SB 1547 (2016): IMPACT OF INCREASED RENEWABLE PORTFOLIO REQUIREMENTS

2021 Report to the Oregon Legislature

Oregon Public Utility Commission

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Executive Summary

In 2016, the Oregon Legislature enacted Senate Bill (SB) 1547 that, among other things, increased the state's renewable portfolio standards (RPS) for electricity providers. The bill also requires the Oregon Public Utility Commission (PUC) to conduct an investigation and report to the Legislature on the impact of the increased RPS requirements on (1) rates; (2) greenhouse gas emissions; (3) electrical system reliability; (4) allocation of risk between electric utilities and their customers; (5) cost recovery for the generation of qualifying electricity; (6) resource procurement process; and (7) forecasting of and rate treatment of projected state and federal production tax credits.

The PUC has concluded its investigation and presents the following findings and recommendations:

1. Rates

Although utilities have significantly grown the amount of renewables in their resource mix since the original passage of the RPS back in 2007, the impact on customer rates from the SB 1547 increase in RPS compliance obligations in 2016 has been minimal for Portland General Electric Company (PGE) and non-existent for PacifiCorp, dba Pacific Power. PGE has acquired only one facility since the passage of SB 1547 for the purposes of RPS compliance—that company's hybrid Wheatridge project that added approximately $15.5 million to PGE's revenue requirement. Since the passage of SB 1547, PacifiCorp has acquired no new renewable generation facilities to satisfy the increased RPS compliance needs.

2. Greenhouse Gas Emissions

At this time the PUC lacks the data to determine the extent to which SB 1547's increase in RPS compliance obligations has impacted Greenhouse Gas (GHG) emissions from either PGE or PacifiCorp. As noted above, the passage of SB 1547 has not resulted in significant resource acquisitions for Oregon's two largest electric utilities. We note that, despite the increased RPS mandates of SB 1547, data reported to the Department of Environmental Quality indicates no near-term impact on their GHG emissions. In fact, since 2016, emissions have been increasing for PGE and PacifiCorp in both absolute terms and relative to retail sales.

3. Electrical System Reliability

Electrical system reliability for Oregon's investor-owned electric utilities (IOUs) has been relatively unchanged since the passage of SB 1547. Data reported to the PUC from the IOUs shows that customers of the IOUs have seen no significant increase or decrease in service reliability from 2014 to 2020.

It is important to note, however, that this data shows only the performance of the distribution system, and does not reveal the isolated impact of any one potential factor that might impact reliability, such as the increased RPS requirements enacted in SB 1547.

4. *Allocation of Risk Between Electric Companies & Customers*

With its favorable treatment for utility recovery of costs to comply with the increased RPS requirements, SB 1547 potentially shifts some risk to customers. The PUC, however, has broad ratemaking authority to address and account for any potential shift in risk.

5. *Eligibility & Timing of Cost Recovery for the Generation of Qualifying Electricity*

The changes to the RPS compliance obligation created in SB 1547 have had no discernable impact on the eligibility and timing of cost recovery for the generation of qualifying electricity. Both PGE and PacifiCorp continue to make regular filings for the timely recovery of prudently incurred costs.

6. *Resource Procurement Process*

The changes to the RPS compliance obligation created in SB 1547 have had no discernable impact on the process to acquire renewable resources. Both PGE and PacifiCorp have continued to acquire large, utility-scale resources for serving retail load through the PUC's competitive bidding process.

7. *Forecasting of State & Federal Production Tax Credits*

At this time there are no state production tax credits for RPS eligible resources. The Federal Production Tax Credit (PTC), however, still exists. For 2022, PGE has forecasted over $45 million in PTCs annually, and PacifiCorp has forecasted the Oregon allocated revenues from PTCs to be $68.4 million. Due to Oregon's approach to the utilities' recovery of power costs, 100 percent of the PTC benefits for both PGE and PacifiCorp are generally realized regardless of wind power production or other potential mitigating factors.

Recommended Legislation

The PUC respectively requests the Oregon legislature consider eliminating the requirement that electricity providers file implementation plans under ORS 469A.075 (while retaining the annual compliance reports under ORS 469A.170.) The legislature may also want to holistically examine the interplay of the RPS requirements with recently enacted clean energy legislation in House Bill 2021 (2021) to ensure the state can implement its energy policies in an efficient and effective manner.

