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December 2, 2015

via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem OR 97308-1088

RE: LC 56 – PGE's 2013 Integrated Resource Plan (IRP) Update

Attention Filing Center:

Portland General Electric Company (PGE) is submitting the enclosed filing as an update to its 2013 Integrated Resource Plan (IRP) in OPUC Docket LC 56.

On December 2, 2014, the Commission acknowledged PGE's 2013 IRP Action Plan, with revisions and requirements. In accordance with OAR 860-027-0400(8) and Commission IRP Guideline 3(g), this update is an informational filing that focuses on the following elements, and no Commission action is requested at this time:

- 2013 IRP Action Plan implementation activities
  - Chapter 1 provides an update on several items in PGE's 2013 IRP Action Plan, including a status update on various Commission requirements and enabling studies.

- Load Forecast and Resource Inputs
  - Chapter 2 presents more detail about load and resource changes, as well as various externally-driven cost and regulatory updates.

- Renewable Portfolio Standard compliance
  - Chapter 3 provides an update to the Company's Renewable Portfolio Standard (RPS) compliance and discusses the use of banked and unbundled Renewable Energy Certificates (REC).

No Commission action is requested at this time.

Per OPUC's request, PGE is providing fifteen copies of the filing. This filing is also simultaneously being filed electronically with the Filing Center.

Thank you in advance for your assistance.

Sincerely,

V. DENISE SAUNDERS
Associate General Counsel

VDS:bop

Enclosures

Portland General Electric
2013 Integrated Resource Plan

2013 Integrated Resource Plan Update

December 02, 2015

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Executive Summary

Pursuant to the Public Utility Commission of Oregon's (OPUC or Commission) Integrated Resource Plan (IRP) Guidelines (Guideline 3g), Portland General Electric Company (PGE) submits this update to its acknowledged 2013 IRP. PGE is not seeking acknowledgement of a revised plan. As such, this update is an informational filing that focuses on the following elements, in accordance with the Commission's Guidelines:

- 2013 IRP Action Plan implementation activities
    - Chapter 1 provides an update on several items in PGE's 2013 IRP Action Plan, including a status update on various Commission requirements and enabling studies.
- Load Forecast and Resource Inputs
    - Chapter 2 presents more detail about load and resource changes, as well as various externally-driven cost and regulatory updates.
- Renewable Portfolio Standard compliance
    - Chapter 3 provides an update to the Company's Renewable Portfolio Standard (RPS) compliance and discusses the use of banked and unbundled Renewable Energy Certificates (REC).

A primary focus of PGE's 2013 IRP Update is to examine multiple RPS compliance strategies, and other changes in the Company's IRP assumptions, that have occurred since acknowledgement of the plan, as well as assess the net impact of these changes to the Action Plan.

While PGE is not requesting acknowledgement of a revised Action Plan, the Company does address changes in the planning environment with respect to load forecast methodology, resource costs, fuel costs, and uncertainty regarding carbon regulation.

When considering the overall effect of the updated IRP assumptions, the Company does not believe the updates warrant changes to the acknowledged Action Plan.

2013 IRP Action Plan

PGE did not include major supply-side actions in the 2013 IRP. PGE continues to work toward the actions for hydro contracts, dispatchable standby generation (DSG) and other supply-side updates, such as new qualifying facility (QF) contracts.

PGE's demand-side actions include new energy efficiency (EE) additions and demand response (DR) pilots. Based on recent actuals and forecasts provided by the Energy Trust of Oregon (ETO), the current net EE acquisition forecast for 2014 through 2017 is approximately 130 MWa. PGE continues to promote market awareness of DR for commercial and industrial customers in order to increase customer participation. On residential DR, PGE initiated two pilots and a technical trial.

In the 2013 IRP, the Commission acknowledged multiple enabling studies and research designed to inform the development of PGE's 2016 IRP. This update provides a brief summary and status for each study. PGE will provide a detailed analysis or copy of the finalized studies in the 2016 IRP.

Load Forecast and Resource Inputs

PGE conducted a study and convened a series of workshops with interested parties to examine the Company's load forecast methodology in detail. Between April 2015 and August 2015, the Company held four public meetings and/or workshops as part of the 2016 IRP public process.[1] As a result, PGE made minor refinements to the energy forecast models for the mid-term horizon (2015 to 2021) and replaced the long-term (beyond 2021) energy and peak forecast methodologies with new regression-based approaches. The long-term energy approach does not impact the load forecast for 2017 and results in a lower long-term energy growth rate of 1.2 percent, compared with a 1.3 percent under the previous methodology.

The load-resource balance calculations for energy and capacity incorporate the updates to the load forecast, energy efficiency forecast, plant parameters, and resource contracts.

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[1] "PGE Presentation," Slides 23-34. Public Meeting #1, April 2, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/pge_presentation.pdf; "Itron Presentation." Public Meeting #1, April 2, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/irp_forecast_review_presentation.pdf; "Load Forecast Methodology." Technical Workshop #1, July 15, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-07-IRP-tech-workshop-1.pdf; "PGE Presentation," Slides 15-17. Public Meeting #2, July 16, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-07-public-meeting-2.pdf; and "PGE Presentation," Slides 140-43. Public Meeting #3, August 13, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-08-13-public-meeting-3.pdf.

The forecast annual average energy load-resource balance shifted, primarily due to a decrease in the forecast average demand. As shown in **Table 0-1**, the forecast 2017 resource surplus increased from 93 MWa to 149 MWa and the forecast 2021 resource deficit decreased from 527 MWa to 419 MWa.

Table 0-1: Forecast energy load-resource balance

Year	Annual Average (MWa)
2017	149
2021	(419)
2030	(793)

The capacity load-resource balance forecasts a resource surplus in 2017 and a resource deficit beyond 2018.

Table 0-2: Forecast capacity load-resource balance

Year	Winter (MW)	Summer (MW)
2017	270	258
2021	(795)	(846)
2030	(1329)	(1443)

PGE updated the assumed cost and performance of commercially available supply-side resources. The Company engaged two industry leaders to inform cost and performance parameters for generic thermal resources (including biomass and geothermal), energy storage resources, wind, and solar resources.

Coal prices assumed in this update are consistent with those assumed in the 2013 IRP. PGE continues to use the long-term natural gas price forecast supplied by Wood Mackenzie, and natural gas prices in this update incorporate revised long-term and short-term forecasts. Natural gas prices have fallen precipitously since 2008, following the widespread commercialization of horizontal drilling and the extraction of natural gas from shale deposits. Lower natural gas prices are forecast in 2015-2035 than PGE assumed in the 2013 IRP. The main drivers of the reduced costs (relative to the 2013 IRP forecast) are increased productivity and efficiency of new natural gas wells, growing recoverable supply from major basins, and more competitive service costs following an oil price drop.

Carbon prices have a strong effect on thermal electric generation and influence natural gas demand and price. Given the relationship between natural gas prices and CO_2 policy, PGE uses a reference CO_2 price from Wood Mackenzie that is consistent with the natural gas forecast.

The Environmental Protection Agency (EPA) released the Clean Power Plan (CPP) on August 3, 2015. Although finalized, much about the CPP remains uncertain. This update includes an overview of federal guidelines and discusses the state implementation plan process. PGE will include robust modeling of the CPP in the 2016 IRP.

Renewable Portfolio Standard

Consistent with the Commission's directives in Order No. 14-415, PGE developed and evaluated multiple RPS compliance strategies in this IRP Update, including the use of RECs and alternatives to physical compliance.

Current RPS compliance targets grow significantly through 2025, and PGE must continue to remain compliant. Risks of deferring procurement of new renewable resources increase due to the compounding effect deferral has on the Company's already large future RPS obligation. While PGE's evaluation of multiple RPS compliance strategies shows that deferring the addition of a physical resource results in lower net portfolio costs, a number of factors represent risks that may require PGE to rely on the current REC bank in future periods, including the potential for Oregon's RPS targets to grow materially relative to the current targets.

Based on the results of a cost and risk analysis, PGE concludes a physical renewable resource addition in 2024, balanced by reliance on banked RECs through 2023, enables the Company to delay costs of physical compliance in 2020. This strategy provides a hedge against factors that pose future cost or compliance risks for PGE.

1. 2013 IRP Action Plan Update

PGE's 2013 Integrated Resource Plan (IRP) Action Plan focused on four categories of actions: Supply-Side Actions, Demand-Side Actions, Enabling Studies, and Transmission. While PGE did not propose new, major resource actions in its 2013 IRP Action Plan, the Company's proposed actions established research objectives to inform development of the 2016 IRP. For example, the research initiative from the 2013 IRP built on work already under way to better understand and respond to PGE's dynamic capacity needs. These efforts include the dynamic dispatch and automated generator control projects. This involved development of modeling and evaluation methods to assess "inside the hour" energy, capacity, and ancillary service needs, as well as evaluating the requirements and potential costs and benefits of participating in new energy market structures.

Since acknowledgement of the 2013 IRP, PGE is moving forward with implementation of the actions in the Action Plan. Specifically, PGE is on pace to acquire the dispatchable standby generation (DSG) targeted in our plan. The Company also implemented Bonneville Power Administration (BPA) 15-minute scheduling for Biglow Canyon Wind Farm (Biglow) and Tucannon River Wind Farm (Tucannon) starting October 1, 2015. PGE is now integrating wind sub-hourly by making wind schedule changes every 15 minutes for these two plants. BPA and PGE are now sharing the responsibility of firming wind within the hour.

The Company continues to assess the efficacy of its Automated Demand Response (ADR) pilot design with EnerNOC. PGE is also rolling out new DR programs and pilots, and analyzing the results of the Enabling Studies set forth in the plan. Finally, PGE continues to work with the ETO to achieve the targeted energy efficiency savings.

Chapter 1 outlines PGE's progress in implementing the actions in the 2013 IRP Action Plan and directives from OPUC acknowledgement Order No. 14-415.

1.1 Supply-Side Actions

PGE did not include major supply-side actions in the 2013 IRP. PGE continues to work toward the actions for hydro contracts and dispatchable standby generation as described below. Chapter 2 provides other supply-side updates, such as new qualifying facility (QF) contracts.

Hydro Contracts

> "PGE should seek to renew its expiring hydro-facility contracts to the extent it is cost-effective to do so and . . . pursu[e] cost-effective hydro contract renewals." *Order No. 14-415* at 7.

The 2013 IRP reported some of PGE's legacy hydro contracts would expire or require re-negotiation and renewal by 2019. As such, it indicated that PGE would seek to renew these contracts during the 2015 – 2017 action plan period.

On March 21, 2014, PGE entered into a contract to continue purchasing the output from the Confederated Tribes of the Warm Springs Reservation of Oregon's 33.33 percent ownership share of the Pelton and Round Butte plants and all of the net output of the Tribes' Re-regulation Dam.[2] At present, negotiations are underway to renew other expiring hydro contracts. PGE will update the Commission on the status of these negotiations as the discussions progress.

Dispatchable Standby Generation

> PGE to add 23 MW of DSG by 2017. *Order No. 14-415* at 7.

PGE's DSG program is experiencing positive growth and is on track to meet the 2013 Action Plan goal of 116 MW of DSG in 2017. PGE is actively engaging potential customers for the program, and providing each customer a thorough analysis and tailored proposal as to how DSG can benefit their business. The DSG program is helping customers generate costs savings for their backup generator and providing them greater reliability.

The Company expects to have approximately 106 MW of projects in service by the end of 2015, which represents an increase of 18 MW relative to the end of year 2013 total of 88 MW. PGE provided stakeholders a status update on the DSG program on September 25, 2015, at a public meeting for the 2016 IRP. Stakeholders learned of the program's progress, and received information regarding current projects and the potential for program growth.

PGE designed the DSG program to provide customers with extensive benefits and enhanced reliability, all at an affordable price. As a result, PGE's DSG program is experiencing great success and interest in the program continues to grow. With continued customer interest, PGE expects to have a queue of projects more than sufficient to meet its 2017 goal, and looks forward to further consideration of DSG in the 2016 IRP.

[2] In Order No. 14-300, the Commission granted PGE a waiver from the RFP Guidelines for the purchase.

1.2 Demand-Side Actions

PGE's post-acknowledgement demand-side additions include new capacity and energy efficiency (EE) gains, as detailed below.

Energy Efficiency

> PGE to acquire "114 MWa of cost-effective Energy Efficiency (EE) by 2017, with a target increase to 124 MWa in the event that statutory cost limitations are relieved through legislative, or other appropriate regulatory action." Order No. 14-415 at 8.

Since acknowledgement of PGE's 2013 IRP, the legislature has not taken any action to relieve the statutory cost limitations for cost-effective EE. However, on January 15, 2015, the Commission opened UM 1713 to investigate the energy efficiency limitations on large customers. That docket is now in abeyance while the parties work to construct a legislative solution that will address all issues currently pending in the docket, including the SB 838 funding cap.[3]

To date, PGE has not reached the statutory cost limitations, and the Company may not reach the limitations in 2016. Based on recent actuals and forecasts provided by the ETO, the forecast net EE acquisition from 2014 through 2017 is approximately 130 MWa.

Demand Response

> PGE to acquire "25 MW of additional demand response by 2017 administered by EnerNOC." Order No. 14-415, Appendix at 1. PGE should pursue other DR options in light of looming energy and capacity needs, and shall notify Staff of any proposed changes to the EnerNOC contract baseline. Order No. 14-415 at 9.

PGE has worked deliberately to meet its DR commitments and to add potential programs to the pipeline. Customers are the central actors and the main focus in the Company's DR programs. Accordingly, the Company engages business and residential customers differently in demand response.

PGE currently has two demand response programs in operation: the curtailment tariff, Schedule 77 for large non-residential customers (able to reduce demand by 201 kW), and the Energy Partner℠ ADR pilot for non-residential customers. In August 2013, PGE transitioned Schedule 77 from a pilot to a program. The Company enrolled three customers in the program and each contracted to deliver 18.3 MW of capacity for a given event. In the summer of 2015, Schedule

[3] *See* ALJ Traci A.G. Kirkpatrick's Rulings dated June 16, 2015 and October 27, 2015.

77 had its most successful season in the history of the program. PGE called four events, as detailed in **Table 1-1** below, and in each event achieved significantly more DR than nominated.

Table 1-1: Summer 2015 Schedule 77 Events

Date	MW Contracted	MW Achieved
July 1, 2015	18.3	72.9 MW
July 2, 2015	18.3	47.9 MW
July 30, 2015	18.3	27.9 MW
August 12, 2015	18.3	23.9 MW

For the four summer 2015 events, PGE achieved participation rates significantly higher than the DR under contract; in fact, the Company realized more than four times the contracted capacity on July 1.

Unfortunately, in recent months, two of the three customers that participated in Schedule 77 (and the vast majority of the contracted load) are no longer participating. PGE's biggest Schedule 77 customer that accounted for significantly more than half of the contracted load was a large pulp mill which ceased operations and will no longer participate in events. In September 2015, another customer in the program elected to have their energy needs met by an Electricity Service Supplier, thereby eliminating their ability to participate in the program. With only one customer remaining, PGE is evaluating that customer's interest in transitioning to Energy Partner℠ to maximize operational efficiency.

