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July 15, 2016

Email / Courier

Public Utility Commission of Oregon
Filing Center
201 SE High Street
P.O. Box 1088
Salem, OR 97308-1088

RE: **UM 1788 - PGE 2016 Revised Renewable Portfolio Implementation Plan**

Enclosed please find Portland General Electric Company's ("PGE") 2016 Revised Renewable Portfolio Implementation Plan ("RPS"). The Report is submitted pursuant to Oregon Public Utility Commission (OPUC) Order No. 16-157 and OARs 860-083-0400 and 860-083-0100. This revised report provides information about how PGE will meet its future RPS requirements in light of the newly enacted SB 1547.

The Work Papers, sent under separate cover, contain protected information and are subject to treatment under the General Protective Order No. 16-262 due to their commercially sensitive nature.

If you have any questions or require further information, please call Rebecca Brown at (503) 464-8545 or Richard George at (503) 464-7611. Please direct all formal correspondence and requests to the following email addresses: richard.george@pgn.com and pge.opuc.filings@pgn.com

Sincerely,

Patrick Hager
Manager, Regulatory Affairs

PGH/sp
Enclosures

Portland General Electric
2016 Revised Renewable Portfolio Standard Implementation Plan[1]
<2017–2040>

As an introduction and summary of PGE's 2016 Revised Renewable Portfolio Standard Implementation Plan, answer the following questions:

WHY IS PGE SUBMITTING THIS 2016 REVISED IMPLEMENTATION PLAN?

PGE submits this Revised 2016 Renewable Portfolio Standard Implementation Plan (RPIP) at the direction of the Oregon Public Utility Commission (Commission) Order No. 16-157. The Commission Order was issued in response to PGE's 2016 RPIP developed and filed in the fourth quarter of 2015; however, a number of factors influencing an RPS compliance strategy have changed materially since that time. The following is a list of significant dates that have influenced this revised filing:

- December 2, 2015 - PGE files the 2013 IRP Update
- December 18, 2015 - Consolidated Appropriations Act of 2016 becomes law, providing extension and phase-down/phase-out of certain renewable resource tax incentives.
- December 31, 2015 - PGE filed its 2016 RPIP relying on strategy and analytical assumptions consistent with the 2013 IRP Update.
- February 16, 2016 - PGE provides estimate of Senate Bill ("SB 1547") impact in Docket No. UM 1755 (PGE's 2016 RPIP).
- March 8, 2016 - Governor Kate Brown signs SB 1547 into law. As discussed throughout this RPIP, many aspects of Oregon's RPS framework are different under SB 1547 than those existing under the prior structure defined by SB 838.
- April 22, 2016 - the Commission issued Order No. 16-157 which, in addition to acknowledging PGE's 2016 RPIP, directs PGE to file a revised RPIP by July 15, 2016.

This revised RPIP includes incremental cost analyses for a range of potential RPS compliance strategies and market conditions over the period 2017–2040. These strategies consider relevant elements of SB 1547, as discussed in detail below, including resource actions to meet the increased RPS requirements.

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[1] On April 22, 2016, OPUC acknowledged PGE's 2016 Implementation Plan but with Conditions (docketed as UM 1755). This Revised Implementation Plan is filed in compliance with OPUC Order No. 16-157, which requires PGE to file a revised Implementation Plan by July 15, 2016.

Background

The Renewable Portfolio Standard (RPS), ORS 469A.052, states that at least 15% of the electricity sold by a large utility to retail electricity consumers must come from qualifying resources from 2015 through 2019.[2] Beginning in 2020, the requirements further increase to 20 percent of retail load through 2024.

The enactment of SB 1547 imposed new resource requirements on PGE that were nonexistent and unknown at the time the 2016 RPIP was filed. Among other things, SB 1547 increases the RPS requirement starting in 2025 as shown in the Table 1 below.

Table 1
RPS Requirements with SB 1547

2020	20%
2025	27%
2030	35%
2035	45%
2040	50%

ORS 469A.075 requires electric companies subject to ORS 469A.052 to develop an implementation plan for meeting the requirements of the RPS and file the plan with the Public Utility Commission. The Commission requested this revised Implementation Plan include a complete analysis of SB 1547. PGE provides the results of its analysis given the requirements of SB 1547 below.

OPUC ORDER NO. 16-157 DIRECTED PGE TO ANSWER THE FOLLOWING QUESTIONS:

In addition to a providing quantitative analysis to meet 2016 Renewable Portfolio Implementation Plan (RPIP) requirements, PGE should provide a complete and thorough narrative describing its plan to satisfy the Renewable Portfolio Standard (RPS) compliance requirements of SB 1547 from 2017 through 2040. At a minimum, the July RPIP should include:

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.

2. An analysis of these aspects of SB 1547: its elimination of the "first in, first out" requirement, its creation of unlimited REC life status for the first 5 years of new resources acquired between 2016-2022, its shortening of the standard Renewable Energy Credit (REC) life, and the steep compliance rate increase between 2025 and 2030. In particular, the analysis should address how these aspects of SB 1547 affect

[2] RPS requirements began in 2011 when the requirement was 5% from 2011–2014.

how the utility plans to optimize the mix of compliance RECs for least cost and lowest risk.

