PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

December 29, 2015

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

Re: UM -___PacifiCorp's Renewable Portfolio Standard Implementation Plan 2017-2021 OAR 860-083-0400 Compliance Filing

In compliance with ORS 469A.075 and OAR 860-083-0400, please find enclosed PacifiCorp's Oregon Renewable Portfolio Standard (RPS) Implementation Plan, for the compliance years 2017-2021. Confidential and public versions of the Implementation Plan are included in this submission. Also enclosed is a compact disk containing confidential work papers associated with this filing. The confidential information is provided under the provisions of OAR 860-001-0070.

The Company has enclosed for filing a Motion for a Protective Order for this compliance filing and requests expedited consideration of this motion.

PacifiCorp respectfully requests that all data requests in this docket 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, Oregon 97232

Informal questions concerning this filing may be directed to Erin Apperson, Manager, Regulatory Affairs, at (503) 813-6642.

Sincerely,

R Bryce Dalley / eea

R. Bryce Dalley
Vice President, Regulation

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's RPS Implementation Plan on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 29th of December, 2015.

Amy Eissler
Coordinator, Regulatory Operations

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM ____

In the Matter of PacifiCorp d/b/a Pacific Power's Implementation Plan Pursuant to ORS 469A.075.	MOTION FOR PROTECTIVE ORDER

Under ORCP 36(C)(7) and OAR 860-001-0080(1), PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) moves the Public Utility Commission of Oregon (Commission) for entry of a standard protective order in this proceeding. Good cause exists to issue a protective order to protect commercially sensitive and confidential business information related to the Company's procurement of resources necessary to comply with Oregon's renewable portfolio standard (RPS).

The Commission's rules authorize PacifiCorp to seek reasonable restrictions on discovery of trade secrets and other confidential business information.[1] The Commission's standard protective order is designed to allow the broadest possible discovery consistent with the need to protect confidential information.[2] PacifiCorp expects to receive discovery requests in these proceedings, including requests for propriety cost data and models, commercially sensitive pricing information, confidential market analyses and business projections, or confidential information regarding contracts for the purchase or sale of

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[1] *See* OAR 860-001-0000(1) (adopting the Oregon Rules of Civil Procedure); ORCP 36(C)(7) (providing protection against unrestricted discovery of "trade secrets or other confidential research, development, or commercial information"). *See also In re Investigation into the Cost of Providing Telecommunication Service,* Docket UM 351, Order No. 91-500 (1991) (recognizing that protective orders are a reasonable means to protect "the rights of a party to trade secrets and other confidential commercial information" and "to facilitate the communication of information between litigants").
[2] OAR 860-001-0080(2).

electric power, power services, or fuel. PacifiCorp will be exposed to competitive injury if it is forced to make unrestricted disclosure of its confidential business information.

It is also substantially likely that the parties to these proceedings will seek to discover further information held by PacifiCorp, including confidential business information. Issuance of a protective order will facilitate the production of relevant information and expedite the discovery process.

For these reasons, PacifiCorp respectfully requests that the Commission enter its standard protective order in this docket.

Respectfully submitted this 29th day of December, 2015.

Etta Lockey
Senior Counsel
PacifiCorp d/b/a Pacific Power

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2017 through 2021

Pursuant to ORS 469A.075 and OAR 860-083-0400, PacifiCorp, d.b.a. Pacific Power (the Company or PacifiCorp), respectfully submits the 2017 through 2021 Oregon Renewable Implementation Plan (the 2017-2021 Plan) to the Public Utility Commission of Oregon (Commission), for meeting the requirements of Oregon's renewable portfolio standard (RPS). This report was prepared consistent with the standardized form adopted by Order No. 11-440.

Summary

This 2017-2021 Plan shows that the Company intends to meet Oregon RPS targets during compliance years 2017-2021 with a combination of bundled renewable energy certificates (RECs) from existing Oregon-eligible renewable resources and resources under development that are anticipated to be Oregon RPS-eligible.

The 2017-2021 Plan was prepared with information consistent with the Company's most recently filed Integrated Resource Plan (IRP) – the 2015 IRP, unless stated otherwise.[1] The Company's IRP process and its filed documentation are based on the best available information at the time the IRP was prepared. The Company's 2015 IRP action plan (2015 IRP Action Plan) represents a road map for implementation of the preferred portfolio. The 2015 IRP does not add any significant new renewable resources, beyond new qualifying facility (QF) projects, through the twenty year planning horizon ending 2034. The current economic and regulatory environments are continually changing, and the Company may modify its plans as state and federal legislation and regulations evolve. Such changes may materially impact resource acquisitions and the timing of those acquisitions.

In the 2017-2021 Plan, the Company has included renewable resources that have been acquired or are under contract and have received Oregon Department of Energy (ODOE) certification to qualify as eligible for the Oregon RPS. The Plan also includes resources under development, which upon commercial operation, are anticipated to receive certification as eligible for the Oregon RPS under ORS 469A.025. The 2017-2021 Plan also assumes that all qualifying resources will be recertified with ODOE to maintain eligibility through the 2017-2021 reporting period. As shown in the 2017-2021 Plan, the existing qualifying resources and resources under development will enable the Company to meet the 2017-2021 Oregon RPS targets. The 2017-2021 Plan does not currently assume that the Company will purchase unbundled RECs to meet RPS targets in the 2017-2021 reporting period.

Similar to the Company's previous implementation plan[2] (the 2015-2019 Plan), the 2017-2021 Plan shows that for some of the eligible resources, the expected incremental costs are positive (costs higher than a proxy resource), while for other resources, the expected incremental costs are negative (costs less than a proxy resource). However, using the methodology

[1] The Company's 2015 IRP was filed with the Commission on March 31, 2015, Docket LC 62.
[2] The Company's 2015-2019 Plan was filed with the Commission on December 26, 2013; an updated version was filed February 28, 2014, Docket UM 1681.

established by Commission-adopted rules, the 2017-2021 Plan shows that the expected incremental costs do not trigger the four percent cost limit under ORS 469A.100.

Implementation Plan

The format used in the 2017-2021 Plan is to state each subsection of OAR 860-083-0400, followed by the Company's response to each of the stated subsections.

OAR 860-083-0400(2)(a)
The annual megawatt-hour target for compliance with the applicable renewable portfolio standard based on the forecast of electricity sales to its Oregon retail electricity customers.

Response: **Table 1** below provides the estimated annual megawatt-hour (MWh) target for compliance, based on the Company's October 2015 load forecast.[2]

Table 1	2017	2018	2019	2020	2021
Applicable RPS Standard as % of Electricity Sold	15%	15%	15%	20%	20%
Estimated PacifiCorp Oregon RPS Target[3] (MWh)	1,918,995	1,933,357	1,936,736	2,576,484	2,566,252

OAR 860-083-0400(2)(b)
An accounting of the planned method to comply with the applicable renewable portfolio standard, including number of banked renewable energy certificates by year of issuance, the numbers of other bundled and unbundled renewable energy certificates, and alternative compliance payments.

Response: For the 2017-2021 Plan, the Company anticipates complying with the applicable Oregon RPS using bundled RECs. **Attachment A** provides an accounting of the RECs applicable to the Oregon RPS program.

[2] For OAR 860-083-0400(2)(a) in this 2017-2021 Plan, the Company used the October 2015 load forecast. The 2015 IRP uses the September 2014 load forecast.
[3] Refer to Attachment A.

OAR 860-083-0400(2)(c)
Identification of generating facilities, either owned by the company or under contract, that are expected to provide renewable energy certificates for compliance with renewable portfolio standard. Information on each generating facility must include: (A) the renewable energy source; (B) the year the facility or contract became operational or is expected to become operational; (C) the state where the facility is located or is planned to be located; and (D) expected annual megawatt-hour output for compliance from the facility for the compliance years covered by the implementation plan.

Response: **Table 2** below shows the generating facilities that have been certified by ODOE as eligible for the Oregon RPS program and resources that are under development and expected to be certified as eligible for the Oregon RPS program. The generating facilities, either owned by the Company or under contract, are expected to provide bundled RECs for compliance with the Oregon RPS during the 2017-2021 reporting period. However, there are additional generating facilities that may be eligible in the future, either Company owned or under contract.

Table 2 also lists the year the generating facilities became operational, or are expected to become operational, the energy source and the state where each facility is located. **Confidential Attachment B** provides Oregon's allocation of the expected annual MWh output for each resource.

Table 2

Energy Source	Generating Facility	State	Commercial Operation Year
Biogas	Hill Air Force Base (PPA)	UT	2005
Geothermal	Blundell II	UT	2007
Wind	Campbell Hill-Three Buttes (PPA)	WY	2009
	Chevron Casper Wind Farm (PPA)	WY	2009
	Combine Hills (PPA)	OR	2003
	Dunlap I	WY	2010
	Foote Creek I	WY	1999
	*Foote Creek II	WY	1999
	*Foote Creek III	WY	1999
	Glenrock I	WY	2008
	Glenrock III	WY	2009
	Goodnoe Hills	WA	2008
	High Plains	WY	2009
	*Latigo	WY	2015
	Leaning Juniper I	OR	2006
	Marengo	WA	2007
	Marengo II	WA	2008
	McFadden Ridge	WY	2009
	Mountain Wind Power (PPA)	WY	2008
	Mountain Wind Power II (PPA)	WY	2008
	*Pioneer Wind	WY	2016
	Rock River I (PPA)	WY	2001
	Seven Mile Hill I	WY	2008
	Seven Mile Hill II	WY	2008
	Top of the World (PPA)	WY	2010
	Wolverine Creek (PPA)	ID	2005
Hydro-Low Impact	Ashton	ID	1917
	Clearwater 1	OR	1953
	Clearwater 2	OR	1953
	Cutler	UT	1927
	Fish Creek	OR	1952
	Grace	ID	1923
	Lemolo 1	OR	1955
	Lemolo 2	OR	1956
	Oneida	ID	1915
	Prospect 3	OR	1932
	Slide Creek	OR	1951
	Soda	ID	1924
	Soda Springs	OR	1952
	Toketee	OR	1950

