PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

December 30, 2011

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: **PacifiCorp's Renewable Portfolio Standard Implementation Plan 2013-2017**
OAR 860-083-0400 Compliance Filing and Motion for Protective Order

In compliance with OAR 860-083-0400, please find enclosed PacifiCorp's Oregon Renewable Portfolio Standard (RPS) Implementation Plan, for the compliance years 2013-2017. Confidential and public versions of the Implementation Plan are included in this submission. The confidential information is included pursuant to OAR 860-001-0070. Also enclosed is a CD containing confidential work papers associated with this filing.

The filing also includes a motion for a standard protective order for this matter.

It is respectfully requested that all formal data requests to the Company regarding this filing be addressed to the following:

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

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
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Formal communications concerning this proceeding should be addressed to the following.

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Please direct any informal inquiries to Joelle Steward, Regulatory Manager, at (503) 813-5542.

Sincerely,

Andrea L. Kelly /B

Andrea L. Kelly
Vice President, Regulation

Enclosures

cc: Service List UM 1467

CERTIFICATE OF SERVICE

I hereby certify that on this 30th of December, 2011, I caused to be served, via E-Mail, a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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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

Pursuant to OAR 860-001-0080(1), PacifiCorp d/b/a Pacific Power (Company) moves for the entry of the Public Utility Commission of Oregon's (Commission) general protective order in this proceeding. As good cause for this motion, PacifiCorp states:

1. The Commission's rules authorize PacifiCorp to seek reasonable restrictions on discovery of trade secrets and other confidential business information. *See* OAR 860-001-0080(3) (allowing confidential designation of information that is protected under Oregon Rule of Civil Procedure 36(C)(7) or is exempt from public disclosure under the Public Records Law). *See also 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. The Company anticipates that parties to this docket may request proprietary cost data, commercially sensitive load and resource projections, confidential market analyses and business projections, and confidential information relating to renewable energy credits and/or compliance with ORS 469A. This confidential business information is of significant commercial value, which could expose the Company to competitive injury if disclosure is unrestricted.

3. It is substantially likely that Staff and others in this proceeding will seek to discover a large amount of information held by PacifiCorp, including confidential business information. "The Commission's standard blanket protective order is designed to facilitate discovery in cases involving discovery of large numbers of documents." *See In re Portland Extended Area Service Region*, Docket UM 261, Order No. 91-958 (1991). Issuance of a protective order will facilitate the production of relevant information and expedite the discovery process.

For the foregoing reasons, PacifiCorp requests entry of the Commission's standard protective order in this docket.

DATED: December 30, 2011.

Mary Wiencke /JB

PacifiCorp

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Photo courtesy Solar City


PacifiCorp

Renewable Portfolio Standard Oregon Implementation Plan 2013-2017

January 1, 2012

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2013 through 2017

Pursuant to ORS 469A.075 and OAR 860-083-0400, PacifiCorp, d.b.a. Pacific Power (the Company), respectfully submits the 2013 through 2017[1] Oregon Implementation Plan (the 2013-2017 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 2013-2017 Plan shows that the Company intends to meet Oregon RPS targets during the 2013-2017 reporting period with bundled renewable energy certificates (RECs) from existing Oregon allocated eligible renewable resources. With the utilization of bundled RECs, the Company has sufficient eligible renewable resources to comply with the RPS through 2017. The 2013-2017 Plan does not utilize unbundled RECs; however, the Company will evaluate the potential of acquiring unbundled RECs and applying them toward compliance in future years, as indicated in PacifiCorp's comments in the 2011 IRP proceeding.[2]

The 2013-2017 Plan was prepared with information consistent with the Company's most recently filed integrated resource plan (IRP) – the 2011 IRP,[3] unless stated otherwise. 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 IRP action plan represents a road-map for implementation of the preferred portfolio. The current economic and regulatory environments are continually changing and may require the IRP action plan to change, as specific events, legislation and regulations evolve. Such changes may materially impact resource acquisitions and the timing of those acquisitions. In preparing the 2013-2017 Plan, the Company has only 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. The 2011 IRP does not add any significant new renewable resources prior to 2018. As shown in the 2013-2017 Plan, the existing resources will enable the Company to meet the 2013-2017 Oregon RPS targets.

