BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2152

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Detailed Depreciation Study of Electric Utility Properties.	MOTION TO ADMIT OF THE STIPULATING PARTIES

Staff of the Oregon Public Utility Commission, Portland General Electric and the Citizens' Utility Board (collectively, the Stipulating Parties) move for admission into the record of this proceeding the following exhibits submitted on behalf of the Stipulating Parties.

Exhibit	Description
Stipulating Parties/201	Colstrip Enabling Study
Stipulating Parties/202	FERC Uniform System of Accounts Prescribed for Public Utilities, Section 22, Depreciation Accounting
Stipulating Parties/203	Portland General Electric Wind Retirements in 2020 and 2021 for FERC Account 344.01.

DATED this 15th day of October 2021.

Respectfully submitted,

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Colstrip Enabling Study

Summary

The purpose of this study (Study) is to respond to the Oregon Public Utility Commission's (Commission) request for further analysis on the impact of the early removal of Colstrip from Portland General Electric Company's (PGE) portfolio. This Study provides an expansion of PGE's 2019 IRP Colstrip sensitivity analysis as well as estimates of near-term customer price impacts. Results from the portfolio analysis suggest the early removal of Colstrip reduces long term costs and economic risks, and the magnitude of those cost and risk savings increase as the portfolio removal date is accelerated. Revenue requirement analysis suggests that accelerating the capital recovery for Colstrip will increase near-term customer prices. These increases can be partially mitigated by extending the recovery period for environmental and decommissioning costs to better align with actual expenditures. In addition to the cost and risk impacts of Colstrip, it is also important to cite the positive impacts associated with reduction of greenhouse gas emissions from PGE's portfolio, which aligns with PGE's evolving customer expectations. These findings rely heavily on forecasts for an aging plant in a changing economic and policy landscape, assume the ability to acquire replacement capacity timely and at a reasonable cost, and assumes a non-adversarial end to the Colstrip co-owners' relationship and no adverse legislative or regulatory actions. While the shared ownership of Colstrip does not allow PGE to act unilaterally and requires unanimous agreement to shut-down a unit, this report is helpful for PGE as it plans for an eventual exit of the plant from its portfolio that mitigates customer and shareholder risks and minimizes customer price impacts.

Background

Consistent with the requirements of SB 1547, portfolio analysis in PGE's 2019 IRP reflected the depreciation of Colstrip Units 3 & 4 by the end of 2030 and the removal of the units from PGE's portfolio by the end of 2034. Additionally, the 2019 IRP included portfolio analysis sensitivities in which Colstrip was removed from PGE's portfolio at the end of 2027 in response to stakeholder requests.[1] The results of the 2019 IRP Colstrip sensitivities showed that the preferred portfolio's Reference Case cost could be lowered if Colstrip units were to leave PGE's portfolio at the end of 2027. These findings suggested there could be economic benefits to removing Colstrip from PGE's portfolio earlier than the end of 2034. The 2019 IRP noted that a full evaluation of potential actions related to Colstrip Units 3 & 4 would require consideration of cost recovery and customer price impact analysis that were not traditionally incorporated into IRP portfolio analysis.

In the 2019 IRP Final Comments, PGE included an update to Colstrip sensitivities' results due to the updated fuel supply contract and updated consultant estimates of depreciation costs.[2] However, there remained considerable uncertainty surrounding the future cost of operating Colstrip both at that time and at present. These factors include uncertainty surrounding carbon pricing legislation in Oregon, and continued operational uncertainty and costs, arising from PGE's limited ability to pursue unilateral

[1] PGE 2019 IRP Section 7.4.2
[2] LC-73 PGE Final Comments Section 5.2

actions related to Colstrip due to long-standing co-owner agreements. Within Final Comments, PGE proposed to conduct an enabling study that would delve into the potential customer rate impacts of options related to Colstrip Units 3 & 4, including, but not limited to, modified depreciation schedules.

Commission Order No. 20-152 acknowledging the IRP[3] accepted Staff, stakeholder and PGE's recommendation to expand the Colstrip IRP analysis and assess the customer price impact of an accelerated exit from the PGE portfolio. A proposed ownership sale, new coal contract and a Washington law requiring the removal of coal by 2025 have increased PGE and stakeholder interest in the plant and PGE appreciates the opportunity to discuss further with stakeholders.

