PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2017 through 2021
[Submitted July 15, 2016]

In accordance with ORS 469A.075 and OAR 860-083-0400, and Order 16-158, PacifiCorp, d/b/a Pacific Power (Company or PacifiCorp), respectfully submits its updated 2017 through 2021 Oregon Renewable Implementation Plan (2017-2021 Plan) to the Public Utility Commission of Oregon (Commission). On December 29, 2015, PacifiCorp filed its initial 2017-2021 Plan. Subsequent to the Company's filing, the Oregon legislature passed Senate Bill 1547 (SB 1547) which, among other things, doubled the renewable targets for the Oregon Renewable Portfolio Standard (RPS). In light of the increased RPS requirements and recent extensions of federal tax credits for wind and solar facilities, PacifiCorp signaled in its 2015 Integrated Resource Plan (IRP) Update its intent to issue a request for proposals (RFP) to market for RPS-compliance resources, including renewable energy certificates (RECs).

Given the changes in law, the Commission acknowledged PacifiCorp's initial 2017-2021 Plan but with the condition that PacifiCorp "file a new Plan that includes a complete analysis of SB 1547 and restarts the period for review."[1] Consistent with the Commission's directive, PacifiCorp has updated its 2017-2021 Plan to reflect the requested analysis. The updated 2017-2021 Plan reflects updated incremental cost calculations using current gas price forecasts and the modified REC banking provisions of SB 1547. Also included with the 2017-2021 Plan is Confidential Appendix A, which presents an in-depth analysis of the impact of SB 1547 on the Company's long-term RPS compliance outlook. This analysis affirms that long-term RPS compliance costs may be reduced with incremental near-term procurement, consistent with Action Item 1a in PacifiCorp's 2015 IRP Update. PacifiCorp issued renewable resource and REC RFPs on April 20, 2016 and is currently analyzing bids to identify whether near-term procurement opportunities will reduce RPS compliance costs. This competitive procurement process is on schedule to be complete in September 2016. Because PacifiCorp has not yet determined which near-term procurement opportunities will be pursued, if any, the resources identified for the Company's RPS compliance for the period covered by the 2017-2021 RPIP are not significantly changed from the RPIP filed in December 2015.

Summary

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

[1] *In the Matter of PacifiCorp, dba Pacific Power 2017-2021 Renewable Portfolio Standard Implementation Plan*, Docket UM 1754, Order No. 16-158 at 1 (April 22, 2016).

The 2017-2021 Plan was prepared with information consistent with the Company's most recently filed Integrated Resource Plan (IRP) – the 2015 IRP and 2015 IRP Update, unless stated otherwise.[2] The Company's IRP process and its filed documentation are based on the best available information at the time the IRP was prepared. The Company's 2015 IRP Action Plan (2015 IRP Action Plan) represents a road map for implementation of the preferred portfolio. The 2015 IRP does not add any significant new renewable resources, beyond new qualifying facility (QF) projects, through the twenty year planning horizon ending 2034. With the recent extension of federal tax credits, the Company's 2015 IRP Update Action Plan includes an action item to issue RFPs seeking renewable resource bids and REC bids that can be used to meet state RPS targets. The RFPs were issued on April 20, 2016 and the competitive procurement process is on schedule to be completed in September 2016.

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

Similar to the Company's previous implementation plan[2] (the 2015-2019 Plan), the 2017-2021 Plan shows that for some of the eligible resources, the expected incremental costs are positive (costs higher than a proxy resource), while for other resources, the expected incremental costs are negative (costs less than a proxy resource). However, using the methodology established by Commission-adopted rules, the 2017-2021 Plan shows that the expected incremental costs do not trigger the four percent cost limit under ORS 469A.100.

Implementation Plan

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

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[2] The Company's 2015 IRP was filed with the Commission on March 31, 2015and the Company's 2015 IRP Update was filed on March 31, 2016, Docket LC 62.

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

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

Response: **Table 1** below provides the estimated annual megawatt-hour (MWh) target for compliance, based on the Company's October 2015 load forecast.[3]

Table 1	**2017**	**2018**	**2019**	**2020**	**2021**
Applicable RPS Standard as % of Electricity Sold	15%	15%	15%	20%	20%
Estimated PacifiCorp Oregon RPS Target (MWh)	1,958,763	1,909,419	1,921,934	1,936,852	2,576,755

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

Response: For the 2017-2021 Plan, the Company anticipates complying with the applicable Oregon RPS using bundled RECs. **Attachment A** provides an accounting of the RECs applicable to the Oregon RPS program. SB 1547 eliminated the unlimited life of RECs as well as the first in first out REC banking requirement. However, the bill also created an exception to the unlimited life restriction for long-term resources coming on-line between bill passage and the end of 2022—these resources will generate RECs with unlimited REC life for the first five years of the resource's life. Because the Company has not yet identified which, if any, renewable resources or RECs will be procured during this time frame, the updated 2017-2021

[3] Consistent with the 2015 IRP Update, for OAR 860-083-0400(2)(a) in this 2017-2021 Plan, the Company used the October 2015 load forecast.

Plan only reflects the removal of the first in first out restriction. The 2017-2021 Plan assumes that RECs with the shortest life will be used first before RECs from the existing (pre-2016) bank.

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

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

Table 2

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

Table 2			
Energy Source	**Generating Facility**	**State**	**Commercial Operation Year**
Hydro – Upgrades	Big Fork (Upgrade 2001) Copco 1 (Upgrade 1996) Cutler (Upgrade 2007) JC Boyle (Upgrade 2005) Lemolo 1 (Upgrade 2003) Lemolo 2 (Upgrade 2009) Oneida (Upgrade 2004) Pioneer (Upgrade 1999) Prospect 2 (Upgrade 1999) Prospect 3 (Upgrade 1997) Yale (Upgrade 1995/1996)	MT CA UT OR OR OR ID UT OR OR WA	1929 1918 1927 1958 1955 1956 1915 1897 1928 1932 1953
Oregon Solar Capacity Standard	Black Cap	OR	2012

Table 2

Energy Source	Generating Facility	State	Commercial Operation Year
Oregon Solar Incentive Program	*Bourdet	OR	2014
	*Bourdet II	OR	2016
	*Conf. Tribes - Warm Springs (CTWS)	OR	2014
	*Crook County Solar	OR	2014
	Joseph Community Solar	OR	2011
	Lakeview	OR	2012
	*Lakeview II	OR	2013
	*Powell Butte Solar	OR	2014
	Solwatt	OR	2011
	*Solwatt II	OR	2014
	Aggregated Solar Block (CO 1)	OR	2010
	Aggregated Solar Block (CO 2)	OR	2011
	Aggregated Solar Block (CO 3)	OR	2013
	Aggregated Solar Block (CR 1)	OR	2011
	*Aggregated Solar Block (CR 2)	OR	2014
	Aggregated Solar Block (EO 1)	OR	2010
	Aggregated Solar Block (EO 2)	OR	2011
	Aggregated Solar Block (PO 1)	OR	2010
	Aggregated Solar Block (PO 2)	OR	2013
	Aggregated Solar Block (SO 1)	OR	2010
	Aggregated Solar Block (SO 2)	OR	2011
	Aggregated Solar Block (SO 3)	OR	2011
	Aggregated Solar Block (SO 4)	OR	2012
	Aggregated Solar Block (SO 5)	OR	2012
	Aggregated Solar Block (SO 6)	OR	2013
	Aggregated Solar Block (SO 7)	OR	2013
	*Aggregated Solar Block (SO 8)	OR	2013
	*Aggregated Solar Block (SO 9)	OR	2013
	*Aggregated Solar Block (SO 10)	OR	2014
	*Aggregated Solar Block (SO 11)	OR	2014
	*Aggregated Solar Block (SO12)	OR	2015
	Aggregated Solar Block (WV 1)	OR	2010
	Aggregated Solar Block (WV 2)	OR	2011
	Aggregated Solar Block (WV 3)	OR	2012
	Aggregated Solar Block (WV 4)	OR	2013
	Aggregated Solar Block (WV 5)	OR	2013
	Aggregated Solar Block (WV 6)	OR	2013
	*Aggregated Solar Block (WV 7)	OR	2014
	*Aggregated Solar Block (WV 8)	OR	2015
	*Aggregated Solar Blocks (Remaining Capacity)	OR	2016-2017
Solar	*Pavant Solar II	UT	2016

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

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

Response: The 2017-2021 Plan includes a forecast of expected incremental costs of qualifying electricity from four new facilities/contracts[4] and the Oregon Solar Incentive Program (OSIP),[5] which have a cumulative capacity exceeding 50 megawatts. **Table 3** includes the forecasted incremental cost of these new resources, consistent with the methodology in OAR 860-083-0100.[6]

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

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

Table 3 shows the forecast of the expected incremental costs, on an Oregon-allocated basis, for the qualifying electricity for generating facilities or contracts in service after June 6, 2007. Low impact hydroelectric facilities and qualifying generating facilities

[4] Latigo Wind – 60 MW (2015 COD), Pioneer Wind – 80 MW (2016 COD), and Pavant II Solar – 50 MW (2016 COD) are under development and anticipated to be qualifying Oregon RPS-eligible resources. Black Cap – 2 MW (2012 COD) is an existing certified Oregon RPS-eligible resource. Foote Creek II and Foote Creek III are not included in the incremental cost calculation, as these resources became operational before June 6, 2007.
[5] To calculate the estimated incremental costs of the Oregon Solar Incentive Program, capacity added to the OSIP program in each year was treated as an individual resource.
[6] OAR 860-083-100(13)(b) states that “When the capacity of qualifying electricity described in subsection (13)(a) of this rule exceeds 20 megawatts in a compliance year or the cumulative capacity of qualifying electricity in subsection (13)(a) of this rule exceeds 50 megawatts, the incremental cost of all such qualifying electricity must be included in the compliance report for the compliance year and in compliance reports and implementation plans filed after such compliance report.”

or contracts that went into service before June 6, 2007 are deemed to have zero incremental costs, pursuant to OAR 860-083-0100(1)(i).[7]

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

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

Table 3

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

2015 IRP Update Base Case - December 2015 OFPC

Resource	2017	2018	2019	2020	2021
Blundell II	($773)	($775)	($772)	($764)	($762)
Campbell Hill-Three Buttes (PPA)	$1,497	$1,500	$1,495	$1,480	$1,476
Dunlap I	$346	$346	$345	$342	$341
Glenrock I	$540	$541	$539	$534	$532
Glenrock III	$311	$311	$310	$307	$306
Goodnoe Hills	$1,439	$1,442	$1,437	$1,422	$1,418
High Plains	$1,148	$1,150	$1,146	$1,135	$1,131
McFadden Ridge	$60	$60	$60	$59	$59
Marengo	$417	$418	$416	$412	$411
Marengo II	$393	$394	$393	$389	$388
Mountain Wind Power (PPA)	$249	$249	$248	$246	$245
Mountain Wind Power II (PPA)	$789	$791	$788	$780	$778

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

Table 3

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

2015 IRP Update Base Case - December 2015 OFPC

Resource	2017	2018	2019	2020	2021
Seven Mile Hill I	($259)	($260)	($259)	($256)	($255)
Seven Mile Hill II	($60)	($60)	($60)	($59)	($59)
Top of the World (PPA)	$3,066	$3,073	$3,061	$3,030	$3,022
Pioneer Wind Park	($473)	($474)	($472)	($467)	($466)
Latigo Wind Park	$655	$657	$654	$648	$646
Pavant II Solar	($302)	($303)	($301)	($299)	($298)
Black Cap Solar	$104	$104	$104	$104	$104
OSIP 2010	$131	$131	$131	$131	$131
OSIP 2011	$1,265	$1,265	$1,265	$1,265	$1,265
OSIP 2012	$811	$811	$811	$811	$811
OSIP 2013	$958	$958	$958	$958	$958
OSIP 2014	$614	$614	$614	$614	$614
OSIP 2015	$231	$231	$231	$231	$231

For comparative purposes, the Company is including in **Table 4** an additional sensitivity scenario based on the most recent OFPC dated March 2016.

Table 4

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

Additional Scenario - March 2016 OFPC

Resource	2017	2018	2019	2020	2021
Blundell II	($766)	($767)	($765)	($757)	($755)
Campbell Hill-Three Buttes (PPA)	$1,519	$1,523	$1,517	$1,502	$1,498
Dunlap I	$387	$388	$387	$383	$382
Glenrock I	$573	$574	$572	$566	$565
Glenrock III	$323	$324	$323	$320	$319
Goodnoe Hills	$1,463	$1,466	$1,460	$1,446	$1,442
High Plains	$1,180	$1,182	$1,177	$1,166	$1,162
McFadden Ridge	$68	$69	$68	$68	$67
Marengo	$445	$446	$444	$440	$439
Marengo II	$410	$411	$410	$406	$405
Mountain Wind Power (PPA)	$263	$263	$262	$260	$259
Mountain Wind Power II (PPA)	$807	$808	$805	$797	$795
Seven Mile Hill I	($224)	($224)	($223)	($221)	($220)
Seven Mile Hill II	($53)	($53)	($53)	($52)	($52)
Top of the World (PPA)	$3,115	$3,121	$3,109	$3,079	$3,070
Pioneer Wind Park	($428)	($429)	($427)	($423)	($422)
Latigo Wind Park	$678	$679	$676	$670	$668
Pavant II Solar	($282)	($283)	($282)	($279)	($278)
Black Cap Solar	$106	$106	$106	$106	$106
OSIP 2010	$131	$131	$131	$131	$131
OSIP 2011	$1,265	$1,265	$1,265	$1,265	$1,265
OSIP 2012	$812	$812	$812	$812	$812

Table 4

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

Additional Scenario - March 2016 OFPC

Resource	2017	2018	2019	2020	2021
OSIP 2013	$959	$959	$959	$959	$959
OSIP 2014	$615	$615	$615	$615	$615
OSIP 2015	$232	$232	$232	$232	$232

Confidential Attachment D provides additional detail of the forecast of the expected incremental costs calculation, consistent with the methodology in OAR 860-083-0100. The calculations are consistent with assumptions in the Company's 2015 IRP and 2015 IRP Update, as well as the additional sensitivity (Scenario 4) based on the March 2016 OFPC.

Tables 5 and 6 below show the forecast of the expected incremental cost of compliance, compared to the annual revenue requirement for each year in the 2017-2021 reporting period. **Table 5** is based on the incremental cost forecast from **Table 3** (the 2015 IRP Update Base Case – December 2015 OFPC Fuel Curve). **Table 6** is based on the incremental cost forecast from the additional sensitivity scenario shown in **Table 4** (March 2016 OFPC). The Company's 2017-2021 Plan does not forecast the use of alternative compliance payments at this time. The Oregon allocated nominal levelized incremental cost was calculated by using an average $/MWh based on the incremental cost calculations for each resource, multiplied by the number of forecasted bundled RECs.

The annual revenue requirement was calculated consistent with the methodology in OAR 860-083-0200. According to the rule, this methodology adjusts the last approved revenue requirement for forecasted load.[8] These tables show that the four percent cost limit is not triggered. Actual cost of compliance may vary from the calculations shown below.