Consistent with the Company's prior implementation plan[4] (the 2011-2015 Plan), the forecast of expected incremental costs are negative for all existing eligible renewable resources, indicating that the existing eligible renewable resources are less expensive than the proxy plant. In addition, the 2013-2017 Plan shows that, using the methodology established by the rules adopted by the Commission, the incremental costs do not trigger the 4 percent cost limit under ORS 469A.100.

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[1] This 2013-2017 Plan is based on the compliance years January 1, 2013 through December 31, 2017.
[2] The Company's Reply to Staff's Final Comments (pages 3, 6 and 7), dated November 3, 2011, Docket LC 52
[3] The Company's 2011 IRP was filed with the Commission on March 31, 2011, Docket LC 52.
[4] The Company's 2011-2015 Plan was filed with the Commission on December 31, 2009, Docket UM 1467.

Implementation Plan

The format used in the 2013-2017 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 most recent load forecast (November 2011).[5]

Table 1	2013	2014	2015	2016	2017
Applicable RPS Standard as % of Electricity Sold	5%	5%	15%	15%	15%
Estimated PacifiCorp Oregon RPS Target[6] (MWh)	648,272	656,453	1,976,678	1,986,366	2,002,475

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 2013-2017 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.

[5] For OAR 860-083-0400(2)(a) in this 2013-2017 Plan, the Company used the most recently available load forecast; November 2011. The 2011 IRP uses the October 2010 load forecast.
[6] 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 the ODOE 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 2013-2017 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 2013-2017 Plan, because they have not received certification as eligible under the Oregon RPS program. The resources not included 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[7] that recently came on line and for which the Company is in the process of submitting applications to the 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. The 2011 forecast of expected annual MWh output includes the impact of reduced generation and REC production as a result of the Bonneville Power Administration (BPA) Dispatch Standing Order 216 (DSO 216) and Environmental Redispatch (ER). The facilities impacted are Leaning Juniper and Goodnoe Hills. The Company's forecast for 2012 and beyond does not include any reductions in generation and REC production resulting from any future instances of DSO 216 or ER.

[7] The Oregon Solar Incentive Program is implemented through 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
	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
Solar (Oregon Solar Incentive Program)	Central Oregon (CO 1)	OR	2010
	Portland Oregon (PO 1)	OR	2010
	Willamette Valley (WV 1)	OR	2010
	Southern Oregon (SO 1)	OR	2010
	Southern Oregon (SO 2)	OR	2011
	Central Oregon (CO 2)	OR	2011

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: **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 2013-2017 reporting period, pursuant to OAR 860-083-0100.

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 this date are deemed to have zero incremental costs, pursuant to OAR 860-083-0100(1)(h).

The Company did not include the Oregon Solar Incentive Program facilities in its forecast of incremental costs. This program is relatively small and still in its pilot phase with uncertainty for future incentive costs. In light of this, the Company recommends that the parties and the Commission address the development of a methodology for incremental costs for this program, as well as other small facilities, in future investigations or rulemakings associated with RPS compliance.

The forecast of expected incremental cost analysis uses the forecast system generation (SG) allocation factors from the November 2011 load forecast.

Table 3 demonstrates that, under the medium (2015 $19/ton) carbon dioxide ($CO_2$) price and medium fuel price scenario, the forecast of expected incremental costs for qualifying electricity are negative, which means that the costs of a proxy plant of non-qualifying electricity exceed the costs of the qualifying electricity (using the methodology established by the rules adopted by the Commission). The list of qualifying renewable resources below is unchanged from the Company's 2011-2015 Plan.