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The Oregon PUC

The PUC's mission is to ensure that Oregon utility customers have access to safe, reliable and high-quality utility services at just and reasonable rates. We perform quasi-judicial functions involving robust analysis and independent decision-making through deliberative, litigated processes. Our agency also exercises discretion to interpret and incorporate executive and legislative priorities into rules, utility planning, and customer programs.

Our agency is led by a full-time, three-member Commission appointed by the Governor and confirmed by the Senate. With approximately 80 subject-matter experts in utility operations and regulatory policy, we regulate three electric utilities, three natural gas utilities, and numerous telecommunications and water utilities. We implement a variety of statutory directives, review detailed technical information, adjudicate legal disputes, and engage with a wide array of stakeholders and policymakers in the energy, telecommunications, and water sectors across the state.

Senate Bill 1547

In 2016, the Oregon Legislature enacted Senate Bill (SB) 1547 that, among other things, increased the state's renewable portfolio standards (RPS) for electricity providers. Specifically, building on original legislation passed in 2007 that required 25 percent of renewable energy to be used to serve retail customers by 2025. SB 1547 extended and increased the RPS to require that qualifying renewable energy meet the following percentages:

	2011 - 2014	**2015 - 2019**	**2020 – 2024**	**2025 - 2029**	**2030 – 2034**	**2035 – 2039**	**2040**
2007 RPS	5%	15%	20%	25%	25%	25%	25%
SB 1547 RPS	5%	15%	20%	**27%**	**35%**	**45%**	**50%**

Section 27 of SB 1547 requires the PUC to report to the Legislature on the impact of the increased RPS requirements on or before January 1, 2022. Specifically, the PUC is asked to investigate and report on the impacts to:

1. Rates
2. Greenhouse gas emissions
3. Electrical system reliability
4. Allocation of risk between electric utilities and their customers
5. Cost recovery for the generation of qualifying electricity
6. Resource procurement process
7. Forecasting of projected state and federal production tax credits as described in section 18b of SB 1547 and allowing those costs to be included in rates through any variable power cost forecasting process established by the PUC.

In addition, as part of the report, the PUC may make recommendations for legislation.

PUC Investigation

In response to Section 27 of HB 1547, the PUC submits the following information.

1. Rates

The incremental impact on customer rates from the increase in RPS compliance obligations due to SB 1547 has been minimal for PGE and non-existent for PacifiCorp.

Utilities have significantly grown the amount of renewables in their resource mix since the original passage of the RPS back in 2007. This growth has been spurred by the original legislative mandate, as well as the declining costs of the resources. Due to technology improvements and policy drivers, renewable resources—particularly wind and solar—are often the least-cost option for utilities. Thus, decisions to acquire renewables are more frequently driven by economics, rather than regulatory compliance.

Since the passage of SB 1547, PGE has acquired only one facility for the purposes of increased RPS compliance—the company's hybrid Wheatridge project that combines solar, wind, and storage. PGE acquired the resource through a 2018 RFP, and was placed in rates in 2020 initially adding approximately $15.5 million to PGE's revenue requirement. At the time of the Wheatridge renewable facility entering customer rates, it was estimated to increase "cost of service" customer rates by 0.6 percent. For the typical PGE residential customer, this percentage increase raised their bill approximately $0.62 per month. Overall, PGE's *total cost* of all RPS compliance obligations as of 2020 was 3.0 percent of their annual revenue requirement.

While PacifiCorp has completed two RFPs since the passage of SB 1547, none of the new renewable generation facilities were acquired to satisfy the increased RPS compliance needs. In this sense, there has been no additional cost to PacifiCorp ratepayers from SB 1547's increased compliance obligation. PacifiCorp's *total cost* of all RPS compliance obligations as of 2020 was 1.2 percent of their annual revenue requirement.