PGE continues the Energy Partner℠ ADR pilot with EnerNOC. The program reached 6.7 MW at the end of winter 2015 and grew to 9.1 MW at the end of summer 2015. While the program is growing, the growth is slower than forecast. On April 15, 2015, the Company filed its first evaluation of the ADR pilot with the OPUC in compliance with Order No. 13-059. Based on the results of that evaluation, PGE may continue the program as a pilot in 2017, submit the program as an ongoing capacity resource via its 2017 Annual Update Tariff (AUT) filing, or end the program. PGE will incorporate any relevant insights gained into the program design.

Currently, PGE can share several new insights attained from running DR programs for business customers. First, market awareness is crucial. While business customers in other parts of the country are well accustomed to DR, the programs are new to businesses with operations only in the Northwest. The majority of our initial enrollments in Energy Partner℠ came from customers that have national businesses that already participate in DR programs in other parts of the country. As a result, PGE continues to work to drive market awareness of DR for commercial and industrial customers and increase customer participation.

Another key learning, connected to the small number of customers, is the difficulty of effectively forecasting participating load. Economic conditions—both positive and negative—can cause customers to no longer want to or be able to participate in events. Plant and equipment upgrades can also cause customers to temporarily suspend or lower their participation in the program.

While PGE's recent experience with Schedule 77 demonstrates an extreme—and worst case—scenario, the Energy Partner℠ pilot presents similar issues for the Company. Even as customer count will grow in some months, the amount of enrolled load will decrease due to temporary plant outages or increased business demands—i.e., customers are unwilling to curtail load because of their high business demands. PGE will report on the Energy Partner℠ program again in March 2016 to determine the next steps for the pilot.

On residential DR, PGE initiated two pilots and a technical trial. The first pilot tests Nest Learning Thermostats (Nest) as a Direct Load Control (DLC) mechanism for DR. Launching in November 2015, PGE's pilot will be the first use of Nest's thermostats for a winter DR program. One value of the Nest pilot is it seeks to make participation simple (and automated) for customers. Furthermore, Nest's ability to pre-heat homes during the winter and pre-cool them in the summer should limit customer discomfort and enhance participation.

The second pilot launches in the spring of 2016 and will test Time-of-Use (TOU) pricing, Peak Time Rebate (PTR), and Behavioral Demand Response (BDR). The intent of the pilot is to test a number of different possible rate designs to determine which are most attractive to customers and most successful in shifting load. The results of the pilot will inform the full-scale TOU programs that PGE rolls out to all customers.

Additionally, in partnership with the BPA, PGE is developing a technology trial to evaluate the potential to control smart water heaters via a standard (CEA-2045) communications interface. This trial will commence in 2016. PGE will provide further updates on its DR programs and pilots in the 2016 IRP.

1.3 Status of Commission Acknowledged Enabling Studies

In the 2013 IRP, the Commission acknowledged multiple enabling studies and research designed to inform the development of PGE's 2016 IRP. This section provides a brief summary and status update on each study. PGE will provide a detailed analysis or copy of the finalized studies in the 2016 IRP.

Distributed Generation Potential

> PGE to pursue studies and research initiatives with the goal of assessing potential business models and polices that expand the installation of cost-effective distributed generation for all DG sources, including CHP projects. *Order No. 14-415* at 10.

To fulfill the Commission requirement above, PGE conducted studies on the potential to expand the installation of cost-effective distributed generation (DG) for all DG resources, including combined heat and power (CHP) projects. PGE's research included a study on a methodology to assess the value of solar by Clean Power Research (CPR) and a market assessment by Black & Veatch (B&V) of DG solar and other DG resources, under the regulatory structures and incentives currently in place.

Valuation of Solar Methodology Study

The CPR study focused on assessing the value of DG solar to the utility system and customers. Modification of the methodology for use with utility-scale resources (connected to transmission) is also possible. Furthermore, the methodology can be used for other generation technologies in addition to solar, but it does not include dispatch strategies or other methods to produce an assumed generation profile (i.e., the profile is an input to the methodology). The CPR report describes the method for calculating each component cost and benefit of distributed solar, along with supporting methods.[4]

DG Resource Market Assessment Study

B&V prepared two reports to assess the potential deployment of solar and other DG technologies: 1) Non-Solar Distributed Generation Market Research;[5] and 2) Solar Generation Market Research.[6]

These reports examine the potential for DG solar and three classes of non-solar DG for electricity-only applications: battery energy storage systems (BESS), fuel cells, and microturbines.

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[4] Benjamin Norris, "PGE Distributed Solar Valuation Methodology," Clean Power Research, July 13, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/distributed-solar-valuation.pdf.

[5] Black & Veatch, "Non-Solar Distributed Generation Market Research," September 24, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/non-solar_market_research.pdf.

[6] Black & Veatch, "Solar Generation Market Research," September 24, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/solar_generation_market_research.pdf.

B&V modeled different scenarios for DG solar with respect to inflation and incentives. Specifically, it examined scenarios in which expiring incentives are not renewed. This resulted in a market assessment for DG solar between 125 and 223 MWdc in the next 20 years (i.e., the study period from 2015-2035). The assessment of the market for other DG resources found that most DG technology costs are not financially viable for customer installation in the study period. However, B&V projected that some penetration of BESS would become financially viable starting in 2026.

Operational Flexibility Assessment and Evaluation Tools for Optimizing Flexible Resource Mix

> "PGE to conduct a comprehensive analysis of all flexible resource options, including institutional and operational options that lower the need for reserves and lower the cost of reserves." *Order No. 14-415*, Appendix A at 2.

The Commission acknowledged PGE's proposals to continue examining dynamic capacity needs, alternatives to addressing the needs, and tools to optimize the mix of flexible capacity resources. Additionally, the Commission directed PGE to conduct a comprehensive analysis of all flexible resource options and complete an energy imbalance market (EIM) analysis.[7]

As part of its Dynamic Dispatch Program (DDP), PGE completed engineering studies of existing resources to better determine their abilities to provide flexible capacity and the associated costs. PGE also installed hardware and software to allow improved dynamic dispatch of the existing fleet. Finally, the Company incorporated flexibility performance and cost information from the DDP in the flexibility modeling for the 2016 IRP, enhancing the abilities of the existing fleet. In 2014 and 2015, PGE provided external stakeholders, including OPUC staff, updates regarding DDP at multiple PGE-held Quarterly Power Cost meetings and at the first public meeting for the 2016 IRP[8].

PGE also pursued options for expanded regional regulation reserve (a.k.a. following reserve) sharing, beyond the existing ACE Diversity Interchange program[9], through the Northwest Power Pool Market Assessment and

[7] PGE completed an EIM comparative study and filed its report with the OPUC on November 6, 2015. PGE incorporates that report by reference into this IRP update.

[8] *See* PGE's Integrated Resource Plan, Public Meeting #1 presentation at slide 22, April 2, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/pge_presentation.pdf.

[9] ACE Diversity Interchange is the pooling of area control errors (ACE) to take advantage of control error diversity (momentary imbalances of generation and load). www.oasis.oati.com/PPW/PPWdocs/ADI_040107.pdf

Coordination Committee (NWPP MC) Initiative. PGE remains actively engaged with the NWPP and other regional partners with initiatives aimed at improving the reliability and efficiency of the regional grid. The Company expects that work to continue even after PGE completes the process of joining the Western EIM.

PGE's analytical tools for optimizing resource portfolios continue to evolve through on-going development of the Resource Optimization Model (ROM). Additionally, PGE is working with Energy and Environmental Economics, Inc. (E3) to perform a flexible capacity study for the 2016 IRP, leveraging E3's prior experience and Renewable Energy Flexibility Model (REFLEX).

Resource Optimization Model

ROM is a PGE-developed model designed to estimate the incremental variable costs of fully self-integrating variable energy resources (VERs) into PGE's current and future resource portfolio. Initially a two-stage model with the goal of estimating variable wind integration costs, ROM is continually evolving, with each upgrade reviewed by a Technical Review Committee of independent industry experts.

Upgrades will allow PGE to model the costs of integrating both wind and utility scale solar into PGE's system for the 2016 IRP. The Company also updated characteristics of its existing resources to incorporate flexibility parameters and costs from the DDP engineering studies. However, PGE did not update VER integration costs as part of this 2013 IRP Update.

At its September 25, 2015 public meeting, PGE provided stakeholders an update on the status of ROM. The Company will provide the ROM analysis and final results in the 2016 IRP.

Flexible Capacity Study

PGE is working with E3 to conduct a flexibility capacity analysis of PGE's system with various combinations and amounts of new renewable resources and flexible capacity resources. The analysis will use E3's stochastic production simulation model, REFLEX. The study will assess the performance and cost of each portfolio, providing information about potential additional flexibility need, by renewable resource type and penetration level, and the suitability of different capacity resources to provide that flexibility.

PGE provided preliminary information about the study to stakeholders during a public meeting on August 13, 2015. The Company expects to provide final results from the study in the 2016 IRP.

1.4 Status of Additional Commission Requirements

Load Forecast Methodology

> "PGE to convene a series of workshops with interested parties to examine PGE's load forecast methodology." *Order No. 14-415*, Appendix A at 2.

PGE discussed its load forecast methodology and results at four public meetings and/or workshops during the 2016 IRP public process between April and August of 2015. On April 2, 2015, during Public Meeting #1, PGE subject matter experts presented the underlying fundamentals of the Company's load growth including sector level model drivers, input assumptions, and preliminary forecast output. Itron, a third-party industry expert, presented the findings from a review of PGE's load forecast methodology and models including a detailed discussion of fundamental drivers and methodological approach. Following this meeting, PGE, OPUC Staff, and Itron met for additional technical review and a question and answer session.

On July 15, 2015, PGE hosted Technical Workshop #1. The workshop focused on PGE's load forecast methodology and provided a forum for stakeholder participation and feedback. The topics covered during the workshop included PGE's energy forecast methodology, the associated long-term regression models, peak demand forecast, and incorporation of energy efficiency. This workshop was well-attended, with 14 external stakeholders participating.

PGE also discussed load forecast methodology and results during Public Meetings #2 and #3. The meetings included a presentation of the most recent load forecast, a summary of the discussion at the technical workshop, and a review of the high and low load scenarios to be included in IRP portfolio analysis.

Colstrip Analysis

> "PGE required to examine and analyze various shutdown scenarios for Colstrip in next IRP process." *Order No. 14-415*, Appendix A at 1.

The Colstrip power plant comprises four generating units. Unit 1 and Unit 2 were placed into service in 1975 and 1976, respectively, and provide approximately 307 MW of generating capacity each. Unit 3 and Unit 4 each provide approximately 740 MW of generating capacity and were placed service in 1984 and 1985, respectively. PGE owns a 20 percent interest in both Colstrip

Unit 3 and Unit 4. PGE's 2016 IRP will include portfolios that analyze various shutdown scenarios for Colstrip.

2. Load and Resources Update

In this section, PGE provides discussion and detail regarding the Company's updated load forecast, revised EE projections from the ETO, and relevant supply changes.

2.1 Demand

This update uses PGE's long-term load forecast developed in June of 2015. For IRP purposes, PGE identifies annual energy needs assuming normal (15-year average) weather conditions. PGE reports annual peak demand using 1-in-2 or 50 percent probability that the actual peak load will exceed the forecast of peak load during the stated time frame.

Load Forecast

PGE's load forecast used for the IRP is net system load, inclusive of five-year opt-out customers and with embedded EE estimates. **Table 2-1**, below, compares the projected 2017 annual energy and peak load requirement of the current forecast to that in the 2013 IRP filing.

Table 2-1: 2013 IRP vs. 2013 IRP Update Forecast

	Energy		Winter Peak		Summer Peak	
	2017 MWa	2014-33 Growth	2017 MW	2014-33 Growth	2017 MW	2014-33 Growth
Reference Case Forecast						
2013 IRP (December 2013 forecast)	2,422	1.3%	3,613	1.0%	3,523	1.3%
2013 IRP Update (June 2015 forecast)	2,377	1.2%	3,652	0.9%	3,564	1.1%
Difference	(45)		39		41	

When comparing the two forecasts, the 2017 average energy deliveries fall by 1.9 percent, the 2017 winter peak increases by 1.1 percent, and the 2017 summer peak increases by 1.2 percent. The long-term growth rates for both energy deliveries and peak demands are slightly lower than the originally filed 2013 IRP.

The changes in the updated load forecast reflect the following:

- PGE's service territory experienced stronger economic growth in 2014 and 2015 than was predicted in the economic forecast used as an input assumption for the initial 2013 IRP filing. The updated forecast reflects these positive trends in economic conditions and a stronger employment growth outlook for the 2016 to 2018 horizon.

- Despite the strong population and employment growth in 2014 and 2015, PGE's new connects and residential and commercial load growth remains modest. High tech industrial expansion continues to drive PGE's load forecast in the near-term.

- The June 2015 forecast includes a large industrial customer's plans to add new on-site generation operational in 2016, reducing expected energy deliveries from PGE. Additionally, updated actuals and information on the growth and timing of high tech expansion has reduced the 2017 energy forecast.

- Recent trends have led PGE to develop a regression-based peak demand forecast methodology, aimed at better capturing weather-related trends in peak demand. The output of this model is slightly higher seasonal peak demands for the 2017 year relative to the forecast filed in the 2013 IRP—although the peak growth rate is lower than the previously filed peak forecast due to lower energy forecast.

Load Forecast Methodology

Since issuing the December 2013 load forecast, PGE made minor refinements to the energy forecast models for the five-year (2015 to 2021) horizon and replaced the long-term (beyond 2021) energy and peak forecast methodologies with new regression-based approaches. The long-term energy approach does not impact the load forecast for 2017 and results in a lower, long-term energy growth rate of 1.2 percent, compared with a 1.3 percent under the previous methodology.

The regression-based, peak demand forecast directly incorporates weather variables as determinants of peak demand. This change improves the ability for PGE's model to capture the changes in weather response exhibited through recent trends in system peak demand—namely the impact of increased air conditioning saturation. Additionally, PGE adopted this approach in order to align with standard industry practice and increase the model's flexibility for scenario analysis.

PGE presented and discussed its updated peak and long-term energy forecast models with OPUC staff and stakeholders in a series of public workshops as a part of the 2016 IRP public process.

2.2 Resources Update

Energy Efficiency

The EE forecast for the 2013 IRP Update relies upon the ETO's June 2015 forecast. ETO presented the forecast to stakeholders during a 2016 IRP public meeting on July 16, 2015.[10]

While the cost-effectiveness limit decreased in the June 2015 forecast, the volume of expected acquisitions increased. **Table 2-2** compares the forecast incremental, annual net EE acquisitions for 2017 through 2021 from the 2013 IRP to the approximate net values from the 2013 IRP Update.