Colstrip

Located in Colstrip, MT, the Colstrip Electric Station is a mine-mouth coal plant originally consisting of four boiler units. Units 3 & 4 began operation in 1984 and 1986 respectively, and each has a generating capacity of about 740 megawatts (MW). PGE's 20% ownership share in Units 3 & 4 represents an aggregated 297 MW of generation capacity. The current plant operator, Talen Montana, also has an ownership interest in Unit 3 and is currently seeking to purchase from Puget Sound Energy an additional 12.5% interest in Unit 4.

PGE entered into an Ownership and Operation Agreement (O&O Agreement) in May of 1982 that defined its rights and obligations relating to Colstrip Units 3 & 4. The O&O Agreement is a multi-party agreement that defines the voting requirements for a variety of actions including budget approval. The multi-party nature of the O&O Agreement limits PGE's ability to unilaterally make decisions or take actions at the plant or end its involvement in the plant.

As noted in Puget Sound Energy's 2017 IRP[4], key contractual provisions include[5]:

- *Ownership is as "tenants in common," without a right of partition, and the obligations of each owner are several and not joint.*
- *Assignment and ownership transfer to third parties is limited, with a right of first refusal for an existing owner to acquire any ownership offered for sale.*
- *The term of the agreements continues for as long as the units are used and useful or to the end of the period permitted by law.*
- *Each owner must provide enough fuel to operate its share of the units at minimum load.*
- *Failing to pay its share of project costs or failing to provide adequate fuel constitutes a default on the part of the owner.*
- *An owner must continue to pay its share of operating costs and coal costs until it has transferred its ownership to another entity.*
- *No single owner has the ability or right to shut down the plant, so to shut down and decommission any unit, all owners of that unit must unanimously agree.*

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[3] Commission Order No. 20-152, available here: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf
[4] https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/IRP17_AppK_083017.pdf
[5] PGE is quoting Puget Sound's summary without adopting it.

- *The ownership contracts do not establish a "put" right for any owner.*

In addition to the O&O Agreement there is a Common Facilities Agreement and separate agreement governing the Colstrip Transmission System.

The current co-owners of Colstrip Units 3 & 4, before completion of the proposed Puget Sound Energy transaction discussed below, and their ownership percentages are as follows:

Co-owner	Unit 3 Share	Unit 4 Share	Total Share
Talen Montana	30%	0%	15%
NorthWestern Energy	0%	30%	15%
Puget Sound Energy	25%	25%	25%
PacifiCorp	10%	10%	10%
PGE	20%	20%	20%
Avista	15%	15%	15%

Puget Sound Energy (PSE), Avista, PacifiCorp (PAC), NorthWestern Energy (NWE) and PGE are all regulated utilities with costs to operate the plant included in retail customer prices as follows:

Co-owner	State	Depreciation End Year
NorthWestern Energy	MT	2042
Puget Sound Energy	WA	2025
PacifiCorp	WA, OR, ID	OR- 2027[6], WA- 2023
PGE	OR	2030[7]
Avista	WA, ID	2025

Unlike the regulated utilities, Talen Montana recovers its costs to operate the plant through sales of its share of generation to wholesale power market participants. The diversity in co-owner business models, regulatory recovery timelines, legislation and stakeholders create an uncertain environment for potential Colstrip closure scenarios.

Recent Events

Unit 1 & 2 Closure

In June of 2019, Talen and PSE announced plans for a closure of Units 1 & 2 by the end of 2019, well ahead of the previously announced closure date of July 2022. While a bit delayed, both units ceased operations in January of 2020.

The closure of Units 1 & 2 has direct impacts on the cost to run Units 3 & 4. Many of the plant's facilities were shared among the four units and the closure of two units did not result in a material reduction to the cost to operate those shared, or common, facilities. The facilities were built to support the

[6] Not yet acknowledged by OPUC
[7] PGE may include in customer prices the costs and benefits associated with Colstrip through the end of 2034

operations of all four units and as units retire, these facilities are often less efficient and therefore more costly. As more units shut down these costs can increase leading to very challenging operating economics. The cost to operate Units 3 & 4 are continually evaluated by the co-owners to ensure efficient operations while also addressing the remaining efforts to support the decommissioning of Units 1 & 2 and common facilities.