Table 3

2013-2017 Summary
Oregon Allocated Nominal Levelized Incremental Costs [8]
2015 $19/ton CO_2 price (medium), September 2010 medium fuel price curve

Resource	2013	2014	2015	2016	2017
Blundell II	(1,633)	(1,610)	(1,606)	(1,586)	(1,560)
Campbell Hill-Three Buttes (PPA)	(1,523)	(1,500)	(1,497)	(1,478)	(1,454)
Chevron Casper Wind Farm (PPA)	(285)	(281)	(281)	(277)	(273)
Dunlap I	(3,127)	(3,081)	(3,074)	(3,036)	(2,985)
Glenrock I	(3,374)	(3,325)	(3,317)	(3,276)	(3,222)
Glenrock III	(1,101)	(1,085)	(1,083)	(1,069)	(1,051)
Goodnoe Hills	(1,873)	(1,845)	(1,841)	(1,818)	(1,788)
High Plains	(2,192)	(2,160)	(2,154)	(2,128)	(2,092)
McFadden Ridge	(808)	(796)	(794)	(784)	(771)
Marengo	(3,723)	(3,669)	(3,660)	(3,615)	(3,555)
Marengo II	(1,465)	(1,444)	(1,440)	(1,422)	(1,399)
Mountain Wind Power (PPA)	(1,351)	(1,332)	(1,328)	(1,312)	(1,290)
Mountain Wind Power II (PPA)	(1,268)	(1,249)	(1,246)	(1,231)	(1,211)
Seven Mile Hill I	(4,099)	(4,039)	(4,030)	(3,980)	(3,914)
Seven Mile Hill II	(776)	(764)	(762)	(753)	(741)
Top of the World (PPA)	(3,705)	(3,651)	(3,642)	(3,597)	(3,538)
Total	**(32,303)**	**(31,832)**	**(31,754)**	**(31,362)**	**(30,842)**

For comparative purposes, the Company includes an additional sensitivity scenario based on the most recent fuel forecast, the November 8, 2011 official forward price curve (OFPC). **Table 4** provides the results of the additional sensitivity scenario, and shows that the expected incremental costs remain negative using the most recent fuel forecast.

[8] The incremental cost analysis assumptions include (1) 2015 $19 carbon dioxide ($CO_2$), (2) September 2010 Price Curve (medium gas curve), (3) Discount Rate from the 2011 IRP of 7.17%, and (4) Oregon's share based on forecast system generation (SG) allocation factors based on the November 2011 load forecast.

Table 4

Additional Sensitivity Scenario

2013-2017 Summary
Oregon Allocated Nominal Levelized Incremental Costs [9]
2021 \$16/ton CO_2 price (medium), November 8, 2011 medium fuel price curve

Resource	2013	2014	2015	2016	2017
Blundell II	(1,438)	(1,417)	(1,414)	(1,397)	(1,373)
Campbell Hill-Three Buttes (PPA)	(712)	(702)	(700)	(691)	(680)
Chevron Casper Wind Farm (PPA)	(185)	(182)	(181)	(179)	(176)
Dunlap I	(2,192)	(2,160)	(2,154)	(2,128)	(2,092)
Glenrock I	(2,528)	(2,491)	(2,485)	(2,455)	(2,414)
Glenrock III	(779)	(768)	(766)	(756)	(744)
Goodnoe Hills	(1,195)	(1,178)	(1,175)	(1,160)	(1,141)
High Plains	(1,390)	(1,369)	(1,366)	(1,349)	(1,327)
McFadden Ridge	(584)	(576)	(575)	(567)	(558)
Marengo	(2,743)	(2,703)	(2,697)	(2,663)	(2,619)
Marengo II	(989)	(974)	(972)	(960)	(944)
Mountain Wind Power (PPA)	(943)	(929)	(926)	(915)	(900)
Mountain Wind Power II (PPA)	(771)	(760)	(758)	(748)	(736)
Seven Mile Hill I	(3,212)	(3,165)	(3,157)	(3,118)	(3,067)
Seven Mile Hill II	(601)	(592)	(591)	(583)	(574)
Top of the World (PPA)	(2,136)	(2,105)	(2,100)	(2,074)	(2,040)
Total	**(22,398)**	**(22,071)**	**(22,017)**	**(21,745)**	**(21,385)**

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 2011 IRP, as well as the additional sensitivity scenario based on the November 8, 2011 OFPC.

