wind speed of approximately 6.6 m/s, which is based on extensive wind resource analysis and experience in the region
- Central MT Wind: Mean wind speed of approximately 8.2 m/s, which is based on extensive wind resource analysis and experience in the region
- Christmas Valley Solar 1: Result given in AC based on DC capacity factor of 18.1% with DC/AC ratio of 1.2. Assumed 30 deg tilt, due south orientation, Normalized by dc capacity, assumed Performance Ratio of 79.5%, solar resource based on experience, includes loss factor for inverter clipping.

- Christmas Valley Solar 2: Result given in AC based on DC capacity factor of 20.2% with DC/AC ratio of 1.2. Assumed horizontal single axis tracking oriented due south, Normalized by dc capacity, assumed Performance Ratio of 78.6%, solar resource based on regional irradiation data, includes loss factor for inverter clipping.

3.1.3 Power curve

3.1.3.1 Results

- Coos Bay Offshore Wind: The MHI Vestas V164-8.0MW turbine was identified as representative of the technologies being considered for this project.
- Ione Wind: The GE 2.0-116 turbine was identified as representative of the type of technology typically utilized in projects with this wind regime [1].
- Central MT Wind: The GE 2.0-116 turbine was identified as representative of the type of technology typically utilized in projects with this wind regime [1].

3.1.3.2 Methodology

Identified example of turbine likely to be utilized in requested regions and wind conditions.

3.1.3.3 Other Assumptions

- Coos Bay Offshore Wind: This is the turbine on which the project design is currently based.
- Ione Wind: This is an example of a turbine that is appropriate for the wind regime and consistent with latest technology.
- Central MT Wind: This is an example of a turbine that is appropriate for the wind regime and consistent with latest technology.

3.1.4 Expected forced outage rate

3.1.4.1 Results

- Coos Bay Offshore Wind: 2.5%
- Ione Wind: 1%
- Central MT Wind: 1%
- Christmas Valley Solar 1: 1%
- Christmas Valley Solar 2: 1%

3.1.4.2 Methodology

These factors are based on typical industry values and cover balance of plant availability; not included are turbine availability, grid availability (forced and planned outages), and curtailment. It is noted that all of these factors are included in the losses accounted for in the Net Capacity Factors presented above.

3.1.4.3 Other Assumptions

Standard assumed value; grid availability is excluded.

3.1.5 Panel efficiency

3.1.5.1 Results

- Christmas Valley Solar 1: 15.5-16%
- Christmas Valley Solar 2: 15.5-16%

3.1.5.2 Methodology

Based on typical industry values from top-tier panel suppliers.

3.1.5.3 Other Assumptions

This assumes 72 cell panels, 290 w - 310 w.

3.1.6 Inverter efficiency

3.1.6.1 Results

- Christmas Valley Solar 1: 98% - 99%
- Christmas Valley Solar 2: 98% - 99%

3.1.6.2 Methodology

Based on typical industry values.

3.1.6.3 Other Assumptions

This assumes typical aggregate loss factors. Transformers add an additional 1% loss.

3.1.7 Maintenance cycle and average maintenance days

3.1.7.1 Results

- Coos Bay Offshore Wind: Once every 12 months, 4 days per turbine
- Ione Wind: Semi-annual, 60-80 hours per turbine
- Central MT Wind: Semi-annual, 60-80 hours per turbine
- Christmas Valley Solar 1: 3 days per year plus quarterly maintenance (at night)
- Christmas Valley Solar 2: 3 days per year plus quarterly maintenance (at night)

3.1.7.2 Methodology

Based on typical industry values.

3.1.7.3 Other Assumptions

- Coos Bay Offshore Wind: Industry standard, this does not include various inspections
- Ione Wind: Industry standard in US
- Central MT Wind: Industry standard in US
- Christmas Valley Solar 1: maintenance occurs at night, minimal inverter maintenance
- Christmas Valley Solar 2: maintenance occurs at night, minimal inverter maintenance

3.1.8 Approximate footprint

3.1.8.1 Results

- Coos Bay Offshore Wind: 30-40 acres/MW
- Ione Wind: 80 acres/MW
- Central MT Wind: 80 acres/MW
- Christmas Valley Solar 1: 5 acres/MW
- Christmas Valley Solar 2: 7 acres/MW

3.1.8.2 Methodology

Based on typical industry values.

3.1.8.3 Other Assumptions

- Offshore wind project: Based on Block Island (Rhode Island), Rampion (UK), and Kentish Flats Extension (UK)
- Onshore wind projects: Typical in the US
- Solar projects: Standard industry assumption. Trackers need additional area

3.1.9 Construction period, once permitted

3.1.9.1 Results

- Coos Bay Offshore Wind: 18-24 months
- Ione Wind: 10 months
- Central MT Wind: 9 months
- Christmas Valley Solar 1: 6-8 months

- Christmas Valley Solar 2: 6-8 months

3.1.9.2 Methodology

Based on typical industry values.

3.1.9.3 Other Assumptions

- Offshore wind project: Construction period only, assumes financing is also secured
- Onshore wind projects: Based on DNV GL expected durations for construction tasks
- Solar projects: Largely dependent upon EPC contractor man-loading, and also weather dependent

3.2 Financial Parameters

The financial parameters below were requested by the Customer. All cost figures presented herein are in 2015 dollars.

3.2.1 Total overnight capital cost, including EPC and owner's costs

3.2.1.1 Results

- Coos Bay Offshore Wind: $504M ($7,000/kW)
- Ione Wind: $558M ($1,680/kW)
- Central MT Wind: $401M ($1,700/kW)
- Christmas Valley Solar 1: $206M ($1,790/kW)
- Christmas Valley Solar 2: $204M ($1,980/kW)

3.2.1.2 Methodology

The total overnight capital cost is the cost to instantaneously develop and construct a project. Financing costs are excluded. The figures reported here are based on typical costs per unit of energy seen in recent projects and and include estimates for all major project cost categories. Additional background on capital costs can be found in the U.S. Department of Energy's 2014 Wind Technologies Market Report [2].

3.2.1.3 Other Assumptions

- Coos Bay Offshore Wind: Based on industry expectations for floating offshore wind projects
- Ione Wind: Based on the following break-down:
    - $1,000/kW turbine
    - $450/kW EPC
    - $230/kW development/contingency/etc
- Central MT Wind: Based on the following break-down:

- $1,000/kW turbine
- $470/kW EPC
- $230/kW development/contingency/etc

- Christmas Valley Solar 1: Assumes $2.15 per Wp, which includes construction costs and reflects fixed-tilt technologies and the larger utility-scale PV projects that require financing
- Christmas Valley Solar 2: Assumes $2.38 per Wp, which includes construction costs and reflects single axis tracking technologies and the larger utility-scale PV projects that require financing
- These estimates do not include the cost of capital, taxes, or other financing costs.
- These estimates do not include financial impacts associated with any tax credits (e.g. the Production Tax Credit, PTC), or potential impacts from other revenue sources.
- The "development/contingency/etc" cost estimates provided above cover a nominal level of development spending and typical contingency above the price of the construction contract and are included here to reflect more complete project costs. These values are inherently project specific.

3.2.2 Standard deviation from average total overnight capital cost

3.2.2.1 Results

- Coos Bay Offshore Wind: Expected range: $5M-$8M/MW
- Ione Wind: Standard deviation: $0.350M/MW
- Central MT Wind: Standard deviation: $0.350M/MW
- Christmas Valley Solar 1: Expected range: $1.7M-$ 1.9M/MW
- Christmas Valley Solar 2: Expected range: $1.9M-$-2.1M/MW

3.2.2.2 Methodology

- Offshore wind project: The range for the overnight costs represents the expected range of floating offshore wind projects based on previous cost studies for floating wind projects in Europe. The estimate provided in Section 3.2.1.1 above is considered to represent a project installed off Oregon.
- Onshore wind project: DNV GL maintains a large database of wind project costs. These expected value and standard deviation were determined based on projects of a similar size and in the Pacific Northwest region.
- Solar projects: Range based on recent project costs using similar technologies in the Western U.S..

3.2.2.3 Other Assumptions

- Coos Bay Offshore Wind: floating offshore wind assumed to be at the high end of the range
- Ione Wind: Standard deviation is high due to limited availability of recent data of similar projects in this region

- Central MT Wind: Standard deviation is high due to limited availability of recent data of similar projects in this region
- Christmas Valley Solar 1: A cost range of $2.00 -$ 2.30 per Wp is expected for fixed-tilt projects. This is considered to represent the range of typical projects in the Pacific Northwest; it does not capture the extremes of the possible range.
- Christmas Valley Solar 2: A cost range of $2.25 -$ 2.50 per Wp is expected for single-axis tracking projects. This is considered to represent the range of typical projects in the Pacific Northwest; it does not capture the extremes of the possible range.

3.2.3 Escalation rate for capital costs over next 20 years, if different from inflation

3.2.3.1 Results

The following table and plot show DNV GL's projection for the percentage decrease in overnight capital cost for the offshore wind, onshore wind, and solar PV projects PGE has requested. These results were informed by the IEA's Annual Energy Outlook (2013) [3] and by DNV GL's experience with utility-scale project cost trends.

No on-going capital costs are assumed for a given project after it achieves commercial operation.

Table 3-1 Percentage of 2015 Overnight Cost (based on $2015)

Year	Offshore Wind (floating) % (2015)	Onshore Wind % (2015)	PV % (2015)
2015	100%	100%	100%
2016	95%	99%	
2017	90%	98%	
2018	85%	97%	
2019	81%	95%	
2020	76%	94%	91%
2021	72%	93%	
2022	70%	92%	
2023	68%	91%	
2024	66%	90%	
2025	64%	90%	83%
2026	63%	89%	
2027	61%	89%	
2028	60%	89%	
2029	58%	88%	
2030	57%	88%	75%
2031	56%	88%	
2032	54%	87%	
2033	53%	87%	
2034	52%	87%	
2035	50%	87%	68%
2036	49%	87%	
2037	48%	86%	
2038	46%	86%	
2039	45%	86%	
2040	44%	86%	62%

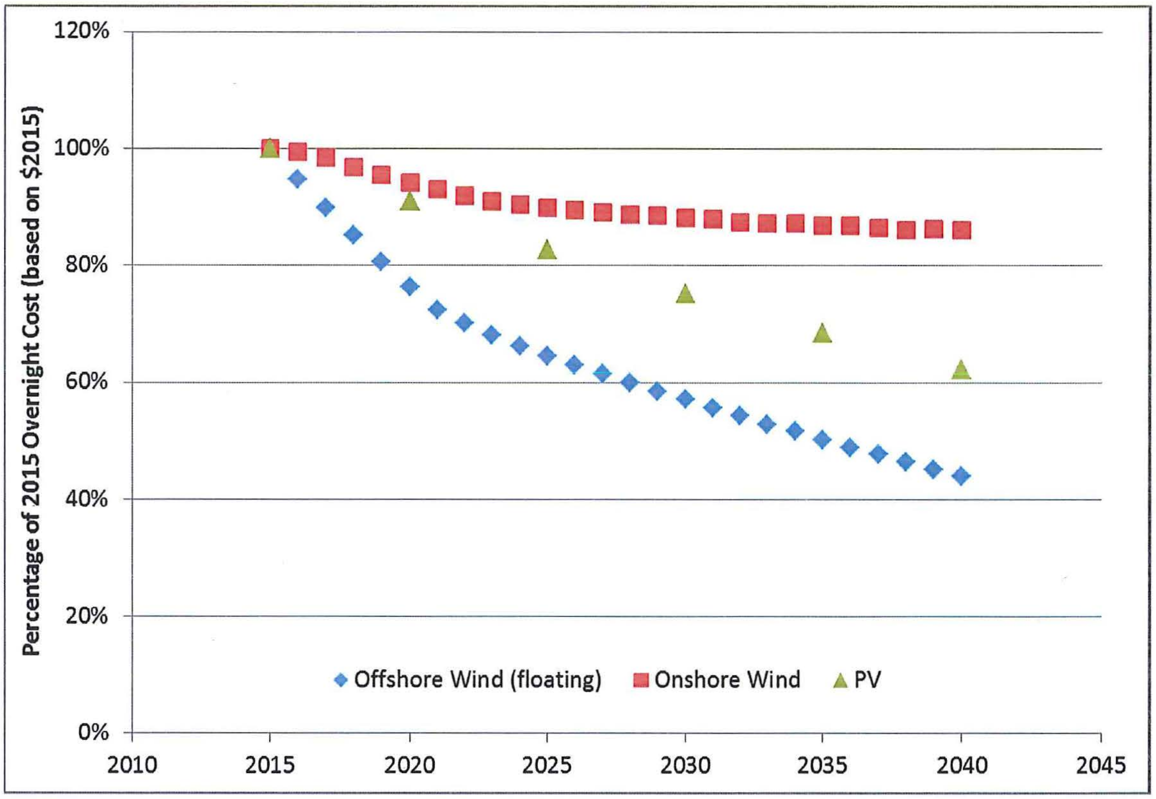

Figure 3-1 Percentage of 2015 Overnight Cost (based on $2015)

3.2.4 Fixed O&M

3.2.4.1 Results

- Coos Bay Offshore Wind: $165,000/MW/yr
- Ione Wind: $45,000/MW/yr
- Central MT Wind: $45,000/MW/yr
- Christmas Valley Solar 1: $9,900/MW/yr
- Christmas Valley Solar 2: $10,000/MW/yr

3.2.4.2 Methodology

Costs in this category are related to scheduled maintenance (e.g. annual or semi-annual maintenance), general facilities maintenance (e.g. roads and buildings), and administrative expenses (e.g. lease payments, labor, etc). These costs are subdivided further in Section 3.2.5.1 below.

