Pacific Power

Renewable Portfolio Standard
Oregon Implementation Plan
2015-2019

January 1, 2014

(Updated February 28, 2014)

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

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Oregon Implementation Plan
2015 through 2019

Pursuant to ORS 469A.075 and OAR 860-083-0400, PacifiCorp, d.b.a. Pacific Power (the Company or PacifiCorp), respectfully submits the 2015 through 2019 Oregon Implementation Plan (the 2015-2019 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

The 2015-2019 Plan shows that the Company intends to meet Oregon RPS targets during the 2015-2019 reporting period with a combination of bundled renewable energy certificates (RECs) from existing Oregon-allocated eligible renewable resources and unbundled RECs from Oregon eligible renewable resources.

The 2015-2019 Plan was prepared with information consistent with the Company's most recently filed Integrated Resource Plan (IRP) – the 2013 IRP.[1] The Company's IRP process and its filed documentation are based on the best available information at the time of the IRP preparation. The Company's 2013 IRP action plan (2013 IRP Action Plan) represents a road-map for implementation of the preferred portfolio. The 2013 IRP does not add any significant new renewable resources prior to 2024. The current economic and regulatory environments are continually changing, and the Company may modify its plans as specific events, legislation and regulations evolve. Such changes may materially impact resource acquisitions and the timing of those acquisitions.

In preparing the 2015-2019 Plan, the Company has included renewable resources that have been acquired or are under contract and that have received certification by the Oregon Department of Energy (ODOE) as eligible for the Oregon RPS. Additionally, the Company is using unbundled RECs purchased for compliance with the Oregon RPS as per the Company's application for deferred accounting of costs related to the purchase of RECs.[2] As shown in the 2015-2019 Plan, the existing resources and supplemental unbundled REC purchases will enable the Company to meet the 2015-2019 Oregon RPS targets.

The Company's prior implementation plan[3] (the 2013-2017 Plan) showed negative expected incremental costs (costs less than a proxy resource) for all resources. In contrast, the 2015-2019 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 remained negative. For resources that now show a positive expected incremental cost, the change is primarily due to the inclusion of firming costs that were not part of the 2013-2017

[1] The Company's 2013 IRP was filed with the Commission on April 30, 2013, Docket LC 57. Where applicable, material differences between the 2013 IRP and the 2015-2019 Plan are identified.

[2] The Company's Application for Deferred Accounting Costs Related to the Purchase of REC Certificates was filed with the Commission on January 24, 2013, Docket UM 1646.

[3] The Company's 2013-2017 Plan was filed with the Commission on December 30, 2011, Docket UM 1570.

Plan. However, the 2015-2019 Plan shows, using the methodology established by the rules adopted by the Commission, that the incremental costs do not trigger the four percent cost limit under ORS 469A.100.

Implementation Plan

The format used in the 2015-2019 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 October 2013 load forecast.[4]

Table 1	**2015**	**2016**	**2017**	**2018**	**2019**
Applicable RPS Standard as % of Electricity Sold	15%	15%	15%	15%	15%
Estimated PacifiCorp Oregon RPS Target[5] (MWh)	1,967,441	1,966,953	1,975,074	1,976,831	1,980,973

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 2015-2019 Plan, the Company anticipates complying with the applicable Oregon RPS using bundled and unbundled RECs. **Attachment A** provides an accounting of the RECs applicable to the Oregon RPS program.

[4] For OAR 860-083-0400(2)(a) in this 2015-2019 Plan, the Company used the October 2013 load forecast. The 2013 IRP uses a July 2012 load forecast.
[5] 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. The generating facilities, either owned by the Company or under contract, are expected to provide bundled or unbundled RECs for compliance with the Oregon RPS during the 2015-2019 reporting period. However, there are additional generating facilities that may be eligible in the future, either Company owned or under contract. These facilities have not been included in the 2015-2019 Plan because they have not received certification from ODOE as eligible under the Oregon RPS program. The facilities that have not been included in the 2015-2019 Plan are (a) facilities for which the Company has pending applications with the Low Impact Hydro Institute for low impact hydro certification, (b) facilities associated with the Oregon Solar Incentive Program (OSIP)[6] that recently came on-line and for which the Company is in the process of submitting applications to ODOE, and (c) facilities that are being evaluated to determine if they are eligible for the Oregon RPS program under ORS 469A.025.

Table 2 lists the year the generating facilities became operational, the energy source and the state where each facility is located. **Confidential Attachment B** provides the expected annual MWh output for each resource for compliance or the expected amount of REC purchases from each facility.

[6] The Oregon Solar Incentive Program is implemented through PacifiCorp Schedules 136 and 137.

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
	Glenrock I	WY	2008
	Glenrock III	WY	2009
	Goodnoe Hills	WA	2008
	High Plains	WY	2009
	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
	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
	Oneida	ID	1915
	Prospect 3	OR	1932
	Slide Creek	OR	1951
	Soda	ID	1924
	Soda Springs	OR	1952
	Grace	ID	1923
	Lemolo 1	OR	1955
	Lemolo 2	OR	1956
	Toketee	OR	1950

Table 2

Energy Source	Generating Facility	State	Commercial 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[7]	OR	2012
Oregon Solar Incentive Program	Joseph Community Solar	OR	2011
	Lakeview	OR	2012
	Solwatt	OR	2012
	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 (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 (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

[7] 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 has been 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, pursuant to OAR 860-084-0070.

Table 2 Energy Source	Generating Facility	Fuel Source	State	Contract Execution Date
Unbundled RECs	AgPower Jerome - Double A Dairy Digester	Biogas	ID	01/2013
	Dry Creek Landfill	Biogas	OR	01/2013
	Finley Buttes Landfill Gas Power Plant	Biogas	OR	01/2013
	Finley Buttes Landfill Gas Power Plant II	Biogas	OR	01/2013
	Rocky Reach Hydroelectric Project (C5)	Hydro	WA	02/2013
	Rocky Reach Hydroelectric Project (C6)	Hydro	WA	02/2013
	Rocky Reach Hydroelectric Project (C9)	Hydro	WA	02/2013
	Rocky Reach Hydroelectric Project (C11)	Hydro	WA	02/2013
	Condon Wind Power Project	Wind	OR	02/2013
	Elkhorn Valley Wind Farm	Wind	OR	01/2013, 02/2013
	Foote Creek II	Wind	WY	02/2013
	Hopkins Ridge	Wind	WA	02/2013
	Kittitas Valley Wind Farm	Wind	WA	01/2013, 02/2013
	Klondike I	Wind	OR	02/2013
	Klondike III	Wind	OR	08/2013, 11/2013
	Mountain View I	Wind	CA	01/2013
	Mountain View II	Wind	CA	01/2013
	Nine Canyon Phase 3	Wind	WA	02/2013, 07/2013
	Nine Canyon Wind Project	Wind	WA	02/2013, 07/2013
	Red Mesa	Wind	NM	06/2013
	Stateline (WA)	Wind	WA	02/2013
	Vansycle II	Wind	OR	06/2013
	Wild Horse	Wind	WA	02/2013
	Wild Horse Phase II	Wind	WA	11/2013

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 Company's 2013 IRP preferred portfolio does not include any additional renewable resources in years 2015-2019 and, as such, no additional forecasted costs associated with new qualifying electric facilities or contracts planned for first operation in the reported compliance years have been included in the 2015-2019 Plan.