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

Table 5

Based on Table 3 Data (2015 IRP Update Base Case – December 2015 OFPC Fuel Curve)

	Oregon Allocated Nominal Levelized Incremental Cost ($000s)			Annual Revenue Requirement ($000s)	Cost as % Oregon Annual Revenue Requirement	4% of Revenue Requirement
	Bundled	Unbundled	Total			
2017	$15,572	$0	$15,572	$1,236,413	1.26%	$49,457
2018	$15,735	$0	$15,735	$1,245,552	1.26%	$49,822
2019	$15,916	$0	$15,916	$1,247,703	1.28%	$49,908
2020	$21,085	$0	$21,085	$1,244,920	1.69%	$49,797
2021	$20,974	$0	$20,974	$1,240,037	1.69%	$49,601

Table 6

Based on Table 4 Data (Sensitivity - March 2016 OFPC Fuel Curve)

	Oregon Allocated Nominal Levelized Incremental Cost ($000s)			Annual Revenue Requirement ($000s)	Cost as % Oregon Annual Revenue Requirement	4% of Revenue Requirement
	Bundled	Unbundled	Total			
2017	$16,073	$0	$16,073	$1,236,413	1.30%	$49,457
2018	$16,240	$0	$16,240	$1,245,552	1.30%	$49,822
2019	$16,427	$0	$16,427	$1,247,703	1.32%	$49,908
2020	$21,996	$0	$21,996	$1,244,920	1.77%	$49,797
2021	$22,049	$0	$22,049	$1,240,037	1.78%	$49,601

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 show the costs for the bundled RECs included in the 2017-2021 Plan.

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

Response: The only material difference between the 2017-2021 Plan and the RPS Position Forecast included in the 2015 IRP[9] are the following changes in qualifying resources:

- 2015 IRP included Bevans Point Solar (Solar Capacity Standard), unlike the 2017-2021 Implementation Plan; however, the Company did not complete the transaction with Bevans Point Solar.
- 2015 IRP included Blue Mountain which was subsequently terminated, unlike the 2017-2021 Implementation Plan.

[9] See PacifiCorp's 2015 IRP – Figure 1.6 at page 5 – Annual State RPS Position Forecasts using the Preferred Portfolio, and pp. 53-55 of the 2015 IRP Update.

- 2015 IRP did not include Pavant II Solar, LLC, a qualifying facility (QF) contract executed on March 25, 2015.

For the 2017-2021 Plan filed on July 15, 2016, PacifiCorp has updated its generation forecasts.

(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 currently included in the Company's 2015 IRP preferred portfolio during the 2017-2021 reporting period. Similarly, there are no applicable resources included in the Company's 2015 IRP Update resource portfolio during the 2017-2021 reporting period. Accordingly, the Company's forecast of expected incremental cost analysis, whether or not existing government incentives continue beyond their current expiration date, would be identical.

(b) **Confidential Attachment D** includes a range of forecasts for expected incremental costs. The summary results for the December 2015 OFPC are shown in **Table 3** of this document. **Confidential Attachment D** also includes the additional sensitivity scenario for the March 2016 OFPC, and the summary results are shown in **Table 4** of this document.

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:

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

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

As stated in PacifiCorp's 2015 IRP Update, the Company has issued RFPs seeking bids for near-term procurement opportunities that may reduce RPS compliance costs. The RFPs were issued on April 20, 2016 and the competitive procurement process is on schedule to be completed in September 2016. While PacifiCorp's 2017-2021 Plan does not include the use of unbundled RECs in the 2017-2021 period, the Company is currently evaluating RFP proposals, including bids for unbundled RECs, that could qualify for Oregon RPS compliance. If the Company does choose to procure near-term unbundled or bundled RECs for Oregon RPS, consistent with the analysis presented in Confidential Appendix A, PacifiCorp will evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. This will balance risks and expected costs as required by the IRP guidelines in 1.b. and c. of Commission Order No. 07-047 and subsequent guidelines related to implementation plans set forth by the Commission.

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

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

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

- Include a "non-confidential summary of RPS total incremental costs for each scenario analyzed…."[10]
    - **Attachment E** provides a summary of the RPS incremental costs by resource for each scenario and **Attachment F** provides a summary of the RPS total incremental costs for each scenario analyzed in the 2017-2021 Implementation Plan.

- Include "in subsequent [implementation plans] a scenario that uses the base case price curve assumptions (medium gas and medium CO_2 prices) similar to that used in the other scenarios in the [implementation plan], with the assumption the Company maximizes the use of unbundled RECs for each year analyzed in the [implementation plan] and assuming an unbundled REC price

[10] *In the Matter of PacifiCorp, dba Pacific Power, Renewable Portfolio Standard Implementation Plan 2015-2019*, Docket UM 1681, Order 14-267 at Appendix A (July 22, 2014).

equal to the weighted average price paid for unbundled RECs used for compliance in their last compliance filing."[11]

- **Table 7** below provides a sensitivity for the base case scenario (December 2015 OFPC Fuel Curve) that maximizes the use of unbundled RECs in each year of the Plan. For this scenario, the Company is assumes the purchase of unbundled RECs at $0.73 per REC, consistent with PacifiCorp's 2014 RPS Compliance Report filed in Docket UM 1739.[12]

Table 7

Additional Sensitivity Scenario – Maximum Use of Unbundled RECs (December 2015 OFPC Base Case)

	Oregon Allocated Nominal Levelized Incremental Cost ($000s)			Annual Revenue Requirement ($000s)	Cost as % Oregon Annual Revenue Requirement	4% of Revenue Requirement
	Bundled	Unbundled	Total			
2017	$12,457	$280	$12,738	$1,236,413	1.03%	$49,457
2018	$12,588	$282	$12,870	$1,245,552	1.03%	$49,822
2019	$12,733	$284	$13,018	$1,247,703	1.04%	$49,908
2020	$16,868	$378	$17,247	$1,244,920	1.39%	$49,797
2021	$16,779	$377	$17,156	$1,240,037	1.38%	$49,601

There were no conditions specified in the Commission's acknowledgment order of the 2013 IRP specific to the Oregon RPS Implementation Plan.[13] The Company's 2015 IRP is ongoing and is pending Commission acknowledgement.

[11] *Id*.
[12] Refer to PAC OR 2017-2021 RPIP – Unbundled RECs Workpaper – CONFIDENTIAL – Refiled July 15, 2016.
[13] *In the Matter of PacifiCorp 2013 Integrated Resource Plan*, Docket LC 57, Order 14-252 (July 8, 2014).

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

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

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

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

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

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

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

Response: In October 2012 the Company acquired the 2.0 MW_{AC} Black Cap Solar project in Lakeview, Oregon, to contribute to PacifiCorp's 8.7 MW_{AC} minimum obligation under the solar photovoltaic capacity standard. In April 2013, PacifiCorp issued a second RFP and as a result finalized a 25-year power purchase agreement for Old Mill Solar, a 5.0 MW_{AC} project located in Bly, Oregon which is now operational. However, the passage of SB 1547 in March 2016 eliminated the solar capacity standard set forth by ORS 757.370(1).

CONFIDENTIAL APPENDIX A

1. A discussion of the differences between SB 838 (i.e. ORS 469A.005 to ORS 469A.210) and SB 1547, with supporting analysis demonstrating the impacts of those differences on utility planning and operations decisions 2017-2040.

The most prominent difference between SB 838 and SB 1547 is the change in renewable portfolio standard targets. Table A-1 lists RPS targets for SB 838 and SB 1547.

Table A-1. Oregon RPS Targets

	SB 838	SB 1547
RPS Target as % of Retail Sales	2016-2019 = 15% 2020-2024 = 20% >2024 = 25%	2016-2019 = 15% 2020-2024 = 20% 2025-2029 = 27% 2030-2034 = 35% 2035-2039 = 45% >2039 = 50%

Further, SB 1547 contains provisions that affect renewable energy credit (REC) accounting and usage. Specifically, SB 1547 introduces the following REC accounting and usage provisions[1]:

- RECs generated before March 8, 2016 have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016 and December 31, 2022 have an unlimited life ("Golden RECs").[2]
- RECs generated on or after March 8, 2016 from resources that came online before March 8, 2016 expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016 and December 31, 2022 expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022 expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the "first-in, first-out" provision under SB 838).

Figure A-1 summarizes PacifiCorp's forecasted Oregon RPS compliance position under SB 838 assuming no further procurement of RECs through 2040. This forecast assumes end-of-life retirement of existing renewable resources and that existing power purchase agreements that terminate over the compliance horizon are not extended. Under SB 838, PacifiCorp

[1] REC accounting and usage provisions apply to both bundled and unbundled RECs.
[2] A "long-term" project is a resource that has a life or power purchase agreement term of at least 20-years.

would surrender its oldest vintage RECs from its bank (i.e., green bars) and experience an initial compliance shortfall (i.e., red bars) in 2026 if no further procurement were pursued.

Figure A-1. PacifiCorp SB 838 Compliance Position without Procurement*

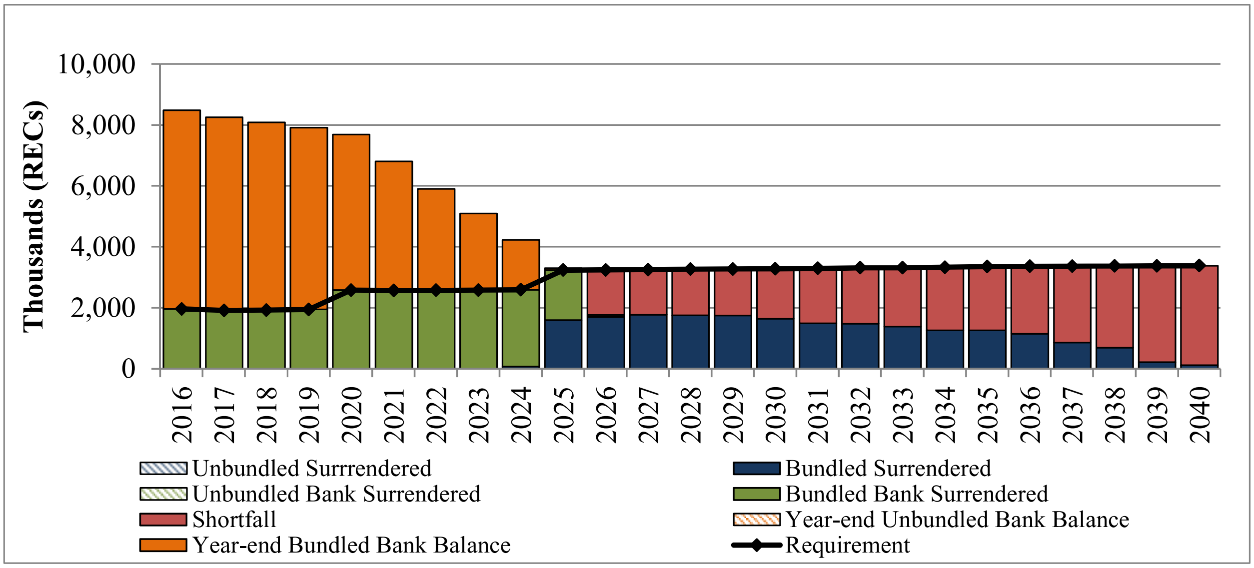
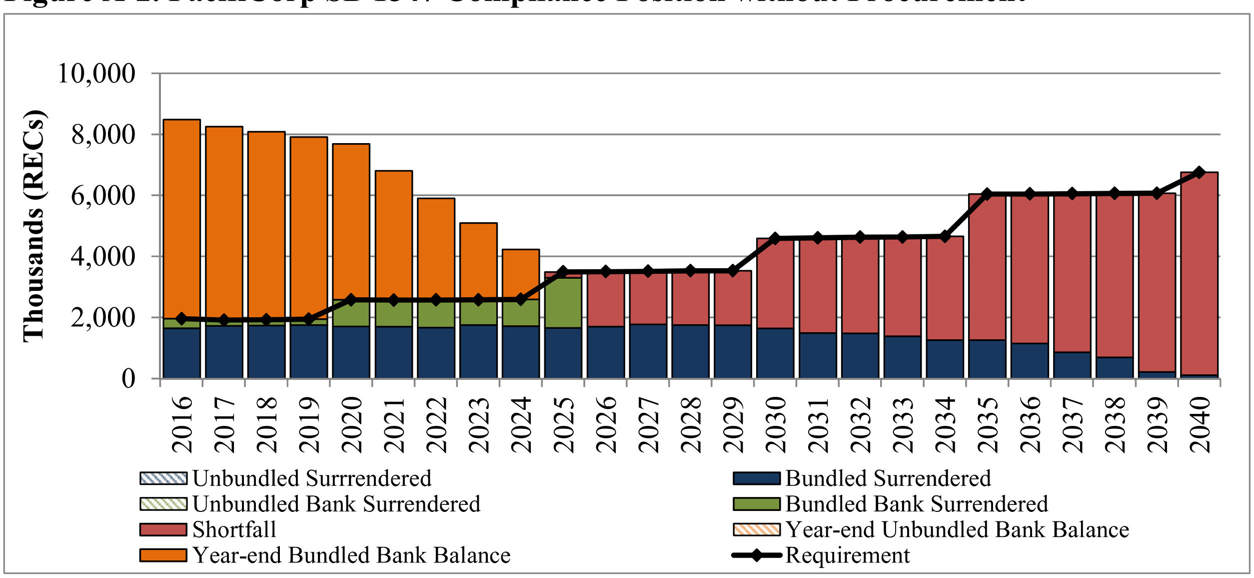


Figure A-2 summarizes the same information under SB 1547. Under SB 1547, PacifiCorp would begin using RECs that expire five years beyond the vintage year (i.e., blue bars) before using older vintage RECs from the bank (green bars), which do not expire. Given the higher RPS targets in SB 1547, PacifiCorp will experience a relative small initial compliance shortfall in 2025—one year earlier than under SB 838.

Figure A-2. PacifiCorp SB 1547 Compliance Position without Procurement



The most notable impact of SB 1547 is the increased need driven by higher targets. Under SB 838, PacifiCorp's 2040 shortfall without further procurement is approximately 3,236

GWh, which equates to about 1,064 MW of renewable resource capacity operating at a 35% capacity factor. Under SB 1547, PacifiCorp's 2040 shortfall without further procurement is approximately 6,639 GWh, which equates to about 2,165 MW of renewable resource capacity operating at a 35% capacity factor.

As described above, REC accounting provisions under SB 1547 apply a REC life to certain RECs. The REC life provisions do not influence PacifiCorp's baseline compliance position under SB 1547 as compared to SB 838. With elimination of the "first-in, first-out" provision in SB 838, RECs that would otherwise expire five years beyond the vintage year under SB 1547 can be surrendered well before they expire. Significant early procurement would be required before RECs would begin to expire. Annual procurement of bundled RECs from over 1,000 MW of existing wind facilities operating at a 35% capacity factor, which would defer PacifiCorp's compliance need to beyond 2040, could be added to PacifiCorp's portfolio beginning 2018 without any of the RECs expiring before being surrendered for compliance.

2. **An analysis of these aspects of SB 1547: its elimination of the "first in, first out" requirement, its creation of unlimited renewable energy credit (REC) life status for the first five years of new resources acquired between 2016-2022, its shortening of the standard REC life, and steep compliance rate increase between 2025 and 2030. In particular, the analysis should address how these aspects of SB 1547 affect how the utility plans to optimize the mix of compliance RECs for least cost and lowest risk.**

   The REC accounting and usage provisions of SB 1547 cannot be considered in isolation. For instance, REC life provisions causing certain RECs to expire five years beyond the vintage year, could limit early procurement activity. However, this is greatly mitigated by eliminating the "first-in, first-out" requirement. As discussed above, PacifiCorp could procure annually the RECs from over 1,000 MW of existing wind facilities operating at a 35% capacity factor beginning in 2018 without any of the RECs expiring before being surrendered for compliance. Likewise, the provisions under SB 1547 that allow unlimited banking of certain RECs from long-term projects coming online between March 8, 2016 and December 31, 2022 will not significantly influence procurement plans.