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2017 through 2021

Table 2 Energy Source	Generating Facility	State	Commercial[4] Operation Year
Hydro – Upgrades	Big Fork (Upgrade 2001)	MT	1929
	Copco 1 (Upgrade 1996)	CA	1918
	Cutler (Upgrade 2007)	UT	1927
	JC Boyle (Upgrade 2005)	OR	1958
	Lemolo 1 (Upgrade 2003)	OR	1955
	Lemolo 2 (Upgrade 2009)	OR	1956
	Oneida (Upgrade 2004)	ID	1915
	Pioneer (Upgrade 1999)	UT	1897
	Prospect 2 (Upgrade 1999)	OR	1928
	Prospect 3 (Upgrade 1997)	OR	1932
	Yale (Upgrade 1995/1996)	WA	1953
Oregon Solar Capacity Standard	Black Cap[5]	OR	2012
Oregon Solar Incentive Program	*Bourdet	OR	2014
	*Bourdet II	OR	2016
	*Conf. Tribes - Warm Springs (CTWS)	OR	2014
	*Crook County Solar	OR	2014
	Joseph Community Solar	OR	2011
	Lakeview	OR	2012
	*Lakeview II	OR	2013
	*Powell Butte Solar	OR	2014
	Solwatt	OR	2011
	*Solwatt II	OR	2014
	Aggregated Solar Block (CO 1)	OR	2010
	Aggregated Solar Block (CO 2)	OR	2011
	Aggregated Solar Block (CO 3)	OR	2013
	Aggregated Solar Block (CR 1)	OR	2011
	*Aggregated Solar Block (CR 2)	OR	2014
	Aggregated Solar Block (EO 1)	OR	2010
	Aggregated Solar Block (EO 2)	OR	2011
	Aggregated Solar Block (PO 1)	OR	2010
	Aggregated Solar Block (PO 2)	OR	2013
	Aggregated Solar Block (SO 1)	OR	2010
	Aggregated Solar Block (SO 2)	OR	2011
	Aggregated Solar Block (SO 3)	OR	2011
	Aggregated Solar Block (SO 4)	OR	2012
	Aggregated Solar Block (SO 5)	OR	2012
	Aggregated Solar Block (SO 6)	OR	2013
	Aggregated Solar Block (SO 7)	OR	2013
	*Aggregated Solar Block (SO 8)	OR	2013
	*Aggregated Solar Block (SO 9)	OR	2013

[4] For Oregon Solar Incentive Program Blocks, Commercial Operation Year represents the first year in which capacity was added to the block/the block was established.

[5] The Company entered into a power purchase agreement to procure the output of this facility for the purposes of meeting PacifiCorp's solar capacity standard requirement set forth in ORS 757.370. The Black Cap facility is certified by ODOE as RPS eligible and ODOE has identified the facility as generating RECs that may be counted twice for purposes of RPS compliance, as allowed by OAR 860-084-0070.

Table 2

Energy Source	Generating Facility	State	Commercial[4] Operation Year
	*Aggregated Solar Block (SO 10)	OR	2014
	*Aggregated Solar Block (SO 11)	OR	2014
	*Aggregated Solar Block (SO12)	OR	2015
	Aggregated Solar Block (WV 1)	OR	2010
	Aggregated Solar Block (WV 2)	OR	2011
	Aggregated Solar Block (WV 3)	OR	2012
	Aggregated Solar Block (WV 4)	OR	2013
	Aggregated Solar Block (WV 5)	OR	2013
	Aggregated Solar Block (WV 6)	OR	2013
	*Aggregated Solar Block (WV 7)	OR	2014
	*Aggregated Solar Block (WV 8)	OR	2015
	*Aggregated Solar Blocks (Remaining Capacity)	OR	2016-2017
Solar	*Pavant Solar II	UT	2016

*Indicates resource has not been included in previous Oregon Implementation Plans.

OAR 860-083-0400(2)(d)
A forecast of the expected incremental costs of new qualifying electricity for facilities or contracts planned for first operation in the compliance year, consistent with the methodology in OAR 860-083-0100.

Response: The 2017-2021 Plan includes a forecast of expected incremental costs of qualifying electricity from four new facilities/contracts[6] and the Oregon Solar Incentive Program (OSIP),[7] which have a cumulative capacity exceeding 50 megawatts. **Table 3** below includes the forecasted incremental cost of these new resources, consistent with the methodology in OAR 860-083-0100.[8]

[6] Latigo Wind – 60 MW (2015 COD), Pioneer Wind – 80 MW (2016 COD), and Pavant II Solar – 50 MW (2016 COD) are under development and anticipated to be qualifying Oregon RPS-eligible resources. Black Cap – 2 MW (2012 COD) is an existing certified Oregon RPS-eligible resource. Foote Creek II and Foote Creek III are not included in the incremental cost calculation, as these resources became operational before June 6, 2007.

[7] To calculate the estimated incremental costs of the Oregon Solar Incentive Program, capacity added to the OSIP program in each year was treated as an individual resource.

[8] OAR 860-083-100(13)(b) states that "When the capacity of qualifying electricity described in subsection (13)(a) of this rule exceeds 20 megawatts in a compliance year or the cumulative capacity of qualifying electricity in subsection (13)(a) of this rule exceeds 50 megawatts, the incremental cost of all such qualifying electricity must be included in the compliance report for the compliance year and in compliance reports and implementation plans filed after such compliance report."

OAR 860-083-0400(2)(e)
A forecast of the expected incremental cost of compliance, the costs of using unbundled renewable energy certificates and alternative compliance payments for compliance, compared to annual revenue requirements, consistent with the methodologies in OAR 860-083-0100 and 860-083-0200, absent consideration of the cost limit in OAR 860-083-0300.

Response: **Confidential Attachment C** provides an explanation of the key assumptions that the Company used to forecast the expected incremental costs of renewable resources during the 2017-2021 reporting period, consistent with OAR 860-083-0100 and Order No. 12-272 in docket UM 1570.

Table 3 below shows the forecast of the expected incremental costs, on an Oregon-allocated basis, for the qualifying electricity for generating facilities or contracts in service after June 6, 2007. Low impact hydroelectric facilities and qualifying generating facilities or contracts that went into service before June 6, 2007 are deemed to have zero incremental costs, pursuant to OAR 860-083-0100(1)(i).[9]

The forecast of expected incremental cost analysis uses Oregon's forecast system generation (SG) allocation factors from the October 2015 load forecast.

Using the September 2014 official forward price curve (OFPC) that was used as a base case in the 2015 IRP, **Table 3** below lists the incremental costs for each qualifying facility. Qualifying resources with a positive expected incremental cost represent costs higher than a proxy resource and negative costs [within brackets] represent a benefit relative to a proxy resource.

[9] OAR 860-083-0100(1)(h) states that "Incremental costs are deemed to be zero for qualifying electricity from generating facilities or contracts that became operational before June 6, 2007 and for certified low-impact hydroelectric facilities under ORS 469A.025(5)."

Table 3

2017-2021 Summary
Oregon Allocated Nominal Levelized Incremental Costs ($000)[10]
For Specific Qualifying Resources

2015 IRP Base Case - September 2014 OFPC

Resource	2017	2018	2019	2020	2021
Blundell II	($905)	($907)	($903)	($894)	($892)
Campbell Hill-Three Buttes (PPA)	$999	$1,001	$998	$988	$985
Dunlap I	($320)	($321)	($319)	($316)	($315)
Glenrock I	($15)	($15)	($15)	($15)	($15)
Glenrock III	$98	$98	$97	$97	$96
Goodnoe Hills	$1,026	$1,028	$1,024	$1,014	$1,011
High Plains	$618	$619	$617	$611	$609
McFadden Ridge	($88)	($88)	($88)	($87)	($87)
Marengo	($121)	($121)	($121)	($120)	($119)
Marengo II	$97	$97	$97	$96	$96
Mountain Wind Power (PPA)	$9	$9	$9	$9	$9
Mountain Wind Power II (PPA)	$483	$484	$483	$478	$476
Seven Mile Hill I	($856)	($858)	($855)	($847)	($844)
Seven Mile Hill II	($178)	($178)	($177)	($175)	($175)
Top of the World (PPA)	$2,016	$2,020	$2,012	$1,993	$1,987
Pioneer Wind Park	($1,216)	($1,219)	($1,214)	($1,202)	($1,199)
Latigo Wind Park	$257	$258	$257	$254	$253
Pavant II Solar	($601)	($602)	($600)	($594)	($592)
Black Cap Solar	$77	$77	$77	$77	$77
OSIP 2010	$130	$130	$130	$130	$130
OSIP 2011	$1,251	$1,251	$1,251	$1,251	$1,251
OSIP 2012	$795	$795	$795	$795	$795
OSIP 2013	$931	$931	$931	$931	$931
OSIP 2014	$591	$591	$591	$591	$591
OSIP 2015	$223	$223	$223	$223	$223

For comparative purposes, the Company included in **Table 4** an additional sensitivity scenario based on the most recent OFPC dated November 2015.

[10] The incremental cost analysis assumptions include (1) September 2014 Price Curve (medium gas curve), (2) Discount Rate from the 2015 IRP of 6.66 percent, and (3) Oregon's allocated share of generation based on forecast SG allocation factors based on the October 2015 load forecast.