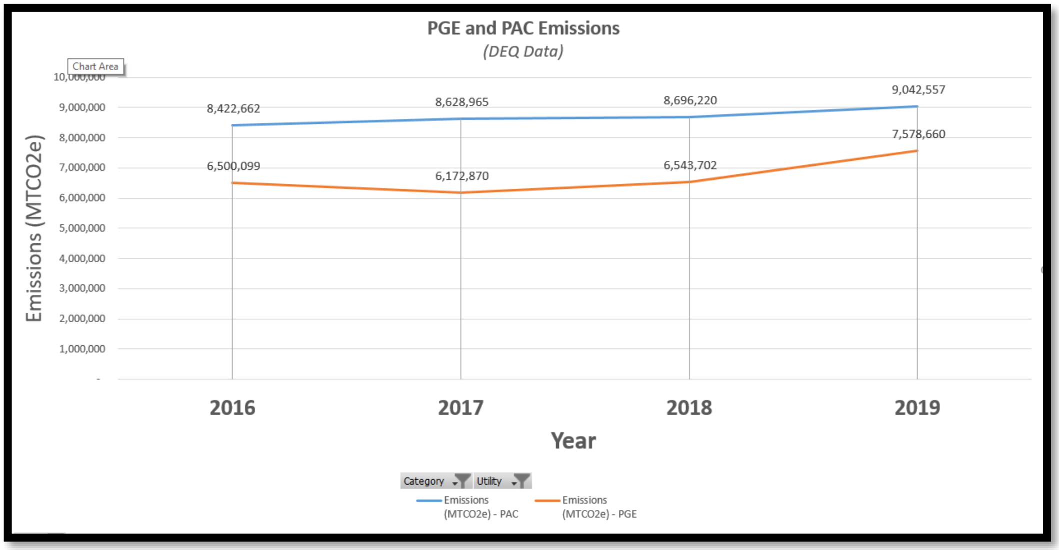
2. Greenhouse Gas Emissions

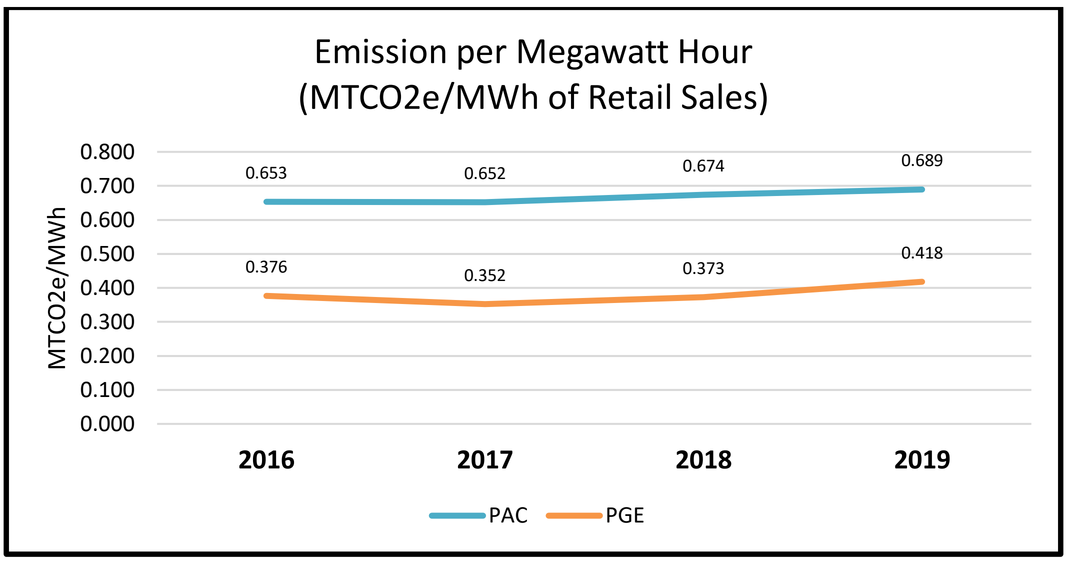
At this time the PUC lacks the data to determine the extent to which SB 1547's increase in RPS compliance obligations has impacted Greenhouse Gas (GHG) emissions from either PGE or PacifiCorp.

As noted above, the passage of SB 1547 has not resulted in significant resource acquisitions for Oregon's two largest electric utilities. PGE acquired the Wheatridge facility, which only recently became operational. There is no publicly available data on how Wheatridge has impacted PGE's overall GHG emissions. For PacifiCorp, as no new facilities were added due to the increase in RPS compliance obligations, we cannot attribute any changes in PacifiCorp's GHG emissions due to SB 1547.