   Figure A-3 shows PacifiCorp's RPS compliance position with procurement of 792 MW of wind operating at a 35% capacity factor in 2018 assuming the project qualifies for "Golden RECs" over the first five years of operation (i.e., from 2018, the vintage year, through 2023). This level of procurement, when accounting for banking, meets PacifiCorp's RPS obligations through 2040. In this case, "Golden RECs" are banked to preserve their use for a later time period. The oldest RECs surrendered in any compliance year under this scenario are two years older than the vintage year.

Figure A-3. PacifiCorp Compliance with 2018 Procurement Qualifying for "Golden RECs"

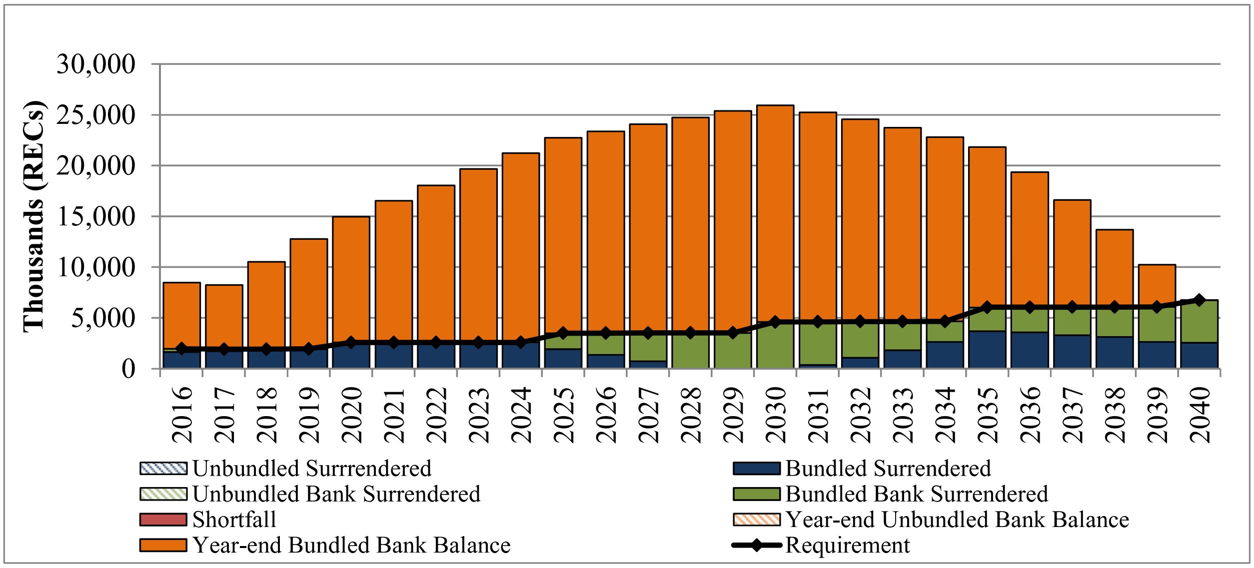
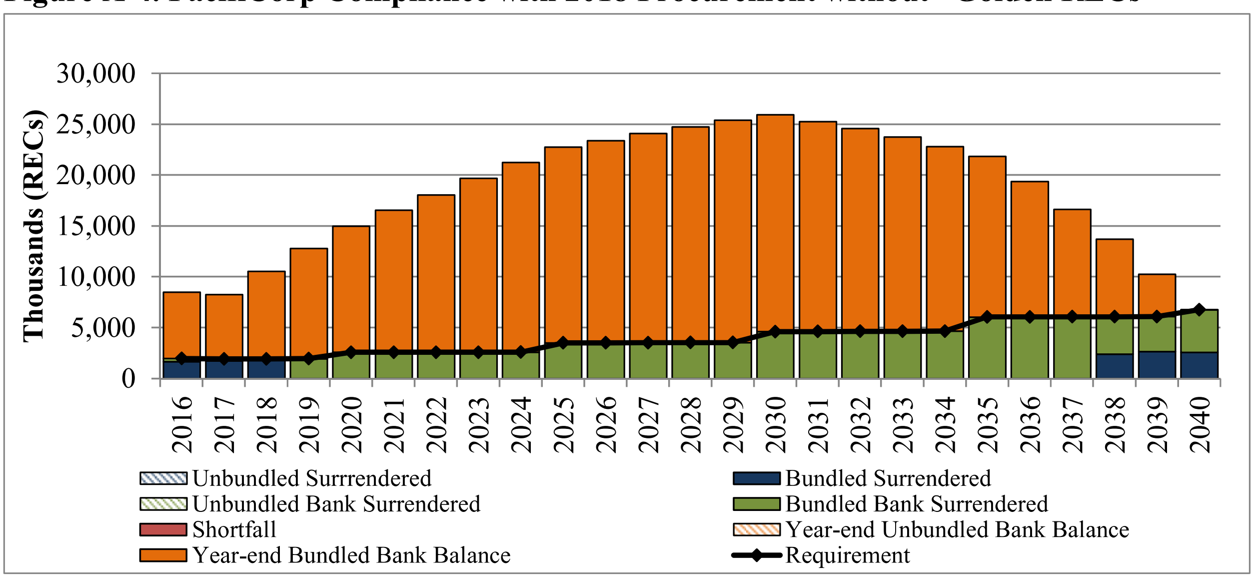


Figure A-4 shows the same compliance profile assuming the acquired resource(s) do not produce RECs that qualify as "Golden RECs". The same level of capacity is added, which achieves the same level of compliance through 2040. The impact of procuring a resource that does not qualify for "Golden RECs" is in how the bank is managed over time. In this case, older vintage RECs (i.e., green bars) are pulled from the bank earlier, to ensure that they can be used before they expire. The oldest RECs surrendered in this scenario are four years older than the vintage year.

Figure A-4. PacifiCorp Compliance with 2018 Procurement without "Golden RECs"



As discussed above, SB 1547 has higher RPS targets, which increases the procurement need over time. Table A-2 summarizes the amount of renewable capacity needed to meet targets under SB 838 and SB 1547 at different time intervals assuming a 35% capacity factor and a just-in-time compliance strategy (i.e., procurement is deferred until the existing bank is depleted).

Table A-2. Procurement Needs over Time (Assuming 35% Capacity Factor)

	SB 838 (Cumulative MW)	SB 1547 (Cumulative MW)
2025	0	62
2030	536	963
2035	683	1,558
2040	1,064	2,165

3. **A discussion of how the timing of new renewable resource acquisitions impact long term cost of compliance with RPS to ratepayers with supporting analysis demonstrating these differences in timing. Under what conditions does the least cost/lowest risk strategy to satisfy the RPS compliance requirements of SB 1547 from 2017 through 2040 lead to new resource acquisition prior to a physical need and how will the utility evaluate this decision? PacifiCorp should provide a "tipping-point" analysis that depicts when physical resource acquisition is more cost effective than buying unbundled RECs.**

The timing of renewable resource and/or REC procurement and its impact on the long-term cost of compliance, as measured by revenue requirement, is driven by the cost and volume of near-term procurement opportunities in relation to forecasted, longer-term needs and cost. Early action procurement can be used to build a bank and defer longer-term procurement. If near-term procurement can defer higher cost longer-term procurement needs, then customers benefit. Conversely, if one expects long-term procurement costs will be lower than near-term procurement opportunities, then early action may not be warranted. Inter-temporal RPS compliance scenarios can be used to evaluate these tradeoffs.

Three different just-in-time compliance scenarios serve as the benchmark for this inter-temporal analysis. Under these scenarios, it is assumed that a just-in-time compliance strategy is implemented, whereby procurement of qualifying resources occurs when there is a physical compliance need.

Table A-3 summarizes resource cost assumptions for the three different just-in-time compliance scenarios. Each scenario assumes progressively lower future costs for wind and solar resources. In Scenario JIT-1, 2018 capital cost, 2018 operations & maintenance (O&M) cost, and capacity factor assumptions are consistent with data presented in PacifiCorp's 2015 IRP Update. It is assumed that wind costs grow at an annual inflation rate of 2.3% per year. Considering that solar PV costs have been declining more steeply than wind resource costs, it is assumed that technological advancements in solar PV projects offset inflation, but that O&M costs grow with inflation over time.

Cost assumptions for Scenarios JIT-2 and JIT-3 are derived from projected potential cost declines through 2025 as published in a recent report issued by the International Renewable Energy Agency (IRENA).[3] The IRENA report discusses potential for solar PV and onshore wind investment costs to decline, in real terms, by 57% and 12%, respectively, by 2025.[4] In Scenario JIT-2, it is assumed that half of the potential cost declines identified in the IRENA report are achieved by 2025 and that O&M costs for both wind and solar projects grow at 2.0% per year, slightly lower than the assumed 2.3% annual inflation rate. In Scenario JIT-3, it is assumed that costs for wind and solar decline consistent with rates reported by IRENA. Future resource costs in JIT-3 are lower than JIT-2, and future resource costs in JIT-2 are lower than JIT-1.

Table A-3. Just-in-Time Scenario Proxy Resource Cost Assumptions

Variable	Scenario JIT-1	Scenario JIT-2*	Scenario JIT-3*
OR Wind CapEx (2018$/kW)	$1,826	$1,792	$1,757
WY Wind CapEx (2018$/kW)	$1,895	$1,860	$1,823
Wind CapEx Ann. Esc. Rate	2.3%	1.7% through 2025, then 0.0%	1.0% through 2025, then 0.0%
Wind O&M (2018$/kW-yr)	$40.19	$38.80	$38.80
Wind O&M Ann. Esc. Rate	2.3%	2.0%	2.0%
OR Wind Capacity Factor	35.0%	35.0%	35.0%
WY Wind Capacity Factor	43.0%	43.0%	43.0%
OR Solar PV CapEx (2018$/kW)	$2,429	$2,352	$2,019
UT Solar PV CapEx (2018$/kW)	$2,318	$2,244	$1,927
Solar CapEx Ann. Esc. Rate	0.0%	-1.1% through 2025, then 0.0%	-6.0% through 2025, then 0.0%
Solar PV O&M (2018$/kW-yr)	$20.93	$20.81	$20.81
Solar PV O&M Ann. Esc. Rate	2.3%	2.0%	2.0%
OR Solar PV Capacity Factor	29.2%	29.2%	29.2%
UT Solar PV Capacity Factor	31.6%	31.6%	31.6%
Solar PV Annual Degradation	0.5%	0.5%	0.5%

* Wind and solar capital annual escalation assumptions for Scenarios JIT-2 and JIT-3 are based on potential cost declines reported by IRENA in real terms. The rates shown in this table are nominal, assuming a 2.3% inflation rate.

As noted earlier, without any incremental procurement, an initial Oregon RPS compliance shortfall is projected to occur in 2025. Procurement for the just-in-time compliance scenarios targets qualifying renewable resources that can avoid incremental transmission upgrade

[3] International Renewable Energy Agency. (2016). *The Power to Change: Solar and Wind Cost Reduction Potential to 2025*: http://www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=2733
[4] *Id.*

costs, if possible. Table A-4 summarizes assumed just-in-time renewable resource procurement limits based on availability of transmission in high-potential renewable resource areas that would open up with future coal unit retirements. Assumed coal unit retirement dates are consistent with planning assumptions used in PacifiCorp's 2015 IRP Update (through 2034) and/or align with current non-Oregon depreciable lives (beyond 2034).

Table A-4. Just-in-Time Scenario Proxy Resource Procurement Limits

Period	Resource	Limit (MW)	Third Party Wheel
2025-2027	OR Wind	400 (Pre-retirements)	BPA
2025-2027	OR Solar	250 (Pre-retirements)	None
≥ 2028	WY Wind	760 (DJ Retirement)	None
≥ 2030	UT Solar	450 (Huntington 2 Retirement)	None
≥ 2033	UT Solar	+466 (Hunter 2 Retirement)	None
≥ 2036	UT Solar	+459 (Huntington 1 Retirement)	None
≥ 2040	WY Wind	+268 (Wyodak Retirement)	None

In each of the just-in-time compliance scenarios, renewable resources are added beginning 2025 and revenue requirement is calculated for incremental renewable resources added to achieve compliance through 2040, consistent with the cost assumptions outlined above. Revenue requirement includes return on and return of capital, taxes, run-rate operating costs, integration costs, third-party wheeling costs, as applicable, net of energy and capacity benefits.

Table A-5 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-5 for Scenario JIT-1. The present value revenue requirement for the JIT-1 renewable resource portfolio yields customer costs totaling $807 million. Much of this cost is driven by high cost resources needed in 2025 and 2026—before lower cost renewable resources can be procured without incremental transmission costs after assumed coal unit retirement dates.

Table A-5. Proxy Renewable Resources in Scenario JIT-1

Resource	MW	Nom. Lev. Net Cost/(Benefit) ($/MWh)
OR Solar 2025	250	$39.92
OR Wind 2026	341	$45.25
WY Wind 2030	416	$20.19
UT Solar 2035	737	$15.81
UT Solar 2040	371	$12.98
Total	2,116	$26.71

Figure A-5. PacifiCorp Compliance for Scenario JIT-1

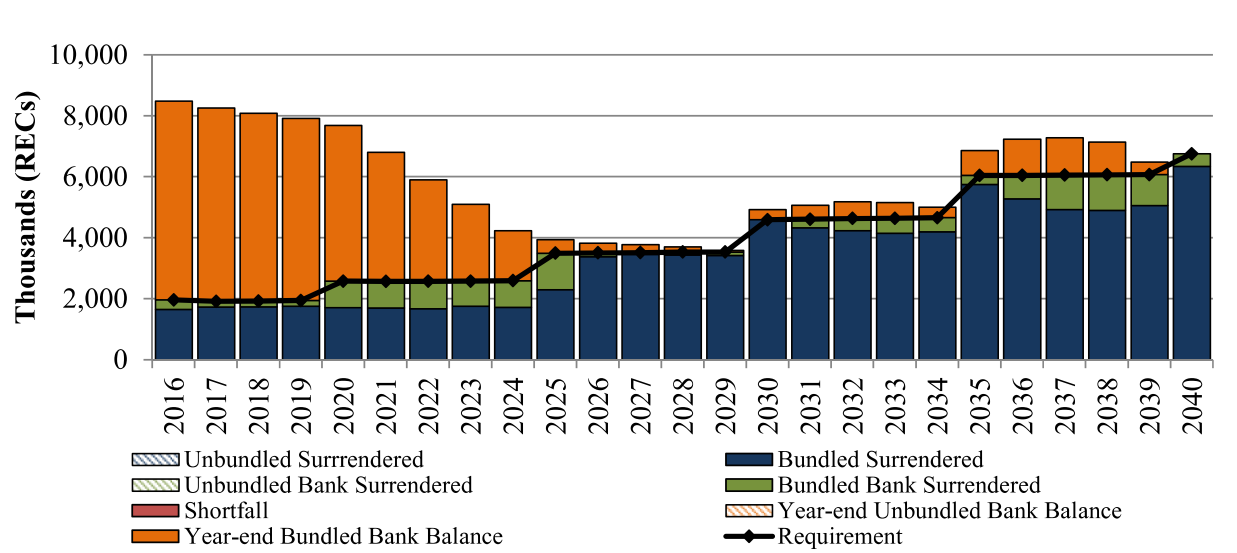


Table A-6 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-6 for Scenario JIT-2. With projected cost declines in future resources, the net cost of these resources is lower than in Scenario JIT-1. However, resources in the 2025-2026 timeframe remain higher cost than longer-term alternatives. The present value revenue requirement for the JIT-2 renewable resource portfolio yields customer costs totaling $529 million.