3. A discussion of how the timing of new renewable resource acquisitions impact long term cost of compliance with the 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? PGE should provide a "tipping-point" analysis that depicts when physical resource acquisition is more cost effective than buying unbundled 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.

5. Throughout the analysis, PGE 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.

PGE Response:

PGE's addresses the Commission's questions below. Due to the complexity of the analysis and resource/time constraints, PGE has given its best efforts to address the issues. PGE commits to continue analyzing the impacts of SB 1547 in its IRP and future RPIPs.

Some of the questions posed by the Commission above are very in-depth and require extensive and thorough analysis in an IRP. We continue to analyze in our IRP how PGE will meet the requirements of SB 1547 while ensuring the balancing of costs and risks. Currently, the RPIP evaluation construct is different than the IRP and may produce different results. We look forward to working with stakeholders to refine the RPIP construct to ensure we are not duplicating efforts and understanding the differences in results. We are presenting this revised RPIP using our best efforts to date and realize there is on-going collaborative work with stakeholders that will continue to take place.

Attachment D provides PGE's comparison of SB 1547 and SB 838. Elements of SB 1547 that may affect PGE's planning and operations decisions relative to SB 838 include:

- eliminating the requirement for "first-in, first-out" REC retirement,
- creating a distinction between RECs with infinite life and five-year life,
- increasing PGE's RPS obligation beginning in 2025,
- requiring 50% of retail load to be met with qualifying renewables by 2040.

PGE's RPIP analysis includes all of the elements listed above in aggregate. The operational impacts of the new SB 1547 requirements are subject to forecast uncertainty over the long-term given the potential for technological developments, evolving market structures, alterations to the resource portfolio, and changing operational practices.

Given the broad uncertainties over the 2017–2040 time frame, PGE has investigated multiple RPS procurement strategies in order to address questions related to both timing and resource type. These considerations and the construction of four key procurement strategies are discussed below.

Impacts to the REC retirement strategy

RPS compliance under SB 838 requires that RECs be retired in chronological order, from first issued to last. As noted in Attachment D, SB 1547 removes this "first in, first out" requirement ("FIFO"). Additionally, SB 1547 creates a distinction between the useful lives of certain RECs; a REC has either an infinite life, or a 5-year life after the compliance year in which it is generated. Infinite-life RECs, as the name implies, can be used for compliance in any future year. The elimination of the FIFO requirement provides additional flexibility in each compliance year. In particular, SB 1547 allows PGE to consider the composition of the REC bank with respect to infinite-life versus five-year-life RECs when making REC retirement decisions. For the RPIP, PGE generally intends to retire RECs according to the following rules on an ongoing basis:

1. Five-year RECs are retired in order of vintage year (earliest vintage year RECs are retired first).
2. Within a given vintage year, five-year RECs are retired in order of incremental cost (least expensive RECs from an incremental cost perspective are retired first).
3. For a given compliance year, infinite-life RECs are retired if the compliance requirement exceeds the number of five-year RECs available (including banked RECs and RECs generated in the compliance year).
4. Infinite-life RECs are retired by resource in order of incremental cost (least expensive RECs from an incremental cost perspective are retired first).
5. Within a given resource, infinite-life RECs are retired in order of vintage year (earliest vintage year RECs are retired first).

This strategy retires five-year-life RECs before infinite-life RECs, and retires RECs associated with the lowest incremental cost resources first. The relatively high incremental cost of infinite-life RECs are forecast to remain in the REC bank through the 2030s in this strategy. These RECs are preserved to mitigate RPS compliance risks, such as those associated with high load conditions, low renewable output, or procurement delays if a lower cost compliance option does not materialize.

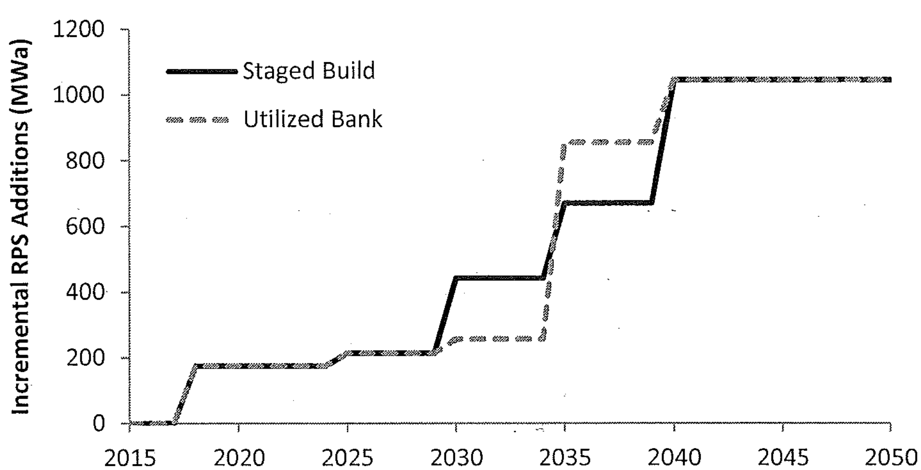
Impacts to the timing of near-term RPS procurement

The timing of resource additions affects the present value cost to customers in three primary ways: the ability to capture sun-setting and/or ramping down of federal tax credits for wind and solar; the potential for future technology cost reductions; and the time value of money. While decreasing technology costs and the time value of money both tend to increase the customer value of deferring renewable procurement. The time-sensitive nature of declining/expiring tax incentives is one example of the conditions under which the least cost/lowest risk strategy results in resource acquisition prior to physical need. PGE will continue evaluating the potential benefits of capturing time-sensitive opportunities while managing the RPS compliance strategy in the future.