[9] The sensitivity analysis incremental cost assumptions include (1) 2021 \$16 carbon dioxide (CO_2), (2) November 8, 2011 Price Curve (medium gas curve), (3) Discount Rate from the 2011 IRP of 7.17%, and (4) Oregon's share based on forecast system generation (SG) allocation factors based on the November 2011 load forecast.

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: **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 2013-2017 reporting period. **Table 5** is based on the incremental cost forecast from **Table 3.** **Table 6** is based on the incremental cost forecast from the additional sensitivity scenario from **Table 4**. The Company's 2013-2017 Plan does not forecast the use of unbundled RECs or alternative compliance payments at this time to meet compliance. These tables show that the 4 percent cost limit is not triggered because the incremental costs are negative.

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.[10] Actual results 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
2013	($32,303)	$44,736	(2.89%)
2014	($31,832)	$45,301	(2.81%)
2015	($31,754)	$45,469	(2.79%)
2016	($31,362)	$45,692	(2.75%)
2017	($30,842)	$46,063	(2.68%)

[10] The Company used the most recently available load forecast; November 2011.

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**
2013	($22,398)	$44,736	(2.00%)
2014	($22,071)	$45,301	(1.95%)
2015	($22,017)	$45,469	(1.94%)
2016	($21,745)	$45,692	(1.90%)
2017	($21,385)	$46,063	(1.86%)

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, provide the costs for the renewable resources included in the 2013-2017 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: There are no 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 IRP.

(a) **Confidential Attachment C** assumes that the existing government incentives continue in accordance with their current expiration date. A separate forecast assuming existing government incentives do not continue beyond their current expiration date is not applicable as there are no applicable renewable resources included in the Company's 2011 IRP action plan during the 2013-2017 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, consistent with the 2011 IRP, the summary results for the medium scenario 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 there are currently no costs applicable to subsection (2)(e).

(b) The Company plans to comply with the Oregon RPS requirements by using bundled RECs during the 2013-2017 reporting period, and does not at this time plan to use (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. Therefore, this requirement is not applicable at this time because the Company does not plan to use any of the listed compliance methods. As noted previously, the Company will evaluate the potential of acquiring unbundled RECs and applying them toward compliance in future years.

(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: There were no conditions specified in the Commission's acknowledgement order of the previous implementation plan.[11] There were no conditions specified in the Commission's acknowledgement order of the 2008 IRP.[12] An acknowledgement of the Company's 2011 IRP is pending with the Commission.[13] Accordingly, this requirement is not applicable at this time.

[11] *See* Order No. 10-172 (May 4, 2010), Docket UM 1467.
[12] *See* Order No. 10-066 (February 24, 2010), Docket LC 47.
[13] Docket LC 52.

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.

PacifiCorp
Renewable Portfolio Standard Oregon Implementation Plan
2013-2017

<u>Attachment A</u>

Accounting of the RECs applicable to the RPS in Oregon

	MWh										
	2007 Actual	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Forecast**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**
Oregon Renewable Portfolio Standard Requirement (1)	-	-	-	-	638,966	643,669	648,272	656,453	1,976,678	1,986,366	2,002,475
Planned Compliance Method (2)											
Bundled RECs by year of issuance	336,936	540,939	810,792	1,233,320	1,719,055	1,500,539	1,499,708	1,477,376	1,467,606	1,445,299	1,363,805
Unbundled RECs by year of issuance	-	-	-	-	-	-	-	-	-	-	-
Cumulative Banked RECs minus RPS requirement by year of compliance (3)	336,936	877,875	1,688,667	2,921,987	4,002,076	4,858,947	5,710,383	6,531,307	6,022,236	5,481,169	4,842,500
Alternative compliance payments					-	-	-	-	-	-	-