For purposes of calculating expected incremental costs, the Company did not include costs associated with the OSIP facilities or the Black Cap Solar facility in its forecast of incremental costs. The capacities associated with these facilities are less than 20 MW and pursuant to OAR 860-083-100(13)(a), the incremental cost for long term qualifying electricity facilities with capacity less than 20 MW are not required to be included in compliance reports or implementation plans.[8]

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 2015-2019 reporting period, pursuant to 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. Qualifying generating facilities or contracts that went into service prior to 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 2013 load forecast.

Using the September 2012 official forward price curve (OFPC) that was used as a base case in the 2013 IRP, **Table 3** below lists the incremental costs for each qualifying facility. The September 2012 OFPC reflects CO_2 price assumptions beginning at $16/ton in 2022 with an annual real escalation rate of 3 percent thereafter.

[8] OAR 860-083-100(13)(a) states that "Except as provided in section (11) of this rule, if new long-term qualifying electricity in a compliance year, including qualifying electricity treated in the same manner as new, qualifying electricity in subsections (4)(b) and (6)(g) of this rule, totals less than 20 megawatts of capacity, the incremental cost for such long-term qualifying electricity is not required to be included in compliance reports of implementation plans. Such long-term qualifying electricity may be included in a compliance report for purposes of determining compliance with the applicable renewable portfolio standard under ORS 469A.052 or 469A.065."

[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

2015-2019 Summary
Oregon Allocated Nominal Levelized Incremental Costs ($000)[10]
For Specific Qualifying Resources
September 2012 OFPC

Resource	2015	2016	2017	2018	2019
Blundell II	($1,195)	($1,189)	($1,183)	($1,173)	($1,173)
Campbell Hill-Three Buttes (PPA)	$864	$860	$855	$849	$848
Dunlap I	($512)	($509)	($507)	($503)	($503)
Glenrock I	($309)	($307)	($306)	($303)	($303)
Glenrock III	($2)	($2)	($2)	($2)	($2)
Goodnoe Hills	$842	$838	$834	$827	$827
High Plains	$433	$430	$428	$425	$425
McFadden Ridge	($116)	($115)	($115)	($114)	($114)
Marengo	($142)	($142)	($141)	($140)	($140)
Marengo II	$127	$126	$125	$124	$124
Mountain Wind Power (PPA)	($46)	($46)	($46)	($45)	($45)
Mountain Wind Power II (PPA)	$421	$419	$417	$413	$413
Seven Mile Hill I	($1,175)	($1,169)	($1,163)	($1,154)	($1,153)
Seven Mile Hill II	($223)	($222)	($221)	($219)	($219)
Top of the World (PPA)	$1,713	$1,704	$1,695	$1,682	$1,681

For comparative purposes, the Company included in **Table 4** an additional sensitivity scenario based on the most recent OFPC dated November 8, 2013. As in the September 2012 OFPC, the November 8, 2013 OFPC reflects CO_2 price assumptions beginning at $16/ton in 2022 with an annual real escalation rate of 3 percent thereafter.

[10] The incremental cost analysis assumptions include (1) 2022 $16 carbon dioxide ($CO_2$), (2) September 2012 Price Curve (medium gas curve), (3) Discount Rate from the 2013 IRP of 6.88%, and (4) Oregon's share based on forecast SG allocation factors based on the October 2013 load forecast.

Table 4

Additional Sensitivity Scenario

2015-2019 Summary
Oregon Allocated Nominal Levelized Incremental Costs ($000)[11]
For Specific Qualifying Resources
November 8, 2013 OFPC

Resource	2015	2016	2017	2018	2019
Blundell II	($1,143)	($1,137)	($1,131)	($1,122)	($1,122)
Campbell Hill-Three Buttes (PPA)	$1,089	$1,083	$1,078	$1,069	$1,069
Dunlap I	($266)	($265)	($264)	($261)	($261)
Glenrock I	($100)	($99)	($99)	($98)	($98)
Glenrock III	$79	$78	$78	$77	$77
Goodnoe Hills	$1,003	$997	$992	$984	$984
High Plains	$633	$629	$626	$621	$621
McFadden Ridge	($60)	($60)	($59)	($59)	($59)
Marengo	$71	$71	$70	$70	$70
Marengo II	$241	$240	$239	$237	$237
Mountain Wind Power (PPA)	$47	$47	$47	$46	$46
Mountain Wind Power II (PPA)	$540	$537	$534	$530	$530
Seven Mile Hill I	($949)	($944)	($939)	($932)	($931)
Seven Mile Hill II	($179)	($178)	($177)	($176)	($176)
Top of the World (PPA)	$2,168	$2,156	$2,145	$2,128	$2,127

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 2013 IRP, as well as the additional sensitivity scenario based on the November 8, 2013 OFPC.

For the cost of unbundled RECs, the Company is assuming a price of $0.73 per-REC based on the Company's executed unbundled REC contracts. The Company estimates the cost of 212,448 unbundled RECs that will be used in 2015 to be $155,086.89.

Tables 5 and 6 below show the forecast of the expected incremental cost of compliance, including the cost of unbundled RECs, compared to the annual revenue requirement for each year in the 2015-2019 reporting period. **Table 5** is based on the incremental cost forecast from **Table 3**. **Table 6** is based on the incremental cost

[11] The sensitivity analysis incremental cost assumptions include (1) 2022 $16 CO_2, (2) November 8, 2013 Price Curve (medium gas curve), (3) Discount Rate from the 2013 IRP of 6.88%, and (4) Oregon's share based on forecast SG allocation factors based on the October 2013 load forecast.

forecast from the additional sensitivity scenario shown in **Table 4**. The Company's 2015-2019 Plan does not forecast the use of alternative compliance payments at this time to meet compliance. The 2015-2019 Plan forecasts the use of unbundled RECs to meet compliance, as noted above, the cost of the forecasted unbundled RECs is $155,086.89. 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 plus the forecasted cost of unbundled RECs for each compliance year.

The annual revenue requirement was calculated consistent with the methodology in OAR 860-083-0200. Pursuant 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

	Oregon Allocated Nominal Levelized Incremental Cost ($000s)			4% of Oregon Annual Revenue Requirement ($000s)	% Oregon Annual Revenue Requirement Threshold
	Bundled	Unbundled	Total		
2015	$1,205	$155	$1,360	$49,442	0.11%
2016	$1,351	$0	$1,351	$49,430	0.11%
2017	$1,356	$0	$1,356	$49,634	0.11%
2018	$1,357	$0	$1,357	$49,678	0.11%
2019	$1,360	$0	$1,360	$49,782	0.11%

12 The Company used the most recently available load forecast: October 2013.

Table 6					
		Based on Table 4 Data			
	Oregon Allocated Nominal Levelized Incremental Cost ($000s)			**4% of Oregon Annual Revenue Requirement ($000s)**	**% Oregon Annual Revenue Requirement Threshold**
	Bundled	**Unbundled**	**Total**		
2015	$5,625	$155	$5,780	$49,442	0.47%
2016	$6,305	$0	$6,305	$49,430	0.51%
2017	$6,331	$0	$6,331	$49,634	0.51%
2018	$6,336	$0	$6,336	$49,678	0.51%
2019	$6,350	$0	$6,350	$49,782	0.51%

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 2015-2019 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:

A material difference between the 2015-2019 Plan and the RPS Position Forecast included in the 2013 IRP[13] is the inclusion of unbundled RECs toward the annual compliance targets for Oregon starting in 2012 and continuing through 2015. As described in the 2013 IRP Action Plan, the Company intends to use unbundled RECs to meet state RPS compliance requirements. Specifically for Oregon, PacifiCorp will issue requests for proposals (RFPs) at least annually seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for compliance with the Company's Oregon RPS obligations. 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.[14]

[13] See Figure 8.32 – Annual State and Federal RPS Position Forecasts using the Preferred Portfolio on page 233 of PacifiCorp's 2013 IRP.
[14] See the Company's 2013 IRP, Action Item 1b.