The procurement strategies investigated in this RPIP are consistent with PGE's request to conduct an RFP for 175MWa of renewables with potential for 100% PTC qualification in 2016 and a target Commercial Operation Date in 2018. PGE has found the benefits of capturing federal tax credits before they decline or expire exceed both of these economic factors under various assumptions regarding technology costs and future procurement strategies. In addition to the 175MWa of procurement in 2018, each strategy includes 38MWa of RPS procurement in 2025 to meet the remaining need for physical compliance in 2025. While not included here, the economic impacts of accelerating RPS procurement to capture the PTC are being evaluated in the 2016 IRP in the context of identifying a least-cost least-risk portfolio. This filing does not replicate that process, rather the RPIP determines the impact of renewable resource procurement decisions on PGE's ability to acquire RPS compliant resources at or below the 4% incremental cost cap.

Impacts to the timing of longer-term RPS procurement

Under SB 1547, the RPS compliance obligation increases between 2025 and 2035, with an eight percentage point increase to 35% in 2030, and a ten percentage point increase to 45% in 2035. PGE's analysis includes two compliance strategies to investigate the timing effects associated with meeting the RPS obligations in 2030 and 2035. The "**Utilized Bank**" strategy defers resource acquisition in 2030 to 2035 to the extent possible while maintaining the minimum recommended REC bank level; this strategy results in relatively small resource quantities acquired in 2030 and 2040, with a large amount in 2035. The "**Staged Build**" strategy acquires equivalent resource quantities in 2030 and 2035, which are in total less than the amount acquired in the same time period under the "**Utilized Bank**" strategy, and acquires relatively more resources in 2040.



Renewable procurement resource options

For each of these timing strategies, PGE also investigates the impact of procuring diverse renewable resources in the 2030s. In the "**Wind**" strategy, renewable resources procured in all periods are assumed to have the cost and behavior of a Columbia River Gorge (Gorge) wind resource. In the "**Diverse**" strategy, renewable resources procured in 2018 and 2025 have the characteristics of a Gorge wind resource and resources procured in 2030, 2035, and 2040 have the characteristics of single-axis tracking solar resources.

Strategies for Procurement

PGE constructed four procurement strategies based on the timing and technology options described above ("**Utilized Bank - Wind**", "**Utilized Bank - Diverse**", "**Staged Build - Wind**", and "**Staged Build - Diverse**"), which are summarized in Table 2 below.

Table 2
Procurement Strategies

	Utilized Bank - Wind			**Staged Build - Wind**			**Utilized Bank - Diverse**			**Staged Build - Diverse**		
Year	Type	MWa	MW	Type	MWa	MW	Type	MWa	MW	Type	MWa	MW
2018	Wind	175	515	Wind	175	515	Wind	175	515	Wind	175	515
2025	Wind	38	113	Wind	38	113	Wind	38	113	Wind	38	113
2030	Wind	43	126	Wind	228	671	Solar	43	172	Solar	228	912
2035	Wind	598	1,759	Wind	228	671	Solar	598	2392	Solar	228	912
2040	Wind	191	561	Wind	376	1,105	Solar	191	763	Solar	376	1,503

The optimal strategy for complying with an RPS obligation arising nearly 15 years in the future cannot be known with certainty today. However, PGE will continually assess the obligation and take actions to reduce the size of the liability in a manner that minimizes costs and execution risk based on the facts known at the time, as occurs in the IRP process. PGE has evaluated the incremental costs associated with the four strategies described above under the Reference price and CO_2 assumptions. These incremental costs are summarized over specific compliance years in Table 3 below:

Table 3
Incremental Cost By Year

Reference Attachments	**A**	**C**	**E**	**F**
Year	Staged Build - Diverse	Utilized Bank - Diverse	Staged Build – All Wind	Utilized Bank – All Wind
2020	$46.6	$46.6	$46.6	$46.6
2025	$37.7	$37.7	$37.7	$37.7
2030	$59.2	$76.1	$45.8	$80.3
2035	$59.1	$27.8	$30.7	($12)
2040	$20.8	$29.1	($27.4)	($28.1)

The incremental costs associated with these strategies suggest that both resource type and resource acquisition timing will impact the incremental costs of RPS compliance as defined within the RPIP. However, this calculation neglects important cost components that impact customers and are evaluated in the IRP. In particular, as prices are affected by evolving market conditions and renewable resource procurement outside of Oregon, the competitiveness of wind versus solar in the 2030–2040 time frame is highly uncertain.

In this Implementation Plan, we provide an analysis of the incremental costs across multiple gas price and carbon price scenarios for the "**Staged Build – Diverse**" strategy. This strategy represents a balanced approach to the timing and quantity of new renewable procurement and incorporates resource diversity. By testing this strategy across various gas and carbon price scenarios, we are able to investigate the conditions under which the risk of exceeding the cost cap is potentially the largest. We also provide the incremental cost analysis for the other three strategies under reference gas and carbon price assumptions. We anticipate that under the various procurement strategies, the gas and carbon price assumptions will have similar impacts to the incremental costs and we plan to further explore these impacts in a supplement to this filing when the analysis concludes.