Notes

(1) Based on Retail Load Forecast, November 2011

(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
2013-2017

<u>Attachment B</u>

Expected Annual MWh Output
(Total Company and Oregon SG Share)

(Redacted Version)

Total Company Generated Renewable Energy Credits (MWh)

								REDACTED						
		State	**COD (1)**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
				Actual	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
BIOGAS	Hill Air Force Base	UT	2005	8,432	7,710	12,317	14,185	[redacted]						
	Total Biogas			**8,432**	**7,710**	**12,317**	**14,185**							
GEOTHERMAL	Blundell II	UT	2007	3,830	66,777	83,230	75,513	[redacted]						
	Total Geothermal			**3,830**	**66,777**	**83,230**	**75,513**							
WIND	Campbell Hill-Three Buttes	WY	2009	0	0	39,975	299,990	[redacted]						
	Chevron Casper Wind Farm	WY	2009	0	0	6,122	38,584							
	Combine Hills	OR	2003	117,181	114,458	104,572	104,663							
	Dunlap I	WY	2010	0	0	0	102,429							
	Foote Creek I	WY	1999	57,092	64,184	51,816	55,910							
	Glenrock I	WY	2008	0	0	253,875	287,941							
	Glenrock III	WY	2009	0	0	84,675	99,967							
	Goodnoe Hills	WA	2008	0	147,308	237,374	212,268							
	High Plains	WY	2009	0	0	72,695	257,349							
	Leaning Juniper I	OR	2006	289,452	312,614	258,767	223,558							
	Marengo	WA	2007	160,636	400,245	316,552	330,943							
	Marengo II	WA	2008	0	78,457	158,279	165,475							
	McFadden Ridge	WY	2009	0	0	20,558	77,366							
	Mountain Wind Power	WY	2008	0	64,968	128,330	149,425							
	Mountain Wind Power II	WY	2008	0	51,315	202,840	202,072							
	Rock River I	WY	2001	140,904	156,957	134,819	138,204							
	Seven Mile Hill I	WY	2008	0	0	303,510	324,123							
	Seven Mile Hill II	WY	2008	0	0	62,229	67,722							
	Top of the World	WY	2010	0	0	0	188,825							
	Wolverine Creek	ID	2005	148,933	170,270	153,761	162,140							
	Total Wind			**914,198**	**1,560,776**	**2,590,749**	**3,488,954**							
HYDRO - LOW IMPACT	Ashton	ID	1917	30,914	32,051	33,735	22,728	[redacted]						
	Clearwater 1	OR	1953	37,424	42,259	35,759	31,476							
	Clearwater 2	OR	1953	45,315	43,375	41,993	29,705							
	Cutler	UT	1927	44,496	54,344	89,033	50,455							
	Fish Creek	OR	1952	35,712	32,544	33,450	37,477							
	Oneida	ID	1915	36,899	34,616	33,304	28,486							
	Slide Creek	OR	1951	81,721	89,523	80,364	79,059							
	Soda	ID	1924	15,603	14,378	12,403	13,960							
	Soda Springs	OR	1952	41,295	56,787	51,112	51,896							
	Grace	ID	1923	76,033	61,403	59,082	63,490							
	Lemolo 1	OR	1955	127,469	148,606	127,486	111,394							
	Lemolo 2	OR	1956	148,711	153,208	89,595	138,473							
	Toketee	OR	1950	209,075	218,891	213,049	188,950							
	Total Hydro - Low Impact			**930,667**	**981,985**	**900,365**	**847,549**							
SOLAR	Oregon Solar Incentive Program - Central Oregon (CO 1)	OR	2010	0	0	0	11	[redacted]						
	Oregon Solar Incentive Program - Portland Oregon (PO 1)	OR	2010	0	0	0	2							
	Oregon Solar Incentive Program - Willamette Valley (WV 1)	OR	2010	0	0	0	0							
	Oregon Solar Incentive Program - Southern Oregon (SO 1)	OR	2010	0	0	0	4							
	Oregon Solar Incentive Program - Southern Oregon (SO 2)	OR	2011	0	0	0	0							
	Oregon Solar Incentive Program - Central Oregon (CO 2)	OR	2011	0	0	0	0							
	Total Solar						**17**							
Total				**1,857,127**	**2,617,248**	**3,586,661**	**4,426,219**	[redacted]						