In 2013, PacifiCorp issued an unbundled REC RFP and subsequently executed several contracts for the purchase of 600,000 unbundled RECs from Oregon RPS certified facilities. The Company included the 600,000 unbundled RECs in the 2015-2019 Plan and filed for deferral of the associated costs in docket UM 1646.

(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 2013 IRP Action Plan during the 2015-2019 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 2012 OFPC are shown in **Table 3**. **Confidential Attachment D** also includes the additional sensitivity scenario, 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 2015-2019 Plan.

(b) For the 2015 through 2019 reporting period, the Company expects to comply with the Oregon RPS requirements by using a combination of bundled and unbundled RECs. At this time, the Company plans to use (A) 212,448 unbundled RECs and does not plan to use any (B) bundled RECs issued between January 1 through March 31 of the year following the compliance year; or (C) alternative compliance payments.

Consistent with the 2013 IRP Action Plan, at least annually the Company will issue requests for proposals seeking historical, then current-year, or forward vintage unbundled RECs that will qualify for compliance with the Company's Oregon RPS obligations. As part of the solicitation and bid evaluation process, the Company will evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potential higher compliance cost alternatives in the long-term. 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 12-272 in docket UM 1570, the Commission acknowledged PacifiCorp's 2013-2017 Plan with the following three conditions for the 2015-2019 Plan:

- Include a "fuel cost hedging methodology . . . that at least captures transaction costs for purchasing fuel forwards."[15]
  - The Company has included 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 are compared total gas consumption by the Company's gas units for CY 2008-2012 are used to calculate an average annual historical gas transaction cost.
- Include "firming costs but not include shaping costs" in the incremental cost calculation.[16]
  - The Company has included firming costs associated with qualifying renewable resources which is the fixed cost of a simple cycle combustion turbine (SCCT) that has been 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
- "[U]se the most recent fuel price forecast filed in [PacifiCorp's] avoided cost or IRP proceeding" in the incremental cost calculation."[17]
  - The following scenarios[18] are considered in the incremental cost analysis:
    - Medium CO2 and low proxy plant fuel costs
    - Medium CO2 and medium proxy plant fuel costs*
    - Medium CO2 and high proxy plant fuel costs
    - High CO2 and medium proxy plant fuel costs*
    - High CO2 and low proxy plant fuel costs*
    - Zero CO2 and medium proxy plant fuel costs*
    - Zero CO2 and high proxy plant fuel costs*
    - For comparative purposes, the Company's analysis includes an additional sensitivity scenario based on the most recent natural gas price forecast from the November 8, 2013 OFPC.

[15] *In the Matter of PacifiCorp, dba Pacific Power, Renewable Portfolio Standard Implementation Plan 2013-2017*, Docket UM 1570, Order 12-272 at Appendix A (July 2, 2012).
[16] *Id*.
[17] *Id*.
[18] Scenarios marked with an asterisk are scenarios included in the 2013 IRP.

There were no conditions specified in the Commission's acknowledgment order of the 2011 IRP specific to the Oregon RPS Implementation Plan.[19] The Company's 2013 IRP is ongoing and is pending Commission acknowledgement.

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 2015-2019 Plan on its website within 30 days after a Commission acknowledgement order is issued. The Company will provide the public portions of the 2015-2019 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.

[19] *In the Matter of PacifiCorp 2011 Integrated Resource Plan*, Docket LC 57, Order 12-082 (Mar. 9, 2012).

Response: In compliance with OAR 860-038-0300, the Company will provide information about the 2015-2019 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: PacifiCorp has procured 2.0MW_{AC} of solar photovoltaic capacity out of the 8.7 MW_{AC} required to meet PacifiCorp's solar capacity standard requirements. In order to procure the remaining 6.7 MW_{AC} Oregon solar capacity requirement, PacifiCorp issued an RFP (2013S RFP) on April 30, 2013 with bids submitted June 11, 2013. Subsequently, PacifiCorp executed one power purchase agreement (PPA) for 5.0[20] and is in the process of negotiating a second PPA for 1.74. Both PPAs are scheduled to reach commercial operation by December 2014.

[20] As part of the 2013S RFP process, the Company acquired a waiver of OAR 860-084-0040(2) from the Commission to allow one of the projects to oversize the DC solar panel installation to offset future degradation and maintain the full AC output of 5.0 MW through 2020.

PacifiCorp
Renewable Portfolio Standard Oregon
Implementation Plan
2015-2019

Attachment A

Accounting of the RECs applicable to the RPS in Oregon

	MWh												
	2007 Actual	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Actual**	**2012 Actual**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**	**2019 Forecast**
Oregon Renewable Portfolio Standard Requirement (1)	-	-	-	-	650,729	638,940	648,264	650,557	1,967,441	1,966,953	1,975,075	1,976,831	1,980,973
Planned Compliance Method (2)													
Bundled RECs					650,729	511,152	518,611	520,446	1,754,993	1,966,953	1,975,075	1,976,831	1,980,973
Unbundled RECs						127,788	129,653	130,111	212,448				
Bundled RECs by vintage year	355,038	572,302	822,402	1,247,291	1,776,846	1,588,069	1,489,331	1,601,124	1,582,938	1,579,897	1,566,746	1,545,234	1,552,383
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	1,098,682	1,921,084	3,176,731	4,425,765	5,618,712	6,513,346	7,463,913	7,079,411	6,692,355	6,284,026	5,852,429	5,423,840
Alternative compliance payments					-	-	-	-	-	-			-

Notes

(1) Based on Retail Load Forecast, October 2013

(2) 2013-2017 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
2015-2019

<u>Attachment B</u>

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

(Redacted Version)

Total Company Generated Renewable Energy Credits (MWh)