The analysis presented in this Implementation Plan provides crucial insight regarding PGE's ability to meet RPS obligations while staying under the cost cap on an ongoing basis. However, it does not aim to identify a single least-cost, least-risk procurement strategy through 2040. PGE acknowledges that in the long term, balanced cost and risk resource procurement may deviate substantially from the strategies presented in this plan for several reasons, including:

1. Uncertainty in long term market conditions
2. Uncertainty in resource technology costs
3. Uncertainty in renewable integration challenges and costs
4. Differences in the costs captured by the incremental cost methodology used in this filing and the revenue requirement impacts of renewable procurement decisions as they are quantified in the IRP

PGE looks forward to continuing to evaluate these factors as part of the 2016 IRP and continuously through future IRPs using the full balanced cost and risk methodology.

PGE's range of incremental costs included in this analysis reflects the effects of market factors including the cost of carbon emissions, the cost of natural gas, and the resulting natural gas-fired plant dispatch (used to determine the size of the proxy resource in the incremental cost calculation). All else equal, load forecast to grow at a faster rate is expected to increase the total incremental cost of compliance as the relatively higher incremental cost RECs that would otherwise remain in the bank would instead be used for compliance. If, however, the strategy is rebalanced to take into account this revised load forecast, additional resources will be procured, potentially mitigating some or all of the increase. Changes in forecast hydroelectric generation are expected to increase or decrease the incremental cost of compliance only to the extent that generation deemed to be the result of efficiency upgrades decreases or increases, respectively. The use of RECs from low-impact hydro generation is capped at 50 MWa annually, thus, forecast changes in generation from these facilities can only affect the incremental cost if total generation is less than 50 MWa. PGE's analysis includes an assumption of declining capital construction costs for all resources in the future. In the 2016 IRP, PGE will discuss the effects of higher and lower resource capital costs in any given year relative to the reference case assumptions, which serve as the basis for the analysis presented here.

WHAT INFORMATION WAS USED AS THE BASIS OF THIS REVISED IMPLEMENTATION PLAN (2017-2040 PLAN)?

This 2017–2040 RPIP is based primarily on assumptions to be used in PGE's 2016 IRP, which includes elements of SB 1547 primarily, elimination of first in, first out for RECs, creation of unlimited REC life status for 6 years for new resources, shortening REC life, and meeting the steep RPS increases in 2025 and 2030. This RPIP also incorporates the RECs anticipated to be generated by all qualifying facility (QF) contracts executed prior to June 1, 2016.

Scenarios

The following are the existing resources for which an incremental cost was calculated in this RPIP:

Resource	In-Service Year	Annual Generation (MWa)	Nameplate Capacity (MW)
Biglow Canyon 1	2008	39	125
Biglow Canyon 2	2010	51	150
Biglow Canyon 3	2011	45	175
Tucannon River	2014	102	267

In addition, PGE has modeled the following new renewable resource additions, based on the "**Staged Build – Diverse**" strategy described above:

Resource	In-Service Year	Annual Generation (MWa)	Nameplate Capacity (MW)
Generic Wind Resource	2018	175	515
Generic Wind Resource	2025	38	113
Generic Solar Resource	2030	228	912
Generic Solar Resource	2035	228	912
Generic Solar Resource	2040	376	1,503

PGE provides incremental costs under four scenarios:

1. Reference Gas - Reference CO_2
2. Reference Gas - No CO_2
3. High Gas - Reference CO_2
4. High Gas - No CO_2

These scenario results are included in Attachment A. PGE is not providing a low gas scenario because gas prices are relatively low at this time. Providing an additional low gas scenario would offer limited information and is not a scenario that is anticipated at this time, thus reference gas may be considered to also represent a low gas scenario.

In addition to the above scenarios, Attachment B presents, under the reference case, using 20% unbundled RECs in each year of the analysis. The incremental cost analysis associated with the alternate procurement strategies under Reference Gas – Reference CO_2 assumptions are included in Attachment C.

Key Assumptions

Gas prices: The Reference Case uses the Wood Mackenzie natural gas price forecast from the second-half of 2015, consistent with PGE's 2016 IRP. The High Gas case uses the Henry Hub price forecast from the 2015 Energy Information Administration's Annual Energy Outlook (EIA AEO) "High Oil Price" scenario, combined with the basis differential from the previously mentioned Wood Mackenzie forecast. This information is also consistent with PGE's 2016 IRP.

CO_2: The Reference Case uses a CO_2 price forecast developed by Synapse dated March 16, 2016. The additional CO_2 scenario assumes that no explicit costs for CO_2 emissions are incurred.

Capacity Contribution: The analysis includes an estimation of variable resource capacity contribution based on an effective load carrying capacity (ELCC) methodology, consistent with PGE's positions in OPUC Docket UM 1719 and PGE's 2016 IRP. The ELCC varies by technology type, the year and size of the addition, due to portfolio effects.

CCCT: PGE uses an H-class combined cycle combustion turbine (CCCT) as a component of the proxy resource used for determining the incremental cost of new resources.