Table 4 Additional Scenario - November 9, 2015 OFPC 2017-2021 Summary Oregon Allocated Nominal Levelized Incremental Costs ($000)[11] For Specific Qualifying Resources					
Resource	**2017**	**2018**	**2019**	**2020**	**2021**
Blundell II	($774)	($776)	($773)	($765)	($763)
Campbell Hill-Three Buttes (PPA)	$1,493	$1,496	$1,491	$1,476	$1,472
Dunlap I	$331	$332	$331	$327	$326
Glenrock I	$529	$530	$528	$523	$521
Glenrock III	$306	$307	$306	$303	$302
Goodnoe Hills	$1,432	$1,434	$1,429	$1,415	$1,411
High Plains	$1,137	$1,139	$1,135	$1,124	$1,120
McFadden Ridge	$57	$57	$57	$56	$56
Marengo	$407	$408	$407	$403	$401
Marengo II	$388	$389	$387	$383	$382
Mountain Wind Power (PPA)	$247	$247	$246	$244	$243
Mountain Wind Power II (PPA)	$786	$788	$785	$777	$775
Seven Mile Hill I	($270)	($271)	($270)	($267)	($266)
Seven Mile Hill II	($62)	($62)	($62)	($61)	($61)
Top of the World (PPA)	$3,058	$3,064	$3,053	$3,022	$3,014
Pioneer Wind Park	($474)	($474)	($473)	($468)	($467)
Latigo Wind Park	$655	$656	$654	$647	$645
Pavant II Solar	($272)	($273)	($272)	($269)	($268)
Black Cap Solar	$27	$27	$27	$27	$27
OSIP 2010	$108	$108	$108	$108	$108
OSIP 2011	$1,267	$1,267	$1,267	$1,267	$1,267
OSIP 2012	$813	$813	$813	$813	$813
OSIP 2013	$961	$961	$961	$961	$961
OSIP 2014	$616	$616	$616	$616	$616
OSIP 2015	$232	$232	$232	$232	$232

Confidential Attachment D provides additional detail of the forecast of the expected incremental costs calculation, consistent with the methodology in OAR 860-083-0100, and the Company's 2015 IRP, as well as the additional sensitivity (Scenario 7) based on the November 9, 2015 OFPC.

Tables 5 and 6 below show the forecast of the expected incremental cost of compliance, compared to the annual revenue requirement for each year in the 2017-2021 reporting period. **Table 5** is based on the incremental cost forecast from **Table 3** (the 2015 IRP Base Case – September 2014 OFPC Fuel Curve). **Table 6** is based

[11] The sensitivity analysis incremental cost assumptions include (1) November 2015 Price Curve (medium gas curve), (2) Discount Rate from the 2015 IRP of 6.66 percent, and (3) Oregon's share based on forecast SG allocation factors based on the October 2015 load forecast.

on the incremental cost forecast from the additional sensitivity scenario shown in **Table 4** (November 9, 2015 OFPC). The Company's 2017-2021 Plan does not forecast the use of alternative compliance payments at this time. The Oregon allocated nominal levelized incremental cost was calculated by using an average $/MWh based on the incremental cost calculations for each resource multiplied by the number of forecasted bundled RECs.

The annual revenue requirement was calculated consistent with the methodology in OAR 860-083-0200. According to the rule, this methodology adjusts the last approved revenue requirement for forecasted load.[12] These tables show that the four percent cost limit is not triggered. Actual cost of compliance may vary from the calculations shown below.

Table 5

Based on Table 3 Data (2015 IRP Base Case – September 2014 OFPC Fuel Curve)

	Oregon Allocated Nominal Levelized Incremental Cost ($000s)					
	Bundled	Unbundled	Total	Annual Revenue Requirement ($000s)	Cost as % Oregon Annual Revenue Requirement	4% of Revenue Requirement
2017	$6,721	$0	$6,721	$1,236,413	0.54%	$49,457
2018	$6,783	$0	$6,783	$1,245,552	0.54%	$49,822
2019	$6,793	$0	$6,793	$1,247,703	0.54%	$49,908
2020	$9,132	$0	$9,132	$1,244,920	0.73%	$49,797
2021	$9,205	$0	$9,205	$1,240,037	0.74%	$49,601

Table 6

Based on Table 4 Data (Sensitivity - November 9, 2015 OFPC Fuel Curve)

	Oregon Allocated Nominal Levelized Incremental Cost ($000s)					
	Bundled	Unbundled	Total	Annual Revenue Requirement ($000s)	Cost as % Oregon Annual Revenue Requirement	4% of Revenue Requirement
2017	$15,672	$0	$15,672	$ 1,236,413	1.27%	$49,457
2018	$15,831	$0	$15,831	$ 1,245,552	1.27%	$49,822
2019	$15,830	$0	$15,830	$ 1,247,703	1.27%	$49,908
2020	$21,192	$0	$21,192	$ 1,244,920	1.70%	$49,797
2021	$21,242	$0	$21,242	$ 1,240,037	1.71%	$49,601

[12] The Company used the most recently available load forecast: October 2015.

OAR 860-083-0400(2)(f)
A forecast of the number and cost of bundled renewable energy certificates issued, consistent with the methodology in OAR 860-083-0100.

Response: **Attachment A** provides the forecasted number of bundled RECs. **Tables 5 and 6** above include the costs for the bundled RECs included in the 2017-2021 Plan.

OAR 860-083-0400(4)
If there are material differences in the planned actions in [OAR 860-083-0400(2)] of this rule from the action plan in the most recently filed or updated integrated resource plan by the electric company, or if conditions have materially changed from the conditions assumed in such filing, the company must provide sufficient documentation to demonstrate how the implementation plan appropriately balances risks and expected costs as required by the integrated resource planning guidelines in 1.b and c. of Commission Order No. 07-047 and subsequent guidelines related to implementation plans set forth by the Commission. Unless provided in the most recently filed or updated integrated resource plan, an implementation plan for an electric company subject to ORS 469A.052 must include the following information: (a) At least two forecasts for subsections (2)(d), (e), and (f) of this rule: one forecast assuming existing government incentives continue beyond their current expiration date and another forecast assuming existing government incentives do not continue beyond their current expiration date; (b) A reasonable range of estimates for the forecasts in subsections (2)(d), (e), and (f) of this rule, consistent with subsection (4)(a) of this rule and the analyses or methodologies in the company's most recently filed or updated integrated resource plan.

Response: The only material difference between the 2017-2021 Plan and the RPS Position Forecast included in the 2015 IRP[13] are the following changes in qualifying resources:

- 2015 IRP included Bevans Point Solar (Solar Capacity Standard), unlike the 2017-2021 Implementation Plan; however, the Company did not complete the transaction with Bevans Point Solar.
- 2015 IRP included Blue Mountain which was subsequently terminated, unlike the 2017-2021 Implementation Plan.
- 2015 IRP did not include Pavant II Solar, LLC, a qualifying facility (QF) contract executed on March 25, 2015.

[13] See PacifiCorp's 2015 IRP – Figure 1.6 at page 5 – Annual State RPS Position Forecasts using the Preferred Portfolio.

(a) As noted in **Confidential Attachment C**, the Company assumes that existing government incentives expire in accordance with their current expiration date. A separate forecast assuming existing government incentives continue beyond their current expiration date is not applicable as there are no applicable renewable resources included in the Company's 2015 IRP Action Plan during the 2017-2021 reporting period. Accordingly, the Company's forecast of expected incremental cost analysis, whether or not existing government incentives continue beyond their current expiration date, would be identical.

(b) **Confidential Attachment D** includes a range of forecasts for expected incremental costs. The summary results for the September 2014 OFPC are shown in **Table 3**. **Confidential Attachment D** also includes the additional sensitivity scenario for the November 2015 OFPC, and the summary results are shown in **Table 4**.

OAR 860-083-0400(5)
Under the following circumstances, the electric company must, for the applicable compliance year, provide sufficient documentation or citations to demonstrate how the implementation plan appropriately balances risks and expected costs as required by the integrated resource planning guidelines in 1.b. and c. of Commission Order No. 07-047 and subsequent guidelines related to implementation plans set forth by the Commission. (a) The sum of costs in subsection (2)(e) of this rule is expected to be four percent or more of the annual revenue requirement in subsection (2)(e) of this rule for any compliance year covered by the implementation plan, (b) The company plans, for reasons other than to meet unanticipated contingencies that arise during a compliance year, to use any of the following compliance methods: (A) Unbundled renewable energy certificates; (B) Bundled renewable energy certificates issued between January 1 through March 31 of the year following the compliance year; or (C) Alternative compliance payments, or (c) The company plans to sell any bundled renewable energy certificates included in the rates of Oregon retail electricity consumers.

Response: The Company provides the following responses:

(a) This requirement is not applicable at this time since the sum of the costs in subsection (2)(e) above are not expected to exceed four percent of the annual revenue requirement in any compliance year that is reported in the Company's 2017-2021 Plan.

(b) For the 2017 through 2021 reporting period, the Company expects to comply with the Oregon RPS requirements by using bundled RECs. At this time, the Company does not intend to use (A) unbundled RECs; (B) bundled RECs issued between January 1 through March 31 of the year following the compliance year; or (C) alternative compliance payments.

As stated in PacifiCorp's 2015 IRP, with a projected bank balance extending out through 2027, the Company plans to defer issuance of RFPs seeking unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets until states develop implementation plans under the Environmental Protection Agency's draft Clean Power Plan rule, providing clarity on whether an unbundled REC strategy is the least cost compliance alternative for Oregon customers.[14] While PacifiCorp's current strategy does not include the use of unbundled RECs in the 2017-2021 period, the Company will continue to evaluate the optimal compliance approach and may opportunistically pursue unbundled RECs that qualify for Oregon RPS compliance. If the Company does choose to seek unbundled RECs for Oregon RPS, as part of the solicitation and bid evaluation process, PacifiCorp will evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. This will balance risks and expected costs as required by the IRP guidelines in 1.b. and c. of Commission Order No. 07-047 and subsequent guidelines related to implementation plans set forth by the Commission.

(c) This requirement is not applicable at this time because the Company's plan does not include the sale of bundled Oregon-allocated RECs from RPS eligible renewable resources included in the rates of Oregon customers.

OAR 860-083-0400(6)
An implementation plan must provide a detailed explanation of how the implementation plan complies, or does not comply, with any conditions specified in a Commission acknowledgement order on the previous implementation plan and any relevant conditions specified in the most recent acknowledgement order on an integrated resource plan filed or updated by the electric company.