Table A-6. Proxy Renewable Resources in Scenario JIT-2

Resource	MW	Nom. Lev. Net Cost/(Benefit) ($/MWh)
OR Solar 2025	250	$30.59
OR Wind 2026	341	$38.86
WY Wind 2030	416	$9.93
WY Wind 2035	344	$4.04
UT Solar 2036	305	$5.80
UT Solar 2040	412	$2.10
Total	2,068	$17.09

Figure A-6. PacifiCorp Compliance for Scenario JIT-2

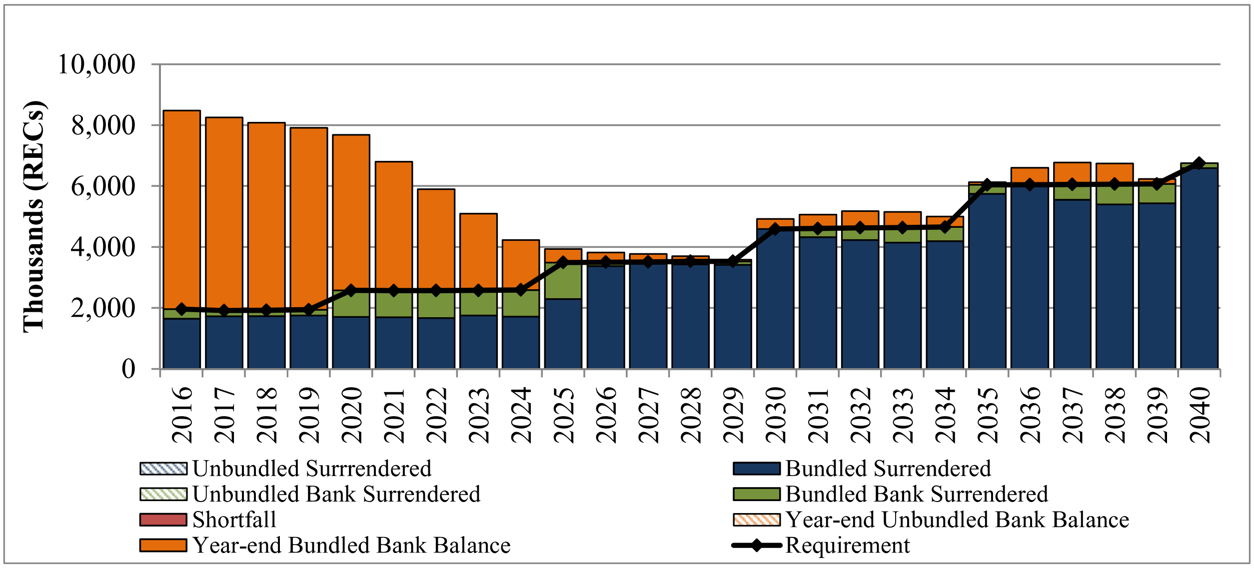


Table A-7 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-7 for Scenario JIT-3. In this case, steeper projected cost declines for future resources yield customer benefits for certain projects. It is assumed that these resources are added on a system basis with costs and benefits shared among PacifiCorp's states. Consequently, for these resources, approximately 25% of the assumed resource potential is allocated to meeting the Oregon RPS targets. As there is not sufficient availability to achieve the target in 2025 without incremental transmission, the 2025 solar resource added in Utah includes incremental network transmission upgrade costs.[5] The present value revenue requirement for the JIT-3 renewable resource portfolio yields customer a customer cost of $2.5 million.

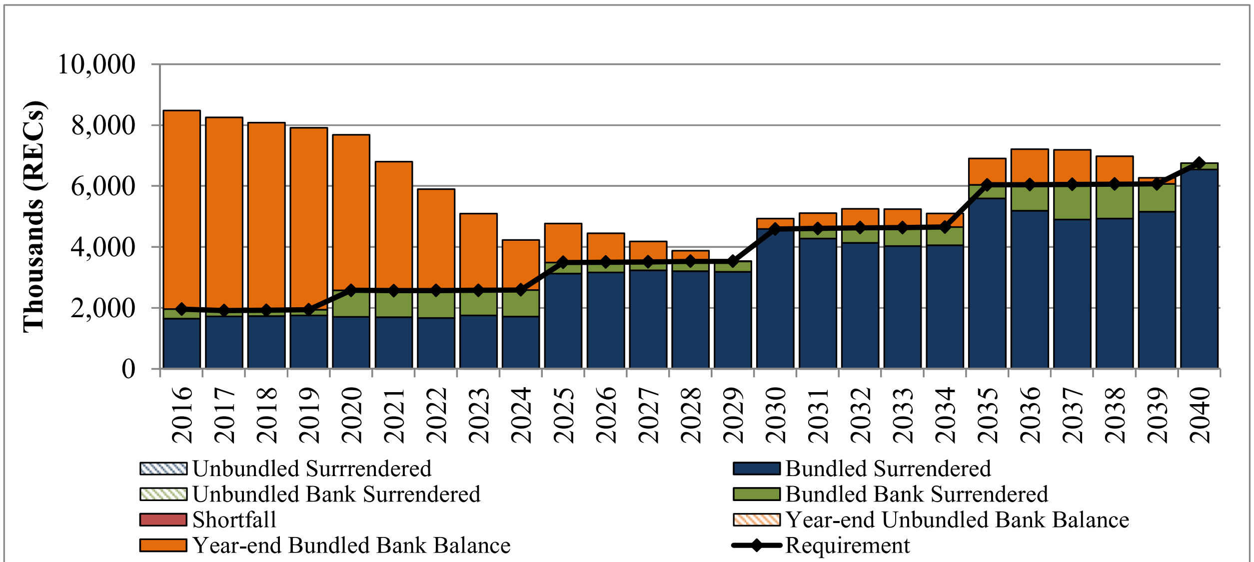
Table A-7. Proxy Renewable Resources in Scenario JIT-3

Resource	MW	Nom. Lev. Net Cost/(Benefit) ($/MWh)
OR Solar 2025	62	($0.55)
UT Solar 2025*	477	$12.66
UT Solar 2030	499	($12.68)
WY Wind 2030	126	$6.92
WY Wind 2035	524	$1.04
UT Solar 2040	113	($24.68)
WY Wind 2040	262	($1.48)
Total	2,068	$0.08

*Includes $218m for assumed network upgrade costs.

[5] Given the sharper cost declines assumed in Scenario JIT-3, UT solar in 2025, with incremental transmission, is lower cost than adding OR wind, with a BPA wheel, in 2025.

Figure A-7. PacifiCorp Compliance for Scenario JIT-3



In the near-term, procurement of resources and/or RECs can defer longer-term procurement needs. Table A-8 summarizes near-term REC and resource cost assumptions used to analyze the inter-temporal trade-off between near-term and long-term procurement strategies. These data are reasonably consistent with offers submitted into PacifiCorp's 2016 renewable resource and REC request for proposals. For resource opportunities, the cost (i.e., PPA price, acquisition cost, operating cost, integration cost, transmission cost, as applicable) net of benefits (i.e., energy and capacity value) is comparable to a REC price. The assumed near-term opportunities are ordered from lowest to highest cost.

Table A-8. Near-Term Resource and REC Procurement Assumptions

Type	REC (GWh)	Resource Size (MW)	Term	Nom. Lev. Cost ($/MWh)	Nom. Lev. (Benefit) ($/MWh)	Net Nom. Lev. Cost or (Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]	2017-2036	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	2017-2036	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	2018-2037	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	2018-2037	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	2017-2036	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	2018-2047	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	2018-2037	[redacted]	[redacted]	[redacted]

The potential benefit of near-term procurement can be analyzed by assuming different levels of near-term procurement, progressing from the lowest cost to highest cost opportunities, relative to the just-in-time compliance scenarios outlined earlier. For the inter-temporal analysis, it is assumed that near-term procurement is pursued at three different intervals—opportunities with a net nominal levelized cost at or below [redacted]/MWh, at or below [redacted]/MWh, and below [redacted]/MWh. In each near-term procurement scenario, long-term procurement is deferred when targeting compliance through 2040.

Table A-9 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-8 for the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-1. In this case, near-term procurement defers long-term procurement from 2025 to 2032. The present value revenue requirement for this scenario is $476 million, which is $331 million lower cost than the JIT-1 Scenario.

Table A-9. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-1 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
UT Solar 2032	450 MW	$20.39
WY Wind 2032	208 MW	$20.58
UT Solar 2035	466 MW	$15.81
WY Wind 2035	417 MW	$21.23
UT Solar 2040	459 MW	$12.98
WY Wind 2040	147 MW	$27.72
Total	[redacted]	[redacted]

Figure A-8. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-1 Scenario

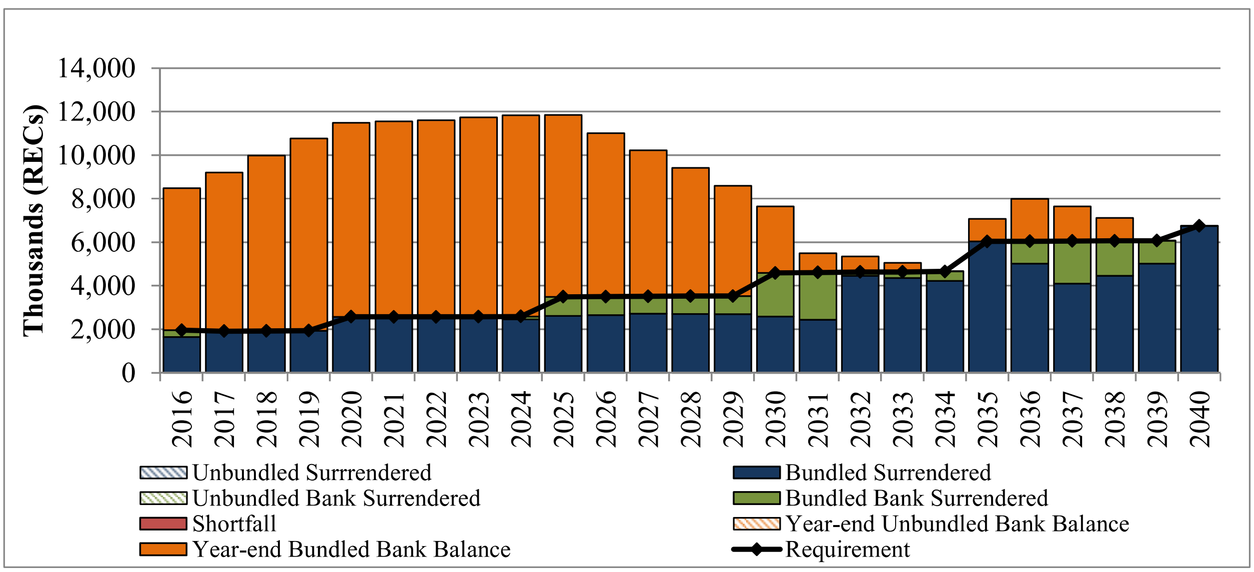


Table A-10 summarizes the renewable resource additions added to achieve the Oregon RPS compliance outcome shown in Figure A-9 for the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-1. In this case, near-term procurement defers long-term procurement from 2025 to 2037. The present value revenue requirement for this scenario is $405 million, which is $402 million lower cost than the JIT-1 Scenario.

Table A-10. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-1 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
UT Solar 2037	1,375 MW	$13.65
WY Wind 2038	291 MW	$24.06
WY Wind 2040	475 MW	$27.72
Total	[redacted]	[redacted]

Figure A-9. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-1 Scenario

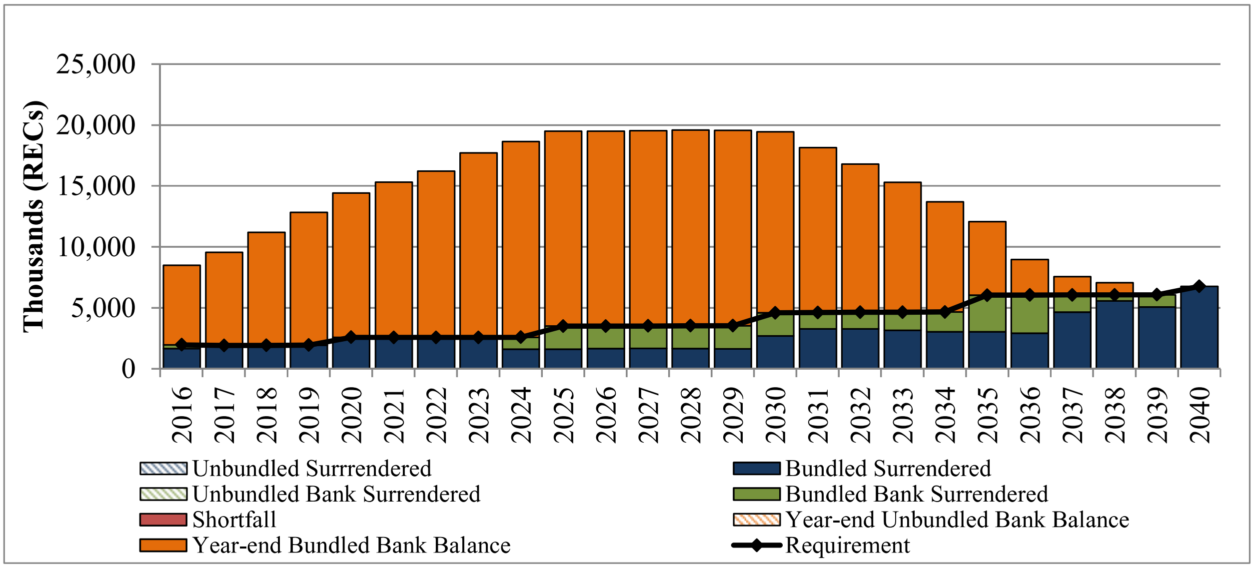


Table A-11 summarizes the renewable resource additions added to achieve the Oregon RPS compliance outcome shown in Figure A-10 for the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-1. In this case, near-term procurement defers long-term procurement from 2025 to 2040. The present value revenue requirement for this scenario is $121 million, which is $686 million lower cost than the JIT-1 Scenario.