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

Oregon's Share Per Allocation Factors[(2), (3)] - Renewable Portfolio Standard Renewable Energy Credits (MWh)

								REDACTED						
		State	**COD [(1)]**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
				Actual[(2)]	**Actual[(2)]**	**Actual[(2)]**	**Actual[(2)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**
BIOGAS	Hill Air Force Base	UT	2005	0	0	0	0	[redacted]						
	Total Biogas													
GEOTHERMAL	Blundell II	UT	2007	1,051	18,822	22,876	19,786	[redacted]						
	Total Geothermal			**1,051**	**18,822**	**22,876**	**19,786**							
WIND	Campbell Hill-Three Buttes	WY	2009	0	0	10,987	78,605	[redacted]						
	Chevron Casper Wind Farm	WY	2009	0	0	1,683	10,110							
	Combine Hills	OR	2003	117,181	114,458	104,572	104,663							
	Dunlap I	WY	2010	0	0	0	26,839							
	Foote Creek I	WY	1999	15,666	18,091	14,242	14,650							
	Glenrock I	WY	2008	0	0	69,779	75,448							
	Glenrock III	WY	2009	0	0	23,274	26,194							
	Goodnoe Hills	WA	2008	0	41,520	65,244	55,620							
	High Plains	WY	2009	0	0	19,981	67,432							
	Leaning Juniper I	OR	2006	79,427	88,113	71,124	58,578							
	Marengo	WA	2007	44,079	112,813	87,007	86,716							
	Marengo II	WA	2008	0	22,114	43,504	43,359							
	McFadden Ridge	WY	2009	0	0	5,651	20,272							
	Mountain Wind Power	WY	2008	0	18,312	35,272	39,153							
	Mountain Wind Power II	WY	2008	0	14,464	55,752	52,948							
	Rock River I	WY	2001	38,665	44,240	37,056	36,213							
	Seven Mile Hill I	WY	2008	0	0	83,422	84,929							
	Seven Mile Hill II	WY	2008	0	0	17,104	17,745							
	Top of the World	WY	2010	0	0	0	49,477							
	Wolverine Creek	ID	2005	40,868	47,992	42,262	42,485							
	Total Wind			**335,885**	**522,117**	**787,916**	**991,436**							
HYDRO - LOW IMPACT	Ashton	ID	1917	0	0	0	5,955	[redacted]						
	Clearwater 1	OR	1953	0	0	0	8,248							
	Clearwater 2	OR	1953	0	0	0	7,783							
	Cutler	UT	1927	0	0	0	13,221							
	Fish Creek	OR	1952	0	0	0	9,820							
	Oneida	ID	1915	0	0	0	7,464							
	Slide Creek	OR	1951	0	0	0	20,716							
	Soda	ID	1924	0	0	0	3,658							
	Soda Springs	OR	1952	0	0	0	13,598							
	Grace	ID	1923	0	0	0	16,636							
	Lemolo 1	OR	1955	0	0	0	29,188							
	Lemolo 2	OR	1956	0	0	0	36,284							
	Toketee	OR	1950	0	0	0	49,510							
	Total Hydro - Low Impact						**222,081**							
SOLAR	Oregon Solar Incentive Program - Central Oregon (CO 1)	OR	2010	0	0	0	11	[redacted]						
	Oregon Solar Incentive Program - Portland Oregon (PO 1)	OR	2010	0	0	0	2							
	Oregon Solar Incentive Program - Willamette Valley (WV 1)	OR	2010	0	0	0	0							
	Oregon Solar Incentive Program - Southern Oregon (SO 1)	OR	2010	0	0	0	4							
	Oregon Solar Incentive Program - Southern Oregon (SO 2)	OR	2011	0	0	0	0							
	Oregon Solar Incentive Program - Central Oregon (CO 2)	OR	2011	0	0	0	0							
	Total Solar						**17**							
Total				**336,936**	**540,939**	**810,792**	**1,233,320**	[redacted]						