3.2.4.3 Other Assumptions

These estimates are based on typical values seen on wind and solar projects and are considered to be representative of projects in the area(s) of interest. The values presented here are averages over the economic life of the project (see Section 3.2.9.1 below).

3.2.5 Breakdown of fixed O&M costs including, but not limited to, service contracts and warranty costs, royalty payments, and labor

3.2.5.1 Results

- Coos Bay Offshore Wind:
    - Vessels: $53,000/MW
    - Parts: $11,000/MW
    - Labor: $22,000/MW
    - Onshore support: $22,000/MW
    - BOP O&M: 3,000/MW
    - Insurance: $16,000/MW
    - Lease payments: $28,000/MW
    - Other: $10,000/MW
- Ione Wind:
    - Scheduled Turbine O&M: $17,000/MW
    - BOP O&M: $3,000-5,000/MW
    - Utilities: $1,000/MW
    - Project Management Administration: $3,000/MW
    - Generation Charges: $1,500/MW
    - Land Lease: $5,500/MW
    - Insurance: $3,000/MW
    - Property Taxes: $5,500/MW
    - Professional Advisory: $3,000/MW
    - Other G&A: $1,500/MW
- Central MT Wind:
    - Scheduled Turbine O&M: $17,000/MW
    - BOP O&M: $3,000-5,000/MW

- Utilities: $1,000/MW
- Project Management Administration: $3,000/MW
- Generation Charges: $1,500/MW
- Land Lease: $5,500/MW
- Insurance: $3,000/MW
- Property Taxes: $5,500/MW
- Professional Advisory: $3,000/MW
- Other G&A: $1,500/MW

- Christmas Valley Solar 1:
  - Module cleaning: $5,000-6,500/MW
  - Other: $3,400-4,900/MW
- Christmas Valley Solar 2:
  - Module cleaning: $5,000-6,500/MW
  - Other: $3,500-5,000/MW

3.2.5.2 Methodology

These estimates are based on typical costs from projects using similar technologies in the US.

Additional information on some of these charges is provided below:

- Scheduled Turbine O&M: annual or semi-annual service
- BOP O&M: maintenance of the physical plant
- Utilities: Electricity, water, sewer, etc. needed to operate the project facilities
- Project Management Administration: On-site and off-site project and asset management
- Generation Charges: Interconnection charges and parasitic power
- Professional Advisory: outside services such as engineering, tax, and legal services
- Other G&A: General and administrative costs not captured above

3.2.5.3 Other Assumptions

- Offshore wind project: Based on European experience, adjusted for floating project
- Onshore wind projects: Based on DNV GL database
- Solar projects:
  - Cleaning: $1,500-$2,000/MWp;

- Budget includes: System monitoring, regular visual inspections, preventative maintenance, periodic electrical testing, inventory management, occasional medium voltage and inverter work; on-site staff is typically present for these services on projects larger than 25 MWp.

3.2.6 Non fuel variable O&M

3.2.6.1 Results

- Coos Bay Offshore Wind: Not applicable
- Ione Wind: Not applicable
- Central MT Wind: Not applicable
- Christmas Valley Solar 1: Not applicable
- Christmas Valley Solar 2: Not applicable

3.2.6.2 Methodology

Based on discussion with the Customer, project operations and maintenance costs are considered to be covered under either "Fixed O&M" or "Ongoing expected Capital Additions or maintenance accrual". As such, no costs are expected in this category.

3.2.6.3 Other Assumptions

None.

3.2.7 Approximate capital drawdown schedule

3.2.7.1 Results

- Offshore wind project:
  - Approx. 15% down
  - 65% for deliveries to port
  - 5% for construction
  - 15% for commissioning (pro rata)
- Onshore wind projects:
  - Approx. 20% down
  - 50% on Ex-works completion (pro rata)
  - 20% on delivery to site
  - 5% on commissioning
  - 5% on final completion

- Solar projects:
    - Approx. 10% down
    - 80% in monthly progress payments
    - 10% at substantial completion.

3.2.7.2 Methodology

These estimates are based on typical contracts in the wind and solar energy industries.

3.2.7.3 Other Assumptions

- Offshore wind project: Based on known projects, will depend on contractual responsibilities
- Onshore wind projects: Typical for US industry
- Solar projects: Typical for US industry

3.2.8 Ongoing expected Capital Additions or maintenance accrual

DNV GL notes that in this Report and at the request of the Customer, the term "ongoing capital additions" is considered to be synonymous with the term "unscheduled maintenance," which is more commonly used in the wind industry.

3.2.8.1 Results

- Coos Bay Offshore Wind: Included in Fixed O&M (above)
- Ione Wind: $16,500/MW/yr
- Central MT Wind: $16,500/MW/yr
- Christmas Valley Solar 1: $2,400/MW/yr
- Christmas Valley Solar 2: $2,500/MW/yr

3.2.8.2 Methodology

Costs in this section are associated with the replacement or repair of major components [4]. These are typically considered to be unscheduled costs [5].

3.2.8.3 Other Assumptions

The values in this section are based on typical values seen within the wind and solar industries. The values presented here are averages over the economic life of the project (see Section 3.2.9.1 below).

- Coos Bay Offshore Wind: Small project, with likely shared vessel resources, so cannot separate scheduled and unscheduled maintenance costs
- Ione Wind: Based on DNV GL database, 25-year average value, does not include unscheduled BOP maintenance

- Central MT Wind: Based on DNV GL database, 25-year average value, does not include unscheduled BOP maintenance
- Christmas Valley Solar 1: Assumes $2.90 per kWp/yr; this is driven by inverter repair/replacement
- Christmas Valley Solar 2: Assumes $3.00 per kWp/yr; this is driven by inverter repair/replacement

3.2.9 Design life: years

3.2.9.1 Results

- Coos Bay Offshore Wind: 25 years
- Ione Wind: 25 years
- Central MT Wind: 25 years
- Christmas Valley Solar 1: 30 years
- Christmas Valley Solar 2: 30 years

3.2.9.2 Methodology

Based on industry-standard values for the specific generating technology.

3.2.9.3 Other Assumptions

None.

3.2.10 Decommissioning accrual

3.2.10.1 Results

- Coos Bay Offshore Wind: $1,600,000/year
- Ione Wind: $0.00
- Central MT Wind: $0.00
- Christmas Valley Solar 1: $0.00
- Christmas Valley Solar 2: $0.00

3.2.10.2 Methodology

- Coos Bay Offshore Wind: Decommissioning costs for offshore wind projects have been found to equate to 7-10% of the capital cost. A bond is required to cover the cost of decommissioning the portion of the project that us under BOEM jurisdiction (see 30 C.F.R. §585). The figure presented here assumes a decommissioning cost equal to 8% of the capital cost, divided into equal annual over the 25-year design life of the project (2015 dollars).

- Onshore wind projects: Decommissioning cost is widely assumed to be offset by salvage value of used components. A bond may be required to accumulate funds, although this is uncommon for onshore wind projects.
- Solar projects: Decommissioning cost is widely assumed to be offset by salvage value of used components. A bond may be required to accumulate funds.

3.2.10.3 Other Assumptions

None.

4 REFERENCES

[1] GE Power & Water, Technical Documentation Wind Turbine Generator Systems 2.0-116 - 50 Hz and 60 Hz, Calculated Power Curve and Thrust Coefficient, *Confidential*, dated 2014

[2] U.S. Department of Energy, 2014 Wind Technologies Market Report, dated August 2015.

[3] U.S. Energy Information Administration, Annual Energy Outlook 2013 with projections to 2040, dated April 2013.

[4] PGE, Accounting Practices and Procedures Document: Wind Generation and Related Equipment, APPD 4-100-06, dated 26 November 2012.

[5] DNV GL, Turbine O&M costs, 703337-USPO-X-02, *Confidential*, dated 25 November 2015.

Docket No. UM 1794
Exhibit PAC/102
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

PACIFICORP

Exhibit Accompanying Opening Testimony of Brian S. Dickman

Black & Veatch Wind Generation Study

October 2016

FINAL

UTILITY-SCALE WIND GENERATION STUDY FOR THE 2017 IRP

Wind Energy Design Basis and Cost Estimate Report

B&V PROJECT NO. 192165

PREPARED FOR

PacifiCorp

13 JULY 2016

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1.0 Executive Summary

Black & Veatch was retained by PacifiCorp to estimate the energy production as well as the capital and operations and maintenance (O&M) cost for a set of generic utility scale wind power plants at five different locations around the country:

- Arlington, OR (IEC Class II wind resource)
- Goldendale, WA (IEC Class II wind resource)
- Pocatello, ID (IEC Class II wind resource)
- Monticello, UT (IEC Class II wind resource)
- Medicine Bow, WY (IEC Class I wind resource)

Four of the sites are considered Class II sites with average wind speeds below 8.5 m/s while one site is considered a Class I site with annual average wind speed above 8.5 m/s. For each location Black & Veatch identified and downloaded representative wind resource data, developed a wind resource model, prepared a conceptual project layout and design, modeled annual energy production and estimated EPC capital costs and Operation and Maintenance (O&M) costs. The conceptual designs and cost estimates were high-level in nature and were designed to be representative of a generic 100 MW wind project. The results of the production estimates are summarized in Table 1-1. The capital costs are summarized in Table 1-2.

Net energy production varies from 275.3 to 389.6 GWh per year (net capacity factor of 31.4 to 43.4 percent). Total capital cost varies from about $1,725 per kW to $1,800 per kW. Operating costs are summarized in Table 1-3.

Table 1-1 Estimated Annual Energy Production

REGION	INSTALLED CAPACITY (MW)	MEAN WIND SPEED @95M (M/S)	AIR DENSITY (KG/M^3)	NET AEP (GWH/YR)	NET CF (%)
Arlington, OR	100	8.0	1.17	361.9	41.3
Goldendale, WA	100	7.5	1.15	332.1	37.9
Pocatello, ID	100	7.9	1.00	334.0	38.1
Monticello, UT	100	6.9	0.96	275.3	31.4
Medicine Bow, WY	102.3	10.6	0.96	389.6	43.4

Table 1-2 Capital Cost Summary

REGION	TURBINE MODEL	CAPACITY (MW)	TOTAL CAPITAL COST (USD)	CAPITAL COST (USD PER KW)
Arlington, OR	V100-2.0	100	176,850,000	1,769
Goldendale, WA	V100-2.0	100	179,300,000	1,793
Pocatello, ID	V100-2.0	100	180,000,000	1,800
Monticello, UT	V100-2.0	100	172,500,000	1,725
Medicine Bow, WY	V112-3.3	102.3	182,500,000	1,784

Table 1-3 Operating Cost Summary

REGION	YEAR 1 COST	FIXED COST $/KW-YR	VARIABLE COST $/MWH
Arlington, OR Goldendale, WA Pocatello, ID Monticello, UT	$5,145,000	$51.45	$0.00
Medicine Bow, WY	$5,436,900	$49.16	$1.05

2.0 Wind Resource Review

2.1 SITE LOCATIONS

Black & Veatch investigated five separate regions across five western states within the PacifiCorp service territory:

- Arlington, OR (IEC Class II wind resource)
- Goldendale, WA (IEC Class II wind resource)
- Pocatello, ID (IEC Class II wind resource)
- Monticello, UT (IEC Class II wind resource)
- Medicine Bow, WY (IEC Class I wind resource)

A map of these locations is shown in Figure 2-1.