SCCT: PGE uses a Simple-Cycle Combustion Turbine (SCCT) for purposes of reflecting capacity value as required by Commission Order No. 14-034. PGE's use of a SCCT to normalize for capacity value in the incremental cost framework is consistent with the Stipulation adopted in Commission Order No. 14-034 (Docket UM 1616).

In the Stipulation adopted in Commission Order No. 14-034, parties agreed that the "fixed costs of a simple-cycle natural gas fired generating facility (SCCT) would be subtracted from the cost of the Proxy CCCT. The SCCT would be sized to equal the difference between the Proxy CCCT's and the RPS Resources' contribution to system reliability."[3] The Stipulation further explains the rationale for this adjustment: "[t]o account for differences in resource capacity values, the *Proxy CCCT costs shall be modified to reflect the costs of the same capacity value as the RPS Resource*" (emphasis added).[4] Parties to the Stipulation in this Docket were: Public Utility Commission of Oregon Staff; the Industrial Customers of Northwest Utilities; Renewable Northwest Project; the Citizens' Utility Board of Oregon; PacifiCorp, dba Pacific Power; Portland General Electric Company; the Oregon Department of Energy; and the NW Energy Coalition. The fixed costs of a SCCT are an appropriate measure of the cost of capacity, and can be used to adjust the capacity value of a resource. The fixed costs of the more expensive reciprocating technology may be an appropriate measure of the cost of *flexible* capacity. However, the capacity adjustment contemplated in the stipulation relates specifically to capacity value, rather than the operational.

Use of Unbundled RECs

RECs purchased separately from the electricity generated by a qualifying renewable resource are "unbundled" RECs. The Oregon RPS limits the use of unbundled RECs to a maximum of 20 percent of the compliance obligation in each year. In Staff's memo for Docket No. UM 1683 (PGE's 2014 RPIP), Staff requested that PGE's 2016 RPIP include a scenario in which unbundled RECs are used to meet the maximum of 20% of the annual RPS obligations. PGE provided that scenario in UM 1755. Attachment B reflects this same scenario for this Revised 2016 RPIP. While PGE has provided this additional scenario, PGE strongly asserts that it is both strategically detrimental and highly hypothetical to forecast REC prices and purchases.

The absence of an organized market enabling availability and efficient pricing of RECs makes it difficult to propose a long-term strategy predicated on the use of unbundled RECs in lieu of planning for physical compliance. Additionally, PGE expects increasing uncertainty in REC markets due to increasing RPS requirements in states across the Western Electricity Coordinating Council (WECC) region. As such, unbundled RECs at the volumes required may not be available from current inventory of eligible renewable resources at or near current market rates. The uncertainty in long-term supply of unbundled RECs is sufficiently uncertain that their use is not a primary strategy for achieving compliance, but instead a compliment to a physical compliance strategy. Limited supply certainty and increasing demand when coupled with the required retirement of 20% unbundled RECs on an annual basis may shift market dynamics and call into question the cost effectiveness and risk of the strategy. Should opportunities continue to avail themselves in the REC market, PGE will continue to act appropriately to balance risks and expected costs. It is important that PGE be able to assess the market and the financial feasibility of using unbundled RECs in any particular year. PGE believes that, on a long-term basis, reliance on an illiquid unbundled REC marketplace is not an appropriate RPS compliance strategy.

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[3] Public Utility Commission of Oregon Order No. 14-034 (UM 1616), pp. 3–4

[4] Public Utility Commission of Oregon Order No. 14-034 (UM 1616), Appendix A, p. 3

In contrast to purchasing unbundled RECs on the market, utilities can achieve physical compliance either by owning the qualifying resource or by signing long-term power purchase agreements (PPA) and acquiring the bundled RECs. There is no limitation on the use of bundled RECs for RPS compliance. Bundled RECs created by physical compliance may be banked to meet future RPS obligations, subject to the useful life restrictions under SB 1547 noted above. While both forms of physical compliance can be considered long-term, ownership of a qualifying resource provides the opportunity to generate RECs throughout a resource's operating life, plus the potential for residual value (e.g. the option to extend plant life or repower the project) after that time. Whereas, a long-term PPA will have a finite term that may be shorter than an equivalent resource's useful life and then require some incremental action at expiration in order to maintain compliance.

Calculation of Incremental Cost

OAR 860-083-0100 describes in specific detail how to calculate the incremental cost. PGE applies the incremental cost of each resource to the number of RECs retired in a year to calculate the total incremental cost for each year. PGE also provides the total incremental cost of all RECs generated in each year. PGE complies with ORS 469A with regard to banking RECs and then using those banked RECs to comply with future years' RPS requirements. As the RPS requirements increase, PGE will eventually use RECs for compliance in the same year they are generated. However, since PGE has effectively established and efficiently utilizes banked RECs, this is not yet the situation.

Although PGE is complying with the rules for calculating incremental cost, we believe a review of the rules would be beneficial as the results of the calculation (pursuant to the rules) may not capture the true incremental cost of complying with Oregon's RPS requirements. For instance, the rules state that the levelized cost of a renewable resource is compared to a proxy Combined Cycle Combustion Turbine (CCCT), but gas prices are updated for the CCCT. Therefore the renewable resource is compared to a proxy with updated gas prices. In addition, actual generation is updated with each implementation plan. In future years, adjusting the resource actuals amounts hindsight review of the cost-effectiveness of the resource decision, rather than one based on the information known at the time. PGE believes the renewable resource should be compared to a proxy CCCT using construction and fuel assumptions that existed at that time.