		State	COD[1]	WREGIS ID	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
					Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
BIOGAS	Hill Air Force Base	UT	2005	W1263 / W1273	8,432	7,710	12,317	14,185	14,381	14,227	[redacted]						
	Total Biogas				**8,432**	**7,710**	**12,317**	**14,185**	**14,381**	**14,227**	[redacted]						
BIOMASS	Roseburg Forest Products - Dillard	OR	1976	W912	151,588	138,294	163,561	168,638	94,295	0	[redacted]						
	Total Biomass				**151,588**	**138,294**	**163,561**	**168,638**	**94,295**		[redacted]						
GEOTHERMAL	Blundell II	UT	2007	W230	3,830	66,777	83,230	75,513	83,074	81,810	[redacted]						
	Total Geothermal				**3,830**	**66,777**	**83,230**	**75,513**	**83,074**	**81,810**	[redacted]						
WIND	Campbell Hill-Three Buttes	WY	2009	W1383	0	0	39,975	299,990	359,800	340,033	[redacted]						
	Chevron Casper Wind Farm	WY	2009	W1370	0	0	6,122	38,584	48,823	45,768	[redacted]						
	Combine Hills	OR	2003	W189	117,181	114,458	104,572	104,663	118,643	108,721	[redacted]						
	Dunlap I	WY	2010	W1687	0	0	0	102,429	421,086	387,973	[redacted]						
	Foote Creek I	WY	1999	W201	57,092	64,184	51,816	55,910	63,075	51,103	[redacted]						
	Glenrock	WY	2008	W964	0	0	253,875	287,941	340,863	314,476	[redacted]						
	Glenrock III	WY	2009	W965	0	0	84,675	99,967	130,197	119,142	[redacted]						
	Goodnoe Hills	WA	2008	W536	0	147,308	237,374	212,268	239,431	221,156	[redacted]						
	High Plains	WY	2009	W1334	0	0	72,695	257,349	335,463	315,879	[redacted]						
	Leaning Juniper I	OR	2006	W200	289,452	312,614	258,767	223,558	234,789	190,905	[redacted]						
	Marengo	WA	2007	W185	160,636	400,245	316,552	330,943	403,408	358,669	[redacted]						
	Marengo II	WA	2008	W772	0	78,457	158,279	165,475	194,378	177,552	[redacted]						
	McFadden Ridge	WY	2009	W1341	0	0	20,558	77,366	102,595	94,789	[redacted]						
	Mountain Wind Power	WY	2008	W1022	0	64,968	128,330	149,425	186,503	171,518	[redacted]						
	Mountain Wind Power II	WY	2008	W1023	0	51,315	202,840	202,072	240,845	227,793	[redacted]						
	Rock River I	WY	2001	W187	140,904	156,957	134,819	138,204	136,079	135,098	[redacted]						
	Seven Mile Hill I	WY	2008	W975	0	0	303,510	324,123	381,679	342,192	[redacted]						
	Seven Mile Hill II	WY	2008	W976	0	0	62,229	67,722	83,613	72,558	[redacted]						
	Top of the World	WY	2010	W1749	0	0	0	188,825	685,448	665,128	[redacted]						
	Wolverine Creek	ID	2005	W188	148,933	170,270	153,761	162,140	198,629	178,431	[redacted]						
	Total Wind				**914,198**	**1,560,776**	**2,590,749**	**3,488,954**	**4,905,347**	**4,518,884**	[redacted]						
HYDRO	Ashton	ID	1917	W146	30,914	32,051	33,735	22,728	18,098	2,028	[redacted]						
	Big Fork	MT	1929	W179	24,435	27,562	28,977	32,262	34,671	33,426	[redacted]						
	Clearwater 1	OR	1953	W148	37,424	42,259	35,759	31,476	43,500	50,701	[redacted]						
	Clearwater 2	OR	1953	W149	45,315	43,375	41,993	29,705	56,329	54,153	[redacted]						
	Copco 1	CA	1918	W142	95,316	97,312	79,739	67,544	113,105	85,352	[redacted]						
	Cutler	UT	1927	W151	44,496	54,344	89,033	50,455	158,075	51,760	[redacted]						
	Fish Creek	OR	1952	W153	35,712	32,544	33,450	37,477	46,160	42,829	[redacted]						
	Grace	ID	1923	W137	76,033	61,403	59,082	63,490	163,373	82,593	[redacted]						
	JC Boyle	OR	1958	W180	275,892	276,946	222,073	193,133	335,014	240,436	[redacted]						
	Lemolo 1	OR	1955	W157	127,469	148,606	127,486	111,394	168,158	166,546	[redacted]						
	Lemolo 2	OR	1956	W158	148,711	153,208	89,595	138,473	182,966	207,037	[redacted]						
	Oneida	ID	1915	W160	36,899	34,616	33,304	28,486	77,321	32,971	[redacted]						
	Pioneer	UT	1897	W162	12,267	14,734	24,695	15,491	28,639	15,104	[redacted]						
	Prospect 2	OR	1928	W140	271,507	239,349	226,390	225,108	251,221	238,047	[redacted]						
	Prospect 3	OR	1932	W164	44,199	41,051	35,639	35,330	46,679	37,518	[redacted]						
	Slide Creek	OR	1951	W168	81,721	89,523	80,364	79,059	37,135	96,627	[redacted]						
	Soda	ID	1924	W170	15,603	14,378	12,403	13,960	35,155	20,023	[redacted]						
	Soda Springs	OR	1952	W171	41,295	56,787	51,112	51,896	70,977	50,541	[redacted]						
	Toketee	OR	1950	W173	209,075	218,891	213,049	188,950	263,816	263,788	[redacted]						
	Yale	WA	1953	W141	539,916	539,777	540,238	629,932	661,211	702,744	[redacted]						
	Total Hydro				**2,194,199**	**2,218,716**	**2,058,116**	**2,046,349**	**2,791,603**	**2,474,224**	[redacted]						
SOLAR INCENTIVE PROG	Oregon Solar Incentive Program - Central Oregon (CO 1)	OR	2010	W1686	0	0	0	11	209	403	[redacted]						
	Oregon Solar Incentive Program - Central Oregon (CO 2)	OR	2010	W2391	0	0	0	0	7	194	[redacted]						
	Oregon Solar Incentive Program - Central Oregon (CO 3)	OR	2010	W3671	0	0	0	0	0	0	[redacted]						
	Oregon Solar Incentive Program - Columbia River (CR 1)	OR	2010	W1970	0	0	0	0	126	192	[redacted]						
	Oregon Solar Incentive Program - Eastern Oregon (EO 1)	OR	2010	W1737	0	0	0	2	137	340	[redacted]						
	Oregon Solar Incentive Program - Eastern Oregon (EO 2)	OR	2010	W2611	0	0	0	0	0	116	[redacted]						
	Oregon Solar Incentive Program - Portland Oregon (PO 1)	OR	2011	W1738	0	0	0	2	81	189	[redacted]						
	Oregon Solar Incentive Program - Portland Oregon (PO 2)	OR	2011	W3672	0	0	0	0	0	0	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 1)	OR	2011	W1806	0	0	0	3	362	419	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 2)	OR	2011	W2240	0	0	0	0	161	545	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 3)	OR	2011	W2392	0	0	0	0	35	453	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 4)	OR	2011	W2690	0	0	0	0	0	316	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 5)	OR	2011	W3207	0	0	0	0	0	8	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 6)	OR	2011	W3516	0	0	0	0	0	0	[redacted]						
	Oregon Solar Incentive Program - Southern Oregon (SO 7)	OR	2011	W3554	0	0	0	0	0	0	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 1)	OR	2011	W1739	0	0	0	6	253	280	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 2)	OR	2011	W2326	0	0	0	0	14	202	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 3)	OR	2011	W3208	0	0	0	0	0	25	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 4)	OR	2011	W3396	0	0	0	0	0	0	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 5)	OR	2011	W3410	0	0	0	0	0	0	[redacted]						
	Oregon Solar Incentive Program - Willamette Valley (WV 6)	OR	2011	W3673	0	0	0	0	0	0	[redacted]						
	Oregon Solar Incentive Program - (Joseph Community) Large System Wallo	OR	2011	W2448	0	0	0	0	44	666	[redacted]						
	Oregon Solar Incentive Program (Solwatt)	OR	2011	W2968	0	0	0	0	0	257	[redacted]						
	Lakeview			W3468	0	0	0	0	0	0	[redacted]						
	Total Solar							**25**	**1,429**	**4,605**	[redacted]						
SOLAR CAPACITY STD	Black Cap	OR	2012	W3104	0	0	0	0	0	585	[redacted]						
	Total Utility Solar									**585**	[redacted]						
Total					**3,272,247**	**3,992,273**	**4,907,972**	**5,793,664**	**7,890,129**	**7,094,335**	[redacted]						

(1) COD means commercial operation date (year).