Table A-11. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-1 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
UT Solar 2040	50 MW	$12.98
Total	[redacted]	[redacted]

Figure A-10. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-1 Scenario

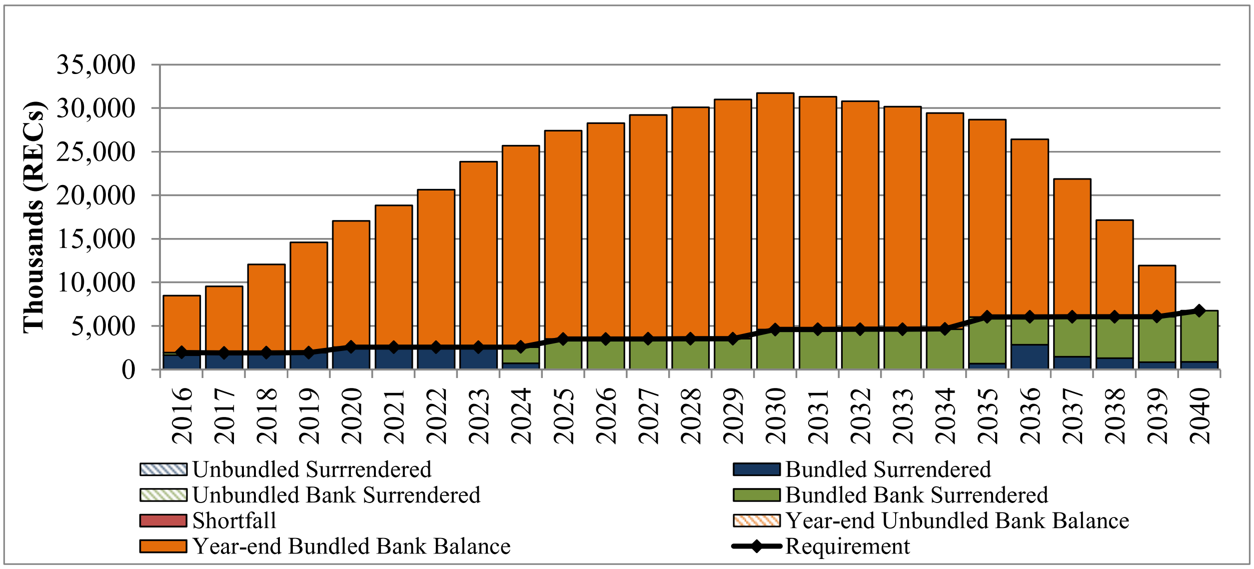


Table A-12 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-11 for the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-2. In this case, near-term procurement defers long-term procurement from 2025 to 2032. The present value revenue requirement for this scenario is $156 million, which is $373 million lower cost than the JIT-2 Scenario.

Table A-12. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-2 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
WY Wind 2032	540 MW	$7.65
WY Wind 2035	220 MW	$4.04
UT Solar 2035	732 MW	$7.45
WY Wind 2040	268 MW	$1.68
UT Solar 2040	214 MW	$4.25
Total	[redacted]	[redacted]

Figure A-11. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-2 Scenario

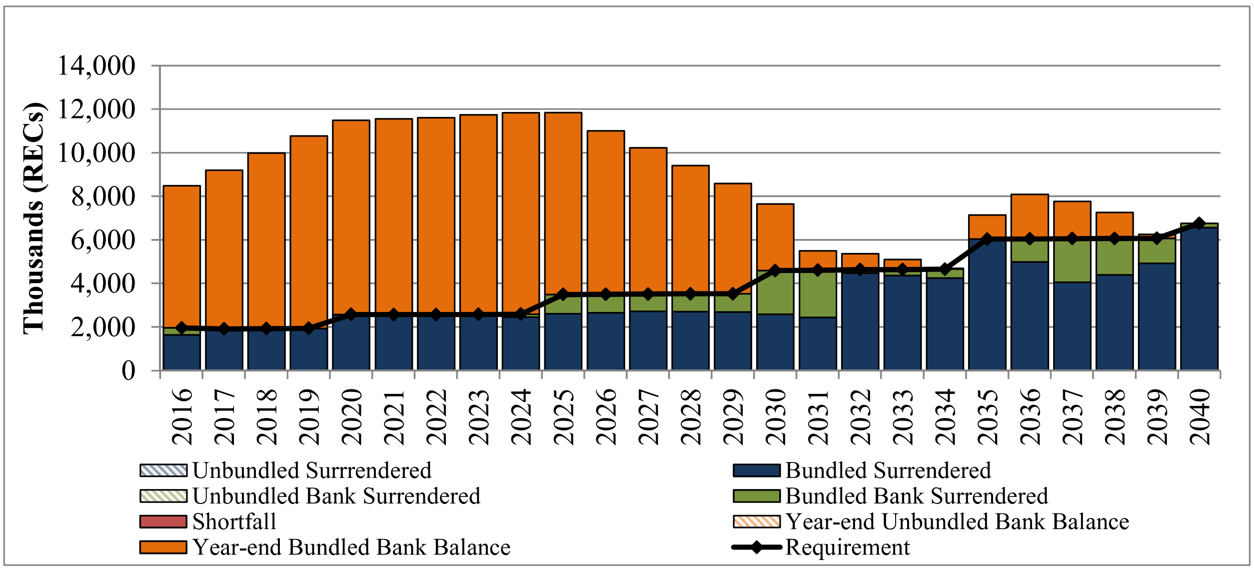


Table A-13 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-12 for the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-2. In this case, near-term procurement defers long-term procurement from 2025 to 2037. The present value revenue requirement for this scenario is $87 million, which is $442 million lower cost than the JIT-2 Scenario.

Table A-13. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-2 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
WY Wind 2037	760 MW	$2.21
UT Solar 2038	927 MW	$4.78
WY Wind 2040	268 MW	$1.68
UT Solar 2040	15 MW	$4.25
Total	[redacted]	[redacted]

Figure A-12. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-2 Scenario

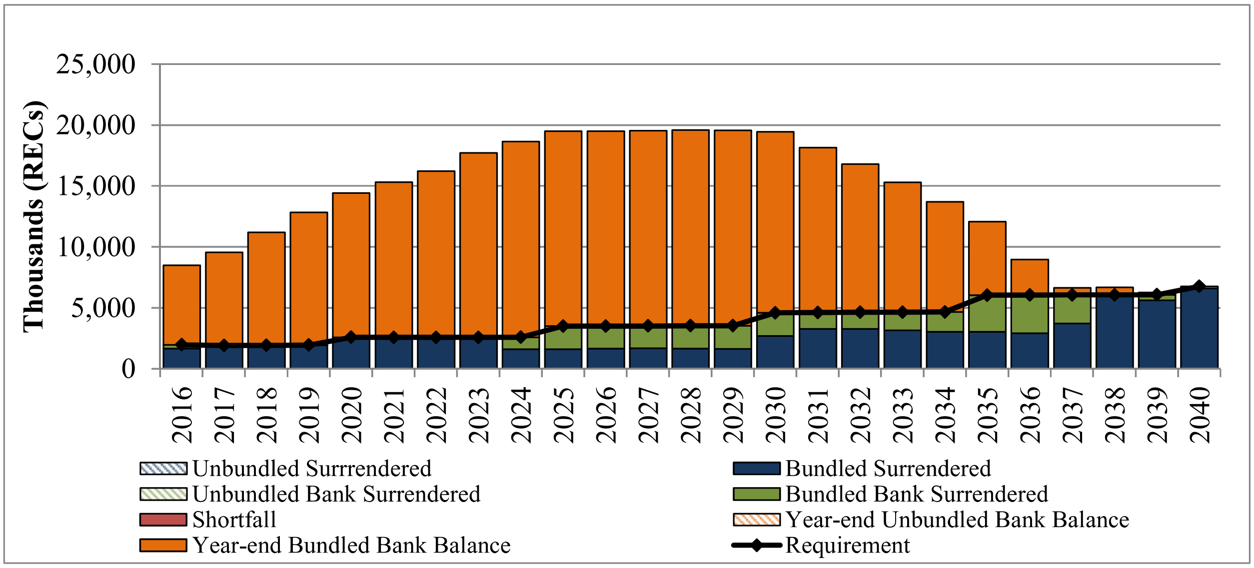


Table A-14 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-13 for the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-2. In this case, near-term procurement defers long-term procurement from 2025 to 2040. The present value revenue requirement for this scenario is $118 million, which is $411 million lower cost than the JIT-2 Scenario.

Table A-14. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-2 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
WY Wind 2040	37 MW	$1.68
Total	[redacted]	[redacted]

Figure A-13. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-2 Scenario

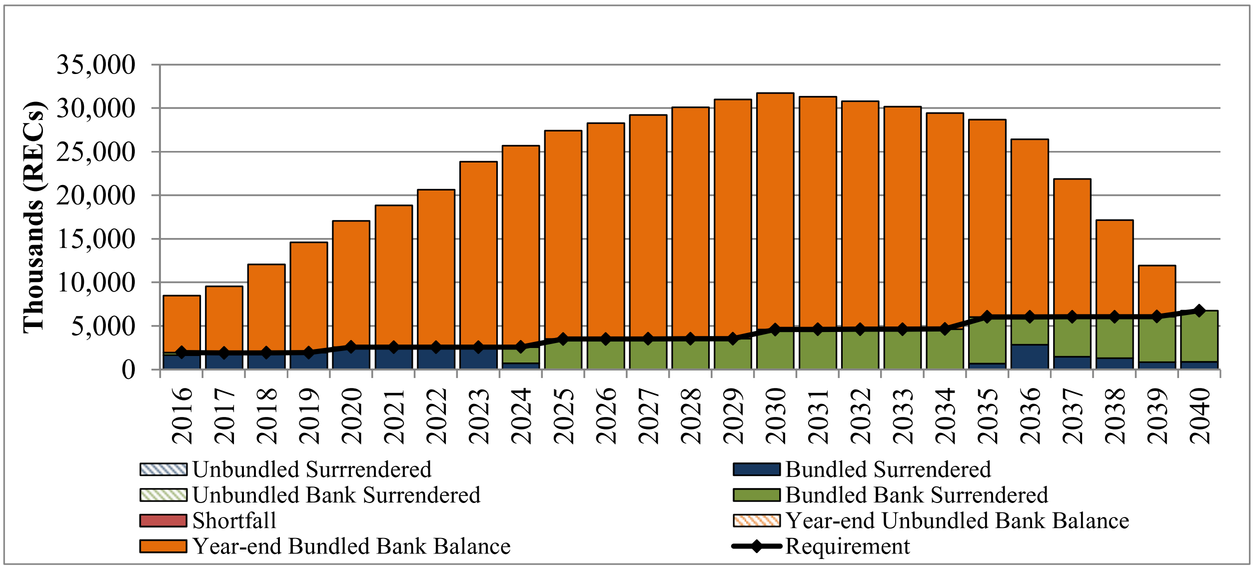


Table A-15 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-14 at the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-3. In this case, near-term procurement defers long-term procurement from 2025 to 2032. The present value revenue requirement for this scenario yields a $102 million customer benefit, which is a $105 million higher benefit than the JIT-3 Scenario.

Table A-15. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-3 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
UT Solar 2032	111 MW	($15.75)
OR Solar 2032	62 MW	($12.86)
UT Solar 2032*	568 MW	$1.64
UT Solar 2035	297 MW	($20.18)
WY Wind 2035	542 MW	$1.04
UT Solar 2040	115 MW	($24.68)
WY Wind 2040	400 MW	($1.48)
Total	[redacted]	[redacted]

*Includes $256m for assumed network upgrade costs.

Figure A-14. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-3 Scenario

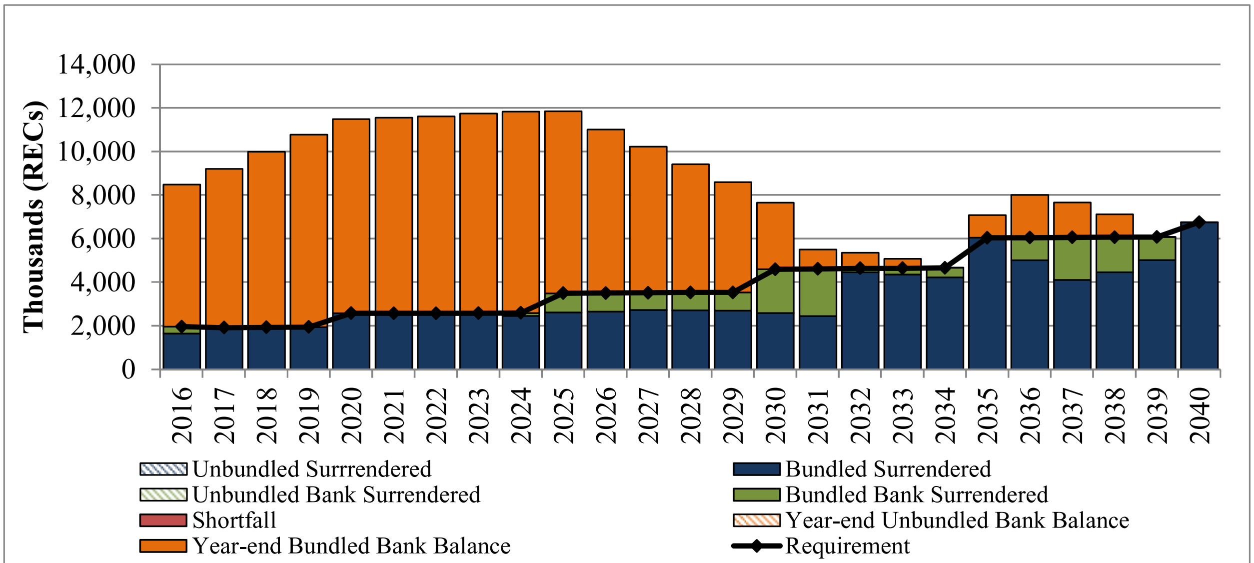


Table A-16 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-15 at the [redacted]/MWh near-term procurement level and costs as defined under Scenario JIT-3. In this case, near-term procurement defers long-term procurement from 2025 to 2037. The present value revenue requirement for this scenario yields a $110 million customer benefit, which is a $112 million higher benefit than the JIT-3 Scenario.

Table A-16. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-3 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
UT Solar 2037	339 MW	($22.70)
OR Solar 2037	62 MW	($20.93)
UT Solar 2037*	750 MW	($7.96)
WY Wind 2038	671 MW	($1.15)
Total	[redacted]	[redacted]

*Includes $289m for assumed network upgrade costs.

Figure A-15. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-3 Scenario

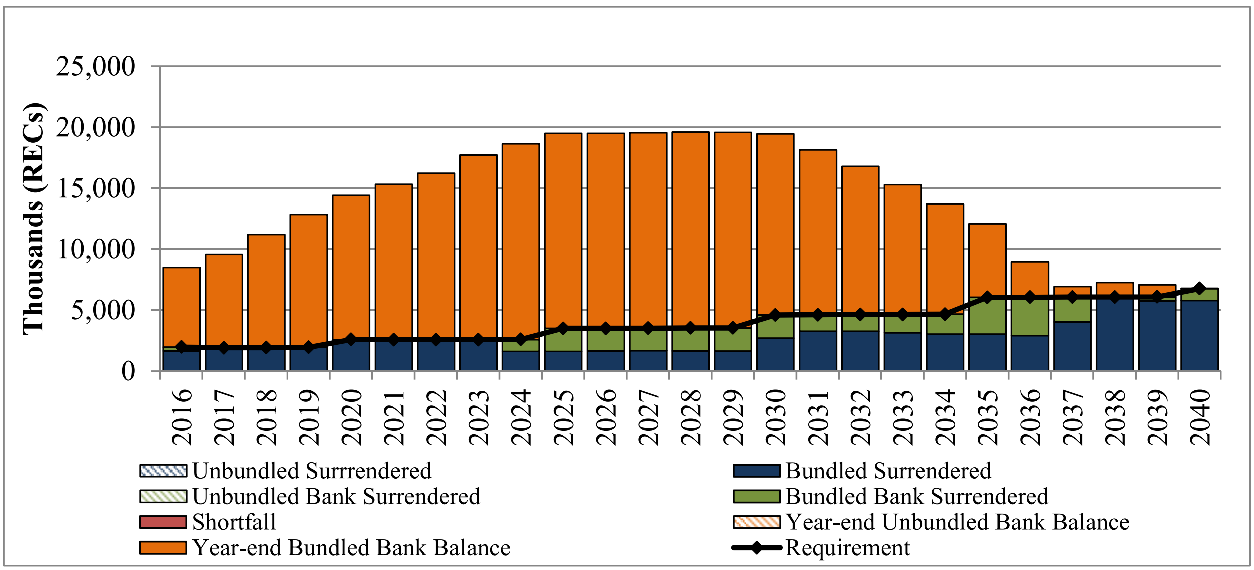


Table A-17 summarizes the renewable resource additions added to achieve Oregon RPS compliance as shown in Figure A-16 at the [redacted]/MWh near-term procurement level and long-term costs as defined under Scenario JIT-3. In this case, near-term procurement defers long-term procurement from 2025 to 2040. The present value revenue requirement for this scenario is $108 million, which is $106 million higher cost than the JIT-3 Scenario.