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Actual[(2)]	**Actual[(2)]**	**Actual[(2)]**	**Actual[(2)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**	**Forecast[(3)]**
Oregon's Share Based on SG Allocation Factors	**27.44%**	**28.19%**	**27.49%**	**26.20%**	[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:
 2011 - Based on Retail Load Forecast, November 2010
 2012 through 2017 - Based on Retail Load Forecast, November 2011

PacifiCorp
Renewable Portfolio Standard Oregon
Implementation Plan
2013-2017

<u>Attachment C</u>

Preliminary Key Assumptions
Incremental Cost Calculation

(Redacted Version)

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2013 through 2017

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, 2012 that provides, among other things, a forecast of expected incremental costs of renewable resources in service during the 2013-2017 Oregon Implementation Plan (2013-2017 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 2013-2017 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 2011 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 forecasts available.[1] Data for renewable resources acquired through a power purchase agreement (PPA) reflect the associated contract terms. The cost for wind integration ($9.70 per megawatt hour (MWh)) is based on the 2010 Wind Integration Study as utilized in the Company's 2011 IRP.

Consistent with the 2011 IRP, a discount rate of 7.17 percent (%) has been used in this expected incremental cost analysis. Capital carrying costs have been modeled on a real levelized basis, with the effects of inflation removed, consistent with supply-side resources in the 2011 IRP.

Inflation values are based on the Company's official inflation forecast. Where a calculation requires a single value, 1.8% per year – the average of the yearly values from 2011-2030 – has been used. Otherwise, yearly values from the Company's official inflation forecast have been applied.

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[1] Except Blundell II. The Company does not forecast separate expenses for Blundell between units I and II. As there have not been any significant changes in the Blundell costs since the 2011-2015 Plan, it has been assumed that the capital and O&M values for Blundell II remain unchanged from 2011-2015 Plan.

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2013 through 2017

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 2013-2017 Plan. This list of qualifying renewable resources is unchanged from the Company's 2011-2015 Plan.

Table 1

Resource	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	98.7	20
Chevron Casper Wind Farm (PPA)	[redacted]	2009	16.5	5
Dunlap I	[redacted]	2010	111.0	25
Glenrock I	[redacted]	2008	99.0	25
Glenrock III	[redacted]	2008	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]	2008	99.0	25
Seven Mile Hill II	[redacted]	2008	19.5	25
Top of the World (PPA)	[redacted]	2010	200.2	20

The Company did not include the Oregon Solar Incentive Program facilities in its forecast of incremental cost. This program is relatively small and still in its pilot phase with uncertainty for future incentive costs. In light of this, the Company recommends that the parties and the Commission address the development of a methodology for incremental costs for this program, as well as other small facilities, in future investigations or rulemakings associated with RPS compliance.

In addition, the Rolling Hills facility is excluded as this resource is not included in Oregon rates.[2]

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 Term (Years)	Average Capacity (MW)	PPA Contract Price ($/MWh)
Campbell Hill-Three Buttes (PPA)	20	99.0	[redacted]
Chevron Casper Wind Farm (PPA)	5	16.5	
Mountain Wind Power (PPA)	25	60.9	
Mountain Wind Power II (PPA)	25	79.8	
Top of the World (PPA)	20	200.2	

PacifiCorp receives Federal Production Tax Credits (PTC) associated with owned wind projects, but does not from these PPAs. Levelized PTC values for eligible resources have been adjusted to correspond to the in-service year of each resource.