Table 2-2: Incremental Annual Net EE Acquisitions for 2017 - 2021

Incremental Cost-Effective Energy Efficiency (MWa)						
	2017	2018	2019	2020	2021	Total
2013 IRP (Aug 2013 Forecast)	25.2	22.2	19.9	17.7	16.3	101.3
2013 IRP Update[11] (Jun 2015 Forecast)	32.4	31.4	29.7	26.1	24	143.6

As in the 2013 IRP, the EE forecast from ETO shows a decline in the incremental available cost-effective EE over time. In both forecasts, the decline is almost entirely due to declining incremental savings from SB 838.

In the 2016 IRP, PGE intends to evaluate portfolios with higher levels of EE than the cost-effective ETO forecast. PGE will discuss portfolio options with stakeholders in upcoming 2016 IRP public meetings.

Demand Response

PGE currently has two demand response programs in operation: the curtailment tariff, Schedule 77 for large non-residential customers (able to reduce demand by 201 kW), and the ADR pilot for non-residential customers. For the 2013 IRP Update, the modeling of these two programs remains the same as in the 2013 IRP, as does the modeling for incremental DR acquired after 2017.

Table 2-3 shows the annual capacity values for 2017 through 2021.

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[10] "PGE Presentation," Slides 18-47. PGE's 2016 IRP Public Meeting #2, July 16, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-07-public-meeting-2.pdf.

[11] Net values approximated from gross values based on ratio provided by ETO.

Table 2-3: Modeled Demand Response Capacity for 2017 through 2021

	2017	2018	2019	2020	2021
Demand Response (MW)	45	45.1	45.3	46.4	48.6

PGE will update the DR forecast for the 2016 IRP. In preparation for the update, the Company engaged the Brattle Group to prepare a demand response potential study. On August 13, 2015, PGE presented draft information from the study to stakeholders during a public meeting.[12]

PGE Plants

PGE updated existing plant parameters, maintenance schedules, and forced outage rates to incorporate current information. The updates include the 2016 five-year average energy forecasts for Biglow and Tucannon generation, as well as Carty plant parameters used in PGE's net variable power cost (NVPC) forecast filed in UE 294. The net result is a decline of 0.6 percent in PGE's forecast of available energy.

PGE added one new hydro resource to the Company's fleet, a 0.5 MWa RPS compliant microturbine. The Harriet Powerhouse microturbine is located at "Crack-in-the-Ground" below Lake Harriet Dam. The powerhouse will utilize the Oak Grove Diversion flow to generate electricity and PGE expects it to be operational in late December 2015.

Contracts

The 2013 IRP Update contains approximately 63 MW of additional executed wind and solar contracts as summarized in **Table 2-4** below. These are primarily qualifying facility (QF) contracts.

[12] "PGE Presentation," Slides 96-139. Public Meeting #3, August 13, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-08-13-public-meeting-3.pdf.

Table 2-4: Additional Wind and Solar Contracts Included

Name	Seller	Type	Description	Deliveries (approx.)	MW[13] (approx.)	PGE RECs
Bear Creek Butte Wind QF	R-Squared Energy, LLC	Standard QF	Wind turbines in Crook County, OR	Nov 2015 - Nov 2033	10 MW	none
West Butte Wind QF	R-Squared Energy, LLC	Standard QF	Wind turbines in Crook & Deschutes Counties, OR	Nov 2015 - Nov 2033	10 MW	none
Domaine Drouhin Solar QF[14]	Domaine Drouhin Oregon	Standard QF (Apr 2013)	Fixed-tilt PV plant in Yamhill County, OR	Aug 2008 - Apr 2028	0.08 MW	none
Starbuck Solar QF[14]	Starbuck Properties	Standard QF	Fixed-tilt PV plant in Marion County	Jan 2011 - Nov 2030	0.02 MW	none
Steel Bridge Solar QF	OneEnergy Oregon Solar, LLC	Standard QF	Fixed-tilt PV plant in Polk County, OR	Aug 2015 - Feb 2034	2.5 MW	none
Portland Public Schools Solar	Bank of America Leasing & Capital, LLC	sale / leaseback / buy-out	Fixed-tilt PVs on six PPS school rooftops in Multnomah County, OR	Fall 2015 - Oct 2021 (option to buy)	1.02 MW	Yr 1-5: 0% Yr 6: 44%
Fossil Lake Solar QF	Fossil Lake Solar, LLC	Solar QF	Single-axis tracking PV plant in Lake County, OR	Dec 2016 - Apr 2035	10 MW	2020 - 2031
Lakeview Solar QF	Obsidian Solar, LLC	Solar QF	Single-axis tracking PV plant in Lake County, OR	Spring 2018 - Jul 2035	10 MW	2020 - Q1 2033
Group of Nine Solar QFs	Various LLCs from Santa Monica, CA	Solar QF	Fixed-tilt PV plant in Marion, Clackamas, Yamhill, and Polk Counties, OR	Nov 2016 - Jul 2035	19.8 MW (2.2 MW ea.)	2020 - 2031

13 AC Rating for solar.

14 The Domaine Drouhin Solar QF and Starbuck Solar QF contracts are included in this table because they were not captured in the 2013 IRP Load-Resource Balance due to their size.

In addition to the wind and solar contracts, PGE included one additional QF contract and one mid-term contract as listed in **Table 2-5**.

Table 2-5: Additional Contracts Included

Name	Seller	Type	Description	Deliveries	Avg. Energy	PGE RECs
Tillamook Bay Digester QF	Port of Tillamook Bay	Standard QF	Methane digester in Tillamook County, OR	Jan 2014 - Dec 2028	0.8 MWa	none
Shell Purchase Option	Shell Energy NA	Purchase Option	Power purchase option	Mar 2014 - Dec 2017	300 MWa	none

The 2013 IRP included modeling for a then pending contract with Warm Springs Power and Water Enterprises (WSPWE) to purchase the output from their ownership share of Pelton, Round Butte, and the Pelton Re-regulating Dam from 2015 through 2024. PGE has updated the modeling of the contract to reflect the final terms of the agreement. This update results in a minor increase to the expected energy and capacity received from the contract.

2.3 Load-Resource Balance

The load-resource balance calculations for energy and capacity in this 2013 IRP Update incorporate the updates to the demand forecast, energy efficiency forecast, plant operating parameters, and contracts discussed above. These updates created relatively minor changes to the annual surplus and deficits as described below.

Energy Load-Resource Balance

As in the 2013 IRP, the energy load-resource balance in this IRP update refers to the difference between the expected energy capability of PGE's resources (generating plants, contracts, and EE) and the expected annual average load under normal hydro and weather conditions.[15] Additionally, per the 2013 IRP, peaking (Beaver and Port Westward 2) and duct-firing ability (Coyote, Port Westward 1, and Carty) plants are not included in the energy load-resource balance.

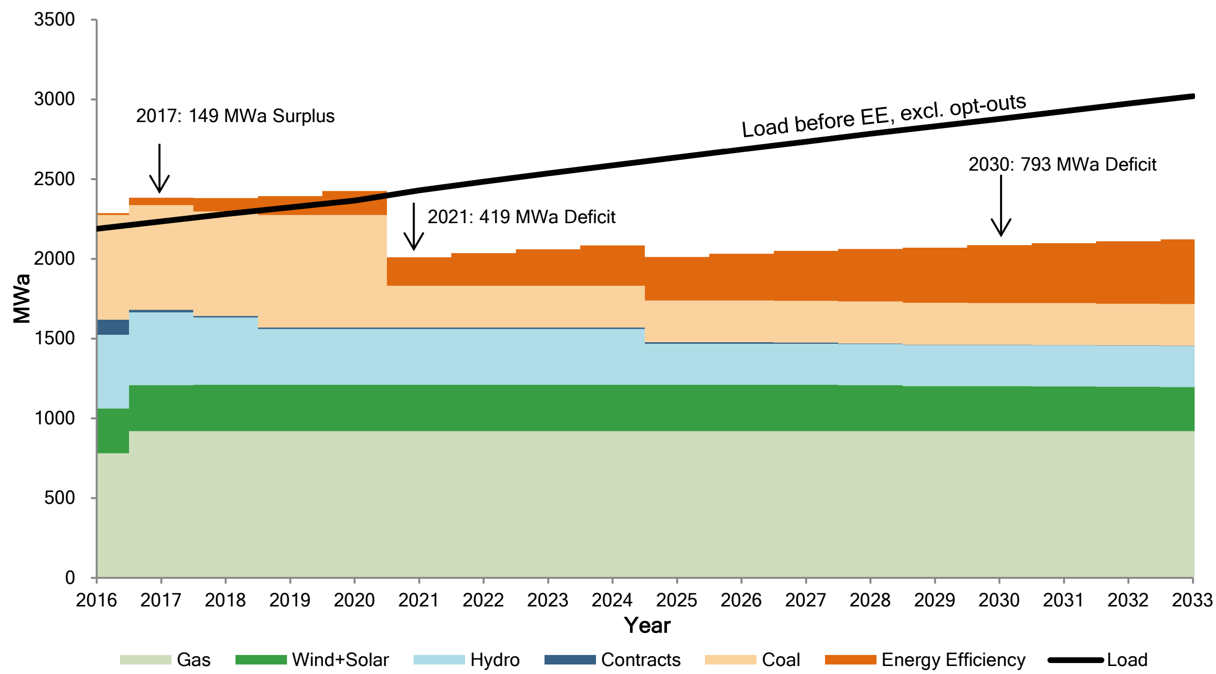
The forecast annual average energy load-resource balance shifted since the 2013 IRP, primarily due to a decrease in the forecast average demand. The forecast

[15] In the load-resource balance analysis, both for energy and for capacity, PGE's load is before all reductions due to post-2015 energy efficiency. EE is included as part of the resource portfolio.

2017 resource surplus increased from 93 MWa to 149 MWa and the forecast 2021 resource deficit decreased from 527 MWa to 419 MWa.

Figure 2-1 shows PGE's projected annual average energy load-resource balance for 2016 through 2033.

Figure 2-1: PGE's Projected Annual Average Energy Load-Resource Balance



Capacity Load-Resource Balance

For the 2013 IRP Update, PGE continues to base its capacity assessment on a one-hour peak 1:2 load forecast, reserve needs of approximately 12 percent, and a five percent capacity contribution from wind and solar resources. As discussed below, the 2016 IRP will update the methodology to determine capacity needs and contributions from variable energy resources.

The winter and summer capacity balances in 2017 reflect larger surpluses than in the 2013 IRP, primarily due to a contract that expires at the end of 2017. In 2021, the deficits from the IRP and the IRP Update nearly align. In the outer years, the lower growth rate in the seasonal peak demands in the 2013 IRP Update load forecast lead to reductions in the seasonal capacity deficits compared to the 2013 IRP. **Figure 2-2** and **Figure 2-3** show the 2013 IRP Update winter and summer capacity needs for 2016 through 2033.

Figure 2-2: PGE's Projected Winter Capacity Need

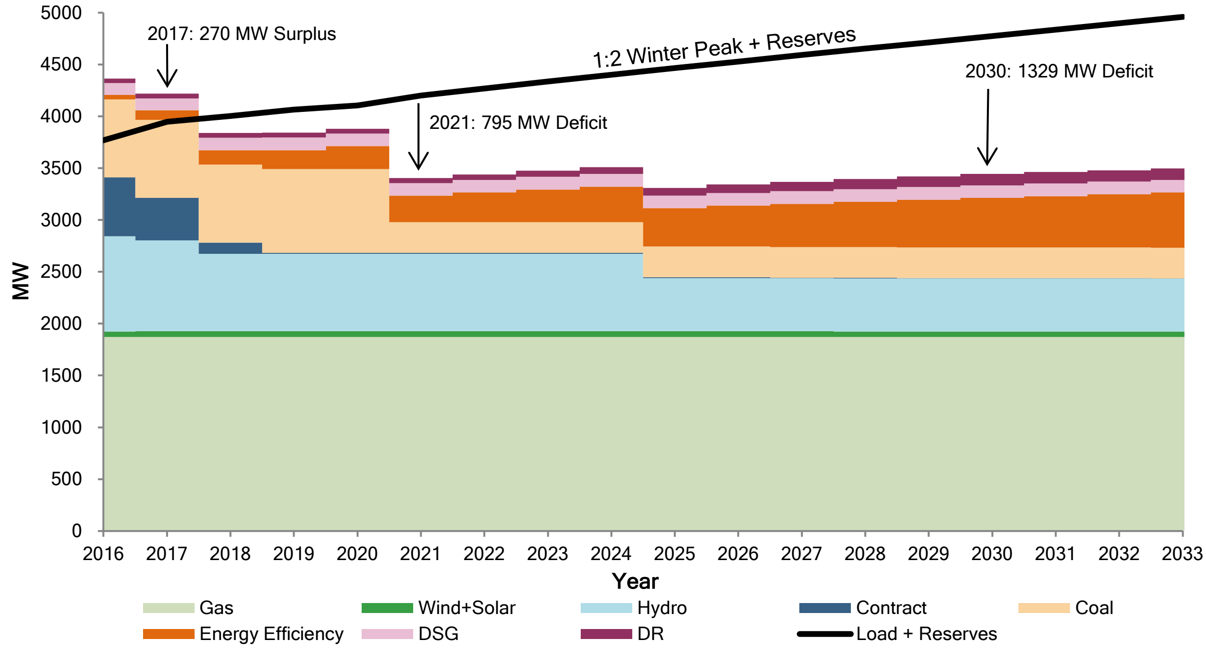
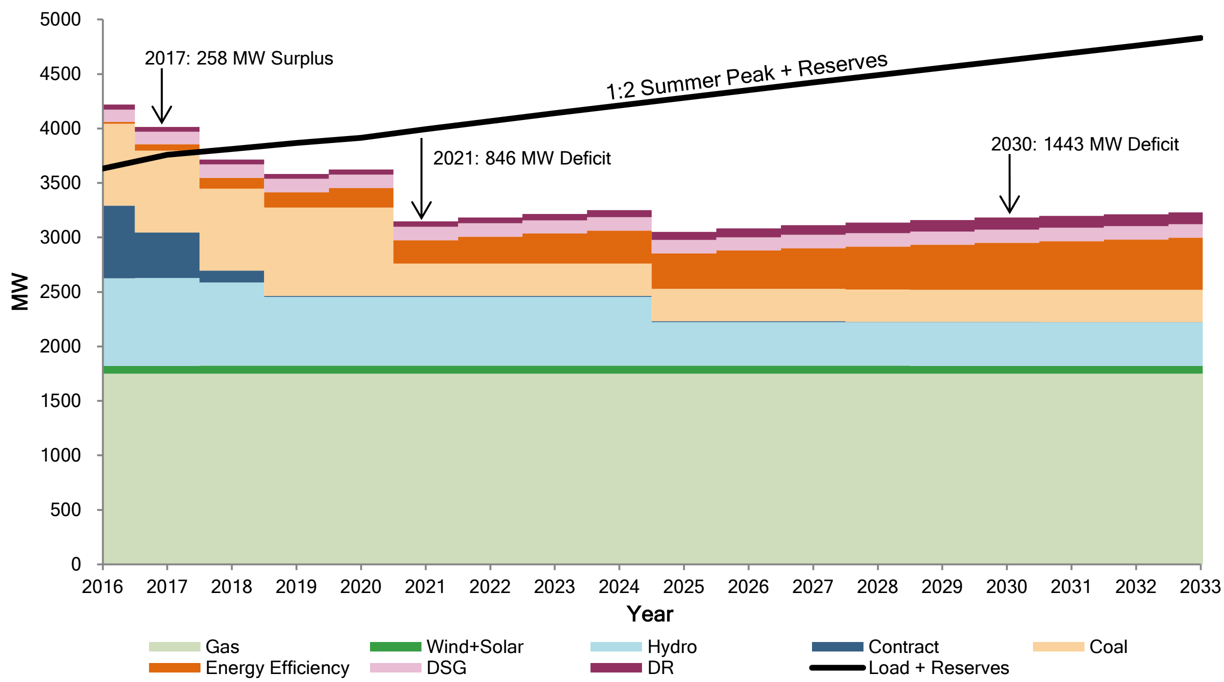


Figure 2-3: PGE's Projected Summer Capacity Need



In the 2013 IRP, PGE indicated that it would likely revisit the adequacy of the planning reserve margin in the next IRP. In 2015, PGE engaged E3 to complete a planning reserve margin and variable energy resource capacity contribution study. The study provides a statistical assessment of PGE's entire portfolio and assesses the capacity gap in 2021 to meet a resource adequacy target. E3 based the modeling on its publicly available Renewable Energy Capacity Planning model (RECAP). PGE shared the draft study with stakeholders during a public meeting on August 13, 2015,[16] and will incorporate the study into the 2016 IRP.