The Clean Energy Transformation Act

The Clean Energy Transformation Act (CETA) was passed in Washington in 2019 and requires a Washington utility to eliminate coal-fired electricity from its state portfolio by 2025. Oregon has had Cap and Trade bills introduced at the legislature without success, but conversations continue about carbon limiting legislation in various forms including models like Washington's.

PSE Unit 4 Sale

It was announced in December of 2019 that PSE had entered into a transaction with NWE where it would sell its 25% ownership (185 MWs) in Unit 4 for $1. PSE will then enter into a Power Purchase Agreement (PPA) with NWE to purchase 90 MW of power for a term of approximately 5 years. The PPA will pay for approximately 50% of the $15 million increase in operations and maintenance and property taxes the increased ownership amount would result in for NWE. PSE would remain responsible for all legacy environmental and decommissioning obligations. In addition, PSE would sell an ownership interest in the Colstrip Transmission System representing 95 MW of capacity for book value[8]. In April of 2020 it was announced that Talen exercised its option under the O&O Agreement as a co-owner to join the transaction under the already negotiated terms[9]. If finalized, this would give each of Talen and NWE an additional 12.5% ownership interest in Unit 4, and the shares would appear as follows:

Co-owner	Unit 3 Share	Unit 4 Share	Total Share
Talen Montana	30%	12.5%	21.25%
NorthWestern Energy	0%	42.5%	21.25%
Puget Sound Energy	25%	0%	12.5%
PacifiCorp	10%	10%	10%
PGE	20%	20%	20%
Avista	15%	15%	15%

The PSE/NWE/Talen transaction also includes a vote sharing agreement which defines how the parties will vote, with respect to the vote currently controlled by PSE, under the O&O Agreement on items that are either specific to a unit or apply to both units.

[8] http://www.northwesternenergy.com/our-company/media-center/current/news-article/2019/12/10/NorthWestern-Energy-to-acquire-25-share-of-Colstrip-Unit-4-from-Puget-Sound-Energy
[9] https://www.mtpr.org/post/talen-energy-wants-colstrip-unit-4-purchase

Coal Supply Agreement

All Colstrip co-owners, except Talen, entered into a coal supply agreement with Westmoreland Mining LLC at the end of 2019 with a term covering 2020 through 2025[10]. This agreement solidified a fuel source for the plant after the bankruptcy of the former mine owner, Westmoreland Coal Co., created uncertainty about the operations of the mine going forward. Coal supply after 2025 remains uncertain and could result in additional cost.

PGE's 2020 AUT reflects the coal prices that were included in the Coal Supply Agreement finalized in December of 2019.

Regulatory Changes

In March of 2020, Avista received a Rate Case Order from the Washington Utilities and Transportation Commission (WUTC) adopting a partial multiparty settlement that included multiple Colstrip related provisions[11]. Both Units 3 & 4 depreciation schedules were accelerated to 2025 with decommissioning and remediation costs recovered over an extended timeframe reflecting the expected actual expenditure of those costs. Avista agreed not to support capital expenditures that extend the plant's operational life beyond December 31, 2025 and to fund a Colstrip Community Transition fund with $3 million. Transition funds are discussed in more detail below.

In July of 2020, WUTC issued a Rate Case Order that authorized a rate increase for PSE's electric operations.[12] Included in this rate increase was an acceleration of the recovery of Colstrip Units 3 & 4 to 2025 through updated depreciation schedules. The recovery of decommissioning and remediation costs were included in this schedule update with WUTC requiring PSE to track these costs separately for eventual true-up with actual expenses and further requiring PSE to file a recovery plan, including recovery timing, in its next GRC.

Current Oregon Colstrip Cost Recovery

SB 1547 established the current recovery mechanism for Colstrip, including accelerating capital recovery from customers by the end of 2030. In addition, PGE may include in customer prices the costs and benefits associated with Colstrip through the end of 2034 recognizing that exiting from the plant is challenging given the multi-party nature of the O&O.