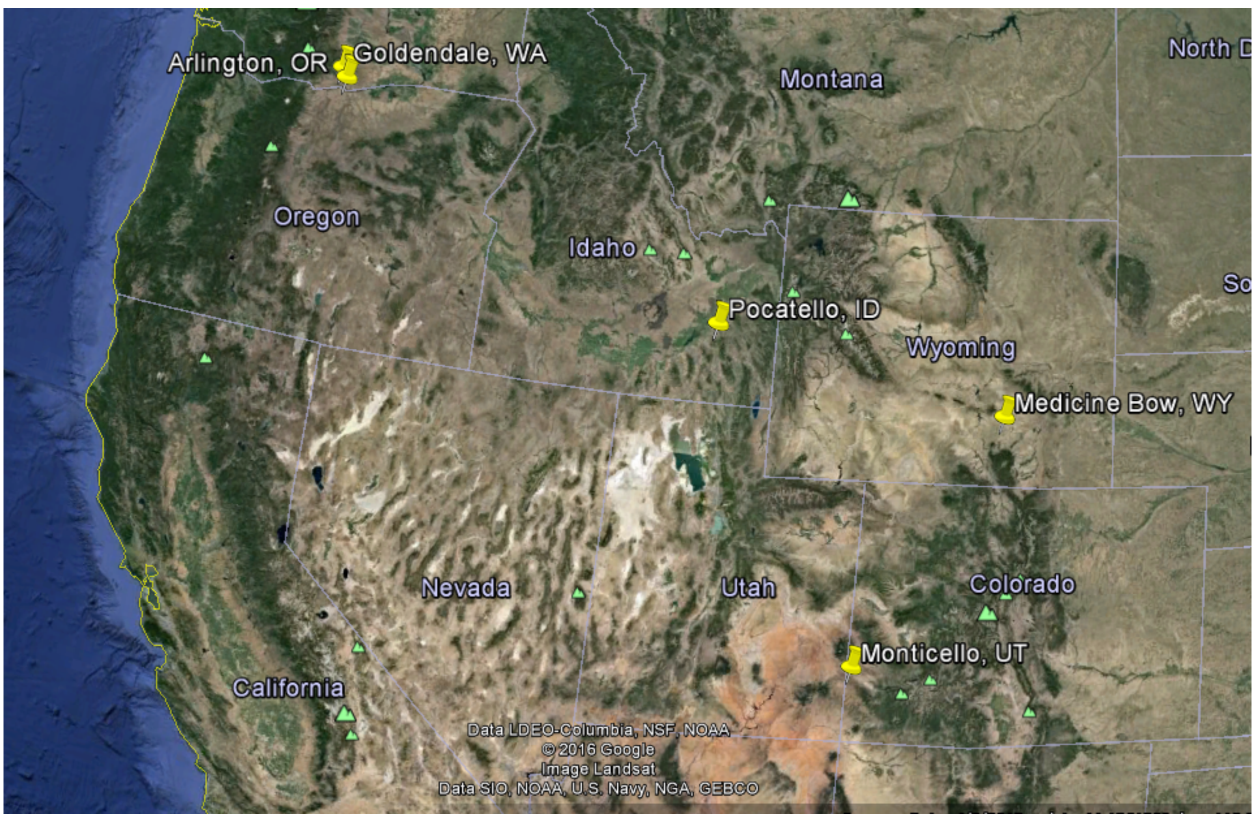


Figure 2-1 Wind Project Locations

Four of the locations are considered Class II wind resources based on the International Electrotechnical Commission (IEC) wind turbine design standards (IEC 61400-1:2005). In general these areas are best suited for a Class II wind turbine design. The Medicine Bow site has stronger winds, and is considered more suitable for an IEC Class I turbine design. Table 2-1 shows the IEC classifications based on average wind speed (V_{ave}) and design reference wind speed (V_{ref}). The reference wind speed is the speed the maximum 10 minute average wind speed with a recurrence period of 50 years that the turbine is designed for. The annual average wind speed is defined in the IEC standard as 0.2 V_{ref}.

Table 2-1 IEC Wind Classes

IEC CLASS	V_{AVE} (M/S)	V_{REF} (M/S)
I	10	50
II	8.5	42.5
III	7.5	37.5

2.2 WIND RESOURCE ESTIMATION

Black & Veatch utilized the National Renewable Energy Laboratory (NREL) Wind Integration National Dataset (WIND)[1] to quantify the wind resource at each location. The WIND dataset is designed to support integration studies. A representative point for each location was chosen and wind resource data from 2007-2012 was utilized for this study. The coordinates of each wind resource point are shown in Table 2-2. The NREL data contains 5-minute time-series data. Data points include wind speed at 100m above ground level, wind direction, air temperature, air pressure and air density.

Table 2-2 Project Coordinates

REGION	LATITUDE	LONGITUDE
Arlington, OR	45.64° N	120.59° W
Goldendale, WA	45.77° N	120.71° W
Pocatello, ID	42.93° N	112.31° W
Monticello, UT	37.96° N	109.07° W
Medicine Bow, WY	41.82° N	106.42° W

Per guidance received from PacifiCorp, Black & Veatch assumed that each site was open and flat, and therefore also assumed a similar wind distribution for each project location. As such, Black & Veatch utilized a generic wind distribution in order to model the wind resource at each location. The Arlington location was chosen as a realistic and representative distribution. Largely unidirectional, 80% of the total wind energy comes from the west while the remaining 20% is

[1] The Wind Integration National Dataset (WIND) Toolkit is an update and expansion of the Eastern and Western Wind Datasets, and is intended to support the next generation of integration studies. The WIND Toolkit includes meteorological conditions and turbine power for more than 126,000 sites in the continental United States for the years 2007–2013. http://www.nrel.gov/electricity/transmission/wind_toolkit.html

distributed mostly from west-northwest and west-southwest, as well as a small percentage from the east as shown in Figure 2-2. This same distribution was used for all five sites. The distribution was scaled to match the actual annual average wind speed at each location as found from the six years of WIND data. The annual average wind speeds at each location are reported in Table 2-3. The wind energy distribution from Arlington which was used at all five sites is shown in Figure 2-2. The monthly average wind speeds for all five sites are shown in Figure 2-3.

Table 2-3 Annual Average Wind Speeds

REGION	ANNUAL V_{AVE} (M/S)
Arlington, OR	8.0
Goldendale, WA	7.5
Pocatello, ID	7.9
Monticello, UT	6.9
Medicine Bow, WY	10.6

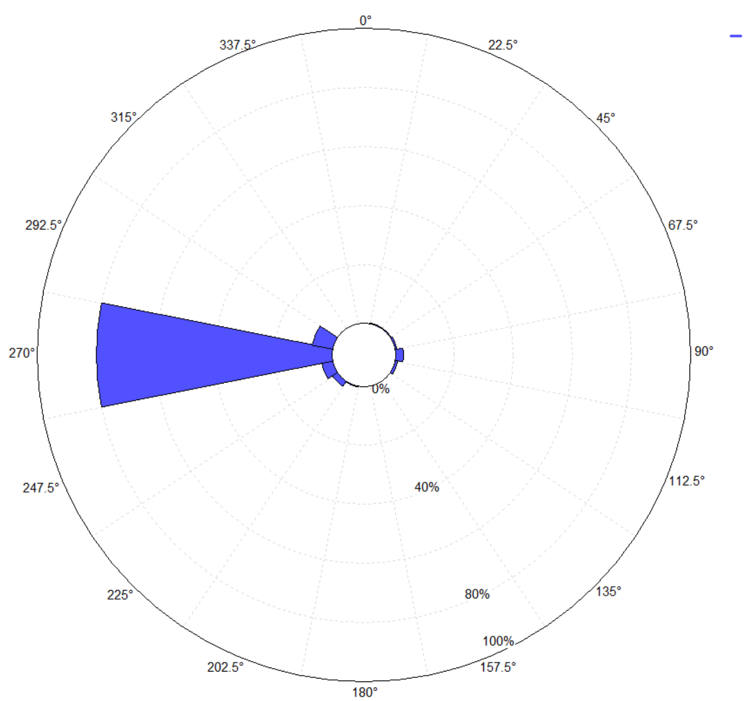
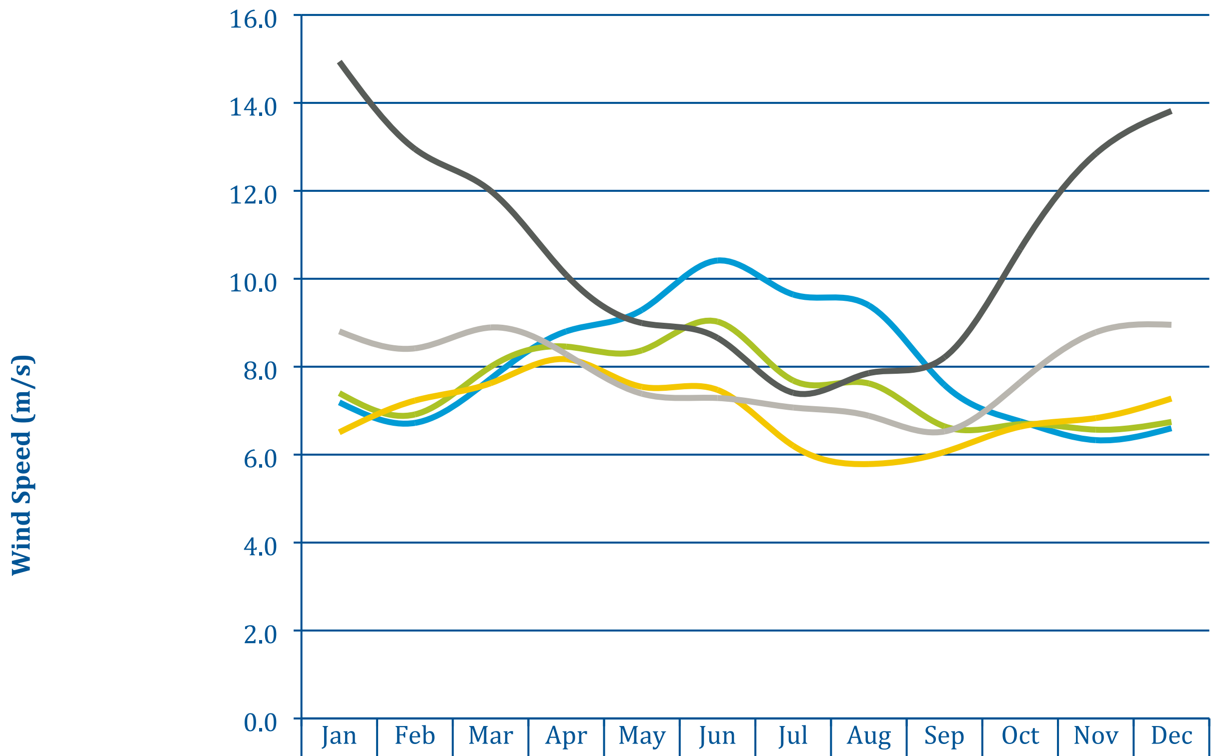


Figure 2-2 Typical Site Wind Rose (Percent of Energy Basis)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Arlington	7.2	6.7	7.7	8.8	9.3	10.4	9.6	9.4	7.6	6.8	6.3	6.6
Goldendale	7.4	6.9	8.0	8.5	8.4	9.0	7.7	7.6	6.6	6.7	6.6	6.7
Medicine Bow	14.9	13.0	12.0	10.1	9.0	8.7	7.4	7.9	8.2	10.7	12.8	13.8
Monticello	6.5	7.2	7.6	8.2	7.5	7.5	6.2	5.8	6.1	6.6	6.8	7.3
Pocatello	8.8	8.4	8.9	8.3	7.4	7.3	7.1	6.9	6.5	7.6	8.8	9.0

Figure 2-3 Monthly Average Wind Speed

3.0 Conceptual Project Design

3.1 TURBINE SELECTION

Black & Veatch selected two turbine models. One turbine model is an IEC class II machine for Arlington, Goldendale, Pocatello and Monticello. The second turbine model is an IEC class I machine meant for the high wind resource at Medicine Bow. The three top wind turbine manufacturers are generally considered GE, Vestas and Siemens. For the purpose of this study Black & Veatch chose two Vestas machines, the Vestas V100-2.0 MW and V112-3.3 MW. Specifications for each machine are summarized in Table 3-1 and the power curves at standard air density (1.225 kg/m^3) are shown in Figure 3-1.