RPS Compliance Balance

The RPS compliance balance is the surplus or deficit of renewable energy certificates (RECs) produced by qualified resources compared to the annual requirement for RECs based on a percentage of load (adjusted for EE).

Table 2-6 compares the 2013 IRP and IRP Update RPS compliance balances for 2020. The estimated compliance gap declined from a deficit of 119 MWa in the 2013 IRP to a deficit of 95 MWa in the IRP Update, largely due to the updated customer demand and EE forecasts discussed above.

Table 2-6: Comparison of PGE's 2020 RPS Compliance Balance

	2013 IRP	2013 IRP Update
Load net of EE (MWa)	2,338	2,215
RPS Compliance Percentage	20%	20%
RPS Requirement	468	443
Qualifying Resources	349	348
Resource Surplus/(Deficit)	(119)	(95)

Chapter 3 discusses Oregon's RPS and PGE's RPS compliance in more detail.

2.4 Resource Costs

Capital Costs

In support of the 2013 IRP Update, and the upcoming 2016 IRP, PGE updated the assumed cost and performance of commercially available supply-side resources. PGE also engaged two industry leaders in technology cost and performance analysis to assist in this effort. Black & Veatch provided the Company with cost

[16] "PGE Presentation," Slides 14-48. Public Meeting #3, August 13, 2015. https://portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-08-13-public-meeting-3.pdf

and performance parameters for generic thermal resources (including biomass and geothermal) and energy storage resources. DNV GL provided the cost and performance parameters for new wind and solar resources. PGE will provide Black & Veatch and DNV GL's generic resource reports in the 2016 IRP.

Consistent with the consultants' reports, PGE updated assumed generic resource overnight capital costs. **Table 2-7** details how the updated overnight capital costs compare to the 2013 IRP.

Table 2-7: Updated Resource Overnight Capital Costs

Technology	2013 IRP Update (2015$ / kw)	2013 IRP (2015$ / kw)	Percent Change %	Notes
Natural Gas CCCT	$ 1,050	$ 1,166	-10%	IRP update is based on the GE H-class machine. The 2013 IRP was based on a Mitsubishi G-Class machine
Wind	$ 1,555	$ 2,301	-32%	IRP Update assumes 2.0 MW machines in PNW Gorge
Solar	$ 1,801	$ 2,908	-38%	IRP Update assumes tracking solar project near Christmas Valley
Natural Gas Reciprocating Engine	$ 1,414	$ 1,777	-20%	Based upon Wartsila 18V50SG
Natural Gas Aeroderivative	$ 1,094	$ 1,446	-24%	Based upon GE LMS-100

Tax Credits

Production Tax Credit

In this IRP Update, PGE continues to assume that the Production Tax Credit (PTC) is available to new wind generation projects. The PTC expired at the end of 2014, and Congress has yet to extend the credit in 2015. There are indications that a 2-year extension may happen at year end, creating a retroactive extension for 2015 and extending the credit through 2016. Since its inception in 1992, the PTC has expired without replacement four times. Following the three previous expirations, Congress extended the tax credit on a short-term basis. PGE expects that short-term extensions of the PTC will continue to subsidize new renewable energy at levels near the $0.023/kWh tax credit, available in 2014, for several more years. Despite the politicization of the PTC, PGE expects that political support for incentives for renewables will grow as states and utilities develop plans to comply with the requirements of the Clean Power Plan (CPP) and seek tools to mitigate the rate impacts of transitioning utility fleets to lower carbon generation.

While it is difficult to forecast the particular levels of incentives for new renewable generation, PGE finds the recently expired PTC an appropriate proxy for 2013 IRP Update modeling efforts.

Investment Tax Credit

The 2013 IRP Update assumes that the 30 percent investment tax credit (ITC) is available for new solar generation projects in-service by the end of 2016. At the end of 2016, the current 30 percent ITC for solar resources reduces to 10 percent with no expiration date set for the reduced tax incentive level. After 2016, the 10 percent credit currently available for geothermal heat pumps, hybrid solar lighting, small wind, fuel cells, microturbines, and combined heat and power systems will expire. The existing ITC for geothermal power projects will remain at 10 percent.

PGE believes that Congress will continue to provide some level of federal subsidies for future renewable energy projects. The 2013 IRP assumes the extension of the ITC at today's levels past 2016.

Cost of Capital

PGE updated the financial assumptions, for planning purposes, to reflect the current cost of debt and long-term inflation. **Table 2-8** details the updated financial parameters.

Table 2-8: Financial Assumptions

				Percentage
Composite Income Tax Rate				39.94%
Property Tax Rate				1.42%
Inflation Rate				1.97%

Capitalization:		Share	Cost	Weighted Cost of Capital
	Preferred	0%		
	Common	50%	9.68%	4.84%
	Debt	50%	4.85%	2.42%
Cost of Capital				7.26%
After-Tax Nominal Cost of Capital				6.30%
After-Tax Real Cost of Capital				4.24%

2.5 Other Updates

Fuel Prices

Coal

Coal prices assumed in the 2013 IRP Update are consistent with those assumed in the 2013 IRP. For a discussion of PGE's assumptions and methods regarding coal prices, please refer to page 94 of the 2013 IRP.

Natural Gas

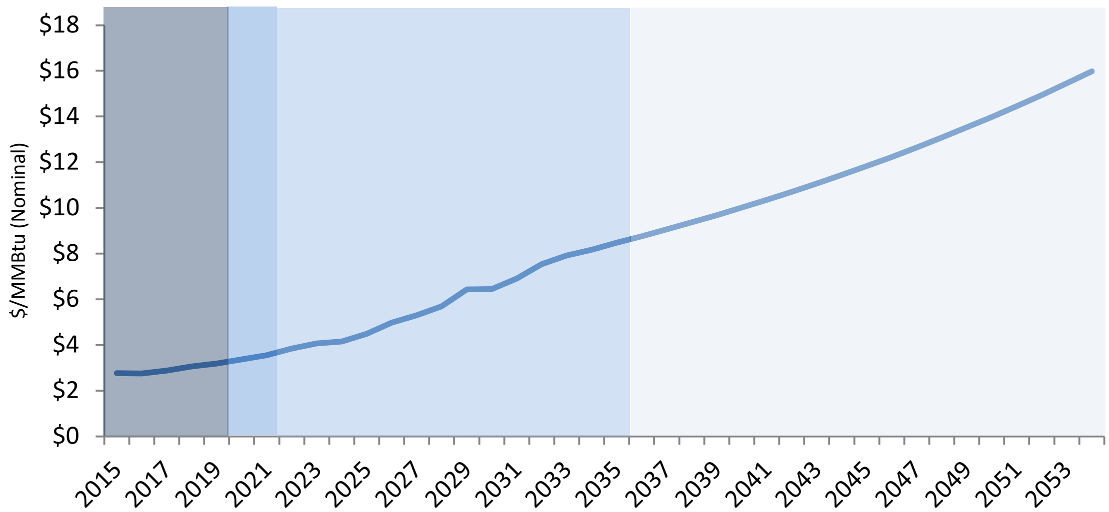
The 2013 IRP Update incorporates updated long-term and short-term natural gas price forecasts. Natural gas prices have a significant effect on IRP portfolio results, as they drive not only the economic performance of generic natural gas resources, but are also a primary driver for setting marginal prices in the wholesale electricity market.

PGE continues to use the long-term natural gas price forecast supplied by Wood Mackenzie. The May 2015 Wood Mackenzie's forecast extends to 2035. Wood Mackenzie forecasts rely upon fundamental based modeling of natural gas supply and demand in North America, updating the primary inputs on a bi-annual basis. The model identifies the recoverable supply of natural gas in North American basins and identifies the break-even price necessary for future well development to realize a profit. Wood Mackenzie estimates natural gas demand by sector and region, including liquefied natural gas exports. Interstate natural gas pipelines constrain the movement of gas from areas of supply to areas of demand, further affecting supply-demand balances and establishing regional price differentials.

Natural gas prices have fallen precipitously since 2008, following the widespread commercialization of horizontal drilling and the extraction of natural gas from North American shale deposits. Wood Mackenzie forecasts lower natural gas prices for 2015-2035 than PGE assumed in the 2013 IRP. The main drivers of the reduced costs (relative to the 2013 IRP forecast) are increased productivity and efficiency of new natural gas wells and drilling operations, growing recoverable supply from major basins, and more competitive service costs following an oil price drop.

Figure 2-4 illustrates the reference natural gas price for the 2013 IRP Update. The figure displays the average annual price of natural gas at the AECO and Sumas trading hubs, where PGE purchases most of the Company's natural gas.

Figure 2-4: 2013 IRP Update Natural Gas Forecast
Average of Sumas and AECO Hub Prices
Real Levelized Price: $4.71 (2015$)

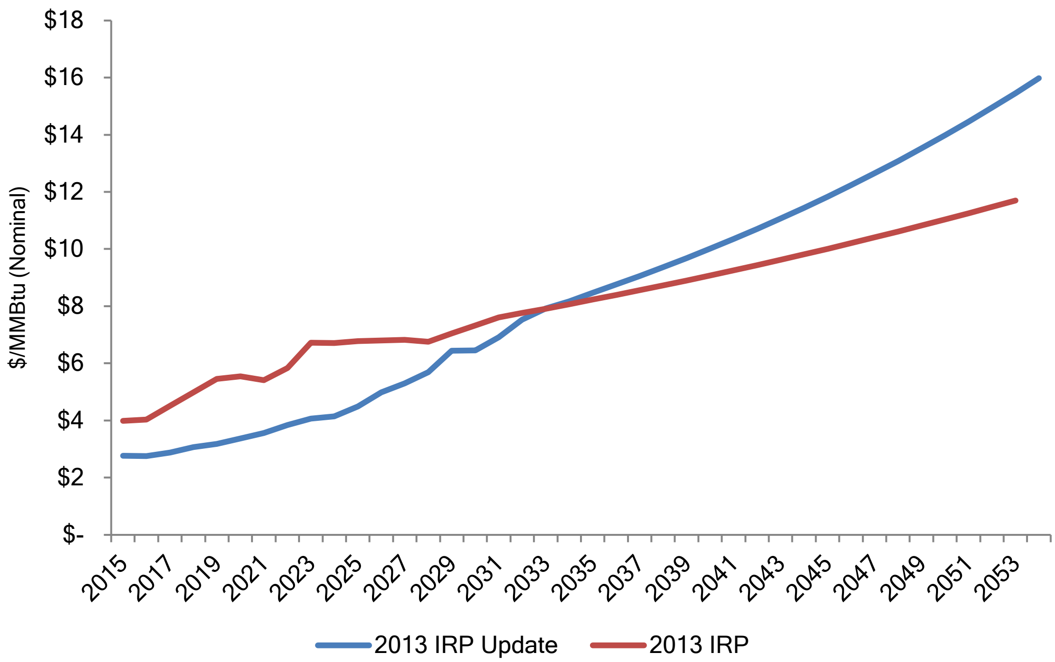


In the 2013 IRP Update, PGE's reference natural gas forecast extends to 2054, and blends four forecast periods. Between 2015 and 2019, the forecast relies upon the short-term forward curve, which reflects the market's appraisal of commodity pricing. Market forecasts are sparse in years beyond 2019, leading PGE to transition its reference forecast to Wood Mackenzie's long-term fundamental forecast. To transition between data sources, in 2020 PGE interpolates from the forward curve to the fundamental forecast. Wood Mackenzie's forecast continues through 2035. After 2035, PGE extrapolates the forecast based on inflation and the compound annual growth observed between 2033 and 2035.

In the 2013 IRP, PGE's natural gas forecast relied on slightly different mechanics to blend the four forecast periods. Whereas the 2013 IRP extended Wood Mackenzie's forecast based on inflation alone, PGE now extends the forecast based on the growth factor observed at the end of the fundamental forecast. The Company reasoned that the macro-economic conditions leading to increasing prices are likely to persist beyond the forecast period.

Figure 2-5 compares the average of Sumas and AECO prices between the 2013 IRP Update and the 2013 IRP.

Figure 2-5: 2013 IRP Update vs 2013 IRP Forecasts
2013 IRP Update Real Levelized Price: $4.71 (2015$)
2013 IRP Real Levelized Price: $5.42 (2015$)



Wood Mackenzie's fundamental forecast model does not endogenously model the Clean Power Plan (CPP), but it does include a CO_2 price that begins in 2020. The following section provides additional details about this CO_2 price assumption.