Table A-17. Renewable Resources with [redacted]/MWh Near-Term Procurement under the JIT-3 Scenario

Type	MW or RECs	Nom. Lev. Net Cost/(Benefit) ($/MWh)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
UT Solar 2040	50 MW	($24.68)
Total	[redacted]	[redacted]

Figure A-16. PacifiCorp Compliance with [redacted]/MWh Near-Term Procurement under the JIT-3 Scenario

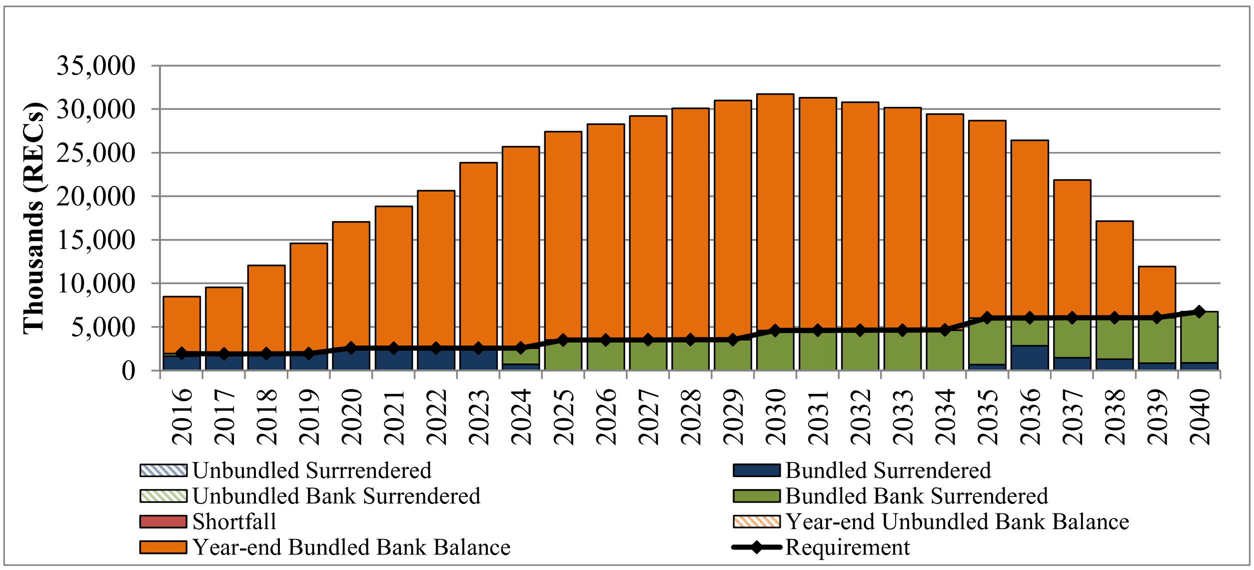


Table A-18 summarizes the present revenue requirement differential (PVRR(d)) between near-term procurement scenarios at varying penetration levels and the three just-in-time compliance scenarios. When future costs are relatively high (i.e., under Scenario JIT-1), near-term procurement opportunities having a net cost at, or even above, [redacted]/MWh yield customer benefits. With more moderate future costs (i.e., under Scenario JIT-2), near-term procurement continues to yield customer benefits; however, benefits are maximized when near-term costs are around [redacted]/MWh or less. With steeper cost reduction assumptions for future renewable resources (i.e., under Scenario JIT-3), near-term procurement can continue to provide customer benefits if those near-term procurement opportunities are competitively priced.

Table A-18. PVRR(d) Cost/(Benefit) of Near-Term Procurement Among JIT Scenarios ($ Million)

	JIT-1 Scenario	JIT-2 Scenario	JIT-3 Scenario
[redacted] MWh Scenario	($331)	($373)	($105)
[redacted] MWh Scenario	($402)	($442)	($112)
[redacted] MWh Scenario	($686)	($411)	$106

This analysis suggests, with the assumed range in future costs and near-term procurement cost and volume assumptions, that near-term procurement can lower RPS compliance costs over the long-term. Near-term procurement with a net cost above [redacted]/MWh may increase customer costs if future resource costs experience relatively steep declines. Competitively priced near-term procurement opportunities that can defer the need for future renewable resources until the 2028-2030 timeframe are most likely to yield customer benefits. Deferring future procurement to this timeframe provides an opportunity to align procurement of lower cost renewable resources with coal unit retirements, thereby avoiding incremental transmission upgrade costs.

While the above analysis assumes varying levels of near-term bundled REC procurement, unbundled RECs can also be used to satisfy Oregon RPS targets. The Oregon RPS rules allow up to 20% of the compliance mix to be comprised of unbundled RECs in any given compliance year.[6] Unbundled RECs can be banked under the same rules as are applicable to bundled RECs, and therefore, unbundled RECs can be banked for use in a future compliance year if the 20% limit is reached.

PacifiCorp could acquire over 1,250,000 unbundled RECs annually, assuming these qualify as "Golden RECs" for the first five years, over a 20-year term without having any of the unbundled RECs expire before being used for compliance through 2040. Figure A-17 summarizes this hypothetical compliance profile, which shows a compliance shortfall in 2030. However, the unbundled REC bank is carried forward and used for compliance through 2040.

[6] The restriction on use of unbundled RECs does not apply to unbundled RECs procured from a qualifying facility project located in Oregon.

Figure A-17. Hypothetical Compliance Using Unbundled RECs that Qualify as Golden RECs

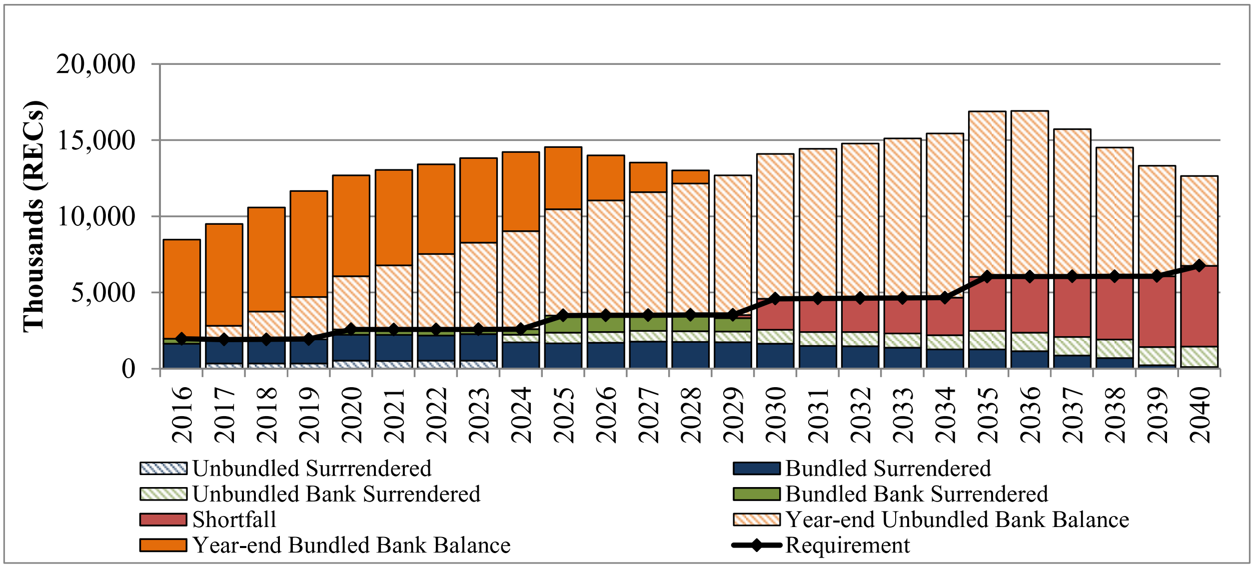
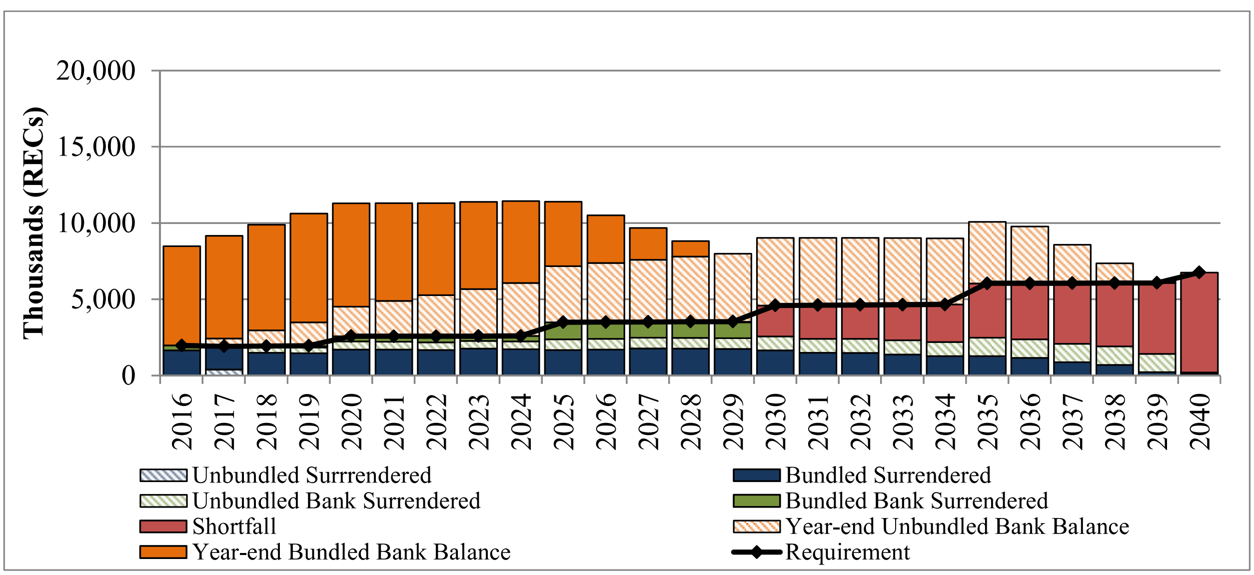


Figure A-18 shows a similar hypothetical compliance profile assuming none of the unbundled RECs qualify as "Golden RECs". In this case, PacifiCorp could procure over 900,000 unbundled RECs annually over a 20-year term (18 million total unbundled RECs) without having any of the unbundled RECs expire before being used for compliance through 2040.

Figure A-18. Hypothetical Compliance Using Unbundled RECs that Qualify as Golden RECs



4. **A discussion of how key market assumptions impact the relative range of risk and uncertainty related to cost over the compliance horizon. Load growth, hydroelectric**

generation, project cost, natural gas and electricity market prices are some examples of key assumptions to be assessed in this discussion.

As discussed above, the relative cost of near-term and longer-term procurement is a key uncertainty that affects risk and cost over the compliance horizon. A key uncertainty in evaluating the net cost of renewable resources is the market value of energy produced by renewable resources. Higher market prices increase the value of energy produced by renewable resources, which reduces the net cost of renewable resource procurement. Conversely, lower market prices decrease the value of energy produced by renewable resources, which increases the net cost of renewable resource procurement.

The impact of market prices, assuming an adjustment of +/- 10% from the energy value of renewable resources and no change to the renewable resource portfolios assumed in the inter-temporal analysis presented above, is shown in Tables A-19 and A-20. Generally, near-term procurement improves customer benefits with lower wholesale energy prices and reduces customer benefits with higher wholesale energy prices. Nonetheless, near-term procurement of competitively priced resources and/or RECs can lower RPS compliance costs over the long-term—even when long-term resource costs are assumed to decline (i.e., as in Scenario JIT-3) concurrent with higher wholesale market prices.

Table A-19. PVRR(d) Cost/(Benefit) of Near-Term Procurement Among JIT Scenarios ($ Million) with 10% Increase in Energy Value

	JIT-1 Scenario	JIT-2 Scenario	JIT-3 Scenario
$3/MWh Scenario	($315)	($348)	($84)
$6/MWh Scenario	($388)	($419)	($72)
$8/MWh Scenario	($556)	($278)	$240

Table A-20. PVRR(d) Cost/(Benefit) of Near-Term Procurement Among JIT Scenarios ($ Million) with 10% Decrease in Energy Value

	JIT-1 Scenario	JIT-2 Scenario	JIT-3 Scenario
$3/MWh Scenario	($347)	($398)	($126)
$6/MWh Scenario	($416)	($464)	($152)
$8/MWh Scenario	($815)	($544)	($29)

Because RPS targets are calculated as a percentage of retail sales, changes to load growth will impact the timing and quantity of renewable resources needed for compliance. Figure A-17 shows PacifiCorp's initial compliance position, assuming no incremental procurement, with a 0.5% increase in the compounded annual retail sale growth rate relative to the base forecast. Figure A-18 shows the impact of a 0.5% reduction in the compounded annual retail sale growth rate.