Oregon's Share Per Allocation Factors - Renewable Portfolio Standard Renewable Energy Credits (MWh)

		State	COD[1]	WREGIS ID	2007 Actual[2]	2008 Actual[2]	2009 Actual[2]	2010 Actual[2]	2011 Actual[2]	2012 Actual[2]	2013 Forecast[3]	2014 Forecast[3]	2015 Forecast[3]	2016 Forecast[3]	2017 Forecast[3]	2018 Forecast[3]	2019 Forecast[3]
BIOGAS	Hill Air Force Base	UT	2005	W1263 / W1273	0	0	0	0	3,797	3,689	[redacted]						
	Total Biogas								**3,797**	**3,689**							
BIOMASS	Roseburg Forest Products - Dillard	OR	1976	W912	0	0	0	0	0	0	[redacted]						
	Total Biomass																
GEOTHERMAL	Blundell II	UT	2007	W230	2,526	18,822	22,876	19,786	21,937	21,213	[redacted]						
	Total Geothermal				**2,526**	**18,822**	**22,876**	**19,786**	**21,937**	**21,213**							
WIND	Campbell Hill-Three Buttes	WY	2009	W1383	0	0	10,987	78,605	95,012	88,168	[redacted]						
	Chevron Casper Wind Farm	WY	2009	W1370	0	0	1,683	10,110	12,892	11,867							
	Combine Hills	OR	2003	W189	117,181	114,458	104,572	104,663	118,643	108,721							
	Dunlap I	WY	2010	W1687	0	0	0	26,839	111,195	100,599							
	Foote Creek I	WY	1999	W201	15,666	18,091	14,242	14,650	16,656	13,251							
	Glenrock	WY	2008	W964	0	560	69,779	75,448	90,011	81,542							
	Glenrock III	WY	2009	W965	0	0	23,435	26,194	34,381	30,893							
	Goodnoe Hills	WA	2008	W536	232	54,050	65,244	55,620	63,226	57,344							
	High Plains	WY	2009	W1334	0	0	19,981	67,432	88,585	81,906							
	Leaning Juniper I	OR	2006	W200	79,427	88,113	71,124	58,578	62,000	49,501							
	Marengo	WA	2007	W185	51,406	112,813	87,007	86,716	106,527	93,001							
	Marengo II	WA	2008	W772	0	22,114	43,504	43,359	51,329	46,038							
	McFadden Ridge	WY	2009	W1341	0	0	5,651	20,272	27,092	24,578							
	Mountain Wind Power	WY	2008	W1022	0	21,888	35,272	39,153	49,250	44,474							
	Mountain Wind Power II	WY	2008	W1023	0	16,401	55,752	52,948	63,599	59,065							
	Rock River I	WY	2001	W187	38,665	44,240	37,056	36,213	35,934	35,030							
	Seven Mile Hill I	WY	2008	W975	0	376	83,422	84,929	100,789	88,728							
	Seven Mile Hill II	WY	2008	W976	0	0	17,104	17,745	22,080	18,814							
	Top of the World	WY	2010	W1749	0	0	0	49,477	181,005	172,464							
	Wolverine Creek	ID	2005	W188	40,868	47,992	42,262	42,485	52,451	46,266							
	Total Wind				**343,444**	**541,096**	**788,077**	**991,436**	**1,382,657**	**1,252,250**							
HYDRO	Ashton	ID	1917	W146	0	0	0	5,955	4,779	526	[redacted]						
	Big Fork	MT	1929	W179	199	324	332	353	382	362							
	Clearwater 1	OR	1953	W148	0	0	0	8,248	11,487	13,146							
	Clearwater 2	OR	1953	W149	0	0	0	7,783	14,875	14,042							
	Copco 1	CA	1918	W142	105	126	100	81	137	102							
	Cutler	UT	1927	W151	136	628	1,004	13,221	41,743	13,421							
	Fish Creek	OR	1952	W153	0	0	0	9,820	12,189	11,105							
	Grace	ID	1923	W137	0	0	0	16,636	43,142	21,416							
	JC Boyle	OR	1958	W180	372	1,124	879	728	1,273	898							
	Lemolo 1	OR	1955	W157	3,446	4,281	3,581	29,188	44,405	43,184							
	Lemolo 2	OR	1956	W158	363	371	212	36,284	48,315	53,683							
	Oneida	ID	1915	W160	803	746	699	7,464	20,418	8,549							
	Pioneer	UT	1897	W162	194	304	496	297	553	287							
	Prospect 2	OR	1928	W140	1,104	1,167	1,076	1,020	1,148	1,068							
	Prospect 3	OR	1932	W164	1,196	1,259	1,066	9,257	12,326	9,728							
	Slide Creek	OR	1951	W168	0	0	0	20,716	9,806	25,055							
	Soda	ID	1924	W170	0	0	0	3,658	9,283	5,192							
	Soda Springs	OR	1952	W171	0	0	0	13,598	18,743	13,105							
	Toketee	OR	1950	W173	0	0	0	49,510	69,665	68,399							
	Yale	WA	1953	W141	1,150	2,054	2,004	2,228	2,357	2,460							
	Total Hydro				**9,068**	**12,384**	**11,449**	**236,045**	**367,026**	**305,728**							
SOLAR INCENTIVE PROG	Oregon Solar Incentive Program - Central Oregon (CO 1)	OR	2010	W1686	0	0	0	11	209	403	[redacted]						
	Oregon Solar Incentive Program - Central Oregon (CO 2)	OR	2010	W2391	0	0	0	0	7	194							
	Oregon Solar Incentive Program - Central Oregon (CO 3)	OR	2010	W3671	0	0	0	0	0	0							
	Oregon Solar Incentive Program - Columbia River (CR 1)	OR	2010	W1970	0	0	0	0	126	192							
	Oregon Solar Incentive Program - Eastern Oregon (EO 1)	OR	2010	W1737	0	0	0	2	137	340							
	Oregon Solar Incentive Program - Eastern Oregon (EO 2)	OR	2010	W2611	0	0	0	0	0	116							
	Oregon Solar Incentive Program - Portland Oregon (PO 1)	OR	2011	W1738	0	0	0	2	81	189							
	Oregon Solar Incentive Program - Portland Oregon (PO 2)	OR	2011	W3672	0	0	0	0	0	0							
	Oregon Solar Incentive Program - Southern Oregon (SO 1)	OR	2011	W1806	0	0	0	3	362	419							
	Oregon Solar Incentive Program - Southern Oregon (SO 2)	OR	2011	W2240	0	0	0	0	161	545							
	Oregon Solar Incentive Program - Southern Oregon (SO 3)	OR	2011	W2392	0	0	0	0	35	453							
	Oregon Solar Incentive Program - Southern Oregon (SO 4)	OR	2011	W2690	0	0	0	0	0	316							
	Oregon Solar Incentive Program - Southern Oregon (SO 5)	OR	2011	W3207	0	0	0	0	0	7							
	Oregon Solar Incentive Program - Southern Oregon (SO 6)	OR	2011	W3516	0	0	0	0	0	0							
	Oregon Solar Incentive Program - Southern Oregon (SO 7)	OR	2011	W3554	0	0	0	0	0	0							
	Oregon Solar Incentive Program - Willamette Valley (WV 1)	OR	2011	W1739	0	0	0	6	253	280							
	Oregon Solar Incentive Program - Willamette Valley (WV 2)	OR	2011	W2326	0	0	0	0	14	202							
	Oregon Solar Incentive Program - Willamette Valley (WV 3)	OR	2011	W3208	0	0	0	0	0	25							
	Oregon Solar Incentive Program - Willamette Valley (WV 4)	OR	2011	W3396	0	0	0	0	0	0							
	Oregon Solar Incentive Program - Willamette Valley (WV 5)	OR	2011	W3410	0	0	0	0	0	0							
	Oregon Solar Incentive Program - Willamette Valley (WV 6)	OR	2011	W3673	0	0	0	0	0	0							
	Oregon Solar Incentive Program - (Joseph Community) Large System Wallo	OR	2011	W2448	0	0	0	0	44	666							
	Oregon Solar Incentive Program (Solwatt)	OR	2011	W2968	0	0	0	0	0	257							
	Lakeview	OR	2012	W3468	0	0	0	0	0	0							
	Total Solar							**25**	**1,429**	**4,604**							
SOLAR CAPACITY STD	Black Cap	OR	2012	W3104	0	0	0	0	0	585	[redacted]						
	Total Utility Solar									**585**							
Total					**355,038**	**572,302**	**822,402**	**1,247,291**	**1,776,846**	**1,588,069**	**1,489,331**	**1,601,124**	**1,582,938**	**1,579,897**	**1,566,746**	**1,545,234**	**1,552,383**
Oregon's Share Based on SG Allocation Factors					**27.44%**	**28.19%**	**27.49%**	**26.20%**	**26.41%**	**25.93%**	[redacted]						