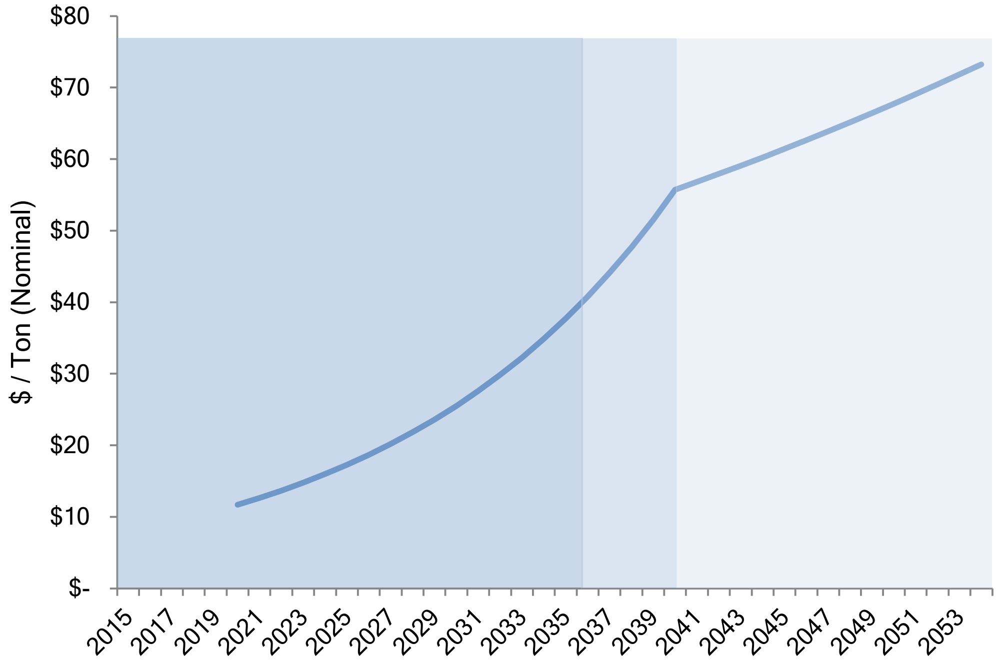
Applying a CO_2 price increases coal-fired plant retirements and replacement of those plants with gas-fired units, thus increasing the demand for natural gas in the electric power sector. Wood Mackenzie has found that the amount of natural gas demand associated with their CO_2 price assumption is comparable to the natural gas demand forecast by EPA as a part of the agency's CPP rulemaking.

Carbon

The 2013 IRP Update includes Wood Mackenzie's updated carbon price assumption. Carbon prices have a strong effect on thermal electric generation and influence natural gas demand and price. Given the relationship between natural gas prices and CO_2 policy, PGE uses a reference CO_2 price that is consistent with the natural gas forecast.

Figure 2-6 displays the 2013 IRP Update assumed CO_2 prices.

Figure 2-6: 2013 IRP Update Assumed CO2 Prices
Real Levelized Price: $28.78 / Short Ton (2015$)



PGE extrapolates the CO_2 price beyond the Wood Mackenzie forecast period, based upon the 2020-2035 compound annual growth rate, until 2040. From 2040 forward, the assumed CO_2 price rises with inflation.

The assumed CO_2 price serves as a reasonable proxy for existing and future policy designed to lower the carbon intensity of the electric power sector.

Clean Power Plan

On August 3rd, 2015, the President of the United States announced the release of the CPP—the results of a final rulemaking issued by the EPA under section 111(d) of the Clean Air Act (CAA).[17] The rule will regulate CO_2 pollutants from qualifying electric generating units (EGUs).[18] (On the same date, the EPA also released final rules under section 111(b) to regulate new EGUs according to a separate rulemaking.[19])

[17] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64661, 64663 (Oct. 23, 2015) (amending 40 C.F.R. pt. 60)
[18] *Id.*
[19] Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64510 (Oct. 23, 2015), (amending 40 C.F.R. pts. 60, 70, 71, and 98).

Although the EPA rule is final, much about the implementation of the CPP remains uncertain. Similar to previous rulemakings under the CAA, the CPP requires that states develop implementation plans that adhere to federal guidelines. The EPA has granted states considerable flexibility in the design of approvable implementation plans. States are required to file initial compliance plans by September 2016, but are free to redesign their plans before the final filing in September 2018.[20]

Federal Guidelines

Targets

Through several regulatory and judicial proceedings, the EPA found CO_2 to be a pollutant threatening public health and welfare, and subject to the CAA. In its final rule, the EPA establishes the 'Best System of Emission Reductions' (BSER), which enables compliance entities to lower CO_2 emissions at a reasonable cost.[21] The EPA calculates BSER for both coal and natural gas combined cycle (NGCC) sub-categories. Both BSER standards are uniform across the county. The BSER standards increase in stringency over time until reaching the final standard in 2030.[22] The final BSER standard for coal (and other steam) units is 1305 lb/MWh.[23] The final BSER standard for NGCC units is 771 lb/MWh.[24]

In the CPP, the EPA identifies unique state CO_2 targets to limit CO_2 emissions within state borders. The state targets are the result of the EPA's subcategory BSER standards applied to historical baseline generation levels.[25] Specifically, a state's 'rate-based' CO_2 target is the average of the BSER subcategory standards weighted by a state's historical subcategory generation levels.[26]

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[20] 80 Fed. Reg. 64661, 64669.
[21] *Id* at 64663.
[22] *Id* at 64785.
[23] *Id* at 64742, 64752.
[24] *Id*.
[25] *Id*. at 64821.
[26] *Id*.

Figure 2-7 details how Oregon's rate-based goal results from BSER.[27]

Figure 2-7: Oregon's CPP Target

Coal BSER = 1305 lb/MWh
NGCC BSER = 771 lb/MWh
Oregon's State Goal:
19% x Coal BSER
+ 81% x NGCC BSER
871 lb/MWh

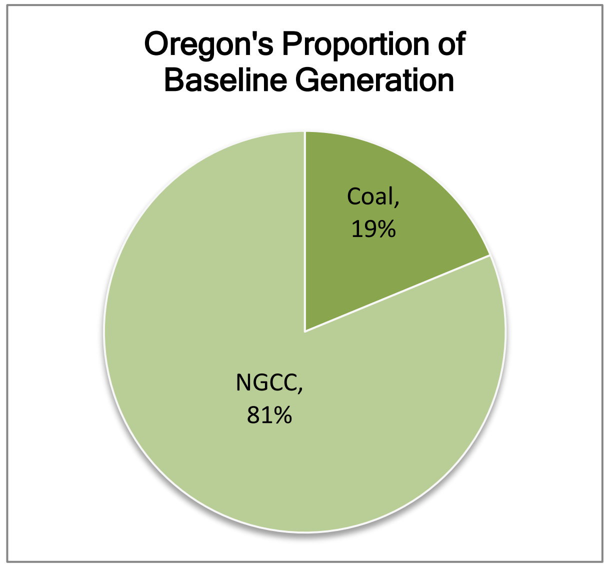
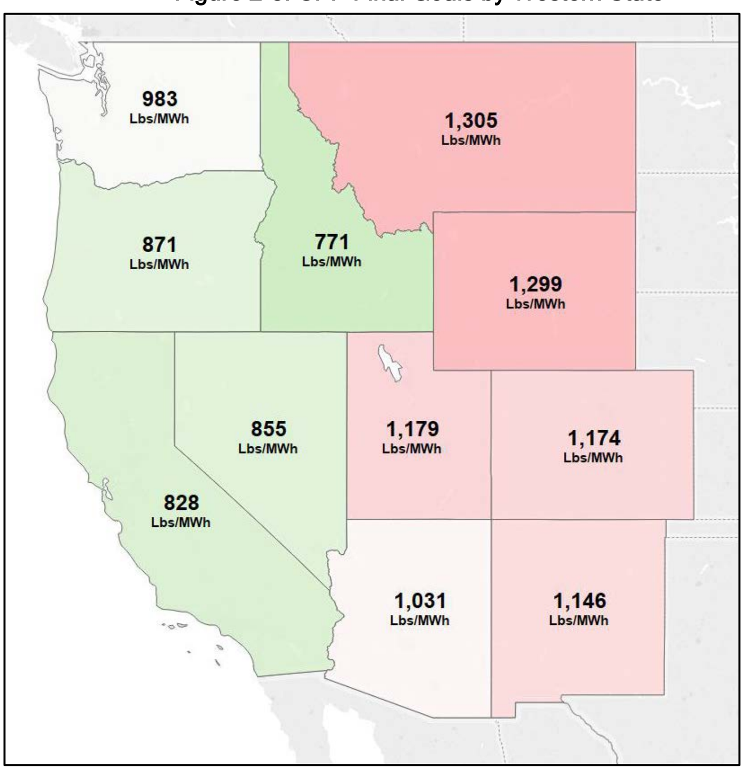


Figure 2-8 identifies how final state rate-based goals differ across the WECC.

Figure 2-8: CPP Final Goals by Western State



[27] 80 Fed. Reg. 64661, 64824.

The EPA defines a rate-based goal as an annual limit on the average emission intensity of qualifying units but does not limit total emissions.[28] In addition to the rate-based state goals detailed above, EPA identifies unique mass-based goals for each state consistent with the rate-based goals. The CPP defines the mass-based goal as a limit on the total tons of CO_2 that qualifying units may emit annually.

Each state has the option to implement a rate-based or mass-based implementation plan.[29] While the CPP designed the two standards to be of equivalent stringency, states will likely find compliance with one or another standard preferable. Depending on the implementation plan decision, states will base compliance with the CPP on either a carbon-intensity basis or a total emission basis.[30]

Eligibility

EPA has issued the CPP under its authority granted by the CAA section 111(d) which relates to existing resources.[31] For this reason, the CPP applies only to existing resources. As part of an implementation plan, a state may choose to also regulate new resources, but the EPA does not require such regulation if the state implements a rate-based plan. If a state implements a mass-based plan, it must address emissions from new plants, so as to prevent CO_2 emission "leakage" from existing to new units.[32] As described in more detail later, EPA defines leakage as the potential for dispatch from eligible units to shift to new units in a manner that diminishes the emissions reductions associated with the BSER standard.[33]

Of all existing CO_2 emitting resources, the CPP defines eligible EGU units as all units in operation or having commenced construction before January 8, 2014 (whichever is earlier).[34] Further, eligible units must be greater than 25 MW. The rule excludes stationary combustion turbines that do not meet the definition of a combined cycle facility.

[28] 80 Fed. Reg. 64510, 64527.
[29] 80 Fed. Reg. 64661, 64812.
[30] *Id.*
[31] 80 Fed. Reg. 64661, 64812.
[32] *Id.* at 64821.
[33] *Id.* at 64822-64823.
[34] *Id.* at 64747 (footnote 421); 79 Fed. Reg. 1430, 1462; Clean Air Act Section 111(b)

Table 2-9: CPP Eligible Units in Oregon and Montana Units with PGE Ownership (full or partial) Highlighted

Oregon	Montana
Beaver	J E Corette Plant
Boardman	Colstrip 1
Carty Generating Station*	Colstrip 2
Coyote Springs	Colstrip 3
Coyote Springs II	Colstrip 4
Hermiston Generating Plant	Lewis & Clark
Hermiston Power Partnership	Colstrip Energy LP
Klamath Cogeneration Plant	Yellowstone Energy LP
Port Westward	Hardin Generator Project

*Carty is not listed as an eligible unit in EPA's final rule, yet the unit meets EPA's 'existing unit' criteria and is expected to be subject to CPP.

Timeline

Compliance with the CPP begins in 2022. In years 2020-2022, new renewable energy projects and select energy efficiency measures, installed after the acceptance of the state's final implementation plan, generate credits used for CPP compliance. In years 2022-2029, eligible units must comply with interim standards. States will define interim standards through the implementation plan, but those targets must meet minimum federal criteria.35 By year 2030, all eligible units must comply with the final state goal.

Point of regulation

Under the CPP, eligible units must have an enforceable obligation to comply with the CPP—likely administered through the facility's Title V (of the CAA) Operating Permit. In a mass-based system, that obligation would most likely present as an obligation to submit allowances for every ton of CO_2 emitted. In a rate-based system, that obligation would likely be expressed as tons per MWh limit with reference to an addendum outside of the permit identifying the compliance tools available. The exact requirements to be included in the Title V Operating permit will remain unknown until the state prepares their CPP implementation plan and the EPA approves the plan.

Compliance Actions

[35] The average 2022-2029 state targets must be equal to the average state goal.

There are four primary compliance actions that an eligible unit or a fleet of eligible units, can use to reduce plant CO_2 emissions to comply with the CPP. An eligible unit may:

1. Improve plant efficiency
2. Re-dispatch from coal units to existing natural gas units
3. Install new carbon free resources elsewhere in the state
4. Install energy efficiency measures elsewhere in the state

Compliance Instruments

The EPA's BSER includes emission reductions that occur 'outside the fence line' of eligible units. For example, the EPA has found that BSER for existing coal units includes re-dispatch to less carbon intensive gas and new renewable resources. This design lowers the allowed emission intensity of BSER, and requires that eligible units perform compliance actions elsewhere in the state. To facilitate the compliance, EPA allows eligible units to acquire compliance instruments from third parties rather than perform compliance action individually.

Under a rate-based implementation plan, the EPA defines the relevant compliance instrument as an 'Emission Rate Credit' (ERC). One ERC represents one MWh of carbon free generation.[36] An eligible unit must acquire and retire enough ERCs so that the average emission intensity of the unit and ERCs meets the rate-based target.[37]

$$Ratebased\ Target = \frac{EGU\ CO2\ Emissions}{EGU\ MWh\ Generation\ + Emission\ Rate\ Credit\ MWh}$$

Eligible units create ERCs in three ways:

1. An ERC is created along with every MWh of generation from new carbon free resources including (but not limited to) new renewable, nuclear, and energy efficiency resources.[38]

2. A fractional ERC originates from any fossil fuel resource whose emission intensity is less than the applicable rate-based target. The amount of ERC's generated is proportional to the EGU's intensity difference from

[36] 80 Fed. Reg. 64661, 64949; 40 C.F.R. §60.5790(c)(2)(ii).
[37] *Id.*
[38] *Id.* at 64834.

the standard. For example, a highly efficient natural gas plant with a carbon intensity 10 percent lower than the rate-based standard then the unit would create a 10 percent of an ERC (0.1 ERC) for every MWh generated.

3. 'Gas Shift' ERCs are created by all existing NGCC units. Gas Shift ERCs incent existing NGCCs to replace generation at existing coal units. As such, only existing coal and steam units my use Gas Shift ERCs for compliance. Additionally, every MWh of existing NGCC generation creates fractional gas-shift ERCs. EPA is soliciting comments on the appropriate fraction, but has proposed a formula that results in 0.1 ERC for 1 MWh of NGCC generation, depending on the year and the NGCC unit in question.[39]

Under a mass-based standard, EPA defines the relevant compliance instrument as a carbon allowance. Similar to allowances used in the Californian and North Eastern carbon markets, the holder of a carbon allowance may retire the allowance to emit 1 ton of CO_2.

Unlike ERCs, allowances are not created. There is a fixed quantity of allowances, which states dispense according to a mechanism defined in the implementation plan. New carbon free resources and energy efficiency measures do not increase the amount of allowances available to a particular state, but they presumably reduce the need to emit CO_2 and lower the demand for carbon allowances. States are free to auction allowances or allocate them at no cost on whatever basis they choose.