Table 3-1 Wind Turbine Models Selected

TURBINE	RATED CAPACITY (MW)	ROTOR DIAMETER (M)	HUB HEIGHT (M)	IEC CLASS
Vestas V100-2.0	2.0	100	95	II
Vestas V112-3.3	3.3	112	95	I

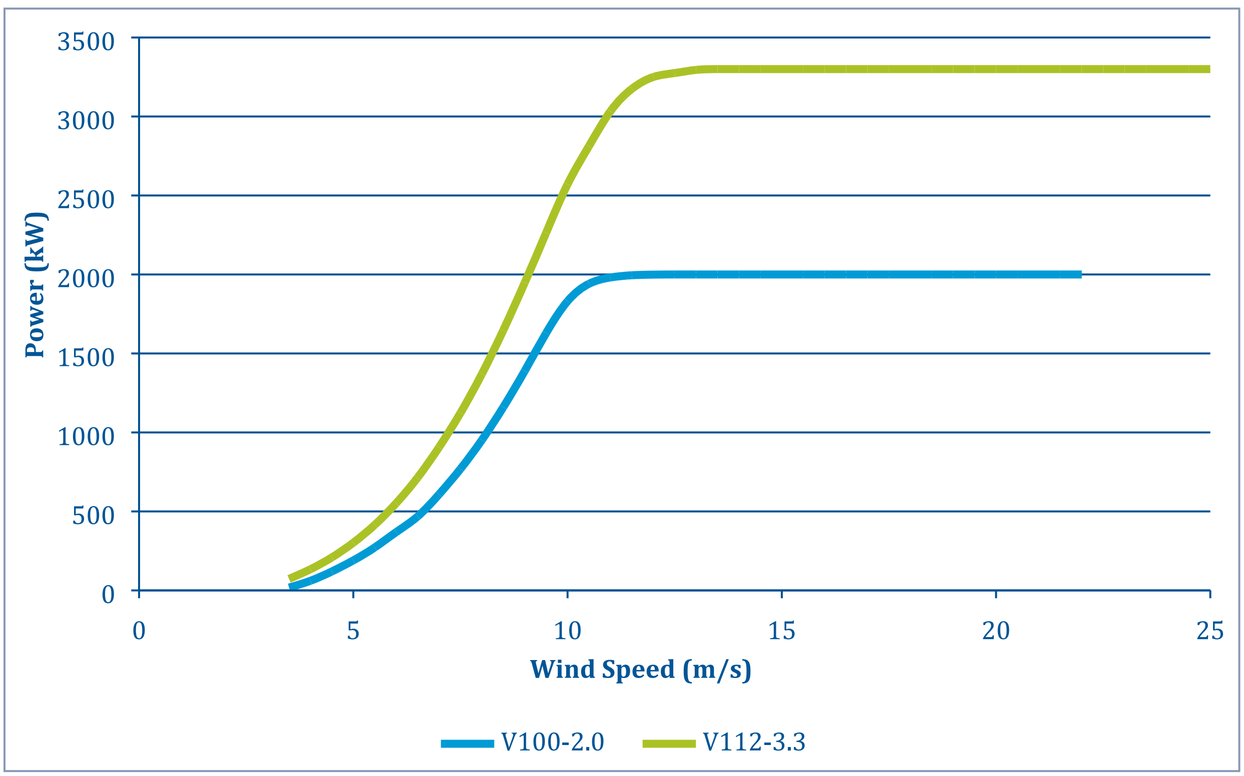


Figure 3-1 Turbine Power Curves

3.2 CONCEPTUAL PROJECT LAYOUT

Black & Veatch developed two generic project layouts, one using the Vestas V100-2.0 and one using the Vestas V112-3.3. Based on the requirements of the IRP, Black & Veatch assumed the project sites are open, flat and have no geographical, environmental, wildlife, infrastructure, or other restrictions on wind turbine placement. For simplicity and wider applicability the layouts were generated as standard grids and were designed to have wake losses in the range of 5-7 percent. This is representative of the generally acceptable range for an optimized cost of energy (COE). A project layout with greater spacing between individual wind turbines would have lower wake losses, but likely result in higher capital costs due influences such as longer collection cable and access roads. Likewise, a more compact layout would have lower capital cost associated with shorter collection cables and access roads but would also have higher wake losses and thus less energy production.

The conceptual designs include access road routing, collection system routing, a project substation area and O&M building. The location of the substation was assumed to be located adjacent to the point of interconnection (POI). In practice, the optimal location of the substation is a balance between efficiency of the project collection system and added capital cost of a transmission line to the POI. Given the assumption of an adjacent POI the substation is located near the edge of the project but still within the project area.

The substation, laydown yard and O&M area were assumed to be 200 feet by 600 feet for a total area of about 2.75 acres. The area is the same size for both layouts. This area includes the project substation, an outdoor laydown yard, an O&M building which includes two offices, a kitchen, bathrooms, parking and a shop and indoor warehouse.

Salient details of the project layouts are described in Table 3-2. The main difference between the two layouts is that the Vestas V112 has a much larger rated capacity and thus requires fewer turbines (31 as opposed to 50 in the V100 layout). In addition the higher wind speeds associated with Medicine Bow, the Class I site, allow closer downwind spacing of the turbines since wind speeds tend to recover faster behind rows. The result is a more compact layout requiring less area for the V112 Class I site compared to the V100 Class II sites. The conceptual project layouts can be seen in Figure 3-2 and Figure 3-3.

Table 3-2 Conceptual Design Overview

LAYOUT	TURBINES	ROTOR SPACING (CROSSWIND X DOWNWIND)	TOTAL CAPACITY (MW)	ACCESS ROAD LENGTH (MILES)	COLLECTION SYSTEM LENGTH (MILES)
Vestas V100-2.0	50	3x10	100	10.8	11.3
Vestas V112-3.3	31	3x7	102.3	7.4	7.6

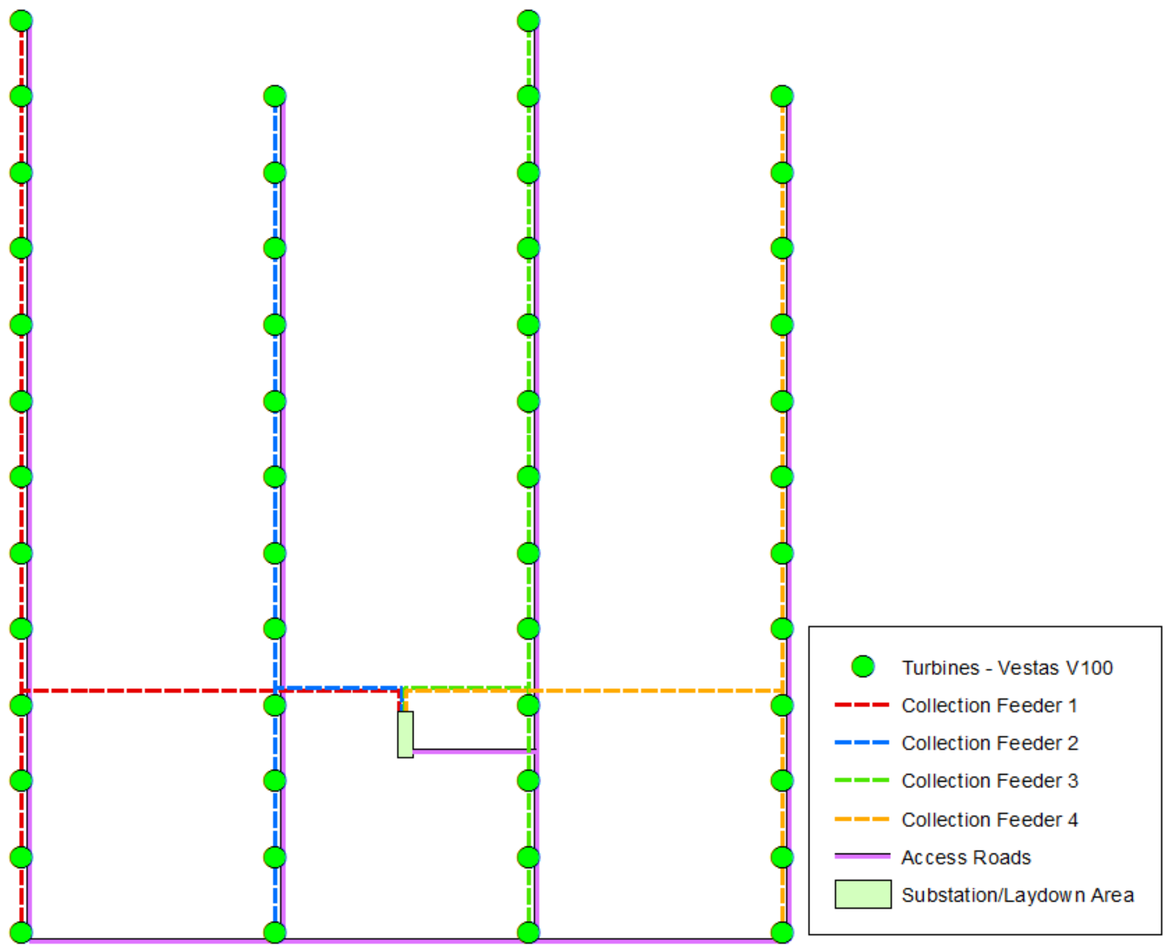


Figure 3-2 Conceptual Layout for Vestas V100-2.0 MW Projects

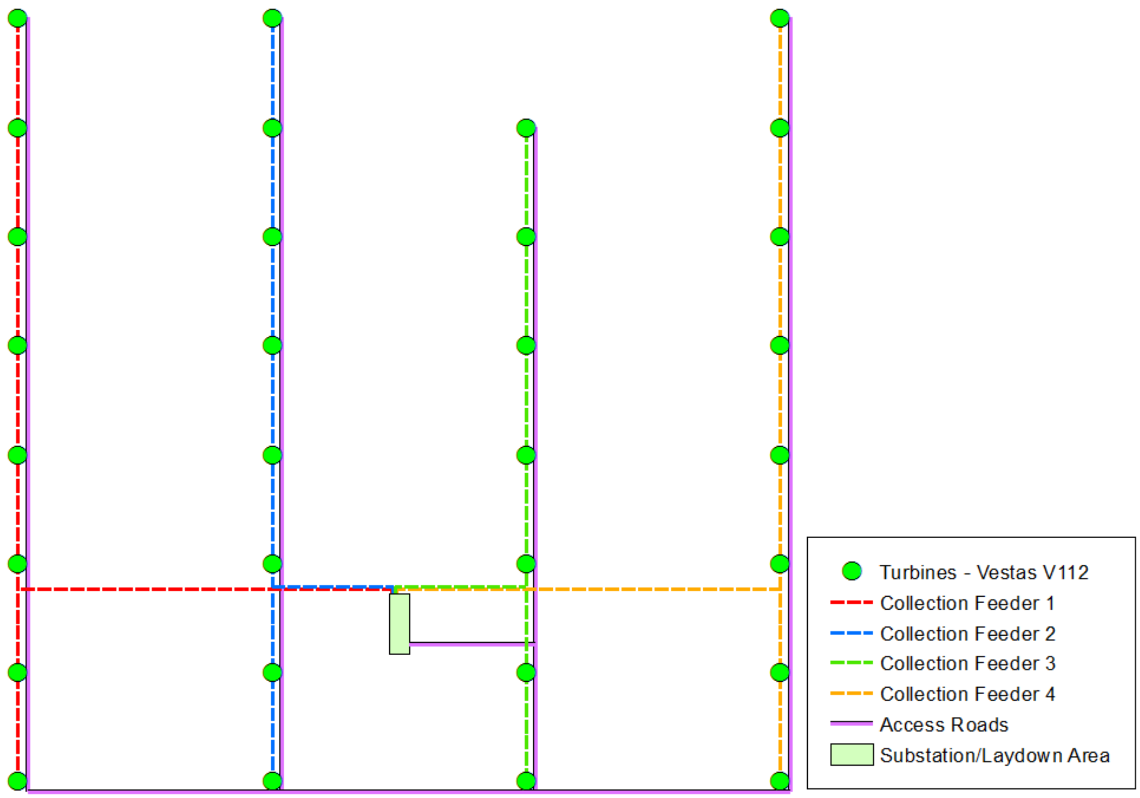


Figure 3-3 Conceptual Layout for Vestas V112-3.3 MW Project

4.0 Energy Production Estimates

Black & Veatch estimated the annual energy production (AEP) at each location based on the wind resource at each site and the conceptual layout developed for each site. Black & Veatch used OpenWind®[2] and its modified park wake model to calculate the AEP.