Response: In Order 14-267 in docket UM 1681, the Commission acknowledged PacifiCorp's 2015-2019 Plan with the following two conditions for the 2017-2021 Plan and subsequent Plans:

- Include a "non-confidential summary of RPS total incremental costs for each scenario analyzed…."[15]

[14] See the Company's 2015 IRP, Action Item 1a on page 10.
[15] *In the Matter of PacifiCorp, dba Pacific Power, Renewable Portfolio Standard Implementation Plan 2015-2019*, Docket UM 1681, Order 14-267 at Appendix A (July 22, 2014).

- **Attachment E** provides a summary of the RPS incremental costs by resource for each scenario and **Attachment F** provides a summary of the RPS total incremental costs for each scenario analyzed in the 2017-2021 Implementation Plan.

- Include "in subsequent [implementation plans] a scenario that uses the base case price curve assumptions (medium gas and medium CO2 prices) similar to that used in the other scenarios in the [implementation plan], with the assumption the Company maximizes the use of unbundled RECs for each year analyzed in the [implementation plan] and assuming an unbundled REC price equal to the weighted average price paid for unbundled RECs used for compliance in their last compliance filing."[16]
  - **Table 7** below provides a sensitivity for the base case scenario (September 2014 OFPC Fuel Curve) that maximizes the use of unbundled RECs in each year of the Plan. For this scenario, the Company is assuming an unbundled REC price of $0.73 per REC, consistent with PacifiCorp's 2014 RPS Compliance Report filed in Docket UM 1739.[17]

Table 7
Additional Sensitivity Scenario – Maximum Use of Unbundled RECs (September 2014 OFPC Base Case)

	Oregon Allocated Nominal Levelized Incremental Cost ($000s)			Annual Revenue Requirement ($000s)	Cost as % Oregon Annual Revenue Requirement	4% of Revenue Requirement
	Bundled	Unbundled	Total			
2017	$3,220	$282	$3,502	$ 1,236,413	0.28%	$49,457
2018	$3,244	$284	$3,528	$ 1,245,552	0.28%	$49,822
2019	$3,250	$284	$3,534	$ 1,247,703	0.28%	$49,908
2020	$4,323	$378	$4,702	$ 1,244,920	0.38%	$49,797
2021	$4,306	$377	$4,683	$ 1,240,037	0.38%	$49,601

There were no conditions specified in the Commission's acknowledgment order of the 2013 IRP specific to the Oregon RPS Implementation Plan.[18] The Company's 2015 IRP is ongoing and is pending Commission acknowledgement.

[16] *Id.*
[17] Refer to PAC OR 2015 RPIP – Unbundled RECs Workpaper – CONFIDENTIAL
[18] *In the Matter of PacifiCorp 2013 Integrated Resource Plan*, Docket LC 57, Order 14-252 (July 8, 2014).

OAR 860-083-0400(7)
If there are funds in holding accounts under ORS 469A.180(4) and if the electric company has not filed a proposal for expending such funds for the purposes allowed under ORS 469A.180(5), the implementation plan must include the electric company's plans for expending or holding such funds. If the plan is to hold such funds, the plan should indicate under what conditions such funds should be expended.

Response: The Company does not have any funds in holding accounts authorized pursuant to ORS 469A.180(4). Accordingly, this requirement is not applicable at this time.

OAR 860-083-0400(9)
(a) Each electric company must post on its website the public portion of its most recent implementation plan under this rule within 30 days after a Commission acknowledgement order has been issued, including any conditions specified by the Commission under ORS 469.075(3). (b) Each electric company must provide a copy of the public portions of the most recently filed implementation plan to any person upon request, until the Commission has issued an acknowledgement order on such plan.

Response: The Company will post the 2017-2021 Plan on its website within 30 days after a Commission acknowledgement order is issued. The Company will provide the public portions of the 2017-2021 Plan to any persons upon request.

OAR 860-083-0400(10)
Consistent with Commission orders for disclosure under OAR 860-038-0300, each electric company must provide information about the implementation plan to its customers by bill insert or other Commission-approved method. The information must be provided within 90 days of final action by the Commission on the plan or coordinated with the next available insert required under 860-038-0300. The information must include the URL address for the implementation plan posted under subsection (9)(a) of this rule.

Response: In compliance with OAR 860-038-0300, the Company will provide information about the 2017-2021 Plan to its customers via bill inserts within 90 days of the final action by the Commission.

Oregon Solar Capacity Standard **OAR 860-084-0080**
Each electric company must incorporate its plan to achieve, or exceed, and maintain the minimum solar photovoltaic capacity standards specified in OAR 860-084-0020 into its renewable portfolio standard implementation plans filed pursuant to OAR 860-083-0400

Response: In October 2012 the Company acquired the 2.0 MW_{AC} Black Cap Solar project in Lakeview, Oregon, to contribute to PacifiCorp's required 8.7 MWAC minimum obligation under the solar photovoltaic capacity standard. In April 2013, PacifiCorp issued a second RFP and as a result finalized a 25-year power purchase agreement for Old Mill Solar, a 5.0 MW_{AC} project located in Bly, Oregon which is scheduled to be operational by December 31, 2015. The Company continues to pursue the remaining 1.7 MW_{AC} solar capacity, seeking the lowest cost alternative to meet the 2020 obligation.

PacifiCorp
Renewable Portfolio Standard Oregon Implementation Plan 2017-2021

Attachment A

Accounting of RECs Applicable to Oregon RPS

PacifiCorp Oregon - 2017-2021 RPS Implementation Plan
Attachment A - Accounting of RECs Applicable to Oregon RPS

	MWh														
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Oregon Renewable Portfolio Standard Requirement [(1)]	-	-	-	-	650,729	638,940	654,498	647,937	1,961,678	1,957,528	1,918,995	1,933,357	1,936,736	2,576,484	2,566,252
Planned Compliance Method [(2)]															
Bundled RECs					650,729	511,152	523,600	518,350	1,749,952	1,957,528	1,918,995	1,933,357	1,936,736	2,576,484	2,566,252
Unbundled RECs						127,788	130,899	129,587	211,726						
Bundled RECs by vintage year	355,038	572,302	822,402	1,247,291	1,776,846	1,588,069	1,476,704	1,549,424	1,342,663	1,664,434	1,706,912	1,704,620	1,703,718	1,685,364	1,672,536
Unbundled RECs by vintage year	44,000	127,342	-	8,356	122,916	243,819	53,567								
Cumulative Banked RECs minus RPS requirement by year of compliance [(3)]	399,038	1,098,683	1,921,085	3,176,732	4,425,765	5,618,713	6,494,486	7,395,973	6,776,959	6,483,864	6,271,781	6,043,044	5,810,026	4,918,906	4,025,189
Alternative compliance payments					-	-	-	-	-	-	-	-	-	-	-

Notes

(1) Based on Retail Load Forecast, October 2015

(2) 2017-2021 Implementation Plan - Attachment B - Oregon's Share Per Allocation Factors - Renewable Portfolio Standard Renewable Energy Credits (MWh), page 2

(3) Oldest RECs retired first for RPS compliance

PacifiCorp
Renewable Portfolio Standard Oregon
Implementation Plan
2017-2021

<u>Confidential Attachment B</u>

Bundled and Unbundled RECs
Expected Annual MWh Output
(Total Company and Oregon Share)

(Redacted Version)

PacifiCorp Oregon - 2017-2021 RPS Implementation Plan

Attachment B - Oregon's Renewable Energy Credit Share Per Allocation Factors (MWh) [1]