Trading

Ability to trade compliance instruments, both intra-state and inter-state, is generally expected to lower the overall cost of compliance by allowing the transfer of instruments from regions of supply to regions of demand. The EPA requires that state implementation plans incorporate a mechanism to track the creation, transfer, and use of compliance instruments. Generally, the EPA CPP allows for the intra-state trading of compliance instruments. Inter-state trading of compliance instruments is also encouraged by the EPA, and expected to reduce the cost of compliance. However, in order for a state's implementation plan to include inter-state trading it must satisfy several criteria.

Inter-state trading can only occur between states with compatible state implementation plans. States with mass-based plans cannot trade with rate-

[39] 80 Fed. Reg. 64661, 64795-98.

based states and an allowance cannot be converted into an ERC (or vice-versa). Furthermore, rate-based states may not trade unless the states are under the same target. Rate-based states can align their targets by forming a regional plan with other states. In a more likely outcome, states can align their targets by complying with sub-category specific rate standards, similar to the proposed model rule detailed below.

State Implementation Plans

States must submit to the EPA an implementation plan that details how the state's eligible units will meet the EPA's targets. There are three different categories of state implementation plans that the EPA is willing to accept:[40]

1. rate-based plans
2. mass-based plans
3. state measure plans

The EPA proposed rate-based and mass-based model rules. The compliance mechanisms included in the proposed state plans are presumptively approvable. Should a state choose not to submit a state implementation plan, the EPA will require that units comply with one of the proposed model rules.

Rate-based

States with rate-based implementation plans must first determine which standard plants must comply with the CPP. There exist three general choices. A state may adopt the EPA rate-based standard unique for the state. Each eligible unit would acquire adequate ERCs to meet the state target. Alternatively, a state may join a regional implementation plan under a blended rate-based goal.

Under the proposed rate-based model rule, states would adopt two standards associated with the coal & steam BSER and the NGCC BSER. Eligible units would acquire ERCs to meet the relevant sub-category specific standard. The advantage of the proposed federal rule is that it is deemed 'trading ready' and would allow trading of ERCs with any other state also adopting the sub-category specific standard; no political agreements are required nor must state standards be blended.

The proposed rate-based model rule enables existing NGCC generators to create gas-shift ERCs. EPA argues that the inclusion of gas-shift ERCs increases the incentive for existing NGCC generation to increase output. Because gas-shift

[40] 80 Fed. Reg. 64661, 64832-33.

ERCs are created only by existing NGCC units (rather than new units), EPA argues there will exist an incentive to operate existing gas resources which would avoid CO_2 emission 'leakage' to new resources. PGE details the EPA's concept of 'leakage' further below.

Mass-Based

States with mass-based implementation plans must decide how to dispense CO_2 allowances among eligible units and how to address leakage. The EPA will only approve a mass-based plan if the agency determines that a state's approach will prevent 'leakage' from existing units to new units.

EPA defines leakage as the potential for dispatch to from eligible units to shift to new units in a manner that diminishes the emissions reductions associated with the BSER standard. The potential of leakage results from regulating existing and new resources under different standards.[41] Unusual for CAA regulation, the standard for existing resources with the CPP is in many ways more stringent than for new resources. The CPP BSER for coal and NGCC of 1305 lbs/MWh and 771 lbs/MWh is lower than the New Source Performance Standards for new sources with 1400 lbs/MWh and 1000 lbs/MWh standards respectively.[42] In order for the EPA to approve state plans, states must identify a mechanism that diminishes the incentive to reduce dispatch at existing plants and increase at new plants in a manner that increases total emissions.

If, for example a mass-based plan was likely to allow existing coal units to continue operating at historic levels, by reducing dispatch at existing NGCC units and increasing dispatch at new NGCC units, then total emissions may not fall, thereby circumventing BSER. The EPA requires plans include mechanisms that would avoid such an outcome.

EPA's favored means for preventing leakage is for states to regulate new sources under a mass cap as a matter of state law. EPA does not have the authority under section 111(d) of the CAA to regulate new sources. However, EPA does provide a voluntary mass-based standard—adjusted modestly upwards by a 'new source complement' meant to reflect the additional headroom needed to accommodate load growth between 2022 and 2030. If states choose to regulate new resources under a new source complement mass standard, incentives to shift from existing to new units diminish, and the plan is presumptively approvable by EPA.[43]

[41] 80 Fed. Reg. 64661, 64822-23.
[42] 80 Fed. Reg. 64510, 64540.
[43] 80 Fed. Reg. 64661, 64888-89.

Mass-based implementation plans may propose alternative mechanisms to prevent leakage. Such mechanisms may include allowance auctioning or particular allowance set-asides that encourage existing natural gas resources to increase dispatch.[44] Mass-implementation plans relying on unique methods to prevent emission leakage must include credible analysis that demonstrates leakage is unlikely to occur.[45]

The proposed mass-based model rule uses a series of allowance 'set-asides' to prevent leakage from existing resources to new resources. The remaining allowances are allocated based upon the proportion of generation from eligible units from 2010 to 2012, with some exceptions regarding under construction units and units that retire. There are three operative set-asides in the model mass-based rule:

1. Clean Energy Incentive Payment Set Asides

   As part of the Clean Energy Incentive Payment (CEIP), new renewable resources and energy efficiency measures installed in low-income communities after a state's final implementation plan submission, receive CO_2 allowances in years 2020 to 2022. New renewable resources receive 1 MWh worth of allowances for every 2 MWh generated in 2020 and 2021. Eligible EE would receive 1 MWh of allowances for every 1MWh avoided in 2020 to 2021. EPA is taking comments on how many allowances to award for each MWh of CEIP credit. CEIP set-asides partially fund allowances awarded to CEIP generation. In 2022-2024, the EPA removes CEIP set-asides from a state's allowance balance. Table 10 of the proposed model rule details the proposed quantity of set-asides, but it is generally small. For instance, Oregon's 154,343 short-ton CEIP set-aside is just 1.5 percent of Oregon's 2022 mass-based target.

2. Renewable Energy

   The renewable energy set-aside creates an incentive for new renewable generation within the state. The EPA proposed that 5 percent of a state's allowances be set-aside and awarded to renewable generation that comes online after 2012.

3. Output-based Set Asides

   Output-based set asides are removed from the allowance balance and awarded to NGCC units to create an incentive for existing NGCC

[44] 80 Fed. Reg. 64661, 64835.
[45] *Id.* at 64888.

resources to increase output. The amount of set-asides awarded to each unit based on it dispatch above a 50 percent capacity factor in the previous compliance period. For every MWh generated beyond the 50 percent threshold, an NGCC unit receives 0.515 allowances. The rule caps the total number of allowances available under the output based set-aside.

The cap is equivalent to the number of allowances that NGCC units would create if all existing NGCC units increased output to a 60 percent capacity factor relative to the 2012 historical baseline. If eligible output for the output-based set-aside exceeds the state cap, then units receive allowances on a pro-rata basis.

Oregon's existing NGCC generation had a 54 percent capacity factor (on a hydro adjusted basis) in 2012. As a result, relatively few output-based set asides are available for existing units.

After Oregon removes all allowance set-asides from its balance, the state must allocate remaining allowances in proportion to a unit's share of generation in the 2010-2012 baseline period. For example in the 2010-2012 baseline period, Port Westward generated 11 percent of the total MWh from eligible units. As a result, under the proposed mass-based model rule, Port Westward would receive 11 percent of Oregon's allowances, after the State removed set-asides from its balance.

An important element of the proposed model mass-based rule is the treatment of units that retire. As proposed by the EPA, a unit that retires will continue to receive allowances based on its historical generation for three years. After a maximum of four years, the allowances associated with the retired unit are added to the renewable set-aside pool. As a result, retiring units under the proposed mass-based rule would not make additional allowances available for a utility's long-term compliance requirements

The EPA is already receiving substantial feedback on the questionable effectiveness of the proposed allocation scheme. It is likely the EPA will adjust or replace that method of addressing leakage in the final model rule. EPA is also receiving substantial feedback on the treatment of retiring units, noting that the rule is inadvertently incenting operators to continue operations, rather than incenting them to cease and switch to lower emitting units. Senior EPA officials acknowledge the issue, remarking that this provision seems to be as universally hated as the compliance cliff. PGE expects the final model rule to address this issue as well.

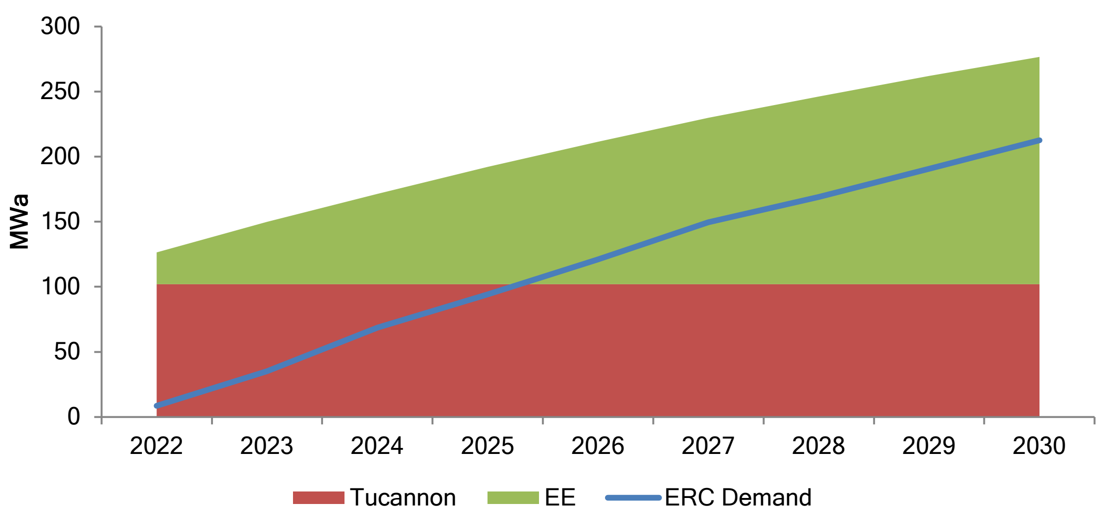
PGE's CPP Compliance Position

PGE is well-positioned to comply with the CPP. A long-term commitment to acquiring cost-effective EE and compliance to date with the RPS allows the Company to produce more ERCs than are required for compliance. The cessation of coal-fired generation at Boardman also greatly diminishes PGE's compliance burden in both a rate-based and mass-based compliance environment. While PGE's partial ownership of Colstrip units 3 and 4 does create additional compliance requirements, the surplus of compliance instruments available in Oregon would allow PGE to cover the Montana compliance need without additional resource actions.

When considering RPS compliance strategy in Chapter 3, PGE need not weigh whether the timing of RPS eligible generation affects PGE's ability to comply with the CPP. PGE's forecast shows compliance with the CPP without additional RPS resources. However, much about the CPP remains unknown—particularly, the details regarding the state implementation plans in Oregon and Montana. PGE will reevaluate its CPP compliance forecast when Oregon releases the initial details of the draft state compliance plans in September 2016. PGE will again reevaluate its forecast compliance position when states file their final implementation plans in 2018.

Figure 2-9 details PGE's forecast CPP compliance position under the proposed model rule rate-based plan. As illustrated, PGE generates enough ERCs from Tucannon and from projected energy efficiency additions to satisfy expected compliance demand for ERCs. The Company does not need additional RPS resources to satisfy the ERC demands for its resources in Oregon and Montana.

Figure 2-9: PGE Forecast ERC Balance: Rate-based Implementation Plan in OR and MT



While PGE expects to generate more ERCs than needed for compliance with the CPP, it is possible that Oregon and Montana choose to adopt mass-based implementation plans. Under a mass-based plan, regulated entities do not generate allowance compliance instruments. Instead, a state dispenses allowances, provided that the allocation mechanism prevents leakage. Without knowing how Oregon or Montana will choose to dispense available allocations, it is challenging to forecast whether PGE will receive adequate allowances necessary to comply with the CPP.

3. Renewable Portfolio Standard

In 2007, Oregon adopted a Renewable Portfolio Standard (RPS) codified under ORS 469A. Among the requirements of the Oregon RPS, certain electric utilities must serve at least 25 percent of their retail energy load with RPS qualifying renewable resources by 2025, with interim targets of 5 percent by 2011, 15 percent by 2015, and 20 percent by 2020.[46] Qualifying renewable resources include the following, if the resource, or an improvement to the resource, came into operation on or after January 1, 1995:[47]

- Wind
- Solar photovoltaic and solar thermal
- Wave, tidal, and ocean thermal
- Geothermal
- Certain types of biomass
- Biogas from organic sources such as anaerobic digesters and landfill gas
- New hydro facilities not located in federally protected areas or on wild and scenic rivers, and incremental hydro upgrades up to 50 MWa per year from certified low-impact hydroelectric facilities.

Electric utilities can use, subject to certain limitations and independent verification, Renewable Energy Certificates (RECs) to fulfill the RPS requirement. In meeting this requirement, the RPS identifies two classifications of RECs:

1. Bundled, where the energy and REC are sourced from the same generating facility, and
2. Unbundled, where the REC is purchased separately from the underlying power.

In both cases, the qualified resources must be located within the boundary of the Western Electric Coordinating Council (WECC) footprint.[48]

The legislation allows the electric utility to "bank" RECs from qualifying resources beginning January 1, 2007, for the purpose of carrying them forward for future compliance. To maintain the integrity of compliance, the Western Renewable Energy Generation Information System (WREGIS) validates the origination of RECs. Up to 20 percent of annual RPS requirements can be met with unbundled RECs. Electric utilities may also elect, or be required by the

[46] ORS § 469A.052(1)(a) – (d).
[47] ORS §§ 469A.020 and 469A.025.
[48] ORS 469A.135(1)(a) and (2).

Commission, to make alternative compliance payments (ACP) to comply with the RPS.

Given the above RPS provisions, PGE must meet at least 80 percent of each annual RPS requirement with some combination of current and banked, bundled RECs from qualifying physical resources. The practical effect of the RPS legislation is to promote the acquisition of renewable resources as the primary means of compliance, while allowing for flexibility in implementation to capture market opportunities, avoid short-term cost excursions, and adapt to timing differences in securing new sources of supply.

3.1 PGE's REC Need and RPS Compliance Strategy

> PGE to, "develop and evaluate multiple RPS compliance strategies – including alternatives to physical compliance – and recommend a least-cost strategy" in its next IRP Update and future IRPs. *Order No. 14-415 at 13.*

Oregon established the provisions of the RPS to incent the proliferation of new renewable resources and the achievement of long-run physical compliance. The flexibility provisions in the RPS discussed above (acquisition of unbundled RECs, REC banking, and ACPs) allow utilities to comply with the RPS while minimizing the risk of significant adverse impacts with regard to cost or reliability, but they are not long-term surrogates for renewable generation.