Balancing risks and expected costs

PGE has and will continue to balance risks and expected costs. This has been demonstrated by PGE since 2011; in particular as the Company has opportunistically used the full 20% unbundled RECs in each compliance year. PGE will continue to use unbundled RECs while it is feasible and economically prudent to do so. Should the market price for RECs inflate, it may not be economically feasible to purchase RECs for RPS compliance. In addition, mandating the purchase of unbundled RECs for any utility will negatively impact the unbundled REC market because with such a requirement, the price will be impacted.

4% Cap

This RPIP shows PGE does not exceed the 4% cap in the Reference Case. The elements of SB 1547, specifically the removal of the first-in, first-out REC usage methodology, can account for the change from previous RPIPs in which PGE was approaching or exceeding the cap in certain cases.

PGE is not expecting to reach the cap within the 2017–2040 time period studied in this Revised 2016 RPIP under the reference case. OAR 860-083-0100(11) states that "[i]f the number of RECs used for compliance ...is reduced due to a cost limit...the electric company...must review the methodologies used to estimate the levelized costs of proxy plans and long-term qualifying electricity." PGE will continue to review the calculation of the cost cap and work with stakeholders to address issues.

Resources Exceeding 50 MW capacity threshold

PGE has not provided incremental cost information for several small projects as allowed for in OAR 860-083-0100 (13) because they have not yet reached the 50 MW aggregate threshold. PGE does not anticipate it will reach this threshold until at least 2020 when PGE starts receiving RECs from QFs who have signed up for renewable-avoided costs. Once these projects reach the aggregate capacity of 50 MW and they are included in a Compliance Report, we will then model the projects for a future RPIP. Therefore, small solar projects have not been assigned an incremental cost in this report.

HOW DOES THE COMPANY INTEND TO MEET THE RPS TARGET?

For long-term planning purposes, PGE intends to meet annual RPS targets with a mix of existing and incremental long-term resources. The timing, quantity, and type of incremental resources will be determined based on the best-available information. PGE will manage the REC bank to mitigate future RPS compliance risks. Opportunities to reduce the cost of compliance will be evaluated and implemented to the extent possible. This RPIP is presented at the request of the OPUC to incorporate elements of SB 1547. PGE views the RPIP as a modeling tool to forecast a range of possible future incremental costs of renewable resources consistent with the modeling approach PGE uses in its IRP analysis. As with all forecasts, reality will either be higher or lower than expected; it is highly unlikely to be exact in any given year. Natural weather variation will dictate annual generation, but on a long-term basis, facility output is anticipated, on average, to equal expected output. OAR 860-083-0100 requires PGE to use the levelized annual costs, thus, PGE uses levelized expected output.

Details of PGE's 2017–2040 Plan are given in the following sections.

Provide responses below following the citation of each element of OAR 860-083-0400.

2016 Revised Implementation Plan

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:
See Attachment A, which is an Excel spreadsheet, Tab 3 – "Annual Compliance by Resource"

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

Response:
See Attachment A, which is an Excel spreadsheet, Tab 3 – "Annual Compliance by Resource" for detail by year.

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 year covered by the implementation plan.

Response:

The Table below summarizes the information requested.

				Expected Output	
Resource Name	**Type/Source**	**Year**	**State**	**MWh**	**Mwa**
Biglow Phase 1	Wind	2007	OR	341,094	38.94
Biglow Phase 2	Wind	2010	OR	445,109	50.81
Biglow Phase 3	Wind	2011	OR	394,941	45.08
Tucannon River	Wind	2014	WA	892,764	101.91

Vansycle Ridge Wind Farm	Wind	1998	OR	71,163	8.12
Klondike II Wind	Wind	2005	OR	217,434	24.82
SunWay I, II, III	Solar	2009/2010	OR	9,150	1.04
Bellevue	Solar	2011	OR	3,792	0.43
Yamhill	Solar	2011	OR	2,587	0.30
Portland Rehabilitation	Solar	2011	OR	1,882	0.21
SPO	Solar	2010–2015	OR	17,840	2.04
Baldock	Solar	2012	OR	2,870	0.33
Outback	Solar	2012	OR	20,244	2.31
Gresham Wastewater Treatment	Biogas	2015	OR	5,143	0.59
North Fork	Hydro Efficiency Upgrade	2001	OR	4,679	0.53
Faraday	Hydro Efficiency Upgrade	various	OR	4,303	0.49
Sullivan	Hydro Efficiency Upgrade	various	OR	7,005	0.80
River Mill	Hydro Efficiency Upgrade	1996–1997	OR	1,480	0.17
Round Butte	Hydro Efficiency Upgrade	2002–2003	OR	83,318	9.51
Pelton-Round Butte	LIH	2007	OR	438,000	50.00

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:

2017 through 2040:
For purposes of this RPIP, PGE presents compliance strategies that add resources in the following years: 2018, 2025, 2030, 2035, and 2040. A forecast of estimated incremental costs is provided in Attachment A, Tab 4-Incremental Cost by Resource.

OAR 860-083-0400(2)(e)
A forecast of the expected incremental costs 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 860-083-0100.