		State	COD[2]	WREGIS ID	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
					Actual[3]	Actual[3]	Actual[3]	Actual[3]	Actual[3]	Actual[3]	Actual[3]	Actual[3]	Forecast[3]	Forecast[3]	Forecast[3]	Forecast[3]	Forecast[3]	Forecast[3]	Forecast[3]
BIOGAS	Hill Air Force Base	UT	2005	W1263 / W1273					3,797	3,689	3,453	3,558	[redacted]						
	Total Biogas								**3,797**	**3,689**	**3,453**	**3,558**	[redacted]						
GEOTHERMAL	Blundell II	UT	2007	W230	2,526	18,822	22,876	19,786	21,937	21,213	18,870	19,455	[redacted]						
	Total Geothermal				**2,526**	**18,822**	**22,876**	**19,786**	**21,937**	**21,213**	**18,870**	**19,455**	[redacted]						
WIND	Campbell Hill-Three Buttes (PPA)	WY	2009	W1383			10,987	78,605	95,012	88,168	85,121	84,600	[redacted]						
	Chevron Casper Wind Farm (PPA)	WY	2009	W1370			1,683	10,110	12,892	11,867	11,081	10,812	[redacted]						
	Combine Hills (PPA)	OR	2003	W189	117,181	114,458	104,572	104,663	118,643	108,721	102,419	107,568	[redacted]						
	Dunlap I	WY	2010	W1687				26,839	111,195	100,599	103,222	97,716	[redacted]						
	Foote Creek I	WY	1999	W201	15,666	18,091	14,242	14,650	16,656	13,251	13,469	15,558	[redacted]						
	Foote Creek II	WY	1999	W1363								763	[redacted]						
	Foote Creek III	WY	1999	W1141								8,336	[redacted]						
	Glenrock	WY	2008	W964		560	69,779	75,448	90,011	81,542	81,242	76,287	[redacted]						
	Glenrock III	WY	2009	W965		0	23,435	26,194	34,381	30,893	30,724	28,785	[redacted]						
	Goodnoe Hills	WA	2008	W536	232	54,050	65,244	55,620	63,226	57,344	57,269	55,304	[redacted]						
	High Plains	WY	2009	W1334			19,981	67,432	88,585	81,906	85,994	82,727	[redacted]						
	Latigo	WY	2015	TBD									[redacted]						
	Leaning Juniper I	OR	2006	W200	79,427	88,113	71,124	58,578	62,000	49,561	51,953	54,917	[redacted]						
	Marengo	WA	2007	W185	51,406	112,813	87,007	86,716	106,527	93,001	83,472	93,735	[redacted]						
	Marengo II	WA	2008	W772		22,114	43,504	43,359	51,329	46,038	38,962	44,589	[redacted]						
	McFadden Ridge	WY	2009	W1341			5,651	20,272	27,092	24,578	26,139	25,108	[redacted]						
	Mountain Wind Power (PPA)	WY	2008	W1022		21,888	35,272	39,153	49,250	44,474	42,065	48,893	[redacted]						
	Mountain Wind Power II (PPA)	WY	2008	W1023		16,401	55,752	52,948	63,599	59,065	57,418	65,199	[redacted]						
	Pioneer Wind	WY	2016	TBD									[redacted]						
	Rock River I (PPA)	WY	2001	W187	38,665	44,240	37,056	36,213	35,934	35,030	35,676	39,759	[redacted]						
	Seven Mile Hill I	WY	2008	W975		376	83,422	84,929	100,789	88,728	89,736	85,481	[redacted]						
	Seven Mile Hill II	WY	2008	W976			17,104	17,745	22,080	18,814	19,416	18,778	[redacted]						
	Top of the World (PPA)	WY	2010	W1749			0	49,477	181,005	172,464	161,824	163,539	[redacted]						
	Wolverine Creek (PPA)	ID	2005	W188	40,868	47,992	42,262	42,485	52,451	46,266	38,811	46,892	[redacted]						
	Total Wind				**343,444**	**541,097**	**788,077**	**991,436**	**1,382,657**	**1,252,260**	**1,216,013**	**1,255,346**	[redacted]						
HYDRO	Ashton	ID	1917	W146				5,955	4,779	526	8,703	8,375	[redacted]						
	Big Fork	MT	1929	W179	199	324	332	353	382	362	317	336	[redacted]						
	Clearwater 1	OR	1953	W148				8,248	11,487	13,146	9,520	10,523	[redacted]						
	Clearwater 2	OR	1953	W149				7,783	14,875	14,042	9,924	11,454	[redacted]						
	Copco 1	CA	1918	W142	105	126	100	81	137	102	78	87	[redacted]						
	Cutler	UT	1927	W151	136	628	1,004	13,221	41,743	13,421	8,421	10,533	[redacted]						
	Fish Creek	OR	1952	W153				9,820	12,189	11,105	3,973	6,157	[redacted]						
	Grace	ID	1923	W137				16,636	43,142	21,416	17,902	14,305	[redacted]						
	JC Boyle	OR	1958	W180	372	1,124	879	728	1,273	898	605	586	[redacted]						
	Lemolo 1	OR	1955	W157	3,446	4,281	3,581	29,188	44,405	43,184	31,220	35,939	[redacted]						
	Lemolo 2	OR	1956	W158	363	371	212	36,284	48,315	53,683	37,800	44,325	[redacted]						
	Oneida	ID	1915	W160	803	746	699	7,464	20,418	8,549	7,179	5,534	[redacted]						
	Pioneer	UT	1897	W162	194	304	496	297	553	287	143	156	[redacted]						
	Prospect 2	OR	1928	W140	1,104	1,167	1,076	1,020	1,148	1,068	958	885	[redacted]						
	Prospect 3	OR	1932	W164	1,196	1,259	1,066	9,257	12,326	9,728	8,504	9,169	[redacted]						
	Slide Creek	OR	1951	W168				20,716	9,806	25,055	13,386	17,967	[redacted]						
	Soda	ID	1924	W170				3,658	9,283	5,192	4,089	3,871	[redacted]						
	Soda Springs	OR	1952	W171				13,598	18,743	13,105	11,537	13,796	[redacted]						
	Toketee	OR	1950	W173				49,510	69,665	68,399	49,366	57,754	[redacted]						
	Yale	WA	1953	W141	1,150	2,054	2,004	2,228	2,357	2,460	1,722	2,314	[redacted]						
	Total Hydro				**9,068**	**12,384**	**11,449**	**236,045**	**367,026**	**305,728**	**225,327**	**254,066**	[redacted]						
OREGON SOLAR INCENTIVE	Oregon Solar Incentive Program - Central Oregon (CO 1)	OR	2010	W1686				11	209	403	409	399	[redacted]						
	Oregon Solar Incentive Program - Central Oregon (CO 2)	OR	2011	W2391					7	194	393	397	[redacted]						
	Oregon Solar Incentive Program - Central Oregon (CO 3)	OR	2013	W3671							22	230	[redacted]						
	Oregon Solar Incentive Program - Columbia River (CR 1)	OR	2011	W1970					126	192	263	327	[redacted]						
	Oregon Solar Incentive Program - Columbia River (CR 2)	OR	2014	W4436									[redacted]						
	Oregon Solar Incentive Program - Eastern Oregon (EO 1)	OR	2010	W1737				2	137	340	371	354	[redacted]						
	Oregon Solar Incentive Program - Eastern Oregon (EO 2)	OR	2011	W2611						116	200	298	[redacted]						
	Oregon Solar Incentive Program - Portland Oregon (PO 1)	OR	2010	W1738				2	81	189	299	310	[redacted]						
	Oregon Solar Incentive Program - Portland Oregon (PO 2)	OR	2013	W3672							17	111	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 1)	OR	2010	W1806				3	362	419	453	437	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 2)	OR	2011	W2240					161	545	573	508	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 3)	OR	2011	W2392					35	453	537	484	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 4)	OR	2012	W2690						316	467	450	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 5)	OR	2012	W3207						7	438	436	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 6)	OR	2013	W3516							302	412	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 7)	OR	2013	W3554							182	408	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 8)	OR	2013	W3673								375	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 9)	OR	2013	W4084								275	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 10)	OR	2014	W4187								152	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 11)	OR	2014	W4485								1	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 12)	OR	2015	W4576									[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 1)	OR	2010	W1739				6	253	280	314	308	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 2)	OR	2011	W2326					14	202	380	395	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 3)	OR	2012	W3208						25	333	329	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 4)	OR	2013	W3396							367	313	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 5)	OR	2013	W3410							256	323	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 6)	OR	2013	W3673							44	348	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 7)	OR	2014	W4085								118	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 8)	OR	2015	TBD									[redacted]						
	Oregon Solar Incentive Program - (Joseph Community) Wallowa County	OR	2011	W2448					44	666	746	740	[redacted]						
	Oregon Solar Incentive Program - Remaining Capacity	OR	2016-2017	TBD									[redacted]						
	Bourdet	OR	2014	W4486									[redacted]						
	Bourdet II	OR	2016	TBD									[redacted]						
	Confederated Tribes of Warm Springs (CTWS)	OR	2014	W4105								292	[redacted]						
	Crook County Solar	OR	2014	W3847							244	973	[redacted]						
	Lakeview	OR	2012	W3468							248	596	[redacted]						
	Lakeview II	OR	2013	W3960								839	[redacted]						
	Powell Butte	OR	2014	W4274								123	[redacted]						
	Solwatt	OR	2012	W2968						257	484	521	[redacted]						
	Solwatt II	OR	2014	W4273								110	[redacted]						
	Total Oregon Solar Incentive							**25**	**1,429**	**4,604**	**8,342**	**12,692**	[redacted]						
SOLAR	Pavant Solar II LLC	OR	2016	TBD									[redacted]						
	Total Solar												[redacted]						
SOLAR CAPACITY STANDARD	Black Cap	OR	2012	W3104						585	4,699	4,307	[redacted]						
	Total Utility Solar									**585**	**4,699**	**4,307**	[redacted]						
Total					**355,038**	**572,302**	**822,402**	**1,247,291**	**1,776,846**	**1,588,069**	**1,476,704**	**1,549,424**	**1,342,663**	**1,664,434**	**1,706,912**	**1,704,620**	**1,703,718**	**1,685,364**	**1,672,536**
Oregon's Share Based on SG Allocation Factors[3]					**27.44%**	**28.19%**	**27.49%**	**26.20%**	**26.41%**	**25.93%**	**25.20%**	**25.51%**	[redacted]						

(1) Includes resources under development that are anticipated to receive certification by ODOE for the Oregon RPS as eligible under ORS 469A.025.

(2) COD means commercial operation date (year). For Oregon Solar Incentive Program Blocks, COD represents the first year in which capacity was added to the block/the block was established.

(3) Oregon's share based on forecasted system generation (SG) allocation factors:
2007 through 2014 - Based on Actual Retail Loads
2015 through 2021 - Based on Retail Load Forecast, October 2015

Compliance Purchases Oregon RPS (MWh)	Transaction Date		Fuel	State	WREGIS ID	Commercial Operation Date	Price	2007	2008	2009	2010	2011	2012	2013
[redacted]	1/25/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Biogas	ID	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Biogas	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Biogas	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	1/25/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	CA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	CA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2/6/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Hydroelectric	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Hydroelectric	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Hydroelectric	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Hydroelectric	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2/11/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2/6/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	1/31/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Biogas	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2/4/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2/4/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	6/28/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	NM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	2/28/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	7/9/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	8/28/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	11/5/2013							[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	OR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Wind	WA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total								44,000	127,342	0	8,356	122,916	243,819	53,567

CONFIDENTIAL ATTACHMENT B
CONFIDENTIAL SUBJECT TO GENERAL PROTECTIVE ORDER

PacifiCorp
Renewable Portfolio Standard Oregon
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2017-2021

<u>Confidential Attachment C</u>

Preliminary Key Assumptions
Incremental Cost Calculation

(Redacted Version)

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Renewable Portfolio Standard
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Key Assumptions – Expected Incremental Cost Calculation

Background

As part of its compliance with ORS 469A, PacifiCorp is required to file an implementation plan with the Public Utility Commission of Oregon (Commission), by January 1, 2016 that provides, among other things, a forecast of expected incremental costs of renewable resources in service during the 2017-2021 Oregon Implementation Plan (2017-2021 Plan) reporting period. The expected incremental cost calculation compares the cost of renewable resources to the cost of a proxy plant, a combined cycle combustion turbine (unless otherwise specified by the Commission). The proxy plant used in this analysis for existing renewable facilities is based on a combined cycle combustion turbine (water-cooled "F" class 2x1 with duct firing) at the Lake Side location. The proxy plant used in this analysis for new qualifying renewable facilities is based on a combined cycle combustion turbine (dry "J" class Adv 1x1) at the Dave Johnston Brownfield location, from PacifiCorp's 2015 IRP. The annual expected incremental cost calculation for renewable resources in service during the 2017-2021 reporting period is the difference between the nominal levelized cost of the renewable resource and the nominal levelized cost of the proxy plants.