4.1 SITE AIR DENSITY

Air density plays a notable role in the energy production of wind energy facilities. In general, projects located at higher altitude have a lower air density and thus lower energy production for a given wind speed. The hub-height air density from NREL data at each location was used to adjust the power curves of each turbine per IEC practice so the energy production estimates accurately reflect the differences in air density across the five locations.

4.2 HUB-HEIGHT WIND SPEEDS

The wind resource at each site was established as described above. The NREL WIND data gave wind speeds at 100m elevation. Both turbine model selections included a hub-height of 95m so the annual average wind speed at each site was adjusted to 95m using the wind shear power law approximation which defines the relationship between wind speed and height above ground as:

$$V(z) = V(z_r)\left(\frac{z}{z_r}\right)^{\alpha}$$

where:

$V(z)$	= wind speed at height of interest
$V(z_r)$	= wind speed at reference height
z	= height of interest
z_r	= reference height
α	= wind shear exponent (assumed 1/7)

Black & Veatch assumed the value of the wind shear exponent (α) to be 1/7 which is a generally accepted value for unknown surface roughness.

4.3 LOSSES

Black & Veatch estimated the production losses that could potentially impact wind energy production at the project sites. Losses external to the project site, including environmental (bird or bat) curtailment, and transmission losses and curtailment beyond the point of delivery were not considered in this analysis. Each loss factor for the layout is discussed below and summarized in Table 4-1.

[2] OpenWind is a wind project design and optimization software developed by AWS Truepower. http://software.awstruepower.com/openwind/

Array Efficiency: This is a calculated value, and part of the output of the wake and energy production model. It represents the ratio of the net to gross energy yield, which only considers calculation of wake losses.

- **Electrical Efficiency:** Losses in the electric collection system and substation prior to the plant's revenue meters are covered by this factor. Points of significant electrical losses in a wind energy project usually include electric collection system lines connecting the turbines to the project substation, the turbine step-up transformers, and the substation's main power transformer. Although these losses are dependent on the distance of wind turbine generators from the substation, Black & Veatch has assumed a standard global electrical loss of 2.0 percent, which is consistent with losses seen in wind projects of this size and technology type.
- **Turbine Availability**: Turbine availability accounts for machine downtime that is either a scheduled or unscheduled outage. This value is typically estimated at 3 to 5 percent. Assumptions for turbine availability are often driven by historical turbine model track record. Based upon Black & Veatch's experience with the turbine manufacturer, a consistent availability loss of 4.0 percent was assumed for the 20 year project life.
- **Environmental:** Wind turbine performance is sensitive to the cleanliness and surface condition of the turbine's blades. The site can contain airborne particulates and insects that may contribute to blade soiling. Blade soiling and blade surface degradation, as well as inclement weather and vegetation growth are considered for this loss. For the Class II sites a loss of 2.0 percent was assumed for the lost energy due to this effect over the 20 year project life. For the Class I site a loss of 3.0 percent was assumed due to very high wind speeds and increased potential of icing at the Medicine Bow location.
- **Balance of Plant (BOP) Maintenance:** Substation maintenance requiring the shutdown of the project is assumed to be infrequent, averaging approximately one day out of each year. Additional minor unscheduled availability events are also expected; therefore, the production loss for balance of plant systems was estimated to be 0.5 percent.
- **Turbine Performance:** Turbine performance losses account for sub-optimal performance experienced by turbines, including instrumentation calibration, pitch and yaw errors, and similar sub-optimal operations. Black & Veatch has assumed a performance loss of 2.5 percent for the Project.
- **Utility Downtime:** Events that require downtime on the part of the utility are assumed to be infrequent; therefore, the utility outages loss was assumed to be 0.5 percent in this analysis.
- **Power Curve Turbulence Variation:** The wind turbine manufacturer will warranty a performance level for the turbine at a percentage of the power curve values. Industry experience shows that while wind turbines historically meet power

curve warranties when including measurement uncertainty, they often operate slightly under published power curves. Based upon the available data, Black & Veatch estimates 2.0 percent loss due to turbulence variation.

- **High Wind Hysteresis:** When wind speeds exceed the operational range of a wind turbine, the turbine shuts down to protect itself. The turbine then waits to restart until wind speeds fall below a lower restart speed. The delay in restart after high wind events can effectively cause lost energy. Black & Veatch estimates a loss of 1 percent for the Class II sites and 2 percent for the Class I site.
- **Wind Sector Management:** Wind sector management is a means of protecting turbines when winds are blowing along the turbine layout direction in which turbines have been given reduced along-wind spacing. Typically the turbines are shutdown to reduce turbulent wake loading by the adjacent upwind machine. Because turbine spacing is a minimum of 3 rotor diameters between machines, Black & Veatch has assumed that the sites will not require sector management.

Table 4-1 Annual Energy Losses

LOSS (%)	CLASS II SITES	CLASS I SITE
Array Efficiency	Calculated	Calculated
Electrical Efficiency	2.0	2.0
Turbine Availability	4.0	4.0
Environmental	2.0	3.0
BOP Downtime	0.5	0.5
Turbine Performance	2.5	2.5
Utility Downtime	0.5	0.5
Power Curve Variation	2.0	2.0
High Wind Hysteresis	1.0	2.0
Wind Sector Management	0.0	0.0
Total (excluding array loss)	**13.7**	**15.4**

Table 4-2 shows the calculated wake loss for each project location as well as the total losses at each location found by combining the loss assumptions in Table 4-1 with the calculated wake losses.

Table 4-2 Total Annual Project Losses

REGION	WAKE LOSS (%)	TOTAL LOSS (%)
Arlington, OR	5.5	18.4
Goldendale, WA	6.2	19.0
Pocatello, ID	6.0	18.8
Monticello, UT	7.6	20.2
Medicine Bow, WY	5.1	19.7

4.4 ANNUAL ENERGY PRODUCTION

Black & Veatch created a model and calculated the estimated AEP for each of the five locations. The results of the AEP estimates are shown in Table 4-3. The net energy production ranges across the locations from 272.6 to 381.8 GWh per year and associated net capacity factor (CF) varies from 31.4 to 43.4 percent.

Table 4-3 Annual Energy Production

REGION	INSTALLED CAPACITY (MW)	MEAN WIND SPEED @95M (M/S)	AIR DENSITY (KG/M3)	NET AEP (GWH/YR)	NET CF (%)
Arlington, OR	100	8.0	1.17	361.9	41.3
Goldendale, WA	100	7.5	1.15	332.1	37.9
Pocatello, ID	100	7.9	1.00	334.0	38.1
Monticello, UT	100	6.9	0.96	275.3	31.4
Medicine Bow, WY	102.3	10.6	0.96	389.6	43.4

5.0 Capital Cost Estimates

Black & Veatch has estimated the capital cost required to build these projects at each location. These cost estimates are based on current industry cost data, the project conceptual designs developed in Section 3, and regional cost differences. The cost estimates include:

- Wind turbine supply and transportation
- Civil and structural works
- Electrical works
- Project substation and interconnection
- Construction indirects
- Project indirects
- Owner's costs

5.1 CAPITAL COST ESTIMATE ASSUMPTIONS

The base assumptions for the cost estimates are:

- The cost estimate represents an order of magnitude (OM) created using historic information from similar projects and recent cost trends in the U.S. wind industry.
- No detailed bill of quantities is developed or presented.
- Estimates are presented in second quarter (2Q) 2016 dollars.
- No vendor quotes were obtained for this project. The estimate is based on recent historical pricing for major original equipment manufacturers and engineered equipment. Recent vendor quotes for similar equipment are referenced where available to improve estimate accuracy.
- A 5 percent contingency has been added to turbine procurement, balance of plant, erection, and transportation costs.
- Development costs include costs such as wind monitoring, energy assessment, consulting, permitting, environmental review, cultural resources inventory, logistics analysis, surveying, land leasing/acquisition and related development costs.
- The baseline owner's costs include PacifiCorp construction management and Owner's Engineering services from a third party engineering firm.
- A placeholder exists for PacifiCorp Owner's Costs. This line item is to represent costs such as AFUDC, Capital Surcharge, Escalation and Property Tax during construction.
- The following estimates include tax: wind turbine cost estimate includes estimated sales tax on equipment based on the state. Sales tax was also applied to 40 percent of the BOP cost estimate.
- Construction labor estimates are based on a fifty-hour work week and labor is assumed to be closed shop.

5.2 LIMITS OF THE COST ESTIMATES

The limits of the cost estimate are generally all equipment and construction within the project boundary up to the connection to the transmission line on the high voltage side of the project. Specifically, the capital cost estimate includes:

- Wind turbine generator purchase, transportation, erection, mechanical completion, and obstruction lighting.
- Initial spare parts inventory purchase
- Power curve testing
- SCADA software and hardware
- All on-site civil works, including clearing, grubbing, grading, storm water management, turbine foundations, permanent access roads, crane walks, temporary turnarounds, and related work.
- All on-site electrical works, including padmount transformers, turbine switchgear, underground and overhead 34.5 kV collection cable, trenches, and structures.
- One project on-site collection system substation, including switches, breakers, transformers, low and high voltage buses, and capacitor banks.
- All engineering required for on-site works
- Temporary construction facilities
- One permanent operations & maintenance building
- Two permanent meteorological towers
- One permanent cellular or microwave communications tower
- Interconnection facilities
- Owner's development costs including Incidental Take Permit (ITP)
- Owner's project team costs

The capital cost estimate specifically excludes the following:

- Public road modifications, improvements, or repairs between public highways and the project site entrance.
- Any transmission line costs, including engineering, procurement, or construction, between the on-site project substation and interconnection point. The presented costs do include a high voltage slack line connection assuming an adjacent project substation and interconnection point.

5.3 CAPITAL COST ESTIMATE RESULTS

The baseline cost estimates are for the Wyoming region. A regional multiplier for labor costs was included for the project estimates for Arlington, OR and Goldendale, WA due to strong union work force and higher labor rates. This results in three cost estimate groups: Oregon and Washington, Idaho and Utah, and Wyoming. The multiplier is assumed to be a 40 percent increase in labor rates which is applied to 20 percent of the cost of line items requiring labor which amounts to an effective multiplier of 1.08 on those items. More detailed cost estimates are included in the appendix and a summary of the cost estimates is shown in Table 5-1. Capital costs for each site are broken down in Table 5-2 through Table 5-6. Full estimates are included in the Appendix.

The Medicine Bow location shows the lowest installed cost per kW due to the smaller site area associated with using the larger capacity Vestas V112-3.3. Overall the cost of the larger turbines is higher but the cost of the balance of plant (BOP) is lower due to the smaller overall project size giving shorter access roads and collection systems. Overall the total installed cost ranges from $1,725 per kW to $1,800 per kW.

These capital costs are considered order of magnitude, and have an estimated accuracy of approximately +/- 30%. Actual costs will vary depending on location due to site-specific layout, terrain, accessibility and other factors which affect the cost of construction.