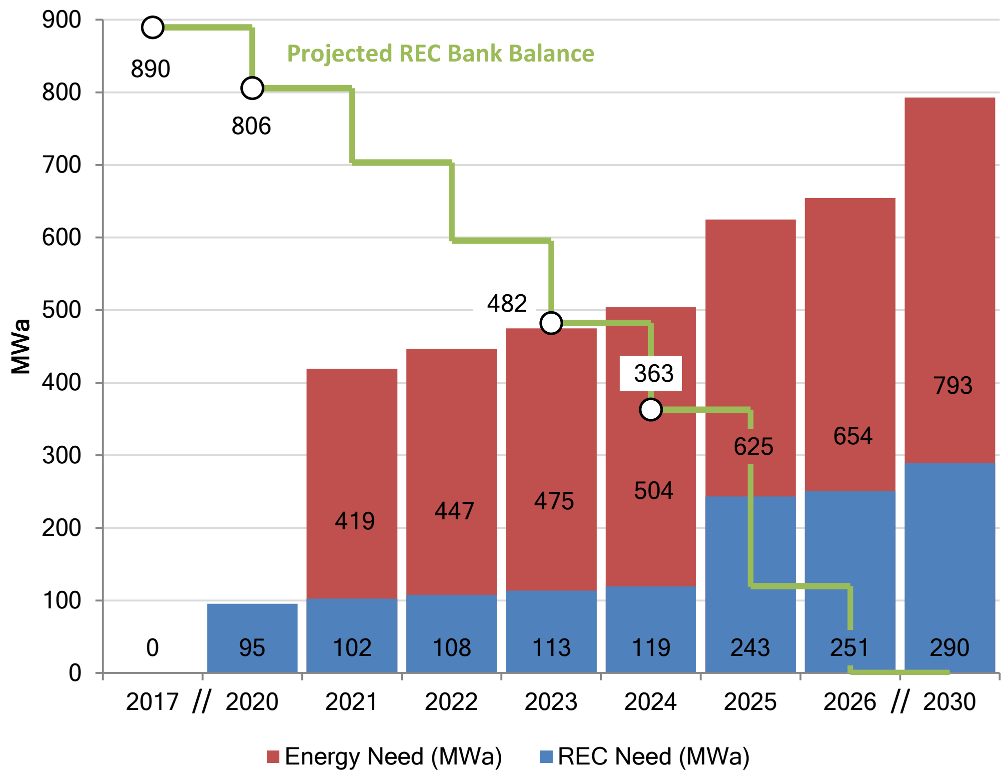
As the Action Plan time horizon in PGE's 2013 IRP did not include a major increase in the RPS target, the acknowledged Action Plan did not include any items associated with Oregon RPS compliance. However, in prior IRPs and IRP Updates, PGE did state that achieving physical compliance with the RPS provided the best balance of cost and risk for PGE and its customers. The Company established that position in light of the then current circumstances and expectations for future development; specifically during the early years of RPS compliance with rapidly increasing targets and competition to acquire renewable resources.

Figure 3-1 shows PGE's projected REC position.[49] PGE's existing REC bank balance is projected to be in excess of the near-term annual RPS compliance obligations using an "energy need" consistent with the energy load-resource

[49] **Figure 3-1** below summarizes PGE's energy needs, REC needs, and REC bank balance projected through 2030. The "REC need" represents the gap between the expected REC generation from PGE's existing qualifying resources and the amount needed for RPS compliance in each year. The "REC bank balance" in Graph 3-1 is a projection of PGE's current REC bank at year-end if no additional resources, bundled RECs, or unbundled RECs were added to the portfolio (that is, unbundled RECs were not assumed to be available to displace the use of banked bundled RECs).

balance presented in Chapter 2, and assuming current RPS obligations persist throughout the time period.

Figure 3-1: PGE's Energy Deficit, REC Need, and REC Balance
2017, 2020-2026, 2030



The remainder of this chapter explores strategies for achieving RPS compliance while taking into consideration the potential benefits and risks associated with relying on the existing REC bank.[50] Sections 3.2–3.4 summarize PGE's current evaluation of its RPS Compliance Strategy.

Based on the results in Sections 3.2–3.4, PGE concludes that the current least-cost, least-risk approach to comply with the 2020 RPS requirement is to rely on a REC bank through 2023 and add a physical renewable resource in 2024, given PGE's current forecasts of loads, renewable generation and compliance obligations. This approach enables PGE to delay costs of physical compliance in 2020, while

[50] PGE's current evaluation is consistent with OPUC Order No. 10-457, which directed PGE to evaluate, "the use of unbundled renewable energy credits (RECs)", and "alternatives to physical compliance with RPS Requirements in a given year, including meeting the RPS Requirements in the most cost-effective/least-risk manner that takes into consideration technological innovations, expiration or extension of production tax credits, and different levels of integration costs for renewable resources."

using the REC bank as a balancing mechanism to hedge against factors that pose future cost or compliance risks for PGE.

3.2 Options for Achieving RPS Compliance

PGE has five primary options for achieving RPS compliance, subject to certain limitations – acquiring physical energy resources with bundled RECs, purchasing bundled RECs, purchasing unbundled RECs, utilizing banked RECs (that result from previous REC acquisitions – both bundled and unbundled), and alternative compliance payments. PGE may also employ a combination of these strategies, either concurrently or at different points in time. A discussion of each strategy follows:

1. Physical Compliance – 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 indefinitely for future RPS obligations or monetization, as discussed below. 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.

2. Bundled RECs – In contrast to long-term PPAs with qualifying resources (including the associated RECs), PGE could execute short-term transactions for bundled RECs. Given the need for recurring transactions, this strategy would create additional uncertainty with respect to PGE's RPS compliance position relative to the longer-term options discussed above.

3. 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.[51] This is not a primary strategy for achieving compliance, but instead used to compliment a physical compliance strategy.

[51] ORS 469A.145(1)

4. Previously banked RECs – A banked REC, in general, is a, "bundled or unbundled renewable energy certificate that is not used by an electric utility or electricity service supplier to comply with a renewable portfolio standard in a calendar year and that is carried forward for the purpose of compliance with a renewable portfolio standard in a subsequent year."[52] Unused RECs accumulate in utilities' banks, which can be drawn from to comply with future years' RPS obligations. Banked RECs (both bundled and unbundled) may be stored indefinitely;[53] there is no limitation on the amount of banked bundled RECs that may be used for compliance.

5. Alternative Compliance Payments (ACP) – Oregon legislation provides for the use of alternative compliance payments in lieu of acquiring bundled or unbundled RECs for meeting RPS obligations.[54] The ACP provision is not intended to be used as a strategy for achieving RPS compliance over time. This is supported by ORS 469A directing the Commission to, "set the rate to provide adequate incentive for the electric company or electricity service supplier to purchase or generate qualifying electricity in lieu of using alternative compliance payments to meet the renewable portfolio standard."[55] The OPUC, in Order No. 12-375, set the alternative minimum compliance payment at $110 per MWh for the years 2014 and 2015.[56] This is the cost that a utility will incur for any REC deficits in those compliance years. Additionally, ORS 469A allows the Commission discretion in rate recovery of ACPs and use of such funds.[57]

3.3 RPS Scenario Analysis

A basic tenet in long-term planning is input assumptions become increasingly uncertain the further in the future the assumption is applied. This is true for all input assumptions ranging from the variable cost of natural gas to the cost estimates for building new generation resources. Additionally, predicting particular RPS compliance cost factors, such as future REC values, with certainly is impracticable. While these uncertainties expand the predicted range of cost for RPS implementation strategies over long time horizons, conducting scenario analysis can be a useful tool in understanding the magnitude of potential outcomes for alternative strategies, should circumstances changes in the future. Accordingly, PGE addresses the Commission's directives in Order No. 14-415 in

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[52] ORS 469A.005(1)
[53] ORS 469A.140(2)
[54] ORS 469.180
[55] *Id.* (2).
[56] Order No. 12-375, Appendix at 1.
[57] *Id.* (4)-(5).

the following scenarios that test changes in costs for various RPS strategies based on potential changes in future environment and prices.

Renewable Energy Certificates

As discussed above, the RPS limits the use of unbundled RECs to a maximum of 20 percent of the compliance obligation in each year. In the long-run, the fundamental market price of unbundled RECs should not exceed the difference between the expected levelized cost of energy from an incremental qualifying resource and the levelized cost of energy from the marginal non-qualifying alternative. The reality is a number of additional factors may influence the market price of unbundled RECs over the short-term, including (but not limited to): the geographic location of the generator, the underlying technology, the vintage of the REC, and factors affecting demand (compliance targets, economic/load growth, energy efficiency, and potentially voluntary markets). These factors generally describe whether the REC can be used for compliance in a given market. If it is expected that unbundled RECs will be available in the market for less than the price of bundled RECs, using up to the maximum amount of unbundled RECs could reduce RPS compliance costs in the short-term.

However, the absence of an organized market enabling efficient pricing of RECs makes it difficult to propose a long-term strategy predicated on unbundled RECs. Further, PGE's experience indicates that short-term supply and demand mismatches largely drive the pricing of unbundled RECs. Constantly changing market dynamics make it unlikely that recent imbalances will persist in the long-run. These factors persuade PGE to not rely on the availability of unbundled RECs in establishing an RPS compliance strategy.

Unbundled RECs, by definition, do not have an energy component. If a utility pursues an unbundled REC strategy and their expected energy needs exceed the expected RPS compliance obligation, they must account for the energy deficit component associated with the unbundled RECs. Beyond 2021, PGE projects that incremental annual average energy needs will exceed the incremental annual RPS requirements. As a result, two options emerge for PGE to achieve RPS compliance:

1. Rely entirely on bundled RECs (both current and banked from either the physical compliance or bundled REC strategies discussed on pages 47–48) to meet RPS compliance.

2. Acquire bundled RECs to meet at least 80 percent of the RPS requirement and acquire a combination of non-qualifying electricity and unbundled

RECs (up to the current 20 percent annual limit) to meet the remaining need.

In order for the second strategy (acquisition of unbundled RECs in lieu of bundled RECs) to be cost-effective, it should meet two economic tests:

1. The expected life-cycle levelized cost for qualifying resources is greater than the capacity equivalent cost for non-qualifying alternatives at the time of the decision.

2. The cost of unbundled RECs is less than the cost difference between the qualifying resource and the non-qualifying alternative identified in 1 above.

Table 3-1 provides an illustrative example of the potential cost impact of pursuing a strategy with no unbundled REC purchases relative to a strategy that pursues purchasing the 20 percent maximum each year. This example evaluates several scenarios with various unbundled REC prices:

- Unbundled REC price is equal to the hypothetical cost premium for RPS renewables (versus a non-renewable alternative)

- Unbundled REC price is less than the hypothetical cost premium for RPS renewables (versus a non-renewable alternative)

- Unbundled REC price is more than the hypothetical cost premium for RPS renewables (versus a non-renewable alternative)

- Unbundled REC prices start less costly point, but rise over time to reach the more costly point.

Table 3-1: Example of Impact of Unbundled RECs on Resource Cost

Assumptions:			
"Typical" New Resource Annual Supply		100	MWa
Resource Life		27	Years
Levelized Cost of Non-Qualifying Resource		$58	per MWh
Premium % for Qualifying Resources		10%	
Premium for Qualifying Resource		$5.80	per MWh
Implied Cost for Bundled RECs		$5.80	per REC
Annual RECs Generated from Qualifying Resource		876,000	
Cost Comparison of Four Hypothetical Cases			
	Year 1	**Year 10**	**Year 20**
Case A: Unbundled RECs price = Bundled RECs price			
Cost of Unbundled RECs (per MWh)	$5.80	$5.80	$5.80
Fill 80% with Bundled RECs (000s)	$4,065	$4,065	$4,065
Fill 20% with Unbundled RECs (000s)	$1,016	$1,016	$1,016
Total cost for RECs (000s)	**$5,081**	**$5,081**	**$5,081**
Total Levelized Resource Cost, with RECs (000s)	$55,889	$55,889	$55,889
Case B: Unbundled RECs price 20% < Bundled RECs price			
Cost of Unbundled RECs (per MWh)	$4.64	$4.64	$4.64
Fill 80% with Bundled RECs (000s)	$4,065	$4,065	$4,065
Fill 20% with Unbundled RECs (000s)	$813	$813	$813
Total cost for RECs (000s)	**$4,878**	**$4,878**	**$4,878**
Cost: B over A (000s)	$(203)	$(203)	$(203)
Cost: B over A (%)	-4.0%	-4.0%	-4.0%
Cost impact to Total Resource Cost	**-0.4%**	**-0.4%**	**-0.4%**
Case C: Unbundled RECs price 20% > Bundled RECs price			
Cost of Unbundled RECs (per MWh)	$6.96	$6.96	$6.96
Fill 80% with Bundled RECs (000s)	$4,065	$4,065	$4,065
Fill 20% with Unbundled RECs (000s)	$1,219	$1,219	$1,219
Total cost for RECs (000s)	**$5,284**	**$5,284**	**$5,284**
Cost: C over A (000s)	$203	$203	$203
Cost: C over A (%)	4.0%	4.0%	4.0%
Cost impact to Total Resource Cost	**0.4%**	**0.4%**	**0.4%**
Case D: Unbundled RECs price starts lower, ends higher than Bundled RECs price			
Cost of Unbundled RECs (per MWh)	$4.64	$5.80	$6.96
Fill 80% with Bundled RECs (000s)	$4,065	$4,065	$4,065
Fill 20% with Unbundled RECs (000s)	$813	$1,016	$1,219
Total cost for RECs (000s)	**$4,878**	**$5,081**	**$5,284**
Cost: D over A (000s)	$(203)	$-	$203
Cost: D over A (%)	-4.0%	0.0%	4.0%
Cost impact to Total Resource Cost	**-0.4%**	**0.0%**	**0.4%**

The examples in **Table 3-1** demonstrate that acquiring and using unbundled RECs is unlikely to significantly impact the overall cost of RPS compliance due to the restricted use (maximum of 20 percent per year). Even when unbundled RECs are available for a cost that is 20 percent less than bundled RECs on an ongoing basis, and employed maximally each year, the impact to the overall cost of RPS compliance is small.

From the four cases examined in **Table 3-1**, any potential benefits from developing a strategy relying on the purchase of unbundled RECs are likely to be minor, as opposed to the acquisition of qualified resources with bundled RECs. Given this finding, the lack of an organized market for unbundled RECs in the region, and the potential for future structural changes in the supply and demand balance for unbundled RECs, PGE continues to recommend acquisition of unbundled RECs as a complementary action when opportunistic purchases potentially reduce the cost of compliance while also providing a buffer to the bundled REC bank. PGE recommends against quantifying a reliance on the future acquisition of unbundled RECs when developing a long-term RPS compliance strategy.

Alternatives to Physical Compliance

While accurately predicting the availability and cost of future renewables is uncertain, the decision-making process regarding whether to acquire RPS resources sooner versus deferring the acquisitions to a later date is relatively straightforward. If new resources are needed to satisfy an overall energy and capacity deficit, and new renewable resources are also needed for future RPS compliance (this is PGE's expected case scenario for 2021), it would make sense to acquire new physical renewable resources as long as those resources can be acquired at a cost and risk profile that is equivalent to the non-renewable generation alternative. If the cost of new renewable resources is greater than the non-renewable generation alternative, the following decision approach may be appropriate:

1. If RPS qualifying renewable resources are available in the later time period, and uncertainties are biased toward the potential for material cost (per MWh) increases, it makes sense to purchase physical resources now, thereby reducing the risk of incurring increased costs to achieve long-run RPS compliance.