Consistent with the methodology used in its 2011-2015 Plan, the Company used its integration costs from the 2010 Wind Integration Study ($9.70 per MWh in 2010 dollars) published in Appendix I of the 2011 IRP, and have been adjusted by inflation to correspond to the in-service year of each resource. As noted in the Commission's Order No. 11-440, agreement on several issues was unresolved, including the definition of and methodology for including shaping and firming costs in the incremental cost calculation. The Company has agreed to the process for resolving this and other issues with other parties.

Bonneville Power Administration (BPA) transmission costs and reserve service charge costs have been included in the expected incremental cost calculation for Goodnoe Hills, which is located in BPA's control area. Additionally, the Company's inter-hour integration costs ($0.86/MWh) are included in the calculation for Goodnoe Hills.

Capacity factors for existing renewable resources are based on the most current data available.

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[2] *See* Order No. 08-548 (November 14, 2008), Docket UE 200.

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2013 through 2017

Key Assumptions – Expected Incremental Cost Calculation

Proxy Plant

No new long-term qualifying electricity is contemplated in the 2013-2017 reporting period, therefore no new proxy plants have been added in this analysis. The existing proxy plant 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 2011-2015 Plan analysis. Consistent with the 2011 IRP, fuel price data is from the Company's September 2010 forward price curve for the Lake Side location.

Scenarios of carbon dioxide (CO_2) and fuel prices considered in this analysis are a subset of those included in the 2011 IRP:

- No CO_2 ($0/ton) and medium proxy plant fuel costs
- Low to Very High CO_2 (2015 $12/ton) and medium proxy plant fuel costs
- Medium CO_2 (2015 $19/ton) and low proxy plant fuel costs
- Medium CO_2 (2015 $19/ton) and medium proxy plant fuel costs
- Medium CO_2 (2015 $19/ton) and high proxy plant fuel costs
- High CO_2 (2015 $25/ton) and medium proxy plant fuel costs

For comparative purposes, the Company's includes an additional sensitivity scenario based on the most recent fuel forecast, the November 8, 2011 official forward price curve (OFPC).

- Medium CO_2 (2021 $16/ton) and medium proxy plant fuel costs (November 8, 2011 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 2011-2015 Plan.[4] The O&M for the existing proxy plant is also unchanged from the 2011-2015 Plan.

Pursuant to OAR 860-083-0100(7) and consistent with the 2011 IRP, fuel price data is from the Company's September 2010 forward price curve for the Lake Side location.

[3] *See* Order No. 09-299 (August 3, 2009), AR 518 Phase III, page 4.
[4] The Company's 2011-2015 Plan was filed with the Commission on December 31, 2009, Docket UM 1467.

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2013 through 2017

Key Assumptions – Expected Incremental Cost Calculation

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 (NPV) of the costs (over the resource life) is 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.

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

Expected Incremental Cost

The annual calculated nominal levelized cost of the proxy plant has been 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 2013-2017 reporting period, and has been calculated for each of the seven scenarios identified in the proxy plant discussion above.

Allocation Factor

Table 3 provides the forecast Oregon allocated system generation (SG) allocation factors from the November 2011 load forecast, used in the forecast of expected incremental cost analysis.

Table 3

Year	SG Allocation Factor
2013	[redacted]
2014	[redacted]
2015	[redacted]
2016	[redacted]
2017	[redacted]

PacifiCorp
Renewable Portfolio Standard Oregon
Implementation Plan
2013-2017

<u>Confidential Attachment D</u>

Incremental Cost Analysis

Subject to Protective Order

THIS ATTACHMENT IS CONFIDENTIAL AND PROVIDED UNDER SEPARATE COVER