Table 5-1 Project Capital and O&M Cost Summary

REGION	TURBINE MODEL	CAPACITY (MW)	TOTAL CAPITAL COST (USD)	CAPITAL COST (USD PER KW)
Arlington, OR	V100-2.0	100	176,850,000	1,769
Goldendale, WA	V100-2.0	100	179,300,000	1,793
Pocatello, ID	V100-2.0	100	180,000,000	1,800
Monticello, UT	V100-2.0	100	172,500,000	1,725
Medicine Bow, WY	V112-3.3	102.3	182,500,000	1,784

Table 5-2 Arlington, OR Cost Breakdown

CATEGORY	COST, $	COST, $/KW
Wind Turbine Supply, Transportation	$103,900,000	$1,039
Balance of Plant Construction	$45,750,000	$458
Project Substation and Interconnection	$10,500,000	$105
Owner's Costs	$16,700,000	$167
Total	**$176,850,000**	**$1,769**

Table 5-3 Goldendale, WA Cost Breakdown

CATEGORY	COST, $	COST, $/KW
Wind Turbine Supply, Transportation	$105,800,000	$1,058
Balance of Plant Construction	$46,100,000	$461
Project Substation and Interconnection	$10,600,000	$106
Owner's Costs	$16,800,000	$168
Total	**$179,300,000**	**$1,793**

Table 5-4 Pocatello, ID Cost Breakdown

CATEGORY	COST, $	COST, $/KW
Wind Turbine Supply, Transportation	$109,700,000	$1,097
Balance of Plant Construction	$43,400,000	$434
Project Substation and Interconnection	$10,000,000	$100
Owner's Costs	$16,900,000	$169
Total	**$180,000,000**	**$1,800**

Table 5-5 Monticello, UT Cost Breakdown

CATEGORY	COST, $	COST, $/KW
Wind Turbine Supply, Transportation	$103,900,000	$1,039
Balance of Plant Construction	$42,400,000	$424
Project Substation and Interconnection	$9,700,000	$97
Owner's Costs	$16,500,000	$165
Total	**$172,500,000**	**$1,725**

Table 5-6 Medicine Bow, WY Cost Breakdown

CATEGORY	COST, $	COST, $/KW
Wind Turbine Supply, Transportation	$123,500,000	$1,207
Balance of Plant Construction	32,100,000	$314
Project Substation and Interconnection	$10,000,000	$97
Owner's Costs	$17,000,000	$166
Total	**$182,500,000**	**$1,784**

6.0 Operations & Maintenance Cost Estimates

In additional to preparing the capital cost estimates, Black & Veatch prepared an operations and maintenance (O&M, or OPEX) cost estimate for the reviewed projects. Estimates include an initial Year 1 estimate, and annual operating cost estimates over an assumed 25 year project life.

6.1 OPERATING COST ASSUMPTIONS

To prepare the operating cost estimate, Black & Veatch made the following assumptions:

- PacifiCorp will engage the turbine vendor for a 5 year full service and maintenance agreement for all wind turbine service at a fixed annual per-turbine fee. This agreement includes all scheduled and unscheduled maintenance, spare parts, consumables, and turbine vendor labor. The service agreement includes 24/7 remote monitoring and monthly data reporting.
- After year 5, PacifiCorp will hire a third party turbine maintenance contract, most likely as part of a fleet-wide service contract. Expected savings in scheduled maintenance costs are assumed to be offset by increased usage and cost of spare parts and unscheduled maintenance.
- Balance of plant O&M services include access road, collection system, and substation maintenance, and will be performed by a third party contractor on a fixed fee annual contract basis.
- The project will include two years of post-construction environmental monitoring, consisting of one full time monitor with office support.
- Incidental Take Permit (ITP) related costs are assumed to be $250,000 per year.
- PacifiCorp staff will include one full time project manager and one project engineer with an average annual cost including overhead of $150,000 per year. All other personnel costs including wind turbine technicians are included in the third party service & maintenance contracts.
- Asset management will be on a fixed fee annual basis, estimated at approximately $300,000 per year.
- Project lease payments are based on a fixed fee per-turbine basis.
- Property tax payments are not included in the operating cost estimate.
- A 5 percent contingency is applied to all project operating costs.

6.2 YEAR ONE OPERATING COST

The estimated year one project operations and maintenance cost for the baseline Vestas V100-2.0 projects are summarized in Table 6-1.

Table 6-2 shows the estimated costs for the Medicine Bow V112-3.3 project, which has fewer turbines but a higher per-turbine cost. The Medicine Bow project also includes a $1/MWh Wyoming Production Tax as an operating cost.

Table 6-1 Year One Operating Cost, Vestas V100-2.0 MW Projects

CATEGORY	YEAR 1 COST	FIXED COST $/KW-YR	VARIABLE COST $/MWH
Turbine service agreement	$2,125,000	$21.25	$0.00
Balance of plant O&M	$400,000	$4.00	$0.00
Post-construction monitoring	$150,000	$1.50	$0.00
PacifiCorp employees	$150,000	$1.50	$0.00
Asset management	$300,000	$3.00	$0.00
Insurance	$500,000	$5.00	$0.00
Utilities	$100,000	$1.00	$0.00
Telecommunications	$50,000	$0.50	$0.00
Consultants, forecasting	$250,000	$2.50	$0.00
Land lease	$625,000	$6.25	$0.00
Incidental Take Permit	$250,000	$2.50	$0.00
Contingency (5%)	$245,000	$2.45	$0.00
Total	**$5,145,000**	**$51.45**	**$0.00**

Table 6-2 Year One Operating Cost, Vestas V112-3.3 MW Project

CATEGORY	YEAR 1 COST	FIXED COST $/KW-YR	VARIABLE COST $/MWH
Turbine service agreement	$2,015,000	$19.70	$0.00
Balance of plant O&M	$400,000	$3.91	$0.00
Post-construction monitoring	$150,000	$1.47	$0.00
PacifiCorp employees	$150,000	$1.47	$0.00
Asset management	$300,000	$2.93	$0.00
Insurance	$500,000	$4.89	$0.00
Utilities	$100,000	$0.98	$0.00
Telecommunications	$50,000	$0.49	$0.00
Consultants, forecasting	$250,000	$2.44	$0.00
Land lease	$625,000	$6.11	$0.00
Wind generation tax	$388,000	$0.00	$1.00
Incidental Take Permit	$250,000	$2.44	$0.00
Contingency (5%)	$258,900	$2.35	$0.05
Total	**$5,436,900**	**$49.16**	**$1.05**

7.0 Future Capital Cost Glide Path

This section provides a glide-path analysis of wind turbine project (100 MW) costs through 2026. It presents a concise review of the latest sources for capital cost projections for wind projects as estimated by several of the top publically available resources within the US. As part of this review, Black & Veatch assessed the latest reports from the U.S Energy Information Administration ("EIA"), the U.S Department of Energy ("DOE"), and the National Renewable Energy Laboratory ("NREL"). The following documents from each of the resource were reviewed as part of this effort.

7.1 REPORTS REVIEWED

- EIA – Annual Energy Outlook 2015 (AEO2015): Evaluates prospective energy capacity changes by technologies in light of changing markets and the overarching balance between all energy sources. Projections are through 2040. Black & Veatch did not directly utilized this source, thought it was found to lend support to other projections used. Black & Veatch also held a live phone discussion with an AEO2015 author on May 10, 2016.

DOE – Wind Vision (2015): The DOE Wind Vision report is a comprehensive review of the state of the U.S wind industry as of January 2015. It uses the ReEDS model in order to project future wind energy installations and the corresponding cost and performance metrics that contribute. Projections are through 2050. Black & Veatch considers Wind Vision to be the highest standing cost projection currently available and utilized its optimal case CAPEX tending as part of this analysis. Black & Veatch also held a live phone discussion with a Wind Vision author on May 11, 2016.

- DOE – 2014 Wind Technologies Market Report: Historical analysis of the wind industry from inception to reporting date. Provided actual historical CAPEX fluctuation through time and opines as to reasoning for past changes. Black & Veatch reviewed historical relations presented in this document between annual capacity demand and overall cost changes from 2001 through 2013. A broadly applicable relationship was found indicating that high turbine demand influences cost increases.
- NREL – Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions: Evaluates the impact of the revised PTC extension structure on results provided by sources like Wind Vision. This source provides an estimation of how installed capacity projections will be affected by the new PTC declination strategy. Black & Veatch utilized newly presented wind capacity install projection from 2017 through 2023 in conjunction with the above relationship in order to estimate the influence of PTC declination on turbine costs.

7.2 CAPITAL COST GLIDE PATH

The results of the literature review are a composite cost glide path considering valuable information provided by three of the four evaluated sources. In referencing industry experience and in the 2014 Wind Market Technologies report, Black & Veatch considered turbine costs to be the predominant driver of overall CAPEX fluctuation. The cost glide path therefore anticipates that construction and financing costs associating with projects will remain essentially constant through 2026. Turbine costs, however, have influenced by demand external and are subject to material costs. The resulting glide path cost estimation is presented below in Table 7-1.

The values in this table represent typical U.S. wind industry costs, and are not specific to the five conceptual projects evaluated for this report. All costs are presented in nominal 2016 dollars with no escalation.

Table 7-1 10 Year 100 MW Wind Cost Glide Path

YEAR	CAPITAL COST ($/KW)				TOTAL (% OF 2016)
	TURBINE	CONSTRUCTION	FINANCING	TOTAL	
2016	$1,279	$325	$145	$1,749	100%

2017	$1,427	$325	$145	$1,897	108%
2018	$1,577	$325	$145	$2,047	117%
2019	$1,397	$325	$145	$1,867	107%
2020	$1,214	$325	$145	$1,684	96%
2021	$1,066	$325	$145	$1,536	88%
2022	$920	$325	$145	$1,390	79%
2023	$947	$325	$145	$1,417	81%
2024	$1,115	$325	$145	$1,585	91%
2025	$1,253	$325	$145	$1,723	99%
2026	$1,248	$325	$145	$1,718	98%

Black & Veatch notes that although price increases are plausible over the next 10 years, LCOE is expected to continue to decline on average. It is anticipated that gains from PTC extensions in tandem with capacity factor improvements will in general outweigh the potential cost increases for turbine equipment.

Appendix A. Detailed Capital Cost Estimates

Project Name	**Pacificorp 2017 IRP**
Project Location	**Arlington, OR**
Capacity (MW)	**100**
Wind Turbine	**Vestas V100-2.0**
Capacity per Turbine (MW)	**2**
Number of Turbines	**50**
Number of Met Towers	**1**
Number of O&M Buildings	**1**