The regulatory proceedings that define the current recovery for Colstrip related costs for PGE customers are the 2019 General Rate Case (GRC) and 2020 Annual Update Tariff (AUT) [13]. In addition, the impacts to customer prices of the 2021 AUT are still being determined under that proceeding. Since those dockets and absent an acceleration action, updates to cost estimates have occurred and those updates

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[10] https://westmoreland.com/2019/12/westmoreland-rosebud-mining-llc-announces-new-coal-supply-agreement-for-colstrip-units-34/

[11] Final Order 09, Dockets UE-190334, UG-190335, and UE-190222 (consolidated)

[12] Final Order 08, Dockets UE-190529 and UG-190530 (consolidated)

[13] General Rate Case: Final Order 18-464, Docket UE 335
AUT: Final Order 19-329, Docket UE 359

would be reflected in a new regulatory proceeding when filed resulting in a customer price increase if deemed prudent.

Environmental and Decommissioning Costs

The environmental and decommissioning costs included in the 2019 GRC will be updated to include the most recent studies under the Administrative Order of Consent (AOC) agreed to by the co-owners and Talen , as plant operator, and the Montana Department of Environmental Quality (MDEQ) to address ground water contamination on site. Those studies include a cost increase as approved by MDEQ of the Effluent Holding Pond Remedy Evaluation Report. Those updated amounts result in an approximate $47 million increase to PGE's obligation under the AOC compared to the 2019 GRC estimates. These numbers remain estimates with required remediation actions, including long-term monitoring, occurring beyond the closure of the plant for 50 years. PGE and all co-owners are responsible for the legacy environmental obligations and as the requirements around those obligations change, the impact to customer prices will also change. An example of a potential change in requirements could be a new administration introducing new standards for environmental cleanup.

Updated Capital Investments and Retirements

Since the 2019 GRC, the plant has continued to make capital investments and retire capital components as appropriate. These updated capital assumptions are continually changing and will require updating in PGE's next GRC.

Pension Obligations

Updated actuarial assumptions, market performance and funding plans continue to impact the cost of the pension PGE is obligated to fund under the O&O agreement. The O&O obligations to fund the pension continue beyond the plants exit from PGE's portfolio requiring flexible regulatory recovery.

Analysis Overview

The 2019 IRP included portfolio analysis of two sensitivities where Colstrip was removed from the portfolio by the end of 2027. This enabling study builds on that prior work by introducing additional scenarios and investigating customer price impacts in addition to long term portfolio cost and risk metrics. Because Colstrip has multiple co-owners subject to the O&O Agreement, the ability to effectuate a removal from PGE's portfolio is challenging. The analysis is presented as informational with the ability to accomplish any given scenario highly dependent upon a combination of regulatory, commercial, and/or legislative actions.

Results suggest that portfolio cost and risk decrease when Colstrip is removed from the portfolio. Further, these cost and risk reductions grow in magnitude as the removal date is accelerated. Revenue requirement analysis suggests accelerating the capital recovery for Colstrip will increase near term customer prices. These initial increases can be partially mitigated through extending the recovery period for environmental and decommissioning costs as well as potentially removing units from the portfolio on different timelines.

Scenarios

Consistent with the requirements of SB 1547, PGE's current cost recovery framework includes the recovery of depreciation through the end of 2030 and the requirement to have all costs removed from customer prices by the end of 2034. As part of this Study, PGE evaluated the following alternative scenarios:

Scenario	Depreciation End Year	Last Year in PGE Portfolio
2025	2025	2025
2025 (+4)	2025	2029
2027	2027	2027
2027 (+4)	2027	2031
Unit 3 2025, Unit 4 2027	Unit 3 2025, Unit 4 2027	Unit 3 2025, Unit 4 2027
Unit 3 2025, Unit 4 2030	Unit 3 2025, Unit 4 2030	Unit 3 2025, Unit 4 2030

As part of the customer price impact analysis, this report also includes a sensitivity that better aligns the recovery of environmental and decommissioning liabilities with actual expenditures. The overall impact of this sensitivity is that those dollars are recovered over a longer duration than the depreciation, which reduces the near-term impacts of a Colstrip acceleration decision on customer prices.