Methodology

The nominal levelized costs have been developed using an approach similar to that used to create the supply-side resource tables in Chapter 6 of the 2015 Integrated Resource Plan (IRP). For qualifying renewable resources currently in service, ongoing capital, and operation and maintenance (O&M) have been updated to reflect the most current information available. Actual ongoing capital and O&M values are used for historical period of 2007-2014. Data for renewable resources acquired through a power purchase agreement (PPA) reflect the associated contract terms.

Consistent with the 2015 IRP, a discount rate of 6.660% has been used in this expected incremental cost analysis. The associated payment factors have also been applied consistent with the 2015 IRP.

Inflation values are based on the Company's official inflation forecast. Where a calculation requires a single value, the 2.1% average annual inflation rate from 2015-2040 has been used. Otherwise, yearly values from the Company's official inflation forecast have been applied.

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Key Assumptions – Expected Incremental Cost Calculation

Renewable Resources

Table 1 provides the qualifying renewable resources that are included in the expected incremental cost calculation in the 2017-2021 Plan.[1]

Table 1 – List of Qualifying Resources Included in Incremental Cost

Resource	Assumed Capacity Factor (%)	In-Service Year	Capacity (MW)	Design Plant Life / Contract Term (Years)
Black Cap Solar	[redacted]	2012	2.0	16
Blundell II	[redacted]	2007	10.0	26
Campbell Hill-Three Buttes (PPA)	[redacted]	2009	99	20
Dunlap I	[redacted]	2010	111.0	25
Glenrock I	[redacted]	2008	99.0	25
Glenrock III	[redacted]	2009	39.0	25
Goodnoe Hills	[redacted]	2008	94.0	25
High Plains	[redacted]	2009	99.0	25
Latigo Wind	[redacted]	2015	60.0	20
Marengo	[redacted]	2007	140.4	25
Marengo II	[redacted]	2008	70.2	25
McFadden Ridge	[redacted]	2009	28.5	25
Mountain Wind Power (PPA)	[redacted]	2008	60.9	25
Mountain Wind Power II (PPA)	[redacted]	2008	79.8	25
Pavant Solar II, LLC	[redacted]	2016	50.0	20
Pioneer Wind	[redacted]	2016	80.0	20
Seven Mile Hill I	[redacted]	2009	99.0	25
Seven Mile Hill II	[redacted]	2009	19.5	25
Top of the World (PPA)	[redacted]	2010	200.2	20
Oregon Solar Incentive Program 2010- 2015[2]	[redacted]	2010-2015	9.2[3]	15

[1] The following new resources were added to the incremental cost calculation since the Company's 2015-2019 Plan, consistent with the methodology in OAR 860-083-0100: Latigo Wind, Pioneer Wind, Pavant Solar II, LLC, Black Cap Solar, and the Oregon Solar Incentive Program projects. These new facilities or contracts have a cumulative capacity exceeding 50 megawatts.
Foote Creek II and Foote Creek III are not included in the calculation, as these resources were in service before June 6, 2007.
[2] To calculate the estimated incremental costs of the Oregon Solar Incentive Program, capacity added to the OSIP program in each year was treated as an individual resource.

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Key Assumptions – Expected Incremental Cost Calculation

Table 2 provides information relating to the PPAs, including nominal prices, which are based on contract terms. The nominal prices do not include the cost of integration, which is added as an adjustment in the levelized cost calculation.

Table 2 – Power Purchase Agreements (PPAs)

Resource	PPA Annual Nominal Levelized Contract Price ($/MWh)	Contract Start Year	Average Capacity (MW)	Contract Term (Years)
Campbell Hill-Three Buttes (PPA)	[redacted]	2009	99	20
Mountain Wind Power (PPA)	[redacted]	2008	60.9	25
Mountain Wind Power II (PPA)	[redacted]	2008	79.8	25
Top of the World (PPA)	[redacted]	2010	200.2	20
Pioneer Wind	[redacted]	2016	80	20
Latigo Wind Park QF	[redacted]	2015	60	20
Pavant II Solar QF	[redacted]	2016	50	20

PacifiCorp receives federal production tax credits (PTC) associated with owned wind projects, but does not from PPAs. Levelized PTC values for eligible resources have been adjusted to correspond to the in-service year of each resource.

Capacity factors for existing renewable resources are based on the most current data available. Capacity factors for owned facilities and PPAs are calculated based on average generation over the life of facility or contract term and nameplate capacity. Generation values for 2007-2014 are actuals; generation values for 2015 include a combination of actual generation from January through September 2015 and forecasted values for October through December 2015. Generation values for years 2016 and beyond are forecasted.

The Company used wind integration costs from the Company's previously filed Oregon Transition Adjustment Mechanism (TAM) filings for calendar year (CY) 2007-2014 Wind integration values for 2015 and beyond are based on the 2015 IRP (2015 IRP Appendix H – Wind Integration). Solar integration costs are also derived from values in the 2015 IRP.

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[3] Due to data limitations, incremental cost estimates for the remaining 1.6 megawatts of OSIP capacity cannot be provided in this Plan, but will be included in subsequent Implementation Plans.

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Key Assumptions – Expected Incremental Cost Calculation

Capacity Contribution values for qualifying facilities are derived from the values from the 2015 IRP.[4]

Payment factors for qualifying facilities are updated using the discount rate from the 2015 IRP.

Actual Bonneville Power Administration (BPA) costs for long-term and short-term point-to-point (PTP) transmission and scheduling charges have been included in the incremental cost calculation for Goodnoe Hills. Starting April 2013, Goodnoe Hills became part of PacifiCorp's control area, which resulted in the termination of BPA integration charges and the inclusion of PacifiCorp's integration cost going forward. The BPA wheeling costs going forward include only long-term PTP rates, and reflect the most recently effective BPA rates.

In accordance with OAR 860-083-0100(1)(i), renewable resources that were in service before June 6, 2007, and low impact hydroelectric facilities have been excluded from the cost analysis. Additionally, the Rolling Hills facility is currently not included in Oregon rates and has been excluded from this cost analysis.[5]

Proxy Plant

The proxy plant used in this analysis for the existing qualifying facilities continues to be a combined cycle combustion turbine (CCCT water-cooled "F" class 2x1 with duct firing) at the Lake Side location from the 2008 IRP.

Four new long-term qualifying renewable resources are contemplated in the 2017-2021 incremental cost analysis. Since the cumulative capacity of the new qualifying resources exceeds 50 megawatts, a new proxy plant has also been added in this analysis for Latigo Wind, Pioneer Wind, Pavant Solar II, LLC, and Black Cap Solar. The proxy plant's characteristics remain unchanged from those stated in the 2015-2019 Plan analysis. The proxy plant used in this analysis for new qualifying renewable facilities is based on a combined cycle combustion turbine (dry "J" class Adv 1x1) at the Dave Johnston Brownfield location, from PacifiCorp's 2015 IRP. Consistent with the 2015 IRP, fuel price data is from the Company's September 2014 official forward price curve (OFPC) with natural gas delivered at the Lake Side and Dave Johnston Brownfield locations.
The following scenarios[6] are considered in the incremental cost analysis:

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[4] See the Company's 2015 IRP – Volume II, Appendix N, Table N.1, p. 405.
[5] *In the Matter of PacifiCorp, dba Pacific Power 2009 Renewable Adjustment Clause Schedule 202*, Docket UE 200, Order 548 at 19-20 (Nov. 14, 2008).
[6] Scenarios 1-6 are from the 2015 IRP.

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Key Assumptions – Expected Incremental Cost Calculation

- Scenario 1: September 2014 dated OFPC (Base case OFPC used in 2015 IRP)
- Scenario 2: Base gas, without 111(d), No Federal CO2
- Scenario 3: Base (dynamic) gas, with 111(d), Medium Federal CO2
- Scenario 4: Base (dynamic) gas, with 111(d), High Federal CO2
- Scenario 5: Low gas with 111(d), No Federal CO2
- Scenario 6: High gas, with 111(d), No Federal CO2
- Scenario 7: November 9, 2015 dated OFPC

For comparative purposes, the Company's analysis includes an additional sensitivity scenario based on the most recent natural gas price forecast from the November 9, 2015 OFPC.

Consistent with the discussion in Commission Order No. 09-299,[7] capital costs and O&M costs for the existing proxy plant based on 2008 IRP remain unchanged from the Company's 2015-2019 Plan.[8] Capital and O&M costs for the 2015 proxy plant are based on 2015 IRP. [9]

The proxy plant CCCTs are sized to have the equal amount of annual energy output as the qualifying renewable resource. The proxy CCCT nameplate capacity is calculated as follows: *Proxy nameplate capacity = (RPS Resource nameplate capacity) X (RPS Resource capacity factor/Proxy CCCT capacity factor)* where the capacity factor of the proxy CCCT equals the capacity factor of a representative CCCT from the IRP.

Consistent with Order No. 12-272 in UM 1570 requiring inclusion of firming costs associated with qualifying renewable resources, the fixed cost of a simple cycle combustion turbine (SCCT) is added to the qualifying resource in order to create a capacity equivalent proxy resource for comparison to qualifying renewable resources supplying intermittent generation. The SCCT is sized to equal the difference between the respective capacity contribution of the proxy CCCT and the qualifying renewable resource. Incremental cost calculations do not include shaping costs, consistent with Order No. 12-272.

Transaction costs associated with fuel purchases are added to the proxy resource costs to comply with Order No. 12-272. Specifically, actual broker fees associated with forward gas purchases compared to total gas consumption by the Company's gas units for CY 2010-2014 are used to calculate an average annual historical gas transaction cost of $0.00002/MMBTU. Values for

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[7] *See* Order No. 09-299 (August 3, 2009), AR 518 Phase III, page 4.
[8] The Company's 2015-2019 Plan was filed with the Commission on December 27, 20131 in docket UM 1570.
[9] See PacifiCorp's 2015 IRP – Volume I, Chapter 6, Tables 6.1 and 6.2.