Figure A-17. PacifiCorp SB 1547 Compliance Position without Procurement and with an 0.5% Increase in the Annual Retail Sale Growth Rate

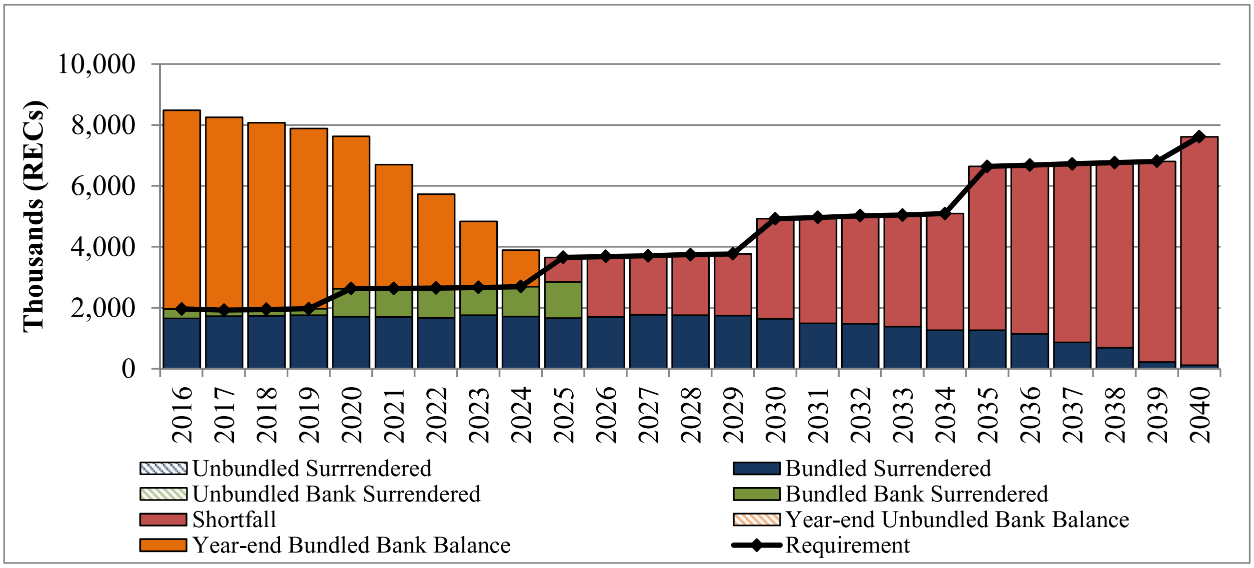
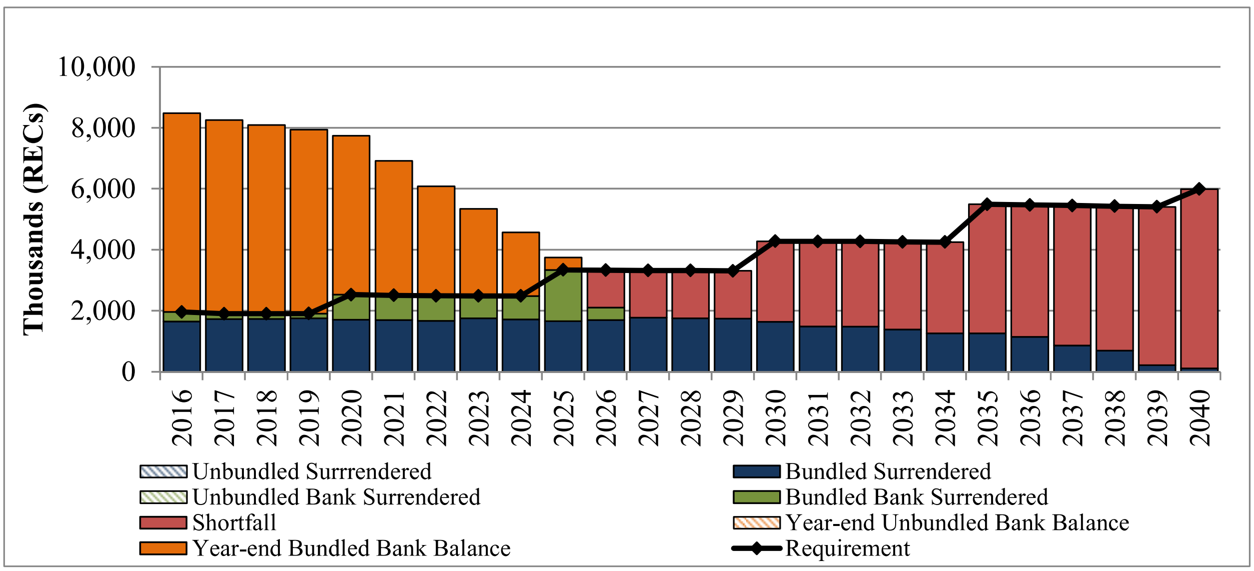


Figure A-18. PacifiCorp SB 1547 Compliance Position without Procurement and with an 0.5% Increase in the Annual Retail Sale Growth Rate



With higher retail sales growth, PacifiCorp's initial shortfall occurs in 2025, which is unchanged from the base initial shortfall year when the base retail sales forecast is applied. The 2025 shortfall is approximately 611 GWh higher relative to the base forecast, which equates to approximately 200 MW of renewable resource capacity operating at a 35% capacity factor. By 2040, the shortfall with a higher retail sales projection is about 857 GWh higher than in the base forecast. This equates to nearly 280 MW of renewable resource capacity operating at a 35% capacity factor.

With lower retail sales growth, PacifiCorp's initial shortfall occurs in 2026, which is one year later than in the base forecast. By 2040, the shortfall with a higher retail sales projection is about 764 GWh lower than in the base forecast. This equates to nearly 250 MW of renewable resource capacity operating at a 35% capacity factor.

5. **Throughout the analysis, PacifiCorp should provide methodologies and assumptions used to support the RPIP along with a narrative describing the reasoning behind the selection of those methodologies and assumptions.**

PacifiCorp has explained its methodology and assumptions throughout its response to Attachment A of Order No. 15-158.

PacifiCorp
Renewable Portfolio Standard Oregon Implementation Plan
2017-2021

<u>Attachment A</u>

Accounting of RECs Applicable to Oregon RPS

Refiled July 15, 2016

PacifiCorp Oregon - 2017-2021 RPS Implementation Plan
Attachment A - Accounting of RECs Applicable to Oregon RPS for 2007-2015

	MWh - 2007 - 2015								
	2007	2008	2009	2010	2011	2012	2013	2014	2015
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Oregon Renewable Portfolio Standard Requirement [1]	-	-	-	-	650,729	638,940	654,498	647,937	1,929,369
Compliance Method									
Bundled RECs					650,729	511,152	523,600	518,350	1,717,643
Unbundled RECs						127,788	130,899	129,587	211,726
Available Resources [2]									
Bundled RECs by vintage year	355,038	572,302	822,402	1,247,291	1,776,846	1,588,069	1,476,704	1,549,424	1,329,263
Unbundled RECs by vintage year	44,000	127,342	-	8,356	122,916	243,819	53,567		
Cumulative Banked RECs minus RPS requirement by year of compliance [3]	399,038	1,098,683	1,921,085	3,176,732	4,425,765	5,618,713	6,494,486	7,395,973	6,795,867
Alternative compliance payments					-	-	-	-	-

Notes

(1) Based on Retail Load Forecast, October 2015

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

(3) Oldest RECs retired first for RPS compliance

Refiled July 15, 2016

PacifiCorp Oregon - 2017-2021 RPS Implementation Plan
Attachment A - Accounting of RECs Applicable to Oregon RPS for 2016-2021

	MWh - 2016-2021						
	Pre-2016	2016	2017	2018	2019	2020	2021
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Oregon Renewable Portfolio Standard Requirement [1]		1,958,763	1,909,419	1,921,934	1,936,852	2,576,755	2,566,748
Planned Compliance Method [2]							
Bundled RECs		1,958,763	1,909,419	1,921,934	1,936,852	2,576,755	2,566,748
Unbundled RECs		-	-	-	-	-	-
Available Resources [3]							
Starting Bank (Beginning of 2016)	6,795,867						
Total Bundled RECs by vintage year		1,649,892	1,706,103	1,703,224	1,692,768	1,674,589	1,661,496
RECs with 6-year Life by Vintage Year		1,220,366	1,562,260	1,559,245	1,549,508	1,532,705	1,587,747
RECs with Indefinite Banking; Post-SB 1547 Commercial Operation		68,659	143,843	143,979	143,261	141,884	73,749
RECs with Indefinite Banking; Pre-SB 1547 Comemrcial Operation		360,867	0	0	0	0	0
Total Unbundled RECs by vintage year		0	0	0	0	0	0
Cumulative Banked RECs minus RPS requirement by year of compliance		6,486,996	6,283,680	6,064,969	5,820,886	4,918,720	4,013,467
Alternative compliance payments		-	-	-	-	-	-

Notes

(1) Based on Retail Load Forecast, October 2015 (Consistent with 2015 IRP Update)

(2) RECs with the shortest banking life will be used first, then oldest RECs from the existing (pre-2016) bank will be retired

(3) 2017-2021 Implementation Plan - Attachment B - Oregon's Share Per Allocation Factors - Renewable Portfolio Standard Renewable Energy Credits (MWh)

PacifiCorp
Renewable Portfolio Standard Oregon
Implementation Plan
2017-2021

Confidential Attachment B

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

(Redacted Version)

PacifiCorp Oregon - 2017-2021 RPS Implementation Plan

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

Refiled July 15, 2016

		State	COD(2)	WREGIS ID	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
					Actual(3)	Actual(3)	Actual(3)	Actual(3)	Actual(3)	Actual(3)	Actual(3)	Actual(3)	Actual(3)	Forecast(3)	Forecast(3)	Forecast(3)	Forecast(3)	Forecast(3)	Forecast(3)
BIOGAS	Hill Air Force Base	UT	2005	W1263 / W1273					3,797	3,689	3,453	3,558	3,751	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Biogas								**3,797**	**3,689**	**3,453**	**3,558**	**3,751**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GEOTHERMAL	Blundell II	UT	2007	W230	2,526	18,822	22,876	19,786	21,937	21,213	18,870	19,455	18,113	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Geothermal				**2,526**	**18,822**	**22,876**	**19,786**	**21,937**	**21,213**	**18,870**	**19,455**	**18,113**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
WIND	Campbell Hill-Three Buttes (PPA)	WY	2009	W1383			10,987	78,605	95,012	88,168	85,121	84,600	75,688	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Chevron Casper Wind Farm (PPA)	WY	2009	W1370			1,683	10,110	12,892	11,867	11,081	10,812	9,533	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Combine Hills (PPA)	OR	2003	W189	117,181	114,458	104,572	104,663	118,643	108,721	102,419	107,568	91,036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Dunlap I	WY	2010	W1687				26,839	111,195	100,599	103,222	97,716	87,447	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Foote Creek I	WY	1999	W201	15,666	18,091	14,242	14,650	16,656	13,251	13,469	15,558	12,586	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Foote Creek II	WY	1999	W1363								763	1,327	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Foote Creek III	WY	1999	W1141								8,336	16,083	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Glenrock	WY	2008	W964		560	69,779	75,448	90,011	81,542	81,242	76,287	74,493	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Glenrock III	WY	2009	W965		0	23,435	26,194	34,381	30,893	30,724	28,785	28,019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Goodnoe Hills	WA	2008	W536	232	54,050	65,244	55,620	63,226	57,344	57,269	55,304	48,072	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	High Plains	WY	2009	W1334			19,981	67,432	88,585	81,906	85,994	82,727	64,577	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Latigo	WY	2015	TBD										[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Leaning Juniper I	OR	2006	W200	79,427	88,113	71,124	58,578	62,000	49,501	51,953	54,917	48,541	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Marengo	WA	2007	W185	51,406	112,813	87,007	86,716	106,527	93,001	83,472	93,735	76,909	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Marengo II	WA	2008	W772		22,114	43,504	43,359	51,329	46,038	38,962	44,589	35,485	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	McFadden Ridge	WY	2009	W1341			5,651	20,272	27,092	24,578	26,139	25,108	20,148	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Mountain Wind Power (PPA)	WY	2008	W1022		21,888	35,272	39,153	49,250	44,474	42,065	48,893	36,164	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Mountain Wind Power II (PPA)	WY	2008	W1023		16,401	55,752	52,948	63,599	59,065	57,418	65,199	47,122	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Pioneer Wind	WY	2016	TBD										[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Rock River I (PPA)	WY	2001	W187	38,665	44,240	37,056	36,213	35,934	35,030	35,676	39,759	30,309	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Seven Mile Hill I	WY	2008	W975		376	83,422	84,929	100,789	88,728	89,736	85,481	76,341	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Seven Mile Hill II	WY	2008	W976			17,104	17,745	22,080	18,814	19,416	18,778	16,491	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Top of the World (PPA)	WY	2010	W1749			0	49,477	181,005	172,464	161,824	163,539	146,747	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wolverine Creek (PPA)	ID	2005	W188	40,868	47,992	42,262	42,485	52,451	46,266	38,811	46,892	36,785	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Wind				**343,444**	**541,097**	**788,077**	**991,436**	**1,382,657**	**1,252,250**	**1,216,013**	**1,255,346**	**1,079,903**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
HYDRO	Ashton	ID	1917	W146				5,955	4,779	526	8,703	8,375	7,715	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Big Fork	MT	1929	W179	199	324	332	353	382	362	317	336	288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Clearwater 1	OR	1953	W148				8,248	11,487	13,146	9,520	10,523	8,128	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Clearwater 2	OR	1953	W149				7,783	14,875	14,042	9,924	11,454	8,274	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Copco 1	CA	1918	W142	105	126	100	81	137	102	78	87	81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cutler	UT	1927	W151	136	628	1,004	13,221	41,743	13,421	8,421	10,533	9,328	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fish Creek	OR	1952	W153				9,820	12,189	11,105	3,973	6,157	2,044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Grace	ID	1923	W137				16,636	43,142	21,416	17,902	14,305	16,282	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	JC Boyle	OR	1958	W180	372	1,124	879	728	1,273	898	605	586	548	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Lemolo 1	OR	1955	W157	3,446	4,281	3,581	29,188	44,405	43,184	31,220	35,939	31,804	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Lemolo 2	OR	1956	W158	363	371	212	36,284	48,315	53,683	37,800	44,325	35,173	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oneida	ID	1915	W160	803	746	699	7,464	20,418	8,549	7,179	5,534	7,430	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Pioneer	UT	1897	W162	194	304	496	297	553	287	143	156	172	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Prospect 2	OR	1928	W140	1,104	1,167	1,076	1,020	1,148	1,068	938	885	721	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Prospect 3	OR	1932	W164	1,196	1,259	1,066	9,257	12,326	9,728	8,504	9,169	7,151	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Slide Creek	OR	1951	W168				20,716	9,806	25,055	13,386	17,967	11,516	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Soda	ID	1924	W170				3,658	9,283	5,192	4,089	3,871	3,869	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Soda Springs	OR	1952	W171				13,598	18,743	13,105	11,537	13,796	8,824	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Toketee	OR	1950	W173				49,510	69,665	68,399	49,366	57,754	47,363	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Yale	WA	1953	W141	1,150	2,054	2,004	2,228	2,357	2,460	1,722	2,314	1,675	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Hydro				**9,068**	**12,384**	**11,449**	**236,045**	**367,026**	**305,728**	**225,327**	**254,066**	**208,386**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OREGON SOLAR INCENTIVE	Oregon Solar Incentive Program - Central Oregon (CO 1)	OR	2010	W1686				11	209	403	409	399	340	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Central Oregon (CO 2)	OR	2011	W2391					7	194	393	397	388	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Central Oregon (CO 3)	OR	2013	W3671							22	230	356	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Columbia River (CR 1)	OR	2011	W1970					126	192	263	327	357	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Columbia River (CR 2)	OR	2014	W4436									41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Eastern Oregon (EO 1)	OR	2010	W1737				2	137	340	371	354	351	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Eastern Oregon (EO 2)	OR	2011	W2611						116	200	298	378	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Portland Oregon (PO 1)	OR	2010	W1738				2	81	189	299	310	311	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Portland Oregon (PO 2)	OR	2013	W3672							17	111	220	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 1)	OR	2010	W1806				3	362	419	453	437	513	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 2)	OR	2011	W2240					161	545	573	508	515	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 3)	OR	2011	W2392					35	453	537	484	482	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 4)	OR	2012	W2690						316	467	450	427	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 5)	OR	2012	W3207						7	438	436	405	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 6)	OR	2013	W3516							302	412	417	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 7)	OR	2013	W3554							182	408	399	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 8)	OR	2013	W3673								375	386	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 9)	OR	2013	W4084								275	338	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 10)	OR	2014	W4187								152	446	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 11)	OR	2014	W4485								1	363	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Southern Oregon (SO 12)	OR	2015	W4576									146	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 1)	OR	2010	W1739				6	253	280	314	308	313	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 2)	OR	2011	W2326					14	202	380	395	391	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 3)	OR	2012	W3208						25	333	329	326	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 4)	OR	2013	W3396							367	313	243	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 5)	OR	2013	W3410							256	323	328	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 6)	OR	2013	W3673							44	348	340	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 7)	OR	2014	W4085								118	323	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Willamette Valley (WV 8)	OR	2015	TBD									37	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - (Joseph Community) Wallowa County	OR	2011	W2448					44	666	746	740	667	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Oregon Solar Incentive Program - Remaining Capacity	OR	2016-2017	TBD									1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Bourdet	OR	2014	W4486									95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Bourdet II	OR	2016	TBD										[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Confederated Tribes of Warm Springs (CTWS)	OR	2014	W4105								292	309	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Crook County Solar	OR	2014	W3847							244	973	870	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Lakeview	OR	2012	W3468							248	596	699	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Lakeview II	OR	2013	W3960								839	898	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Powell Butte	OR	2014	W4274								123	288	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Solwatt	OR	2012	W2968						257	484	521	509	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Solwatt II	OR	2014	W4273								110	294	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Oregon Solar Incentive							**25**	**1,429**	**4,604**	**8,342**	**12,692**	**14,510**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SOLAR	Pavant Solar II LLC	OR	2016	TBD										[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Solar													[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SOLAR CAPACITY STANDARD	Black Cap	OR	2012	W3104						585	4,699	4,307	4,600	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Utility Solar									**585**	**4,699**	**4,307**	**4,600**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total					**355,038**	**572,302**	**822,402**	**1,247,291**	**1,776,846**	**1,588,069**	**1,476,704**	**1,549,424**	**1,329,263**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oregon's Share Based on SG Allocation Factors(3)					**27.44%**	**28.19%**	**27.49%**	**26.20%**	**26.41%**	**25.93%**	**25.20%**	**25.51%**	**25.47%**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

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

(3) Oregon's share based on forecasted system generation (SG) allocation factors:
2007 through 2015 - Based on Actual Retail Loads
2016 through 2021 - Based on Forecast, October 2015

Refiled July 15, 2016

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

PacifiCorp
Renewable Portfolio Standard Oregon
Implementation Plan
2017-2021

Confidential Attachment C

Preliminary Key Assumptions
Incremental Cost Calculation

(Redacted Version)
Subject to Protective Order

PacifiCorp
Renewable Portfolio Standard
Oregon Implementation Plan
2017 through 2021

Key Assumptions – Expected Incremental Cost Calculation

Background

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

The annual expected incremental cost calculation for renewable resources in service during the 2017-2021 reporting period is the difference between the nominal levelized cost of the renewable resource and the nominal levelized cost of the proxy plants.