Customer Price Impact

This Study uses revenue requirement modeling methodology to estimate how the timing of Colstrip's removal from the Company's resource mix would impact customer prices. The scenarios evaluated in this Study are compared to the status quo, which includes full capital and environmental & decommissioning cost recovery by the end of 2030 and the full removal of Colstrip from customer prices by 2035. This base scenario uses the environmental and decommissioning costs per the 2019 GRC to illustrate a critical point: *even without an acceleration of Colstrip recovery, customer prices will increase due to the increased environmental & decommissioning costs.*

The Assumptions made in this study are summarized in Table 1 below. Compared to the analysis in the 2019 IRP, this model includes key updates to the environmental and decommissioning cost, operations and maintenance budgets, transmission tariffs, book value, tax value, depreciation and financial parameters. These components change throughout the IRP process and have significant potential impacts to customer prices.

Table 1: Customer Price Analysis Assumptions

Customer Price Analysis Assumptions[14]	
Start Year	2022
Future Wholesale Market Price Vintage	2019 H2[15]
Carbon Pricing	Consistent with the 2019 IRP, carbon pricing starts in 2021 and is included in all scenarios

[14] These assumptions apply to the Customer Price Impact section and not necessarily the Portfolio Analysis section.

[15] These prices were included in PGE's most recent avoided cost filing, Order 20-171, Docket UM 1728

	except those that are specified to not include carbon prices[16]
Financial Parameters	From Q2 2020
Operations and Maintenance Budget[17]	2020 Budget
Replacement Capacity	IRP proxy capacity resource[18]
Capital included in acceleration	Assets associated with the Colstrip plant, not the transmission system

Results are expressed as the percentage customer price impact in any given year above or below the status quo and the amounts do not compound year over year. The denominator for this calculation is the estimated revenue requirement as of December 31st, 2021. This amount is held constant throughout the analysis as additional changes to customer prices are unknown at this time.

Accelerated Capital Cost Recovery

Accelerating the capital cost recovery may enable PGE to remove Colstrip from its portfolio at an earlier date, but it would have a near term customer price impact. Figure 1 below shows the impact to customer prices if PGE were to accelerate the depreciation of both units and remove the plant from customers prices in 2025 or 2027. This would require an updated schedule for the recovery of capital investment through depreciation. Both scenarios show a near term price increase representing the increase in depreciation required to fully recover the capital costs of the plant over a shorter period than currently contemplated in customer prices. After the units exit PGE's portfolio in 2025 or 2027, the analysis assumes that PGE would replace the capacity Colstrip provided with the proxy resource modeled in the IRP, a Simple Cycle Combustion Turbine (SCCT) with a levelized cost of $103/kW-yr. Replacing the plant with the proxy resource results in a price decrease in comparison to continued operations of Colstrip from 2025 or 2027 through 2034. This is because the proxy resource is anticipated to cost PGE's customers less than the continued operation of Colstrip. The base scenario in Figure 1 includes an increase to the status quo due to more current estimates of environmental and decommissioning expenses not yet included in customer prices.