(1) COD means commercial operation date (year).
(2) Oregon's Share based on actual system generation (SG) allocation factors.
(3) Oregon's share based on forecasted system generation (SG) allocation factors:
2013 - Based on Retail Load Forecast, December 2012
2014 through 2017 - Based on Retail Load Forecast, November 2013

CONFIDENTIAL
Attachment B - Unbundled RECs

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]	Biogas	ID	[redacted]									
			Wind	OR										
			Biogas	OR										
			Biogas	OR										
			Wind	WA										
[redacted]	1/25/2013							[redacted]						
		[redacted]	Wind	CA	[redacted]									
			Wind	CA										
[redacted]	2/6/2013							[redacted]						
		[redacted]	Wind	WA	[redacted]									
			Wind	WA										
			Hydroelectric	WA										
			Hydroelectric	WA										
			Hydroelectric	WA										
			Hydroelectric	WA										
[redacted]	2/11/2013							[redacted]						
		[redacted]	Wind	OR	[redacted]									
[redacted]	2/6/2013							[redacted]						
		[redacted]	Wind	OR	[redacted]									
			Wind	WY										
			Wind	OR										
			Wind	WA										
[redacted]	1/31/2013							[redacted]						
		[redacted]	Biogas	OR	[redacted]									
[redacted]	2/4/2013							[redacted]						
		[redacted]	Wind	WA	[redacted]									
			Wind	WA										
[redacted]	2/4/2013							[redacted]						
		[redacted]	Wind	WA	[redacted]									
			Wind	WA										
[redacted]	6/28/2013							[redacted]						
		[redacted]	Wind	NM	[redacted]									
			Wind	OR										
[redacted]	2/28/2013							[redacted]						
		[redacted]	Wind	WA	[redacted]									
[redacted]	7/9/2013							[redacted]						
		[redacted]	Wind	WA	[redacted]									
			Wind	WA										
[redacted]	8/28/2013							[redacted]						
		[redacted]	Wind	OR	[redacted]									
[redacted]	11/5/2013							[redacted]						
		[redacted]	Wind	OR	[redacted]									
			Wind	WA										
Total								44,000	127,342	0	8,356	122,916	243,819	53,567

PacifiCorp
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<u>Attachment C</u>

Preliminary Key Assumptions
Incremental Cost Calculation

(Redacted Version)

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
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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, 2014 that provides, among other things, a forecast of expected incremental costs of renewable resources in service during the 2015-2019 Oregon Implementation Plan (2015-2019 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 is based on a combined cycle combustion turbine (water-cooled "F" class 2x1 with duct firing) at the Lake Side location. The annual expected incremental cost calculation for renewable resources in service during the 2015-2019 reporting period is the difference between the nominal levelized cost of the renewable resource and the nominal levelized cost of the proxy plant.

Methodology

The nominal levelized costs have been developed using an approach similar to that used to create the supply-side resource tables in Chapter 7 of the 2013 Integrated Resource Plan (IRP). For qualifying renewable resources currently in service, initial capital investment values, 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 2007-2012. Data for renewable resources acquired through a power purchase agreement (PPA) reflect the associated contract terms.

Consistent with the 2013 IRP, a discount rate of 6.882% has been used in this expected incremental cost analysis. Payment factors used to calculate capital carrying costs have been modeled on a real levelized basis, with the effects of inflation removed, consistent with supply-side resources in the 2013 IRP.

Inflation values are based on the Company's official inflation forecast. Where a calculation requires a single value, the 1.8% average annual inflation rate from 2013-2034 has been used. Otherwise, yearly values from the Company's official inflation forecast have been applied.

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.

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Key Assumptions – Expected Incremental Cost Calculation

Qualifying Resources

Table 1 provides the qualifying renewable resources that are included in the expected incremental cost calculation in the 2015-2019 Plan. There has been one change to the list of qualifying renewable resources since the Company's 2013-2017 Plan: the Chevron Casper Wind farm (PPA) is excluded since the contract term ends December 31, 2014.

Table 1

Resource	Assumed Capacity Factor (%)	In-Service Year	MW	Design Plant Life / Contract Term (Years)
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
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
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

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 2007-2012 are actuals, generation amounts for 2013 is a combination of actual generation from January 2013 through September 2013 and forecasted values for the remainder of the year, and for years 2014 and beyond forecasted generation values were used.

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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 wind integration, which is added as an adjustment in the levelized cost calculation.

Table 2

Resource	Contract Start Year	Contract Term (Years)	Average Capacity (MW)	PPA Contract Price ($/MWh)
Campbell Hill-Three Buttes (PPA)	2009	20	99	[redacted]
Mountain Wind Power (PPA)	2008	25	60.9	[redacted]
Mountain Wind Power II (PPA)	2008	25	79.8	[redacted]
Top of the World (PPA)	2010	20	200.2	[redacted]

The Company used wind integration costs from the Company's previously filed Oregon Transition Adjustment Mechanism (TAM) filings for calendar year (CY) 2007-2014. The most recent TAM filing for CY 2014 included integration costs based on PacifiCorp's 2012 Wind Study released in April 2013 as Appendix H to the 2013 IRP. Wind integration costs for 2015 and beyond are estimated by escalating 2014 values at inflation.

Actual Bonneville Power Administration (BPA) transmission 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 have been adjusted to reflect the outcome of BPA's most recent rate case starting in October 2013 and annual increases for inflation thereafter.

Renewable resources that have been excluded from the cost analysis are resources that have not been certified by Oregon Department of Energy as eligible under the Oregon RPS program, including facilities associated with the Oregon Solar Incentive Program and the Oregon Solar Capacity Standard, which are below the 20 MW threshold.

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Key Assumptions – Expected Incremental Cost Calculation

Additionally, the Rolling Hills facility is currently not included in Oregon rates and has been excluded from this cost analysis.[1]

Proxy Plant

No new long-term qualifying electricity is contemplated in the 2015-2019 reporting period, therefore no new proxy plants have been added in this analysis. The existing proxy plant is from the 2008 IRP and is representative of a combined cycle combustion turbine (water-cooled "F" class 2x1 with duct firing) at the Lake Side location. The proxy plant's characteristics remain unchanged from those stated in the 2013-2017 Plan analysis. Consistent with the 2013 IRP, fuel price data is from the Company's September 2012 official forward price curve (OFPC) with natural gas delivered at the Lake Side location.

The following scenarios[2] are considered in the incremental cost analysis:

- Medium CO2 and low proxy plant fuel costs
- Medium CO2 and medium proxy plant fuel costs*
- Medium CO2 and high proxy plant fuel costs
- High CO2 and medium proxy plant fuel costs*
- High CO2 and low proxy plant fuel costs*
- Zero CO2 and medium proxy plant fuel costs*
- Zero CO2 and high proxy plant fuel costs*

For comparative purposes, the Company's analysis includes an additional sensitivity scenario based on the most recent natural gas price forecast from the November 8, 2013 OFPC.