Response:
PGE does not anticipate use of Alternative Compliance Payments (ACP) in any of the compliance years, 2017 through 2040. For a forecast of the expected incremental costs of compliance and the costs of using unbundled renewable energy certificates for compliance compared to annual revenue requirements, see Attachment A, Tab 1-Incremental Cost Summary.

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:
See Attachment A, Tab 5-RECs Generated for a forecast of the number of bundled renewable energy certificates issued. The forecast number of bundled RECs is based on expected generation from qualifying renewable resources.

See Attachment A, Tab 2-Incr. Cost of RECs Generated, for a forecast of the cost of bundled renewable energy certificates issued. Bundled RECs are the RECs from each resource with incremental costs.

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:
In response to OAR 860-083-0400 (4):

PGE is filing this Revised 2016 RPIP at the request of the Commission as a result of the enactment of SB 1547, the requirements of which contain significant implications on

RPS compliance. Also, PGE is in the process of developing its 2016 IRP which is expected to be filed later this year.

In response to requirements OAR 860-083-0400 (4)(a) and (4)(b):

See Attachment A, Tab 4 – "Incremental Cost by Resource." The Biglow Canyon, Tucannon and other relevant new resources are assumed to receive government incentives currently in place and those stated for the future as well.

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 resources planning guidelines in 1.b and c. of Commission Order No. 07-047 and subsequent guideline 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 required 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 certification; (B) Bundled renewable energy certificates issued between January 1 through March 31 of the year following the compliance year: or (C) Alternative compliance payment, or (c) The company plans to sell any bundled renewable energy certificates included in the rates of Oregon retail electricity consumers.

Response:

(a): The costs in PGE's response to OAR 860-083-0400 (2)(e) are provided in Attachment A, Tab 1 – "Incremental Cost Summary." The forecasted incremental cost of compliance will not exceed four percent of the annual revenue requirement in the reference gas/reference CO_2 scenario. Incremental cost is forecasted to exceed four percent of the annual revenue requirement in only one scenario, reference gas/no CO_2, beginning in 2030. Consistent with PGE's 2016 IRP, we have modeled the CO_2 adder starting in 2023 and the RPS target increases in 2020.

(b): For planning purposes, PGE does not forecast the use of unbundled RECs to meet RPS compliance targets within future compliance years 2017 through 2021; however, PGE reserves the right to do so if the availability and market prices for unbundled RECs warrants it in the future. See PGE's 2013 IRP Update for further discussion.

In OPUC Order No. 14-265 acknowledging PGE's 2015–2019 Plan, filed December 31, 2013 (covering the period 2015–2019), OPUC directed PGE to include a scenario in future RPIPs under the reference case that assumes PGE uses unbundled RECs equal to 20% of its annual requirement assuming an unbundled REC price equal to the weighted average price paid for unbundled

RECs used in its last compliance report for each year analyzed in the 2017–2040 Plan. Attachment B, which in confidential and subject to protective order, calculates incremental costs based on retiring unbundled RECs during the period covered.

Pursuant to OAR 860-083-0300 (3)(b)(B), an electric utility company must use, in chronological order (from first issued to last issued) its banked RECs before using, 1) RECs generated in the compliance year, and 2) RECs generated between January 1 through March 31 of the year following the compliance year.

(c): While we do not plan for the sale of bundled RECs, PGE intends to continue monitoring REC markets and may purchase or sell bundled RECs, unbundled RECs, and/or bundled green energy in the market when feasible and the price is perceived to be a good value in relation to other means of achieving RPS compliance.

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 condition specified in the most recent acknowledgement order on an integrated resource plan filed or updated by the electric company.

Response:

Commission Order No. 10-173 acknowledged PGE's first RPIP, 2011–2015 Plan, filed December 31, 2009. The order contained no conditions; however, the order recommends development of a standardized template for the 2011 filing. That form was developed jointly by OPUC Staff and the parties earlier in 2011 and is the format PGE is using for this implementation plan.

Order No. 12-271, dated July 2, 2012, acknowledged PGE's second RPIP, 2013–2017 Plan, filed December 28, 2011. The OPUC required PGE to not include shaping costs in its next implementation plan (2015–2019 Plan), which we have complied with.

Order No. 10-457 acknowledged PGE's 2009 Integrated Resource Plan and 2010 Addendum, with conditions. No conditions pertain directly to implementation plan filing requirements. PGE filed its Draft 2013 Integrated Resource Plan on November 22, 2013.

Order No. 14-265, dated July 22, 2014, acknowledged PGE's 2015–2019 Plan, filed December 31, 2013. The OPUC directed PGE to include a scenario in future implementation plans under the reference case that assumes PGE uses unbundled RECs equal to 20% of its annual requirement assuming an unbundled REC price equal to the weighted average price paid for unbundled RECs used in its last compliance report for each year analyzed in the implementation plan. PGE has complied with that requirement in this Revised RPIP.

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 finds for the purpose 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:
Funds described in this rule pertain to Alternative Compliance Payment (ACP). As of December 2015, PGE has made no ACP and thus has no applicable ACP funds for disposition. The rule is not applicable to PGE at this time.