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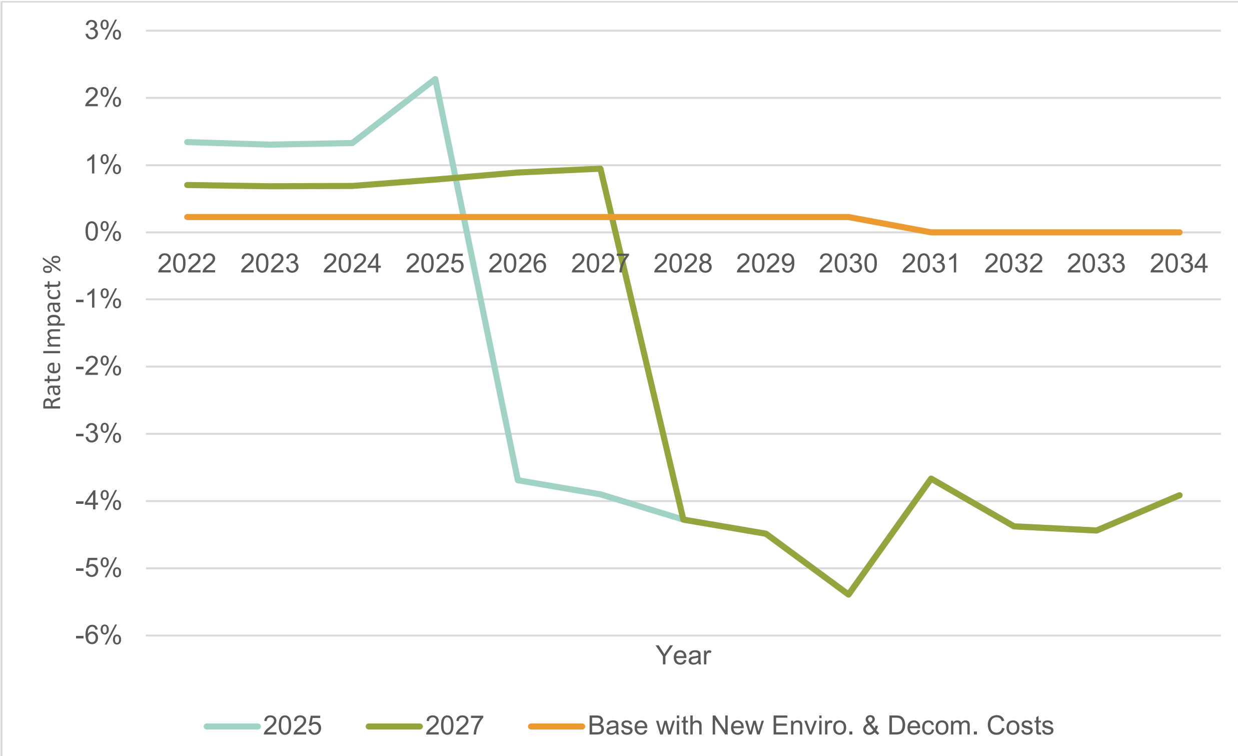
[16] While it is unlikely that a carbon regime is realized starting in 2021, the analysis begins in 2022 when carbon pricing may still be realized through the 2021 legislative session. Additionally, PGE provides a sensitivity that examines customer price impacts without a carbon regime.
[17] The 2019 operations and maintenance budget is utilized across all scenarios to maintain consistency.
[18] See 2019 IRP, Section 7.1.1.1 - Resource Adequacy: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2019-integrated-resource-plan.pdf?la=en

Figure 1: Accelerated Recovery Estimated Price Impact



The increase in price impact seen in 2025 in the 2025 scenario is due to the accelerated recovery of capital assets that are assumed to be put into service towards the end of the recovery window. There is a similar increase in the last year of recovery in the 2027 scenario, but it is not as large as estimated capital expenditures during that period are smaller based on current outage frequency and planning. The uncertainty around these capital investments and outages is high but because there are multiples owners of the plant, PGE is unable to unilaterally control budget decisions at any point along the plant's lifecycle.

An example of why there is uncertainty surrounding ongoing capital expenses is Avista[19] agreeing to not support projects that extend the plant's operational life beyond December 31, 2025. Other Washington utilities may also have similar realities and not support decisions to operate the plant beyond 2025. It is possible that the large repairs and outages forecasted today do not have the voting support required for implementation. In that instance the customer price increases in the 2025 and 2027 scenarios would not be as significant as there would be less capital to recover in the shortened time frame.

Continued Plant Operations Sensitivity

The current recovery mechanism established in SB 1547 allows for the recovery of non-capital Colstrip costs until the end of 2034, after the year it is fully depreciated. In line with the structure established in that legislation, PGE presents the impact on customer prices of keeping non-capital costs in customer prices four years after the plant is fully depreciated but notes that without a change in legislation this

[19] Final Order 09, Dockets UE-190334, UG-190335, and UE-190222 (consolidated)

option is available until 2034. These are the 2025 (+4) and 2027 (+4) scenarios. Figure 2 illustrates the price impact difference between continuing to operate the plant for four years after the units are fully depreciated and replacing the plant with another capacity resource after depreciation is complete. The capacity resource replacement is the same used in the 2019 IRP. While in this instance PGE's customers would see a savings compared to continued operation of the plant, there is no guarantee that a capacity resource would be available at that time and what the cost would be.