Consistent with the discussion in Commission Order No. 09-299,[3] capital costs for the existing proxy plant remain unchanged from the Company's 2013-2017 Plan.[4] The O&M for the existing proxy plant is also unchanged from the 2013-2017 Plan.

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[1] *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)..

[2] Scenarios marked with an asterisk are scenarios included in the 2013 IRP.

[3] *See* Order No. 09-299 (August 3, 2009), AR 518 Phase III, page 4.

[4] The Company's 2013-2017 Plan was filed with the Commission on December 30, 2011 in docket UM 1570.

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Key Assumptions – Expected Incremental Cost Calculation

The proxy CCCT is 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. For this filing, we assumed a CCCT capacity factor of 51.5% (capacity weighted expected CF value for CCCT and duct firing units).

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 are compared total gas consumption by the Company's gas units for CY 2008-2012 are used to calculate an average annual historical gas transaction cost of $0.0001/MMBTU. Values for 2013 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 is similarly calculated with nominal levelized values aligned to the service years of each qualifying resource.

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Key Assumptions – Expected Incremental Cost Calculation

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 2015-2019 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 2013 load forecast.

Table 3

Year	SG Allocation Factor
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]

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Confidential Attachment D

Incremental Cost Analysis

Subject to Protective Order

THIS ATTACHMENT IS CONFIDENTIAL AND PROVIDED UNDER SEPARATE COVER

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Addendum

PacifiCorp
Renewable Portfolio Standard Oregon Implementation Plan
2015-2019

Scenarios 1-8

Summary of Incremental Cost by Resource

PacifiCorp Oregon - 2015-2019 RPS Implementation Plan
2015 - 2019 Summary: RPS incremental costs by resource

Scenario 1: Zero CO2 and Medium Proxy Plant Fuel Costs

	2015	2016	2017	2018	2019
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($1,096)	($1,090)	($1,085)	($1,076)	($1,075)
Campbell Hill-Three Buttes	$1,181	$1,175	$1,169	$1,160	$1,159
Dunlap I	$3	$3	$3	$3	$3
Glenrock	$108	$107	$107	$106	$106
Glenrock III	$158	$158	$157	$155	$155
Goodnoe Hills	$1,144	$1,138	$1,132	$1,124	$1,123
High Plains	$831	$826	$822	$816	$815
McFadden Ridge	($5)	($5)	($5)	($5)	($5)
Marengo	$236	$235	$234	$232	$232
Marengo II	$343	$342	$340	$337	$337
Mountain Wind Power	$130	$129	$129	$128	$128
Mountain Wind Power II	$645	$642	$639	$634	$633
Seven Mile Hill I	($725)	($721)	($718)	($712)	($712)
Seven Mile Hill II	($135)	($134)	($133)	($132)	($132)
Top of the World	$2,408	$2,395	$2,383	$2,364	$2,363

Scenario 2: Zero CO2 and High Proxy Plant Fuel Costs

	2015	2016	2017	2018	2019
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($1,301)	($1,294)	($1,287)	($1,277)	($1,277)
Campbell Hill-Three Buttes	$475	$473	$470	$467	$466
Dunlap I	($1,036)	($1,030)	($1,025)	($1,017)	($1,017)
Glenrock	($744)	($740)	($736)	($731)	($730)
Glenrock III	($169)	($168)	($167)	($166)	($166)
Goodnoe Hills	$518	$515	$513	$509	$508
High Plains	$17	$17	$16	$16	$16
McFadden Ridge	($232)	($230)	($229)	($227)	($227)
Marengo	($562)	($559)	($556)	($552)	($552)
Marengo II	($106)	($105)	($105)	($104)	($104)
Mountain Wind Power	($236)	($235)	($233)	($232)	($231)
Mountain Wind Power II	$180	$179	$178	$176	$176
Seven Mile Hill I	($1,645)	($1,636)	($1,628)	($1,615)	($1,614)
Seven Mile Hill II	($316)	($314)	($313)	($310)	($310)
Top of the World	$889	$884	$880	$873	$872

PacifiCorp Oregon - 2015-2019 RPS Implementation Plan
2015 - 2019 Summary: RPS incremental costs by resource

Scenario 3: Medium CO2 and Low Proxy Plant Fuel Costs

	2015	2016	2017	2018	2019
Resource	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**
Blundell II	($1,007)	($1,001)	($996)	($988)	($988)
Campbell Hill-Three Buttes	$1,563	$1,554	$1,547	$1,534	$1,534
Dunlap I	$421	$419	$417	$413	$413
Glenrock	$465	$463	$460	$457	$456
Glenrock III	$296	$294	$293	$290	$290
Goodnoe Hills	$1,419	$1,411	$1,404	$1,393	$1,392
High Plains	$1,173	$1,167	$1,161	$1,152	$1,151
McFadden Ridge	$90	$90	$89	$89	$89
Marengo	$604	$601	$598	$593	$593
Marengo II	$540	$537	$535	$531	$530
Mountain Wind Power	$290	$289	$287	$285	$285
Mountain Wind Power II	$849	$845	$840	$834	$833
Seven Mile Hill I	($339)	($337)	($336)	($333)	($333)
Seven Mile Hill II	($59)	($58)	($58)	($58)	($58)
Top of the World	$3,186	$3,168	$3,152	$3,128	$3,126

Scenario 4: Medium CO2 and Medium Proxy Plant Fuel Costs

Resource	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**
Blundell II	($1,195)	($1,189)	($1,183)	($1,173)	($1,173)
Campbell Hill-Three Buttes	$864	$860	$855	$849	$848
Dunlap I	($512)	($509)	($507)	($503)	($503)
Glenrock	($309)	($307)	($306)	($303)	($303)
Glenrock III	($2)	($2)	($2)	($2)	($2)
Goodnoe Hills	$842	$838	$834	$827	$827
High Plains	$433	$430	$428	$425	$425
McFadden Ridge	($116)	($115)	($115)	($114)	($114)
Marengo	($142)	($142)	($141)	($140)	($140)
Marengo II	$127	$126	$125	$124	$124
Mountain Wind Power	($46)	($46)	($46)	($45)	($45)
Mountain Wind Power II	$421	$419	$417	$413	$413
Seven Mile Hill I	($1,175)	($1,169)	($1,163)	($1,154)	($1,153)
Seven Mile Hill II	($223)	($222)	($221)	($219)	($219)
Top of the World	$1,713	$1,704	$1,695	$1,682	$1,681

PacifiCorp Oregon - 2015-2019 RPS Implementation Plan
2015 - 2019 Summary: RPS incremental costs by resource

Scenario 5: Medium CO2 and High Proxy Plant Fuel Costs

	2015	2016	2017	2018	2019
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($1,366)	($1,359)	($1,352)	($1,341)	($1,341)
Campbell Hill-Three Buttes	$275	$273	$272	$270	$270
Dunlap I	($1,379)	($1,371)	($1,364)	($1,353)	($1,353)
Glenrock	($1,020)	($1,015)	($1,009)	($1,001)	($1,001)
Glenrock III	($275)	($273)	($272)	($270)	($270)
Goodnoe Hills	$319	$317	$316	$313	$313
High Plains	($247)	($246)	($244)	($242)	($242)
McFadden Ridge	($305)	($303)	($302)	($299)	($299)
Marengo	($810)	($806)	($802)	($796)	($795)
Marengo II	($249)	($247)	($246)	($244)	($244)
Mountain Wind Power	($352)	($350)	($348)	($346)	($345)
Mountain Wind Power II	$32	$32	$32	$31	$31
Seven Mile Hill I	($1,943)	($1,932)	($1,923)	($1,908)	($1,907)
Seven Mile Hill II	($375)	($373)	($371)	($368)	($368)
Top of the World	$443	$440	$438	$435	$434