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PGE Revised 2016 RPS Implementation Plan

Attachment A

Incremental Cost of Compliance Considering SB 1547
Staged Build – Diverse Resources
2017–2040

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PGE Revised 2016 RPS Implementation Plan

Attachment B

Incremental Cost of Compliance Considering SB 1547
Staged Build – Diverse Resources
Using 20% Unbundled RECs Each Year
Reference Case
2017–2040

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Attachment C

Incremental Cost of Compliance Considering SB 1547
Utilized Bank - Diverse Resources
(no Unbundled RECs)
Reference Case
2017–2040

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PGE 2016 Revised RPS Implementation Plan

Attachment D

Comparison of SB 1547 and SB 838

House Bill 4036A Element	Brief Description	Senate Bill 1547A	Reason for change (no change)
Coal Life	Requires costs and benefits associated with coal-fired generation resources to be excluded from OR rates by 1/1/2030	Framework is same as introduced. Amended to clarify 2030 is the date used to determine prudency of investment as requested by the PUC. Allows PUC to consider gain or loss from sale of coal resource.	Clarifies for PUC that costs and benefits cannot be measured beyond a 2030 useful life for ratemaking purposes. Responds to PUC interests in appropriately sharing value from sale of resources. Protects ratepayers from post-2030 costs.
RPS stair step to 50%	27% - 2025; 35% - 2030; 45% - 2035; and 50% by 2040.	Unchanged since introduction	RPS requirement better applies toward anticipated resource need and environmental regulation post-2025.
REC banking	REC compliance life changed to 5 years after bill passage. Removes fist in, first out retirement requirement. Allows a period of unlimited REC banking from 2016-2022 to encourage new development.	Same as HB 4036A in order to incorporate benefits for new biomass and small-scale community renewable resources. Adds changes from -4036-A41s regarding pre-95 biomass production counting for compliance.	Maintains balance between protecting ratepayer costs for compliance with RPS while creating value for new renewable energy development. Responds to OFIC and biomass interest concerns over changes to previously established REC deal.
Modifications to utility ratemaking	Required PUC to investigate terminal value for resource ownership, investigate the recovery of variable power costs, and establish direct pass-through of renewable energy Production Tax Credits. Creates mechanisms to allow deferral of cost recovery for new investments.	Terminal value and power cost investigations removed, new language added providing for evaluation of competitive bidding and diverse resource ownership at request of PUC. Production Tax Credits will be credited to ratepayers through existing power cost mechanisms at request of Citizens Utility Board.	PUC maintains ability to oversee ratemaking using existing mechanisms and ensure fair procurement rules. Responds to PUC concerns about interference with recently established orders.

		Cost deferral unchanged.	
No new resource eligibility for RPS compliance	Resources that count toward meeting OR requirements.	New resources added are existing biomass, municipal solid waste energy, and thermal cogeneration efficiency.	Increases the pool of eligible RECs to meet compliance.
Service territory protection Energy Service Supplier RPS compliance	Requires higher RPS target for an acquiring utility if service territory is acquired without consent; protection applies to PUDs, Co-ops, IOUs, and municipal utilities. "Safe harbor" in cases where a municipality grows through annexation. Competitive retail suppliers must meet same bundled energy requirements and stair steps as incumbent utility.	Requirement has been changed to only the *proportion* of new load acquired without consent must meet higher RPS rather than the entire acquiring utility. Displacement of BPA Tier 1 power associated with higher RPS has also been deleted. MUDs cannot condemn property of PUDs.	SB 1547 responds to concerns over service territory takeovers by all utility business models. Changes requested by OMEU, OPUDA, and ORECA
Community Solar Program	Utilities must provide a voluntary community solar program to customers. Targets participation by 10% low-income customers.	Amendments in 4036-A41 lifted project, program size, and customer class limitations and reduced other prescriptive elements of program. Retained changes made by –A41 in 1547-A18 but added 10% low-income target found in original bill.	May increase likelihood that community solar facilities will be sited and become operational. Provides significant flexibility to PUC to design program by rule.
Community renewables	OR currently has a statewide goal of meeting state renewable electricity needs with 8% of energy from small scale (20MW and below) projects.	4036-A41s turned state goal into mandate for IOUs by 2025. –A18s retain mandate but clarify that it is based on capacity and applies to both large IOUs in sum. Adds biomass thermal CHP as qualifying source.	Responds to interests of both CREA and OFIC.

Electric vehicles	Allows utilities to file applications for programs to accelerate transportation electrification. Describes what may constitute a net benefit to ratepayers of TE investments	-A41 inserted provisions regarding competition and customer choice as required elements of proposed programs. Retained that provision in –A18s.	Responds to concerns from charging station manufacturer and PUC regarding utility influence in competitive marketplace.
Solar Capacity standard	Repeals existing standard but allows solar photovoltaic systems installed under standard to continue to receive benefits allowed under standard.	-A41 inserted provisions clarifying how the 2:1 RECs would work in practice.	Responds to ODOE concerns that language in introduced bill may have implicated "double counting" concerns.

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PGE 2016 Revised RPS Implementation Plan

Attachment E

Incremental Cost of Compliance Considering SB 1547
Staged Build – All Wind
(no Unbundled RECs)
Reference Case
2017–2040

UM 1788
PGE 2016 Revised RPS Implementation Plan

Attachment F

Incremental Cost of Compliance Considering SB 1547
Utilized Bank – All Wind
(no Unbundled RECs)
Reference Case
2017–2040