Methodology

The nominal levelized costs have been developed using an approach similar to that used to create the supply-side resource tables in Chapter 6 of the 2015 Integrated Resource Plan (IRP). For qualifying renewable resources currently in service, forecasted ongoing capital, and operation and maintenance (O&M) from the most recently available 10 year Business Plan are used. Actual ongoing capital and O&M values are used for historical period of 2007-2014. Data for renewable resources acquired through a power purchase agreement (PPA) reflect the associated contract terms.

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

Inflation values are based on the Company's official inflation forecast. Where a calculation requires a single value, the 2% average annual inflation rate from 2015-2040 has been used. Otherwise, yearly values from the Company's official inflation forecast have been applied.

Renewable Resources

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Key Assumptions – Expected Incremental Cost Calculation

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

Table 1 – List of Qualifying Resources Included in Incremental Cost

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

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

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

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

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Key Assumptions – Expected Incremental Cost Calculation

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

Table 2 – Power Purchase Agreements (PPAs)

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

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

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

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

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

[4] See the Company's 2015 IRP – Volume II, Appendix N, Table N.1, p. 405.

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

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

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

Proxy Plant

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

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

The following scenarios[6] are considered in the incremental cost analysis:

- Scenario 1: December 2015 OFPC (Base case OFPC used in 2015 IRP Update)
- Scenario 2: December 2015 OFPC High Gas
- Scenario 3: December 2015 OFPC Low Gas

[5] *In the Matter of PacifiCorp, dba Pacific Power 2009 Renewable Adjustment Clause Schedule 202*, Docket UE 200, Order 548 at 19-20 (Nov. 14, 2008).
[6] Scenarios 1-6 are from the 2015 IRP.

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- Scenario 4: March 2016 OFPC

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

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

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

Transaction costs associated with fuel purchases are added to the proxy resource costs to comply with Order No. 12-272. Specifically, actual broker fees associated with forward gas purchases compared to total gas consumption by the Company's gas units for CY 2010-2014 are used to calculate an average annual historical gas transaction cost of $0.00002/MMBTU. Values for 2015 and beyond are estimated by applying annual inflation rates to the average annual historical gas transaction cost.

<u>Levelized Calculation</u>
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.

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

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

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

Expected Incremental Cost

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

Allocation Factors

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

Table 3 – Allocation Factors

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

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<u>Confidential Attachment D</u>

Incremental Cost Analysis

Subject to Protective Order

THIS ATTACHMENT IS CONFIDENTIAL AND PROVIDED UNDER SEPATATE COVER

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Attachment E

Scenarios 1-7

Summary of Incremental Cost by Resource

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

Scenario 1: Dec 2015 OFPC Fuel Curve

	2017	2018	2019	2020	2021
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($773)	($775)	($772)	($764)	($762)
Campbell Hill-Three Buttes	$1,497	$1,500	$1,495	$1,480	$1,476
Dunlap I	$346	$346	$345	$342	$341
Glenrock	$540	$541	$539	$534	$532
Glenrock III	$311	$311	$310	$307	$306
Goodnoe Hills	$1,439	$1,442	$1,437	$1,422	$1,418
High Plains	$1,148	$1,150	$1,146	$1,135	$1,131
McFadden Ridge	$60	$60	$60	$59	$59
Marengo	$417	$418	$416	$412	$411
Marengo II	$393	$394	$393	$389	$388
Mountain Wind Power	$249	$249	$248	$246	$245
Mountain Wind Power II	$789	$791	$788	$780	$778
Seven Mile Hill I	($259)	($260)	($259)	($256)	($255)
Seven Mile Hill II	($60)	($60)	($60)	($59)	($59)
Top of the World	$3,066	$3,073	$3,061	$3,030	$3,022
Pioneer Wind Park I QF	($473)	($474)	($472)	($467)	($466)
Latigo Wind Park QF	$655	$657	$654	$648	$646
Pavant II Solar QF	($302)	($303)	($301)	($299)	($298)
Black Cap Solar	$104	$104	$104	$104	$104
OSIP_2010	$131	$131	$131	$131	$131
OSIP_2011	$1,265	$1,265	$1,265	$1,265	$1,265
OSIP_2012	$811	$811	$811	$811	$811
OSIP_2013	$958	$958	$958	$958	$958
OSIP_2014	$614	$614	$614	$614	$614
OSIP_2015	$231	$231	$231	$231	$231

Scenario 2: Dec 2015 OFPC Scenario High Gas Fuel Curve

	2017	2018	2019	2020	2021
Resource	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)	Levelized Incremental Cost ($000)
Blundell II	($948)	($950)	($946)	($937)	($934)
Campbell Hill-Three Buttes	$888	$890	$887	$878	$875
Dunlap I	($551)	($552)	($550)	($544)	($543)
Glenrock	($196)	($197)	($196)	($194)	($193)
Glenrock III	$28	$28	$28	$28	$28
Goodnoe Hills	$897	$899	$896	$887	$884
High Plains	$445	$446	$444	$440	$438
McFadden Ridge	($136)	($136)	($136)	($134)	($134)
Marengo	($275)	($276)	($274)	($272)	($271)
Marengo II	$4	$4	$4	$4	$4
Mountain Wind Power	($68)	($68)	($67)	($67)	($67)
Mountain Wind Power II	$387	$387	$386	$382	$381
Seven Mile Hill I	($1,053)	($1,055)	($1,051)	($1,041)	($1,038)
Seven Mile Hill II	($216)	($217)	($216)	($214)	($213)

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Attachment E - Summary of RPS Incremental Costs by Resource

Top of the World	$1,761	$1,764	$1,757	$1,740	$1,735
Pioneer Wind Park I QF	($1,533)	($1,536)	($1,530)	($1,515)	($1,511)
Latigo Wind Park QF	$110	$110	$110	$109	$109
Pavant II Solar QF	($768)	($770)	($767)	($759)	($757)
Black Cap Solar	$68	$68	$68	$68	$68
OSIP_2010	$130	$130	$130	$130	$130
OSIP_2011	$1,247	$1,247	$1,247	$1,247	$1,247
OSIP_2012	$789	$789	$789	$789	$789
OSIP_2013	$921	$921	$921	$921	$921
OSIP_2014	$583	$583	$583	$583	$583
OSIP_2015	$220	$220	$220	$220	$220

Scenario 3: Dec 2015 OFPC Scenario Low Gas Fuel Curve

	2017	2018	2019	2020	2021
Resource	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**
Blundell II	($736)	($738)	($735)	($727)	($725)
Campbell Hill-Three Buttes	$1,601	$1,604	$1,598	$1,583	$1,578
Dunlap I	$553	$554	$552	$546	$545
Glenrock	$705	$706	$704	$697	$695
Glenrock III	$374	$375	$374	$370	$369
Goodnoe Hills	$1,556	$1,559	$1,553	$1,538	$1,533
High Plains	$1,306	$1,309	$1,303	$1,291	$1,287
McFadden Ridge	$104	$104	$103	$102	$102
Marengo	$557	$558	$556	$551	$549
Marengo II	$477	$478	$476	$472	$470
Mountain Wind Power	$317	$318	$316	$313	$312
Mountain Wind Power II	$876	$878	$874	$866	$863
Seven Mile Hill I	($81)	($81)	($81)	($80)	($80)
Seven Mile Hill II	($25)	($25)	($25)	($24)	($24)
Top of the World	$3,302	$3,309	$3,296	$3,263	$3,254
Pioneer Wind Park I QF	($221)	($222)	($221)	($219)	($218)
Latigo Wind Park QF	$782	$783	$780	$773	$770
Pavant II Solar QF	($193)	($194)	($193)	($191)	($191)
Black Cap Solar	$110	$110	$110	$110	$110
OSIP_2010	$131	$131	$131	$131	$131
OSIP_2011	$1,267	$1,267	$1,267	$1,267	$1,267
OSIP_2012	$814	$814	$814	$814	$814
OSIP_2013	$963	$963	$963	$963	$963
OSIP_2014	$619	$619	$619	$619	$619
OSIP_2015	$233	$233	$233	$233	$233

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Attachment E - Summary of RPS Incremental Costs by Resource

Scenario 4: Mar 2016, OFPC Fuel Curve

	2017	2018	2019	2020	2021
Resource	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**	**Levelized Incremental Cost ($000)**
Blundell II	($766)	($767)	($765)	($757)	($755)
Campbell Hill-Three Buttes	$1,519	$1,523	$1,517	$1,502	$1,498
Dunlap I	$387	$388	$387	$383	$382
Glenrock	$573	$574	$572	$566	$565
Glenrock III	$323	$324	$323	$320	$319
Goodnoe Hills	$1,463	$1,466	$1,460	$1,446	$1,442
High Plains	$1,180	$1,182	$1,177	$1,166	$1,162
McFadden Ridge	$68	$69	$68	$68	$67
Marengo	$445	$446	$444	$440	$439
Marengo II	$410	$411	$410	$406	$405
Mountain Wind Power	$263	$263	$262	$260	$259
Mountain Wind Power II	$807	$808	$805	$797	$795
Seven Mile Hill I	($224)	($224)	($223)	($221)	($220)
Seven Mile Hill II	($53)	($53)	($53)	($52)	($52)
Top of the World	$3,115	$3,121	$3,109	$3,079	$3,070
Pioneer Wind Park I QF	($428)	($429)	($427)	($423)	($422)
Latigo Wind Park QF	$678	$679	$676	$670	$668
Pavant II Solar QF	($282)	($283)	($282)	($279)	($278)
Black Cap Solar	$106	$106	$106	$106	$106
OSIP_2010	$131	$131	$131	$131	$131
OSIP_2011	$1,265	$1,265	$1,265	$1,265	$1,265
OSIP_2012	$812	$812	$812	$812	$812
OSIP_2013	$959	$959	$959	$959	$959
OSIP_2014	$615	$615	$615	$615	$615
OSIP_2015	$232	$232	$232	$232	$232

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Attachment F

Scenarios 1 - 7

Summary of RPS Incremental Cost of Compliance

Refiled July 15, 2016

PacifiCorp Oregon - 2017-2021 RPS Implementation Plan

Attachment F - Summary of RPS Total Incremental Cost of Compliance

Scenario 1: 2015 IRP Update Base Case - (December 2015 OFPC) Fuel Curve

	Incremental Costs			Annual Revenue Requirement	Percent of Annual Revenue Requirement	4% Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)			($000s)
2017	$15,572	$0	$15,572	$1,236,413	1.26%	$49,457
2018	$15,735	$0	$15,735	$1,245,552	1.26%	$49,822
2019	$15,916	$0	$15,916	$1,247,703	1.28%	$49,908
2020	$21,085	$0	$21,085	$1,244,920	1.69%	$49,797
2021	$20,974	$0	$20,974	$1,240,037	1.69%	$49,601

Scenario 2: December 2015 OFPC Fuel Curve - High Gas

	Incremental Costs			Annual Revenue Requirement	Percent of Annual Revenue Requirement	4% Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)			($000s)
2017	$3,727	$0	$3,727	$1,236,413	0.30%	$49,457
2018	$3,773	$0	$3,773	$1,245,552	0.30%	$49,822
2019	$3,836	$0	$3,836	$1,247,703	0.31%	$49,908
2020	$5,192	$0	$5,192	$1,244,920	0.42%	$49,797
2021	$5,281	$0	$5,281	$1,240,037	0.43%	$49,601

Scenario 3: December 2015 OFPC Fuel Curve - Low Gas

	Incremental Costs			Annual Revenue Requirement	Percent of Annual Revenue Requirement	4% Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)			($000s)
2017	$18,109	$0	$18,109	$1,236,413	1.46%	$49,457
2018	$18,297	$0	$18,297	$1,245,552	1.47%	$49,822
2019	$18,504	$0	$18,504	$1,247,703	1.48%	$49,908
2020	$24,767	$0	$24,767	$1,244,920	1.99%	$49,797
2021	$24,815	$0	$24,815	$1,240,037	2.00%	$49,601

Scenario 4: March 2016 OFPC

	Incremental Costs			Annual Revenue Requirement	Percent of Annual Revenue Requirement	4% Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)			($000s)
2017	$16,073	$0	$16,073	$1,236,413	1.30%	$49,457
2018	$16,240	$0	$16,240	$1,245,552	1.30%	$49,822
2019	$16,427	$0	$16,427	$1,247,703	1.32%	$49,908
2020	$21,996	$0	$21,996	$1,244,920	1.77%	$49,797
2021	$22,049	$0	$22,049	$1,240,037	1.78%	$49,601

Sensitivity: Scenario 1 - 2015 IRP Update Base Case - (December 2015 OFPC) Fuel Curve - Maximize 20% Unbundled RECs

	Incremental Costs			Annual Revenue Requirement	Percent of Annual Revenue Requirement	4% Annual Revenue Requirement
	Bundled ($000s)	Unbundled ($000s)	Total ($000s)			($000s)
2017	$12,457	$280	$12,738	$1,236,413	1.03%	$49,457
2018	$12,588	$282	$12,870	$1,245,552	1.03%	$49,822
2019	$12,733	$284	$13,018	$1,247,703	1.04%	$49,908
2020	$16,868	$378	$17,247	$1,244,920	1.39%	$49,797
2021	$16,779	$377	$17,156	$1,240,037	1.38%	$49,601