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Key Assumptions – Expected Incremental Cost Calculation

2015 and beyond are estimated by applying annual inflation rates to the average annual historical gas transaction cost.

Levelized Calculation

The levelized calculation for each qualifying resource is based on the year that it is placed into service. Costs per MWh are escalated over the economic life of the resource. The annual cost per MWh is multiplied by the expected annual generation to develop the dollar cost in each year. Once the annual costs are calculated, the net present value of the costs (over the resource life) is calculated using a nominal discount rate, which is in turn used to calculate an annual nominal levelized value.

The proxy plant costs are similarly calculated with nominal levelized values aligned to the service years of each qualifying resource.

Some simplifying assumptions have been made. For example, generation has been included for the full year of the qualifying resource's in-service year and economic lives of resources have been rounded to a full year.

Expected Incremental Cost

The annual calculated nominal levelized cost of the proxy plant is subtracted from the annual calculated nominal levelized cost of each qualifying renewable resource. This difference is the annual incremental nominal levelized cost. The incremental nominal levelized cost is presented for each year of the 2017-2021 reporting period, and has been calculated for each of the fuel price scenarios identified in the proxy plant discussion above.

Allocation Factors

Table 3 provides the forecast Oregon system generation (SG) allocation factors using the October 2015 load forecast.

Table 3 – Allocation Factors

Year	SG Allocation Factor
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]

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Confidential Attachment D

Incremental Cost Analysis

Subject to Protective Order

THIS ATTACHMENT IS CONFIDENTIAL AND PROVIDED UNDER SEPARATE COVER

PacifiCorp
Renewable Portfolio Standard Oregon Implementation Plan 2017-2021

Attachment E

Scenarios 1-7

Summary of Incremental Cost by Resource

PacifiCorp - Oregon 2017-2021 RPS Implementation Plan
Attachment E - Summary of RPS Incremental Costs by Resource

Scenario 1: Sep 2014 OFPC Fuel Curve

	2017	2018	2019	2020	2021
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($905)	($907)	($903)	($894)	($892)
Campbell Hill-Three Buttes	$999	$1,001	$998	$988	$985
Dunlap I	($320)	($321)	($319)	($316)	($315)
Glenrock	($15)	($15)	($15)	($15)	($15)
Glenrock III	$98	$98	$97	$97	$96
Goodnoe Hills	$1,026	$1,028	$1,024	$1,014	$1,011
High Plains	$618	$619	$617	$611	$609
McFadden Ridge	($88)	($88)	($88)	($87)	($87)
Marengo	($121)	($121)	($121)	($120)	($119)
Marengo II	$97	$97	$97	$96	$96
Mountain Wind Power	$9	$9	$9	$9	$9
Mountain Wind Power II	$483	$484	$483	$478	$476
Seven Mile Hill I	($856)	($858)	($855)	($847)	($844)
Seven Mile Hill II	($178)	($178)	($177)	($175)	($175)
Top of the World	$2,016	$2,020	$2,012	$1,993	$1,987
Pioneer Wind Park I QF	($1,216)	($1,219)	($1,214)	($1,202)	($1,199)
Latigo Wind Park QF	$257	$258	$257	$254	$253
Pavant II Solar QF	($601)	($602)	($600)	($594)	($592)
Black Cap Solar	$77	$77	$77	$77	$77
OSIP_2010	$130	$130	$130	$130	$130
OSIP_2011	$1,251	$1,251	$1,251	$1,251	$1,251
OSIP_2012	$795	$795	$795	$795	$795
OSIP_2013	$931	$931	$931	$931	$931
OSIP_2014	$591	$591	$591	$591	$591
OSIP_2015	$223	$223	$223	$223	$223

Scenario 2: Base gas, without 111d, No Federal CO2 Fuel Curve

	2017	2018	2019	2020	2021
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($911)	($913)	($910)	($901)	($898)
Campbell Hill-Three Buttes	$972	$974	$970	$961	$958
Dunlap I	($349)	($350)	($348)	($345)	($344)
Glenrock	($40)	($40)	($40)	($39)	($39)
Glenrock III	$88	$88	$88	$87	$87
Goodnoe Hills	$1,007	$1,009	$1,005	$995	$992
High Plains	$594	$596	$593	$587	$586
McFadden Ridge	($94)	($95)	($94)	($93)	($93)
Marengo	($147)	($147)	($147)	($145)	($145)
Marengo II	$83	$83	$83	$82	$82
Mountain Wind Power	($2)	($2)	($2)	($2)	($2)
Mountain Wind Power II	$469	$470	$468	$464	$463
Seven Mile Hill I	($883)	($885)	($882)	($873)	($870)
Seven Mile Hill II	($183)	($183)	($182)	($181)	($180)
Top of the World	$1,961	$1,965	$1,958	$1,938	$1,933
Pioneer Wind Park I QF	($1,249)	($1,251)	($1,247)	($1,234)	($1,231)
Latigo Wind Park QF	$240	$240	$239	$237	$236
Pavant II Solar QF	($616)	($617)	($614)	($608)	($607)
Black Cap Solar	$75	$75	$75	$75	$75
OSIP_2010	$130	$130	$130	$130	$130
OSIP_2011	$1,250	$1,250	$1,250	$1,250	$1,250
OSIP_2012	$794	$794	$794	$794	$794
OSIP_2013	$929	$929	$929	$929	$929
OSIP_2014	$590	$590	$590	$590	$590
OSIP_2015	$223	$223	$223	$223	$223

Scenario 3: Base (dynamic) gas, with 111d, Medium Federal CO2 Fuel Curve

Resource	2017 Levelized Incremental Cost ($000)	2018 Levelized Incremental Cost ($000)	2019 Levelized Incremental Cost ($000)	2020 Levelized Incremental Cost ($000)	2021 Levelized Incremental Cost ($000)
Blundell II	($1,104)	($1,106)	($1,102)	($1,091)	($1,088)
Campbell Hill-Three Buttes	$379	$380	$378	$374	$373
Dunlap I	($1,389)	($1,391)	($1,386)	($1,372)	($1,368)
Glenrock	($874)	($876)	($873)	($864)	($862)
Glenrock III	($233)	($233)	($232)	($230)	($229)
Goodnoe Hills	$408	$409	$407	$403	$402
High Plains	($203)	($204)	($203)	($201)	($200)
McFadden Ridge	($316)	($317)	($316)	($313)	($312)
Marengo	($892)	($894)	($890)	($882)	($879)
Marengo II	($347)	($348)	($346)	($343)	($342)
Mountain Wind Power	($353)	($353)	($352)	($349)	($348)
Mountain Wind Power II	$24	$24	$24	$24	$23
Seven Mile Hill I	($1,784)	($1,787)	($1,780)	($1,763)	($1,758)
Seven Mile Hill II	($360)	($361)	($360)	($356)	($355)
Top of the World	$637	$639	$636	$630	$628
Pioneer Wind Park I QF	($2,537)	($2,543)	($2,533)	($2,508)	($2,501)
Latigo Wind Park QF	($411)	($411)	($410)	($406)	($405)
Pavant II Solar QF	($1,175)	($1,178)	($1,173)	($1,161)	($1,158)
Black Cap Solar	$41	$41	$41	$41	$41
OSIP_2010	$129	$129	$129	$129	$129
OSIP_2011	$1,235	$1,235	$1,235	$1,235	$1,235
OSIP_2012	$775	$775	$775	$775	$775
OSIP_2013	$894	$894	$894	$894	$894
OSIP_2014	$559	$559	$559	$559	$559
OSIP_2015	$212	$212	$212	$212	$212

Scenario 4: Base (dynamic) gas, with 111d, High Federal CO2 Fuel Curve

Resource	2017 Levelized Incremental Cost ($000)	2018 Levelized Incremental Cost ($000)	2019 Levelized Incremental Cost ($000)	2020 Levelized Incremental Cost ($000)	2021 Levelized Incremental Cost ($000)
Blundell II	($1,199)	($1,201)	($1,196)	($1,185)	($1,181)
Campbell Hill-Three Buttes	$134	$134	$133	$132	$132
Dunlap I	($1,941)	($1,945)	($1,937)	($1,918)	($1,913)
Glenrock	($1,302)	($1,305)	($1,300)	($1,287)	($1,284)
Glenrock III	($397)	($398)	($396)	($392)	($391)
Goodnoe Hills	$112	$112	$111	$110	$110
High Plains	($612)	($614)	($611)	($605)	($603)
McFadden Ridge	($430)	($431)	($429)	($425)	($424)
Marengo	($1,246)	($1,249)	($1,244)	($1,232)	($1,228)
Marengo II	($560)	($561)	($559)	($553)	($552)
Mountain Wind Power	($526)	($527)	($525)	($520)	($518)
Mountain Wind Power II	($196)	($197)	($196)	($194)	($193)
Seven Mile Hill I	($2,245)	($2,250)	($2,241)	($2,219)	($2,213)
Seven Mile Hill II	($451)	($452)	($450)	($446)	($445)
Top of the World	$61	$61	$61	$60	$60
Pioneer Wind Park I QF	($3,251)	($3,258)	($3,245)	($3,213)	($3,204)
Latigo Wind Park QF	($759)	($761)	($758)	($750)	($748)
Pavant II Solar QF	($1,482)	($1,485)	($1,480)	($1,465)	($1,461)
Black Cap Solar	$27	$27	$27	$27	$27
OSIP_2010	$129	$129	$129	$129	$129
OSIP_2011	$1,230	$1,230	$1,230	$1,230	$1,230
OSIP_2012	$768	$768	$768	$768	$768
OSIP_2013	$881	$881	$881	$881	$881
OSIP_2014	$546	$546	$546	$546	$546
OSIP_2015	$207	$207	$207	$207	$207