Cost Breakdown		***Base Cost***	***Per***	***Quantity***	***Regional Multiplier***
Balance of Plant					
Civil & Structural Works					
Access Roads	$3,703,968	*$60*	*LF*	*57,160*	*1.08*
Laydown Yard and Substation	$324,000	*$300,000*	*Project*	*1*	*1.08*
Crane Pads and WTG Site Prep	$1,350,000	*$25,000*	*WTG*	*50*	*1.08*
Site Drainage and Erosion Control	$1,944,000	*$1,800,000*	*Project*	*1*	*1.08*
WTG Foundations	$16,200,000	*$300,000*	*WTG*	*50*	*1.08*
Met Tower Installation	$648,000	*$300,000*	*Met Tower*	*2*	*1.08*
O&M Building - EPC	$432,000	*$400,000*	*Building*	*1*	*1.08*
Wind Turbine Erection	$9,450,000	*$175,000*	*WTG*	*50*	*1.08*
Electrical Works					
WTG Grounding	$810,000	*$15,000*	*WTG*	*50*	*1.08*
WTG Tower Wiring	$810,000	*$15,000*	*WTG*	*50*	*1.08*
Collection System - Materials & Construction (All underground)	$4,172,548	*$65*	*LF*	*59,438*	*1.08*
3rd Party PD Testing	$43,200	*$40,000*	*Project*	*1*	*1.08*
Misc. Construction Indirects					
Temporary Construction Facilities & Services	$1,620,000	*$1,500,000*	*Project*	*1*	*1.08*
WTG Commissioning Support	$540,000	*$10,000*	*WTG*	*50*	*1.08*
Site Mob/Demob	$540,000	*$500,000*	*Project*	*1*	*1.08*
Project Indirects					
BOP Engineering & Studies (3%)	$1,195,335	*3%*	*Project*	*1*	*1.00*
Construction Management (4%)	$1,595,509	*4%*	*Project*	*1*	*1.00*
Field Geotechnical Studies	$378,000	*$350,000*	*Project*	*1*	*1.08*
BOP Sales tax (0%)	$0	*0.0%*	*Project*	*1*	*1.00*
Total Balance of Plant	**$45,756,560**				
Wind Turbines					
Turbine Supply	$95,000,000	*$1,900,000*	*WTG*	*50*	*1.00*
Turbine Transportation	$7,500,000	*$150,000*	*WTG*	*50*	*1.00*
Recommended Spare Parts	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
Power Curve Verification	$300,000	*$300,000*	*Project*	*1*	*1.00*
Backfeed Power During Commissioning	$100,000	*$100,000*	*Project*	*1*	*1.00*
Wind Turbine Sales tax (0%)	$0	*0%*	*Project*	*1*	*1.00*
Total Wind Turbines	**$103,900,000**				
Project Substation and Interconnection					
Low Voltage Side Facilities	$2,160,000	*$2,000,000*	*Substation*	*1*	*1.08*
Main GSU	$4,320,000	*$4,000,000*	*Substation*	*1*	*1.08*
High Voltage Side Facilities	$3,240,000	*$3,000,000*	*Substation*	*1*	*1.08*
Substation Engineering and Studies (8%)	$777,600	*8%*	*Substation*	*1*	*1.00*
Project Substation Sales tax (0%)	$0	*0%*	*Substation*	*1*	*1.00*
Total Project Substation, Interconnection and Network Upgrades	**$10,497,600**				
Owners Costs					
Owner's Contingency (7%)	$8,007,708	*5%*	*Project*	*1*	*1.00*
Development Costs	$7,700,000	*$7,700,000*	*Project*	*1*	*1.08*
Owners Project Team Costs	$1,000,000	*$1,000,000*	*Project*	*1*	*1.08*
PacifiCorp Owner's Cost (AFUDC, Capital Surcharge, Escalation and Property Tax during co	$0	*$0*	*Project*	*1*	*1.00*
Total Owner's Costs	**$16,707,708**				

Project Totals

Category	
Balance of Plant	$45,756,560
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	$103,900,000
Project Substation and Interconnection	$10,497,600
Estimate of Owner's Costs	$16,707,708
TOTAL PROJECT	**$176,861,868**

Category	***($/kW)***
Balance of Plant	*$458*
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	*$1,039*
Project Substation and Interconnection	*$105*
Estimate of Owner's Costs	*$167*
TOTAL PROJECT	***$1,769***

ESTIMATE ACCURACY	**Accuracy Range (-/+)**		**Low**	**Base**	**High**
Balance of Plant	-30%	30%	$ 32,029,592	$ 45,756,560	$ 59,483,528
Wind Turbines	-30%	30%	$ 72,730,000	$ 103,900,000	$ 135,070,000
Project Substation	-30%	30%	$ 7,348,320	$ 10,497,600	$ 13,646,880
Estimate of Owner's Costs	-30%	30%	$ 11,695,396	$ 16,707,708	$ 21,720,020
TOTAL PROJECT	**-30%**	**30%**	**$ 123,803,307**	**$ 176,861,868**	**$ 229,920,428**

Project Name	**Pacificorp 2017 IRP**
Project Location	**Goldendale, WA**
Capacity (MW)	**100**
Wind Turbine	**Vestas V100-2.0**
Capacity per Turbine (MW)	**2**
Number of Turbines	**50**
Number of Met Towers	**1**
Number of O&M Buildings	**1**

Cost Breakdown		***Base Cost***	***Per***	***Quantity***	***Regional Multiplier***
Balance of Plant					
Civil & Structural Works					
Access Roads	$3,703,968	*$60*	*LF*	*57,160*	*1.08*
Laydown Yard and Substation	$324,000	*$300,000*	*Project*	*1*	*1.08*
Crane Pads and WTG Site Prep	$1,350,000	*$25,000*	*WTG*	*50*	*1.08*
Site Drainage and Erosion Control	$1,944,000	*$1,800,000*	*Project*	*1*	*1.08*
WTG Foundations	$16,200,000	*$300,000*	*WTG*	*50*	*1.08*
Met Tower Installation	$648,000	*$300,000*	*Met Tower*	*2*	*1.08*
O&M Building - EPC	$432,000	*$400,000*	*Building*	*1*	*1.08*
Wind Turbine Erection	$9,450,000	*$175,000*	*WTG*	*50*	*1.08*
Electrical Works					
WTG Grounding	$810,000	*$15,000*	*WTG*	*50*	*1.08*
WTG Tower Wiring	$810,000	*$15,000*	*WTG*	*50*	*1.08*
Collection System - Materials & Construction (All underground)	$4,172,548	*$65*	*LF*	*59,438*	*1.08*
3rd Party PD Testing	$43,200	*$40,000*	*Project*	*1*	*1.08*
Misc. Construction Indirects					
Temporary Construction Facilities & Services	$1,620,000	*$1,500,000*	*Project*	*1*	*1.08*
WTG Commissioning Support	$540,000	*$10,000*	*WTG*	*50*	*1.08*
Site Mob/Demob	$540,000	*$500,000*	*Project*	*1*	*1.08*
Project Indirects					
BOP Engineering & Studies (3%)	$1,195,335	*3%*	*Project*	*1*	*1.00*
Construction Management (4%)	$1,595,509	*4%*	*Project*	*1*	*1.00*
Field Geotechnical Studies	$378,000	*$350,000*	*Project*	*1*	*1.08*
BOP Sales tax (2.025% on 40% of BOP Cost or 0.81%)	$370,628	*0.81%*	*Project*	*1*	*1.00*
Total Balance of Plant	**$46,127,188**				
Wind Turbines					
Turbine Supply	$95,000,000	*$1,900,000*	*WTG*	*50*	*1.00*
Turbine Transportation	$7,500,000	*$150,000*	*WTG*	*50*	*1.00*
Recommended Spare Parts	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
Power Curve Verification	$300,000	*$300,000*	*Project*	*1*	*1.00*
Backfeed Power During Commissioning	$100,000	*$100,000*	*Project*	*1*	*1.00*
Wind Turbine Sales tax (2.025% on turbines)	$1,944,000	*2.025%*	*Project*	*1*	*1.00*
Total Wind Turbines	**$105,844,000**				
Project Substation and Interconnection					
Low Voltage Side Facilities	$2,160,000	*$2,000,000*	*Substation*	*1*	*1.08*
Main GSU	$4,320,000	*$4,000,000*	*Substation*	*1*	*1.08*
High Voltage Side Facilities	$3,240,000	*$3,000,000*	*Substation*	*1*	*1.08*
Substation Engineering and Studies (8%)	$777,600	*8%*	*Substation*	*1*	*1.00*
Project Substation Sales tax (2.025% on equipment)	$87,480	*2.025%*	*Substation*	*1*	*1.00*
Total Project Substation, Interconnection and Network Upgrades	**$10,585,080**				
Owners Costs					
Owner's Contingency (7%)	$8,127,813	*5%*	*Project*	*1*	*1.00*
Development Costs	$7,700,000	*$7,700,000*	*Project*	*1*	*1.08*
Owners Project Team Costs	$1,000,000	*$1,000,000*	*Project*	*1*	*1.08*
PacifiCorp Owner's Cost (AFUDC, Capital Surcharge, Escalation and Property Tax during co	$0	*$0*	*Project*	*1*	*1.00*
Total Owner's Costs	**$16,827,813**				

Project Totals	
Category	
Balance of Plant	$46,127,188
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	$105,844,000
Project Substation and Interconnection	$10,585,080
Estimate of Owner's Costs	$16,827,813
TOTAL PROJECT	**$179,384,081**

Category	***($/kW)***
Balance of Plant	*$461*
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	*$1,058*
Project Substation and Interconnection	*$106*
Estimate of Owner's Costs	*$168*
TOTAL PROJECT	***$1,794***

ESTIMATE ACCURACY	**Accuracy Range (-/+)**		**Low**	**Base**	**High**
Balance of Plant	-30%	30%	$ 32,289,031	$ 46,127,188	$ 59,965,344
Wind Turbines	-30%	30%	$ 74,090,800	$ 105,844,000	$ 137,597,200
Project Substation	-30%	30%	$ 7,409,556	$ 10,585,080	$ 13,760,604
Estimate of Owner's Costs	-30%	30%	$ 11,779,469	$ 16,827,813	$ 21,876,157
TOTAL PROJECT	**-30%**	**30%**	**$ 125,568,857**	**$ 179,384,081**	**$ 233,199,306**

Project Name	**Pacificorp 2017 IRP**
Project Location	**Pocatello, ID**
Capacity (MW)	**100**
Wind Turbine	**Vestas V100-2.0**
Capacity per Turbine (MW)	**2**
Number of Turbines	**50**
Number of Met Towers	**1**
Number of O&M Buildings	**1**

Cost Breakdown		***Base Cost***	***Per***	***Quantity***	***Regional Multiplier***
Balance of Plant					
Civil & Structural Works					
Access Roads	$3,429,600	*$60*	*LF*	*57,160*	*1.00*
Laydown Yard and Substation	$300,000	*$300,000*	*Project*	*1*	*1.00*
Crane Pads and WTG Site Prep	$1,250,000	*$25,000*	*WTG*	*50*	*1.00*
Site Drainage and Erosion Control	$1,800,000	*$1,800,000*	*Project*	*1*	*1.00*
WTG Foundations	$15,000,000	*$300,000*	*WTG*	*50*	*1.00*
Met Tower Installation	$600,000	*$300,000*	*Met Tower*	*2*	*1.00*
O&M Building - EPC	$400,000	*$400,000*	*Building*	*1*	*1.00*
Wind Turbine Erection	$8,750,000	*$175,000*	*WTG*	*50*	*1.00*
Electrical Works					
WTG Grounding	$750,000	*$15,000*	*WTG*	*50*	*1.00*
WTG Tower Wiring	$750,000	*$15,000*	*WTG*	*50*	*1.00*
Collection System - Materials & Construction (All underground)	$3,863,470	*$65*	*LF*	*59,438*	*1.00*
3rd Party PD Testing	$40,000	*$40,000*	*Project*	*1*	*1.00*
Misc. Construction Indirects					
Temporary Construction Facilities & Services	$1,500,000	*$1,500,000*	*Project*	*1*	*1.00*
WTG Commissioning Support	$500,000	*$10,000*	*WTG*	*50*	*1.00*
Site Mob/Demob	$500,000	*$500,000*	*Project*	*1*	*1.00*
Project Indirects					
BOP Engineering & Studies (3%)	$1,106,792	*3%*	*Project*	*1*	*1.00*
Construction Management (4%)	$1,477,323	*4%*	*Project*	*1*	*1.00*
Field Geotechnical Studies	$350,000	*$350,000*	*Project*	*1*	*1.00*
BOP Sales tax (6% of 40% of Total BOP or 2.4% of Total BOP)	$1,016,812	*2.4%*	*Project*	*1*	*1.00*
Total Balance of Plant	**$43,383,997**				
Wind Turbines					
Turbine Supply	$95,000,000	*$1,900,000*	*WTG*	*50*	*1.00*
Turbine Transportation	$7,500,000	*$150,000*	*WTG*	*50*	*1.00*
Recommended Spare Parts	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
Power Curve Verification	$300,000	*$300,000*	*Project*	*1*	*1.00*
Backfeed Power During Commissioning	$100,000	*$100,000*	*Project*	*1*	*1.00*
Wind Turbine Sales tax (6% on equipment)	$5,760,000	*6%*	*Project*	*1*	*1.00*
Total Wind Turbines	**$109,660,000**				
Project Substation and Interconnection					
Low Voltage Side Facilities	$2,000,000	*$2,000,000*	*Substation*	*1*	*1.00*
Main GSU	$4,000,000	*$4,000,000*	*Substation*	*1*	*1.00*
High Voltage Side Facilities	$3,000,000	*$3,000,000*	*Substation*	*1*	*1.00*
Substation Engineering and Studies (8%)	$720,000	*8%*	*Substation*	*1*	*1.00*
Project Substation Sales tax (6% on equipment)	$240,000	*6%*	*Substation*	*1*	*1.00*
Total Project Substation, Interconnection and Network Upgrades	**$9,960,000**				
Owners Costs					
Owner's Contingency (7%)	$8,150,200	*5%*	*Project*	*1*	*1.00*
Development Costs	$7,700,000	*$7,700,000*	*Project*	*1*	*1.00*
Owners Project Team Costs	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
PacifiCorp Owner's Cost (AFUDC, Capital Surcharge, Escalation and Property Tax during cc	$0	*$0*	*Project*	*1*	*1.00*
Total Owner's Costs	**$16,850,200**				