Scenario 6: High CO2 and Low Proxy Plant Fuel Costs

	2015	2016	2017	2018	2019
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($1,095)	($1,089)	($1,083)	($1,075)	($1,074)
Campbell Hill-Three Buttes	$1,312	$1,305	$1,298	$1,288	$1,287
Dunlap I	($54)	($54)	($53)	($53)	($53)
Glenrock	$87	$87	$87	$86	$86
Glenrock III	$151	$150	$149	$148	$148
Goodnoe Hills	$1,151	$1,144	$1,139	$1,130	$1,129
High Plains	$812	$808	$804	$797	$797
McFadden Ridge	($10)	($10)	($10)	($10)	($10)
Marengo	$275	$274	$272	$270	$270
Marengo II	$348	$346	$344	$341	$341
Mountain Wind Power	$134	$133	$132	$131	$131
Mountain Wind Power II	$650	$646	$643	$638	$638
Seven Mile Hill I	($747)	($743)	($739)	($733)	($733)
Seven Mile Hill II	($139)	($138)	($137)	($136)	($136)
Top of the World	$2,616	$2,601	$2,588	$2,568	$2,566

PacifiCorp Oregon - 2015-2019 RPS Implementation Plan
2015 - 2019 Summary: RPS incremental costs by resource

Scenario 7: High CO2 and Medium Proxy Plant Fuel Costs

	2015	2016	2017	2018	2019
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($1,330)	($1,323)	($1,316)	($1,306)	($1,305)
Campbell Hill-Three Buttes	$496	$494	$491	$487	$487
Dunlap I	($1,246)	($1,239)	($1,232)	($1,223)	($1,222)
Glenrock	($891)	($886)	($882)	($875)	($874)
Glenrock III	($225)	($224)	($223)	($221)	($221)
Goodnoe Hills	$431	$428	$426	$423	$422
High Plains	($123)	($123)	($122)	($121)	($121)
McFadden Ridge	($270)	($269)	($268)	($265)	($265)
Marengo	($644)	($641)	($637)	($632)	($632)
Marengo II	($169)	($168)	($167)	($166)	($166)
Mountain Wind Power	($287)	($285)	($284)	($281)	($281)
Mountain Wind Power II	$115	$115	$114	$113	$113
Seven Mile Hill I	($1,804)	($1,794)	($1,785)	($1,771)	($1,770)
Seven Mile Hill II	($347)	($345)	($344)	($341)	($341)
Top of the World	$863	$859	$854	$848	$847

Scenario 8: Nov 8 2013 OFPC

	2015	2016	2017	2018	2019
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($1,143)	($1,137)	($1,131)	($1,122)	($1,122)
Campbell Hill-Three Buttes	$1,089	$1,083	$1,078	$1,069	$1,069
Dunlap I	($266)	($265)	($264)	($261)	($261)
Glenrock	($100)	($99)	($99)	($98)	($98)
Glenrock III	$79	$78	$78	$77	$77
Goodnoe Hills	$1,003	$997	$992	$984	$984
High Plains	$633	$629	$626	$621	$621
McFadden Ridge	($60)	($60)	($59)	($59)	($59)
Marengo	$71	$71	$70	$70	$70
Marengo II	$241	$240	$239	$237	$237
Mountain Wind Power	$47	$47	$47	$46	$46
Mountain Wind Power II	$540	$537	$534	$530	$530
Seven Mile Hill I	($949)	($944)	($939)	($932)	($931)
Seven Mile Hill II	($179)	($178)	($177)	($176)	($176)
Top of the World	$2,168	$2,156	$2,145	$2,128	$2,127

PacifiCorp
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Scenarios 1 - 8

Summary of Incremental Cost of Compliance

PacifiCorp Oregon - 2015-2019 RPS Implementation Plan
2015 - 2019 Summary: RPS Total Incremental Cost of Compliance

Scenario 1: Zero CO2 and Medium Proxy Plant Fuel Costs

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	$9,270	$155	$9,425	$49,442	0.76%
2016	$10,389	$0	$10,389	$49,430	0.84%
2017	$10,432	$0	$10,432	$49,634	0.84%
2018	$10,441	$0	$10,441	$49,678	0.84%
2019	$10,463	$0	$10,463	$49,782	0.84%

Scenario 2: Zero CO2 and High Proxy Plant Fuel Costs

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	($7,569)	$155	($7,414)	$49,442	-0.60%
2016	($8,483)	$0	($8,483)	$49,430	-0.69%
2017	($8,518)	$0	($8,518)	$49,634	-0.69%
2018	($8,526)	$0	($8,526)	$49,678	-0.69%
2019	($8,544)	$0	($8,544)	$49,782	-0.69%

Scenario 3: Medium CO2 and Low Proxy Plant Fuel Costs

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	$16,832	$155	$16,987	$49,442	1.37%
2016	$18,865	$0	$18,865	$49,430	1.53%
2017	$18,943	$0	$18,943	$49,634	1.53%
2018	$18,960	$0	$18,960	$49,678	1.53%
2019	$19,000	$0	$19,000	$49,782	1.53%

Scenario 4: Medium CO2 and Medium Proxy Plant Fuel Costs

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	$1,205	$155	$1,360	$49,442	0.11%
2016	$1,351	$0	$1,351	$49,430	0.11%
2017	$1,356	$0	$1,356	$49,634	0.11%
2018	$1,357	$0	$1,357	$49,678	0.11%
2019	$1,360	$0	$1,360	$49,782	0.11%

Scenario 5: Medium CO2 and High Proxy Plant Fuel Costs

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	($12,859)	$155	($12,704)	$49,442	-1.03%
2016	($14,412)	$0	($14,412)	$49,430	-1.17%
2017	($14,472)	$0	($14,472)	$49,634	-1.17%
2018	($14,484)	$0	($14,484)	$49,678	-1.17%
2019	($14,515)	$0	($14,515)	$49,782	-1.17%

Scenario 6: High CO2 and Low Proxy Plant Fuel Costs

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	$9,736	$155	$9,891	$49,442	0.80%
2016	$10,912	$0	$10,912	$49,430	0.88%
2017	$10,957	$0	$10,957	$49,634	0.88%
2018	$10,966	$0	$10,966	$49,678	0.88%
2019	$10,989	$0	$10,989	$49,782	0.88%

Scenario 7: High CO2 and Medium Proxy Plant Fuel Costs

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	($9,629)	$155	($9,474)	$49,442	-0.77%
2016	($10,792)	$0	($10,792)	$49,430	-0.87%
2017	($10,837)	$0	($10,837)	$49,634	-0.87%
2018	($10,846)	$0	($10,846)	$49,678	-0.87%
2019	($10,869)	$0	($10,869)	$49,782	-0.87%

Scenario 8: Nov 8 2013 OFPC

	Incremental Costs			4% Annual Revenue Requirement	Percent of Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)	($000s)	
2015	$5,625	$155	$5,780	$49,442	0.47%
2016	$6,305	$0	$6,305	$49,430	0.51%
2017	$6,331	$0	$6,331	$49,634	0.51%
2018	$6,336	$0	$6,336	$49,678	0.51%
2019	$6,350	$0	$6,350	$49,782	0.51%