2. If RPS qualifying renewable resources are scarce in the later time period, it makes sense to purchase physical resources earlier, thereby avoiding scarcity premiums or alternative compliance payments in the future. Banked RECs would then also be more valuable in the future, as renewable resources become more limited in availability.

3. If RPS renewable resources are to be available in the future, and uncertainties are biased toward the potential for material cost decreases (as compared to the cost of earlier acquisition), it makes sense to temporarily rely on banked RECs, deferring physical renewable resource purchases.

Table 3-2 provides an illustrative example regarding the potential impacts of meeting RPS requirements under various scenarios. PGE based the below scenarios on the projected cost of constructing 95 MWa of new wind generation (PGE's current estimate of the required amount of new renewables to maintain physical compliance with RPS standards in 2020) at two book-end points in time, 2020 and 2025. Two implementation strategies are considered:

- Acquire new renewable resources to maintain physical compliance with RPS standards in 2020, or

- Acquire new renewable resources to meet PGE's 2020 RPS obligation (physical compliance) in 2025, and utilize banked RECs to meet the RPS obligation from 2020-2024.

By interpolating between these two end points, PGE can estimate the relative effects of interim physical compliance strategies. The Company designed the portfolios to be term and energy equivalent (on an annual basis) across the 36-year time horizon of the simulation—achieving term and energy equivalence with an assumed contract priced at market. Implicit in this assumption is the depletion of PGE's existing REC bank to maintain RPS compliance. All portfolios include a CCCT online in 2021, as proposed by the preferred portfolio from PGE's 2013 IRP, and add the same quantity of physical resource (approximately 95 MWa), achieving physical compliance by 2025.

The selected "alternative futures" provide a sense of the relative magnitude of potential change in cost for RPS compliance based on several key uncertainty factors. This analysis focuses on factors that may influence the following aspects of resource cost and performance:

- <u>Renewable resource overnight capital costs</u> – The overnight capital costs of renewable resources would be expected to increase as a result of increased demand, all else equal. The CPP, as discussed earlier in this 2013 IRP Update, could increase the regional and national demand for renewable resources while reducing the demand for fossil fuel-fired resources, particularly for more emissions-intensive generation types. While it is difficult to predict the price impact of such policy changes in the long-run, it is reasonable to assume that, in the time horizon prior to enforcement (through 2021), demand for new renewables will be amplified and near-term costs may increase while industry and markets adjust to the new policy. (Chapter 2 discusses the CPP.) PGE does not reflect any potential requirements arising from the CPP in this RPS compliance strategy discussion. Other emissions constraints and costs (such as a state- or regional-level CO_2 tax) could have impacts similar to the Clean Power Plan.

Growing regional and national RPS obligations could also have the effect of increasing demand for renewables. While Oregon RPS requirements, as they exist today, increase rapidly between 2015 and 2025, the potential exists for further increases to these compliance targets. On October 7, 2015, California Governor Jerry Brown signed into law Senate Bill 350 ("S.B. 350"), increasing the state's RPS target to 50 percent by the end of 2030.[58] S.B. 350 includes interim targets of 40 percent by year-end 2024 and 45 percent by year-end 2027.[59] Given the interconnected nature of the electricity market in the west, it is possible that mandates for increased penetration of renewable generation will negatively affect the availability of quality renewable resource sites. Additional aspects of site-specific considerations are discussed further below.

It is also possible, however, for these various mandates to drive technological evolution, resulting in reduced capital costs and/or improved generator efficiency. This learning curve effect may be more pronounced for resources that are less mature from a technical perspective. More mature technologies, such as simple cycle combustion turbines, are less likely to see significant reductions in capital costs. Emerging technologies, like battery energy storage, are more likely to realize substantial cost declines. It is possible that further technology-driven cost declines, in relatively mature renewable resources (i.e., wind), could be offset by decreasing energy production capability of sites available for new construction. Section 2.4 discusses PGE's recent supply-side resource cost assumptions.

- Renewable resource performance – Renewable resources are typically tied to an underlying natural resource at a specific site (e.g., wind plants are only viable when built at windy locations). Additionally, constraints on available transmission may impose greater costs on the future development of renewable generation sites. Several factors discussed above may contribute to increasing competition for high quality

[58] Clean Energy and Pollution Reduction Act of 2015, 2015 Cal. Legis. Serv. Ch. 547 (S.B. 350). https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB350.
[59] *Id.*

renewable resources in the future: increased demand for non-emitting resources to comply with carbon dioxide emissions targets under the CPP, the growing obligations under existing RPS requirements across the western United States, and the potential for the targets under those existing RPS programs to be increased. Given these factors, increasing competition and the potential for resource scarcity represent growing risks over time. Ultimately, increased competition or reduced availability of sites could result in higher site acquisition, operating, and integration costs, and reduced capacity factors in the future. Unless offset by other developments (such as the technology-driven capital cost or generator efficiency improvements discussed above), such supply challenges could result in substantial cost increases (on a per MWh basis) for future renewable resources.

- <u>Alternative non-renewable generation costs</u> – Changes in the cost for non-renewable generation alternatives could impact the cost effectiveness of future renewable resources. Significant cost changes for non-renewable generation could further influence demand and, in turn, the cost for new renewables. Two examples of this type of scenario risk are the potential for significant changes in fuel prices for natural gas-fired generation and the potential for changes to the assumed reference case cost or constraints on CO_2 emissions. Over the last decade, the spot and forecast prices for natural gas have seen periods of both large increases and decreases. These fuel price movements resulted in significant changes in the expected cost of new natural gas-fired generation, and, as a result, the relative cost-effectiveness of new renewables. Continued natural gas price reductions since mid-2008 have effectively lowered costs for natural gas-fired generation. To the extent that gas-fired resources are on the margin in the region, changes in natural gas prices and costs or constraints on CO_2 emissions will affect regional power prices as well. While it is difficult to predict future fundamental changes in gas supply or market prices, history has proven that substantial changes are possible. The same is likely true with regard to future state-, regional-, or national-level policy actions. Section 2.5 discussed PGE's recent long-term fundamental natural gas price forecast, reference case CO_2 cost assumptions, and CO_2 regulation under the CPP.

Table 3-2 demonstrates the potential impact on the three implementation strategies of these uncertainties associated with acquiring new renewable resources to meet RPS obligations over time.

Table 3-2: Illustrative Scenarios - RPS Compliance Portfolios and Varied Futures

NPVRR 2015$ (millions)	Ref. Case	Wind CF - 5% Pts.	Wind CF +5% Pts.	Wind O/N Capital -20%	Wind O/N Capital +20%	High Natural Gas Prices	Zero CO_2 Cost
Portfolios:							
2020 Wind	$ 23,386	$ 23,685	$ 23,135	$ 23,127	$ 23,645	$ 25,876	$ 21,097
2025 Wind	$ 23,317	$ 23,593	$ 23,083	$ 23,078	$ 23,557	$ 25,828	$ 21,009
Change from 2020 Portfolio:							
2025 Wind	$ (69)	$ (92)	$ (52)	$ (50)	$ (88)	$ (48)	$ (87)
Change from Ref. Case:							
2020 Wind		$ 299	$ (251)	$ (259)	$ 259	$ 2,490	$(2,289)
2025 Wind		$ 276	$ (234)	$ (240)	$ 240	$ 2,511	$(2,308)

The values in **Table 3-2** represent the net present value (2015$) of the simulated net cost for each of the three resource portfolios across the seven futures PGE examined. Under this scenario analysis structure, deferring the addition of a physical resource results in a lower net portfolio cost, on a present value basis, under all futures. However, such a strategy does not take into consideration the risks to RPS compliance posed by depleting PGE's existing REC bank. These risks are discussed below and should be considered when developing a balanced compliance strategy.

3.4 Considerations for REC Bank Management

The banking provisions of the Oregon RPS provide an important flexibility mechanism for electric utilities. The RPS provisions allowed for the banking of RECs from qualified resources starting in 2007, four years prior to the first compliance year of 2011. As a result, once banked, RECs may act as a balancing mechanism to hedge against a number of factors that pose future cost or compliance risks for PGE. Earlier in this chapter, PGE discussed a number of factors and indicators that require consideration when evaluating potential strategies for achieving RPS compliance (future changes in environmental policy, resource availability, technological innovations, etc.). PGE examines six general roles the REC bank may potentially play, including:

1. <u>Mitigating timing differences in acquiring and constructing new renewable generation</u> – As discussed previously in this 2013 IRP Update, changes in national environmental policy may have a significant impact to the future cost and availability of both renewable and non-renewable resources. While PGE does not reflect any potential requirements arising from the CPP in this RPS compliance strategy discussion, other emissions

constraints and costs (such as a state- or regional-level CO_2 tax) could have impacts similar to the Clean Power Plan. Where incremental RPS obligations do exist outside of any CPP needs, maintaining a REC bank balance allows PGE the flexibility to adjust the timing of that resource action.

2. <u>Acting as a temporary alternative to physical supply in the event of adverse market conditions (e.g., an RFP results in unsatisfactory RPS resource options)</u> – Section 3.3 addresses several factors potentially leading to increased competition or reduced availability of quality renewable resource sites. Unless offset by other developments, these factors could result in higher costs and reduced capacity factors for renewable resources in the future. An RFP process would likely reflect these results. If that were to be the case, a REC bank balance of sufficient size provides PGE the option to defer resource selection and re-run an RFP process with the goal of achieving a better result for customers.

3. <u>Replacing RECs from physical resources generating at levels less than forecast (e.g., below forecast wind year)</u> – PGE's current RPS resource portfolio is predominantly composed of wind resources. Developing a long-run RPS compliance strategy relies on a forecast of the generation from these resources. The actual amount of wind generation is inherently uncertain and will likely exceed or fall short of the forecast in each RPS compliance period. The ability to draw from the existing REC bank allows PGE to maintain RPS compliance during times of relative under-generation.

4. <u>Aligning timing differences in acquiring and constructing new renewable generation with tax policy</u> – As discussed in Section 2.4 and 3.3, PGE believes that federal subsidies to the renewable energy sector will continue for the foreseeable future. While changes in tax policy are not a factor directly influencing the RPS compliance strategy in this IRP Update, the benefits of additional flexibility with regard to the timing of resource actions discussed in "1" above apply here as well.

5. <u>Providing a temporary means of compliance with increased RPS targets (beyond those currently enacted)</u> – Section 3.3 provides information regarding Oregon's current RPS requirements, as well as the potential for increases to those compliance targets. If PGE's obligations under the Oregon RPS increase, the existing REC bank will be a valuable tool to maintain compliance on a short-term basis as long-term compliance strategies are pursued.

6. Filling the incremental RPS compliance obligation resulting from retail load growing more quickly than forecast – Similar to the reliance on a long-term generation forecast for RPS resources as discussed above in "3", as PGE's annual RPS obligations are a function of retail load, an RPS compliance strategy also relies on a long-run load forecast. The amount of load that will actually materialize will either exceed or fall short of the forecast in each RPS compliance period. The ability to draw from the existing REC bank allows PGE to maintain RPS compliance during times of relatively high load growth.

Scenarios which assess the potential magnitude for each of these risk factors, given PGE's current resource portfolio and the current Oregon RPS targets, are quantified in **Table 3-3** below.

Risks related to in-service dates for future RPS resources (factors 1, 2, and 4 above) are represented by a need for banked RECs sufficient to cover the incremental RECs associated with that resource for one year. For example, the amount associated with the "2020-2024" window in **Table 3-3** below (95 MWa) is equivalent to PGE's current projected incremental need to achieve 2020 RPS compliance presented in **Figure 3-1** above. The amounts for the "2025-2029" and "2030+" time periods assume that compliance was achieved for the prior periods (i.e., they reflect the incremental need for that period). It is also possible that an RFP resulting in sub-par bids could create a delay of more than one year.

To assess the risk of under-generation relative to forecast (factor 3), PGE assumes RPS resources under-generate by approximately 22 percent (approximately the largest consecutive 12-month difference between actual and forecast generation wind experienced by PGE to-date). This 22 percent under-forecast generation is applied to existing wind and assumes that a wind resource is used to achieve RPS compliance in each period.

For this exercise, PGE estimated the magnitude of a future RPS increase, beyond those currently enacted (factor 5), to result in a five percentage point increase in the annual REC need. Future increases to the current RPS targets could materially exceed this five percentage point level, which creates additional exposure for PGE and points to the need for a larger bank.

Finally, to assess the REC demands associated with a high load growth scenario for one year relative to the base forecast (factor 6), PGE relied on the difference in the year-over-year growth rates of PGE's reference case and high load growth scenarios. **Table 3-3** below summarizes the results of these sensitivities to provide context to the potential risks posed by depleting the REC bank. The "worst year", given these exposures, adjusts the "total exposure" to account for the mutual exclusivity of a resource being both the subject of an in-service date delay and under-generation relative to forecast. This adjustment applies a one-period lag to the under-generation effect.

Table 3-3: Example of Risk Factors Influencing REC Bank Needs (MWa)

Risk Factor	2015-2019	2020-2024	2025-2029	2030+
1 / 2 / 4. RPS resource in-service date	-	95	148	47
3. Generation < forecast	59	80	112	120
5. Future RPS increase	-	111	118	126
6. Load growth > forecast	6	10	12	12
Total Exposure to Risk Factors (MWa)	**65**	**296**	**390**	**304**
Potential "Worst" Year (MWa)	**65**	**275**	**358**	**296**

As the existing REC bank is finite in nature, a strategy that relies on drawing down the current bank is not a viable long-run means for meeting RPS obligations. However, the REC bank does represent a valuable tool for ensuring flexibility in implementing PGE's RPS strategy over time. The factors discussed above lead PGE to recommend maintaining a minimum REC balance sufficient to cover one- to two-years' worth of event risks over the 2020-2024 planning horizon, or approximately 300-600 MWa.[60]

3.5 RPS Recommendation

Our evaluation of multiple RPS compliance strategies shows that deferring the addition of a physical resource results in lower net portfolio cost.

However, for the reasons cited throughout this chapter, a number of factors represent risks that may require PGE to rely on the current REC bank in future periods, including the potential for Oregon's RPS targets to increase materially relative to the targets currently in place. Based on these factors PGE intends to maintain a minimum REC bank balance of 300–600 MWa. Based on a minimum REC bank balance of 300–600 MWa, PGE concludes a physical renewable resource addition in 2024, balanced by reliance on banked RECs through 2023, enables PGE to delay costs of physical compliance in 2020. This strategy provides a hedge against factors that pose future cost or compliance risks for PGE.

[60] 275 MWa from Potential "Worst" Year multiplied by two years equals 550 MWa.