Scenario 5: Low gas, with 111d, No Federal CO2 Fuel Curve

Resource	2017 Levelized Incremental Cost ($000)	2018 Levelized Incremental Cost ($000)	2019 Levelized Incremental Cost ($000)	2020 Levelized Incremental Cost ($000)	2021 Levelized Incremental Cost ($000)
Blundell II	($802)	($804)	($801)	($793)	($791)
Campbell Hill-Three Buttes	$1,331	$1,334	$1,329	$1,316	$1,312
Dunlap I	$221	$222	$221	$219	$218
Glenrock	$425	$426	$424	$420	$419
Glenrock III	$267	$267	$266	$263	$263
Goodnoe Hills	$1,345	$1,348	$1,343	$1,329	$1,326
High Plains	$1,038	$1,040	$1,036	$1,026	$1,023
McFadden Ridge	$29	$29	$29	$29	$29
Marengo	$280	$281	$280	$277	$276
Marengo II	$326	$327	$325	$322	$321
Mountain Wind Power	$195	$196	$195	$193	$193
Mountain Wind Power II	$721	$723	$720	$713	$711
Seven Mile Hill I	($382)	($383)	($382)	($378)	($377)
Seven Mile Hill II	($84)	($84)	($84)	($83)	($83)
Top of the World	$2,745	$2,751	$2,741	$2,713	$2,706
Pioneer Wind Park I QF	($572)	($573)	($571)	($565)	($563)
Latigo Wind Park QF	$589	$590	$588	$582	$580
Pavant II Solar QF	($319)	($320)	($319)	($316)	($315)
Black Cap Solar	$97	$97	$97	$97	$97
OSIP_2010	$131	$131	$131	$131	$131
OSIP_2011	$1,260	$1,260	$1,260	$1,260	$1,260
OSIP_2012	$806	$806	$806	$806	$806
OSIP_2013	$950	$950	$950	$950	$950
OSIP_2014	$608	$608	$608	$608	$608
OSIP_2015	$229	$229	$229	$229	$229

Scenario 6: High gas, with 111d, No Federal CO2 Fuel Curve

Resource	2017 Levelized Incremental Cost ($000)	2018 Levelized Incremental Cost ($000)	2019 Levelized Incremental Cost ($000)	2020 Levelized Incremental Cost ($000)	2021 Levelized Incremental Cost ($000)
Blundell II	($1,054)	($1,057)	($1,053)	($1,042)	($1,039)
Campbell Hill-Three Buttes	$431	$432	$430	$426	$425
Dunlap I	($1,061)	($1,064)	($1,059)	($1,049)	($1,046)
Glenrock	($633)	($634)	($632)	($626)	($624)
Glenrock III	($140)	($140)	($140)	($138)	($138)
Goodnoe Hills	$564	$565	$563	$557	$556
High Plains	$28	$28	$27	$27	$27
McFadden Ridge	($252)	($253)	($252)	($249)	($249)
Marengo	($723)	($724)	($722)	($714)	($712)
Marengo II	($235)	($235)	($235)	($232)	($232)
Mountain Wind Power	($262)	($262)	($261)	($258)	($258)
Mountain Wind Power II	$140	$140	$139	$138	$138
Seven Mile Hill I	($1,523)	($1,526)	($1,521)	($1,506)	($1,501)
Seven Mile Hill II	($309)	($310)	($308)	($305)	($304)
Top of the World	$825	$827	$824	$816	$813
Pioneer Wind Park I QF	($2,077)	($2,082)	($2,074)	($2,053)	($2,047)
Latigo Wind Park QF	($194)	($194)	($194)	($192)	($191)
Pavant II Solar QF	($982)	($985)	($981)	($971)	($968)
Black Cap Solar	$42	$42	$42	$42	$42
OSIP_2010	$129	$129	$129	$129	$129
OSIP_2011	$1,233	$1,233	$1,233	$1,233	$1,233
OSIP_2012	$774	$774	$774	$774	$774
OSIP_2013	$896	$896	$896	$896	$896
OSIP_2014	$563	$563	$563	$563	$563
OSIP_2015	$214	$214	$214	$214	$214

Scenario 7: Nov 9 2015, OFPC Fuel Curve

	2017	2018	2019	2020	2021
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($774)	($776)	($773)	($765)	($763)
Campbell Hill-Three Buttes	$1,493	$1,496	$1,491	$1,476	$1,472
Dunlap I	$331	$332	$331	$327	$326
Glenrock	$529	$530	$528	$523	$521
Glenrock III	$306	$307	$306	$303	$302
Goodnoe Hills	$1,432	$1,434	$1,429	$1,415	$1,411
High Plains	$1,137	$1,139	$1,135	$1,124	$1,120
McFadden Ridge	$57	$57	$57	$56	$56
Marengo	$407	$408	$407	$403	$401
Marengo II	$388	$389	$387	$383	$382
Mountain Wind Power	$247	$247	$246	$244	$243
Mountain Wind Power II	$786	$788	$785	$777	$775
Seven Mile Hill I	($270)	($271)	($270)	($267)	($266)
Seven Mile Hill II	($62)	($62)	($62)	($61)	($61)
Top of the World	$3,058	$3,064	$3,053	$3,022	$3,014
Pioneer Wind Park I QF	($474)	($474)	($473)	($468)	($467)
Latigo Wind Park QF	$655	$656	$654	$647	$645
Pavant II Solar QF	($272)	($273)	($272)	($269)	($268)
Black Cap Solar	$108	$108	$108	$108	$108
OSIP_2010	$131	$131	$131	$131	$131
OSIP_2011	$1,267	$1,267	$1,267	$1,267	$1,267
OSIP_2012	$813	$813	$813	$813	$813
OSIP_2013	$961	$961	$961	$961	$961
OSIP_2014	$616	$616	$616	$616	$616
OSIP_2015	$232	$232	$232	$232	$232

PacifiCorp
Renewable Portfolio Standard Oregon Implementation Plan
2017-2021

<u>Attachment F</u>

Scenarios 1 - 7

Summary of RPS Incremental Cost of Compliance

PacifiCorp Oregon - 2017-2021 RPS Implementation Plan
Attachment F - Summary of RPS Total Incremental Cost of Compliance

Scenario 1: Sep 2014 OFPC Fuel Curve (2015 IRP Base Case)

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	$6,721	$0	$6,721	$1,236,413	$49,457	0.54%
2018	$6,783	$0	$6,783	$1,245,552	$49,822	0.54%
2019	$6,793	$0	$6,793	$1,247,703	$49,908	0.54%
2020	$9,132	$0	$9,132	$1,244,920	$49,797	0.73%
2021	$9,205	$0	$9,205	$1,240,037	$49,601	0.74%

Scenario 2: Base gas, without 111d, No Federal CO2 Fuel Curve

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	$6,297	$0	$6,297	$1,236,413	$49,457	0.51%
2018	$6,354	$0	$6,354	$1,245,552	$49,822	0.51%
2019	$6,365	$0	$6,365	$1,247,703	$49,908	0.51%
2020	$8,561	$0	$8,561	$1,244,920	$49,797	0.69%
2021	$8,635	$0	$8,635	$1,240,037	$49,601	0.70%

Scenario 3: Base (dynamic) gas, with 111d, Medium Federal CO2 Fuel Curve

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	($7,041)	$0	($7,041)	$1,236,413	$49,457	-0.57%
2018	($7,128)	$0	($7,128)	$1,245,552	$49,822	-0.57%
2019	($7,100)	$0	($7,100)	$1,247,703	$49,908	-0.57%
2020	($9,407)	$0	($9,407)	$1,244,920	$49,797	-0.76%
2021	($9,300)	$0	($9,300)	$1,240,037	$49,601	-0.75%

Scenario 4: Base (dynamic) gas, with 111d, High Federal CO2 Fuel Curve

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	($13,725)	$0	($13,725)	$1,236,413	$49,457	-1.11%
2018	($13,884)	$0	($13,884)	$1,245,552	$49,822	-1.11%
2019	($13,847)	$0	($13,847)	$1,247,703	$49,908	-1.11%
2020	($18,409)	$0	($18,409)	$1,244,920	$49,797	-1.48%
2021	($18,285)	$0	($18,285)	$1,240,037	$49,601	-1.47%

Scenario 5: Low gas, with 111d, No Federal CO2 Fuel Curve

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	$13,760	$0	$13,760	$1,236,413	$49,457	1.11%
2018	$13,898	$0	$13,898	$1,245,552	$49,822	1.12%
2019	$13,900	$0	$13,900	$1,247,703	$49,908	1.11%
2020	$18,615	$0	$18,615	$1,244,920	$49,797	1.50%
2021	$18,670	$0	$18,670	$1,240,037	$49,601	1.51%

Scenario 6: High gas, with 111d, No Federal CO2 Fuel Curve

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	(3,505)	0	(3,505)	$1,236,413	$49,457	-0.28%
2018	(3,553)	0	(3,553)	$1,245,552	$49,822	-0.29%
2019	(3,530)	0	(3,530)	$1,247,703	$49,908	-0.28%
2020	(4,645)	0	(4,645)	$1,244,920	$49,797	-0.37%
2021	(4,545)	0	(4,545)	$1,240,037	$49,601	-0.37%

Scenario 7: November 9 2015, OFPC Fuel Curve

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	$15,672	$0	$15,672	$1,236,413	$49,457	1.27%
2018	$15,831	$0	$15,831	$1,245,552	$49,822	1.27%
2019	$15,830	$0	$15,830	$1,247,703	$49,908	1.27%
2020	$21,192	$0	$21,192	$1,244,920	$49,797	1.70%
2021	$21,242	$0	$21,242	$1,240,037	$49,601	1.71%

Sensitivity with Maximum Unbundled RECs - Scenario 1: Sep 2014 OFPC Fuel Curve (2015 IRP Base Case)

	Incremental Costs			Annual Revenue Requirement	4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	($000s)	
2017	$5,376	$282	$5,658	$1,236,413	$49,457	0.46%
2018	$5,426	$284	$5,710	$1,245,552	$49,822	0.46%
2019	$5,434	$284	$5,718	$1,247,703	$49,908	0.46%
2020	$7,306	$378	$7,684	$1,244,920	$49,797	0.62%
2021	$7,364	$377	$7,741	$1,240,037	$49,601	0.62%