We note that, despite the increased RPS mandates of SB 1547, data reported to the Department of Environmental Quality indicates no near-term impact on their GHG emissions. In fact, since 2016, emissions have been increasing for PGE and PacifiCorp in both absolute terms and relative to retail sales.[1]

[1] *See* Oregon Department of Environmental Quality, GHG Emissions Reported to DEQ, Electricity Suppliers, https://www.oregon.gov/deq/aq/programs/Pages/GHG-Emissions.aspx





The combination of several factors over the next ten years, however, should result in significantly reduced GHG emissions by PGE and PacifiCorp. These factors include:

- The December 2020 retirement of PGE's Boardman coal plant
- The current trend of continual reductions in the prices for wind, solar, and various types of storage technologies
- SB 1547's gradually increasing RPS requirements, which begins in 2025
- SB 1547's elimination of coal from electricity supply, beginning in 2030
- The significant GHG emission reduction targets of House Bill 2021 (2021), beginning in 2030
- New innovations in clean, dispatchable generation technology such as generators capable of using 100 percent green hydrogen and small, modular, nuclear reactors

3. Electrical System Reliability

Electrical system reliability for Oregon's investor-owned electric utilities (IOUs) has been relatively unchanged since the passage of SB 1547. Data reported to the PUC from the IOUs show that customers of the IOUs have seen no significant increase or decrease in service reliability from 2014 to 2020.

The PUC has adopted rules to improve reliability and to ensure the overall robustness and integrity of the distribution systems in Oregon. PUC rules also require the utilities to report reliability data. Accurate data allows meaningful comparisons year-to-year and utility-to-utility. PUC rules conform to the nation's industry standards to evaluate utilities' reliability performance accurately and consistent with practices that other utilities across the nation exercise.

Appendix A to this report is a Seven-Year Electric Service Reliability Statistics Summary (2014-2020) that includes graphical representations of reliability trends of Oregon IOUs' based on four reliability indices. These multi-year graphs, which provide a representation of what Oregon's IOU customers experienced over the past seven years, show no significant trend that demonstrates an overall increase or decrease in service reliability.

Although the PUC can use the information reported by the utilities to track reliability trends, there is no data that would allow us to track the impact of isolated factors on reliability—such as the RPS requirements found in SB 1547. A broad range of variables impact the reliability of electricity supply. These include generation adequacy, condition of power system infrastructure, utility financial and operational performance, weather, and energy sector regulation. The data tracks only the performance of the distribution system—not the impact that various factors may have on reliability.

4. Allocation of Risk Between Customers of Electric Companies & Electric Companies

With its favorable treatment for utility recovery of costs to comply with the increased RPS requirements, SB 1547 potentially shifts some risk to customers. The PUC, however, has broad ratemaking authority to address and account for any potential shift in risk.

SB 1547 mandates the PUC to utilize certain regulatory processes to streamline utility recovery of costs incurred under the bill's increased RPS requirements. Under traditional ratemaking, a utility may only seek to recover costs associated with the acquisition of new resources through a general rate proceeding. In these proceedings, the PUC examines the overall operations of the utility to determine the utility's revenue requirement, and then sets rates among customer classes to allow the utility an opportunity to recover that revenue requirement. Costs associated with new investments are examined, as well as potential cost decreases in other areas of operation.

General rate proceedings are lengthy, nearly a year long, and create a delay in the utility's ability to recover incurred costs. This delay is known as regulatory lag, that is, the time between a utility's request for new rates and the approval of new rates by the PUC. The relationships between regulatory lag, asset life, construction costs, and utility cost recovery have implications for utility management, shareholders and consumers. The risks of delayed recovery is generally born by utility shareholders.

SB 1547 addresses this delay by requiring the PUC to adopt automatic adjustment clauses (AAC) to allow more timely recovery of costs prudently incurred by a utility to comply with the increased RPS requirements. Those provisions, codified in ORS 469.120, confirm that prudently incurred costs associated with complying with the RPS requirements are recoverable by the utility in rates charged to customers. That statute further provides:

> (2)(a) The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission and costs related to associated energy storage.

In response to this mandate, the PUC has created mechanisms that provide for annual forecasting and true-up of costs eligible for recovery under SB 1547. This process allows utilities to recover associated costs with little or no regulatory lag, thus shifting the risk allocation to customers. This also creates a potential mismatch between when a new investment is placed in rates, and when a depreciated investment is removed from rates. New investments are quickly placed in rates through the AACs, but depreciated investments are taken out of rates if and when a utility files a general rate case.

The PUC has broad ratemaking authority, however, to address and account for any potential shift in risk allocation or mismatch in ratemaking. As part of a general rate proceeding, the PUC determines a return on investment based on risks carried by the utility. If the reallocation of risk to customers created by the AAC rate recovery mechanism mandated by SB 1547 is material and significant, the PUC can adjust the utility's authorized return on investment to offset this shift. In addition, the PUC may have the authority to update depreciation rates through the annual AACs to reduce or minimize the mismatch between when investments are added to and removed from rates.