Project Totals

Category	
Balance of Plant	$43,383,997
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	$109,660,000
Project Substation and Interconnection	$9,960,000
Estimate of Owner's Costs	$16,850,200
TOTAL PROJECT	**$179,854,197**

Category	***($/kW)***
Balance of Plant	*$434*
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	*$1,097*
Project Substation and Interconnection	*$100*
Estimate of Owner's Costs	*$169*
TOTAL PROJECT	***$1,799***

ESTIMATE ACCURACY	**Accuracy Range (-/+)**			**Low**		**Base**		**High**
Balance of Plant	-30%	30%	$	30,368,798	$	43,383,997	$	56,399,197
Wind Turbines	-30%	30%	$	76,762,000	$	109,660,000	$	142,558,000
Project Substation	-30%	30%	$	6,972,000	$	9,960,000	$	12,948,000
Estimate of Owner's Costs	-30%	30%	$	11,795,140	$	16,850,200	$	21,905,260
TOTAL PROJECT	**-30%**	**30%**	**$**	**125,897,938**	**$**	**179,854,197**	**$**	**233,810,456**

Project Name	**Pacificorp 2017 IRP**
Project Location	**Monticello, UT**
Capacity (MW)	**100**
Wind Turbine	**Vestas V100-2.0**
Capacity per Turbine (MW)	**2**
Number of Turbines	**50**
Number of Met Towers	**1**
Number of O&M Buildings	**1**

Cost Breakdown		***Base Cost***	***Per***	***Quantity***	***Regional Multiplier***
Balance of Plant					
Civil & Structural Works					
Access Roads	$3,429,600	*$60*	*LF*	*57,160*	*1.00*
Laydown Yard and Substation	$300,000	*$300,000*	*Project*	*1*	*1.00*
Crane Pads and WTG Site Prep	$1,250,000	*$25,000*	*WTG*	*50*	*1.00*
Site Drainage and Erosion Control	$1,800,000	*$1,800,000*	*Project*	*1*	*1.00*
WTG Foundations	$15,000,000	*$300,000*	*WTG*	*50*	*1.00*
Met Tower Installation	$600,000	*$300,000*	*Met Tower*	*2*	*1.00*
O&M Building - EPC	$400,000	*$400,000*	*Building*	*1*	*1.00*
Wind Turbine Erection	$8,750,000	*$175,000*	*WTG*	*50*	*1.00*
Electrical Works					
WTG Grounding	$750,000	*$15,000*	*WTG*	*50*	*1.00*
WTG Tower Wiring	$750,000	*$15,000*	*WTG*	*50*	*1.00*
Collection System - Materials & Construction (All underground)	$3,863,470	*$65*	*LF*	*59,438*	*1.00*
3rd Party PD Testing	$40,000	*$40,000*	*Project*	*1*	*1.00*
Misc. Construction Indirects					
Temporary Construction Facilities & Services	$1,500,000	*$1,500,000*	*Project*	*1*	*1.00*
WTG Commissioning Support	$500,000	*$10,000*	*WTG*	*50*	*1.00*
Site Mob/Demob	$500,000	*$500,000*	*Project*	*1*	*1.00*
Project Indirects					
BOP Engineering & Studies (3%)	$1,106,792	*3%*	*Project*	*1*	*1.00*
Construction Management (4%)	$1,477,323	*4%*	*Project*	*1*	*1.00*
Field Geotechnical Studies	$350,000	*$350,000*	*Project*	*1*	*1.00*
BOP Sales tax (0%)	$0	*0.0%*	*Project*	*1*	*1.00*
Total Balance of Plant	**$42,367,185**				
Wind Turbines					
Turbine Supply	$95,000,000	*$1,900,000*	*WTG*	*50*	*1.00*
Turbine Transportation	$7,500,000	*$150,000*	*WTG*	*50*	*1.00*
Recommended Spare Parts	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
Power Curve Verification	$300,000	*$300,000*	*Project*	*1*	*1.00*
Backfeed Power During Commissioning	$100,000	*$100,000*	*Project*	*1*	*1.00*
Wind Turbine Sales tax (0%)	$0	*0%*	*Project*	*1*	*1.00*
Total Wind Turbines	**$103,900,000**				
Project Substation and Interconnection					
Low Voltage Side Facilities	$2,000,000	*$2,000,000*	*Substation*	*1*	*1.00*
Main GSU	$4,000,000	*$4,000,000*	*Substation*	*1*	*1.00*
High Voltage Side Facilities	$3,000,000	*$3,000,000*	*Substation*	*1*	*1.00*
Substation Engineering and Studies (8%)	$720,000	*8%*	*Substation*	*1*	*1.00*
Project Substation Sales tax (0%)	$0	*0%*	*Substation*	*1*	*1.00*
Total Project Substation, Interconnection and Network Upgrades	**$9,720,000**				
Owners Costs					
Owner's Contingency (7%)	$7,799,359	*5%*	*Project*	*1*	*1.00*
Development Costs	$7,700,000	*$7,700,000*	*Project*	*1*	*1.00*
Owners Project Team Costs	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
PacifiCorp Owner's Cost (AFUDC, Capital Surcharge, Escalation and Property Tax during co	$0	*$0*	*Project*	*1*	*1.00*
Total Owner's Costs	**$16,499,359**				

Project Totals

Category	
Balance of Plant	$42,367,185
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	$103,900,000
Project Substation and Interconnection	$9,720,000
Estimate of Owner's Costs	$16,499,359
TOTAL PROJECT	**$172,486,544**

Category	***($/kW)***
Balance of Plant	*$424*
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	*$1,039*
Project Substation and Interconnection	*$97*
Estimate of Owner's Costs	*$165*
TOTAL PROJECT	***$1,725***

ESTIMATE ACCURACY	**Accuracy Range (-/+)**		**Low**	**Base**	**High**
Balance of Plant	-30%	30%	$ 29,657,029	$ 42,367,185	$ 55,077,340
Wind Turbines	-30%	30%	$ 72,730,000	$ 103,900,000	$ 135,070,000
Project Substation	-30%	30%	$ 6,804,000	$ 9,720,000	$ 12,636,000
Estimate of Owner's Costs	-30%	30%	$ 11,549,551	$ 16,499,359	$ 21,449,167
TOTAL PROJECT	**-30%**	**30%**	**$ 120,740,581**	**$ 172,486,544**	**$ 224,232,507**

Project Name	**Pacificorp 2017 IRP**
Project Location	**Medicine Bow, WY**
Capacity (MW)	**102.3**
Wind Turbine	**Vestas V112-3.3**
Capacity per Turbine (MW)	**3.3**
Number of Turbines	**31**
Number of Met Towers	**1**
Number of O&M Buildings	**1**

Cost Breakdown		***Base Cost***	***Per***	***Quantity***	***Regional Multiplier***
Balance of Plant					
Civil & Structural Works					
Access Roads	$2,352,480	*$60*	*LF*	*39,208*	*1.00*
Laydown Yard and Substation	$300,000	*$300,000*	*Project*	*1*	*1.00*
Crane Pads and WTG Site Prep	$930,000	*$30,000*	*WTG*	*31*	*1.00*
Site Drainage and Erosion Control	$1,500,000	*$1,500,000*	*Project*	*1*	*1.00*
WTG Foundations	$10,850,000	*$350,000*	*WTG*	*31*	*1.00*
Met Tower Installation	$600,000	*$300,000*	*Met Tower*	*2*	*1.00*
O&M Building - EPC	$400,000	*$400,000*	*Building*	*1*	*1.00*
Wind Turbine Erection	$6,200,000	*$200,000*	*WTG*	*31*	*1.00*
Electrical Works					
WTG Grounding	$558,000	*$18,000*	*WTG*	*31*	*1.00*
WTG Tower Wiring	$558,000	*$18,000*	*WTG*	*31*	*1.00*
Collection System - Materials & Construction (All underground)	$2,615,275	*$65*	*LF*	*40,235*	*1.00*
3rd Party PD Testing	$40,000	*$40,000*	*Project*	*1*	*1.00*
Misc. Construction Indirects					
Temporary Construction Facilities & Services	$1,500,000	*$1,500,000*	*Project*	*1*	*1.00*
WTG Commissioning Support	$310,000	*$10,000*	*WTG*	*31*	*1.00*
Site Mob/Demob	$500,000	*$500,000*	*Project*	*1*	*1.00*
Project Indirects					
BOP Engineering & Studies (3%)	$805,913	*3%*	*Project*	*1*	*1.00*
Construction Management (4%)	$1,076,150	*4%*	*Project*	*1*	*1.00*
Field Geotechnical Studies	$300,000	*$300,000*	*Project*	*1*	*1.00*
BOP Sales tax (6% of 40% of Total BOP or 2.4% of Total BOP)	$753,500	*2.4%*	*Project*	*1*	*1.00*
Total Balance of Plant	**$32,149,317**				
Wind Turbines					
Turbine Supply	$109,972,500	*$3,547,500*	*WTG*	*31*	*1.00*
Turbine Transportation	$5,425,000	*$175,000*	*WTG*	*31*	*1.00*
Recommended Spare Parts	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
Power Curve Verification	$300,000	*$300,000*	*Project*	*1*	*1.00*
Backfeed Power During Commissioning	$100,000	*$100,000*	*Project*	*1*	*1.00*
Wind Turbine Sales tax (6% on equipment)	$6,658,350	*6%*	*Project*	*1*	*1.00*
Total Wind Turbines	**$123,455,850**				
Project Substation and Interconnection					
Low Voltage Side Facilities	$2,000,000	*$2,000,000*	*Substation*	*1*	*1.00*
Main GSU	$4,000,000	*$4,000,000*	*Substation*	*1*	*1.00*
High Voltage Side Facilities	$3,000,000	*$3,000,000*	*Substation*	*1*	*1.00*
Substation Engineering and Studies (8%)	$720,000	*8%*	*Substation*	*1*	*1.00*
Project Substation Sales tax (6% on equipment)	$240,000	*6%*	*Substation*	*1*	*1.00*
Total Project Substation, Interconnection and Network Upgrades	**$9,960,000**				
Owners Costs					
Owner's Contingency (7%)	$8,278,258	*5%*	*Project*	*1*	*1.00*
Development Costs	$7,700,000	*$7,700,000*	*Project*	*1*	*1.00*
Owners Project Team Costs	$1,000,000	*$1,000,000*	*Project*	*1*	*1.00*
PacifiCorp Owner's Cost (AFUDC, Capital Surcharge, Escalation and Property Tax during co	$0	*$0*	*Project*	*1*	*1.00*
Total Owner's Costs	**$16,978,258**				

Project Totals

Category	
Balance of Plant	$32,149,317
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	$123,455,850
Project Substation and Interconnection	$9,960,000
Estimate of Owner's Costs	$16,978,258
TOTAL PROJECT	**$182,543,426**

Category	***($/kW)***
Balance of Plant	*$314*
Wind Turbines - (Base Cost, Transportation & Optional Equipment)	*$1,207*
Project Substation and Interconnection	*$97*
Estimate of Owner's Costs	*$166*
TOTAL PROJECT	***$1,784***

ESTIMATE ACCURACY	**Accuracy Range (-/+)**		**Low**	**Base**	**High**
Balance of Plant	-30%	30%	$ 22,504,522	$ 32,149,317	$ 41,794,113
Wind Turbines	-30%	30%	$ 86,419,095	$ 123,455,850	$ 160,492,605
Project Substation	-30%	30%	$ 6,972,000	$ 9,960,000	$ 12,948,000
Estimate of Owner's Costs	-30%	30%	$ 11,884,781	$ 16,978,258	$ 22,071,736
TOTAL PROJECT	**-30%**	**30%**	**$ 127,780,398**	**$ 182,543,426**	**$ 237,306,454**