5. Eligibility &Timing of Cost Recovery for the Generation of Qualifying Electricity

In the context of the RPS, ORS 469A.010 defines qualifying electricity as electricity generated from a renewable energy source that may be used to comply with a renewable portfolio standard only if the facility that generates the electricity meets the requirements of statute. ORS 469A.120, enacted as part of the original RPS legislation, further specifies that prudently incurred costs of qualifying electricity are recoverable in rates through an automatic adjustment clause. The changes to the RPS from SB 1547 have had no impact on the eligibility and timing of cost recovery of qualifying electricity. Both utilities continue to operate a renewable adjustment clause, which they utilize for the timely recovery of prudently incurred RPS costs.

6. Resource Procurement Process

The changes the RPS compliance obligation created in SB 1547 have had no discernable impact on the process to acquire renewable resources. Both PGE and PacifiCorp have continued to acquire large, utility-scale resources for serving retail load through the PUC's competitive bidding process.

7. Forecasting of State & Federal Production Tax Credits

At this time there are no state production tax credits for RPS eligible resources. The Federal Production Tax Credit (PTC), however, still exists.

When SB 1547 passed in 2016, the Federal PTC was set to reduce annually from 100 percent in 2016, to 40 percent in 2019, and then expire by 2020. However, the PTC has been extended several times. Most recently, in December 2020 the Federal PTC was extended to the end of 2021 at the 60 percent level. Additionally, President Biden Administration's proposed the "Build Back Better Act" (H.R. 5376) which includes a five year extension of the Federal PTC, to January 2027. This Act includes a new credit structure for projects meeting prevailing wage and apprenticeship requirements, and would also bring back the PTC for solar projects.

With regards to current Federal PTCs, both PGE and PacifiCorp forecast and track the ratepayer benefits through annual power cost filings. For 2022, PGE has forecasted over $45 million in PTC's annually. In 2022 PacifiCorp has forecasted the Oregon allocated revenues from PTCs to be $68.4 million. Due to Oregon's approach to the utilities' recovery of power costs, 100 percent of the PTC benefits for both PGE and PacifiCorp are generally realized regardless of wind power production or other potentially mitigating factors.

Legislative Recommendations

The PUC respectively requests the Oregon legislature consider, in future legislation, eliminating the requirement that electricity providers file implementation plans under ORS 469A.075. The legislature may also want to holistically examine the interplay of the RPS requirements with recently enacted clean energy legislation to ensure the state can implement its energy policies in an efficient and effective manner.

Oregon's clean energy regulatory landscape has changed significantly with the recent passage of House Bill 2021. That bill requires retail electricity providers to file Clean Energy Plans (CEP) and reduce greenhouse gas (GHG) emissions associated with electricity sold to Oregon consumers to:

- 80 percent below baseline emissions levels by 2030
- 90 percent below baseline emissions levels by 2035, and
- 100 percent below baseline emissions levels by 2040

Notably, HB 2021 neither replaces nor modifies the RPS requirements updated in SB 1547.

The administration of two separate but reinforcing regulatory programs will be challenging. To implement HB 2021, the PUC will need to adapt guidelines and rules to incorporate CEPs into the existing integrated resource planning (IRP) processes, as well as consider interactions and resolve potential conflicts with the RPS processes and requirements.

One option to help ease administration of these two regulatory programs would be to eliminate the requirement in the RPS provisions that electric companies file RPS implementation plans at least every two years. *See* ORS 469A.075. The PUC must review and approve the plan within six months through a public process.

The elimination of the RPS implementation plans will not impair compliance with RPS targets, nor prevent the PUC from monitoring the electric companies' progress on renewable targets. First, the existing PUC IRP processes incorporate utility plans to meet all regulatory obligations, including the RPS standards passed in SB 1547. Second, electricity providers subject to the RPS requirements are required, under a separate statutory provision, to make annual compliance filings with the PUC. *See* ORS 469A.170. In these filings, electricity providers must report on compliance and provide information detailing actions taken to meet the targets. Retaining this annual reporting will help the PUC differentiate between costs due to RPS compliance and CEP requirements.

Finally, to help streamline and enhance the coordination of the separate regulatory obligations, the legislature may want to examine the interplay of the RPS requirements with the CEP requirements. For example, both regulatory regimes have cost caps on compliance actions. These cost caps appear to operate in isolation from each other, but questions exist whether the costs caps are cumulative. As currently written, these cost caps are likely to raise questions in their operation, particularly when an electricity provider incurs costs by acquiring a resource that helps meet both the RPS and CEP requirements.