Figure 2: Estimated Price Impact of Continued Operations

Environmental and Decommissioning Expenses Extension

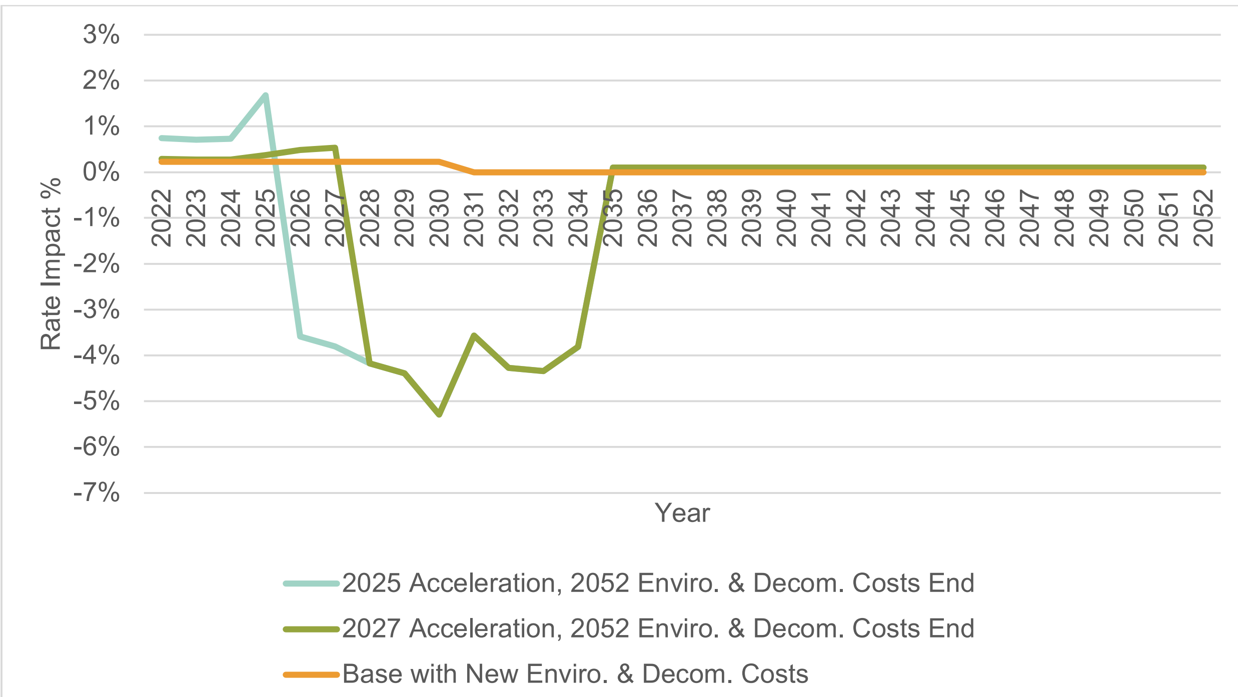
The environmental obligations and decommissioning expenses are a material consideration when evaluating customer price impacts. As addressed above, there has been a significant increase resulting from the MDEQ approving the estimated environmental and decommissioning costs associated with Colstrip, a change subsequent to the estimate included in the 2019 GRC and what is currently included in customer prices. The costs to remediate and decommission are likely to be incurred over an extended timeframe with current plans for expenditure over the next 50 years. A sensitivity to the analysis presented looks at the customer price impact if the recovery of decommissioning and remediation expenses occurred on a timeline that reflected the actual long-term nature of these obligations. For this sensitivity, PGE selected 2052 as the year to complete the recovery of environmental and decommissioning costs which is when most of the material expenditures are expected to have occurred. Extending the recovery reduces the near-term customer price impacts associated with the $47 million increase from the updated estimate of these expenses. By extending the timeline in which PGE recovers the decommissioning and environmental obligations until 2052, PGE estimates a decrease in the annual price impact percentage from 0.4%-0.6% depending on the acceleration scenario, as can be seen in

Table 2 and Figure 3 below. This decrease in comparison to the 2025 and 2027 scenarios is only during the capital recovery term and is the same amount each year until the capital is fully recovered.

Table 2: Reduction in Price Increase due to Extension of Environmental and Decommissioning Cost Collection

2022 Rate Impact % as Compared to Status Quo			
Capital Recovery End Year	Standard ARO Collection	Extended ARO Collection	Reduction in Price Increase
2025	1.34%	0.74%	0.60%
2027	0.70%	0.29%	0.41%

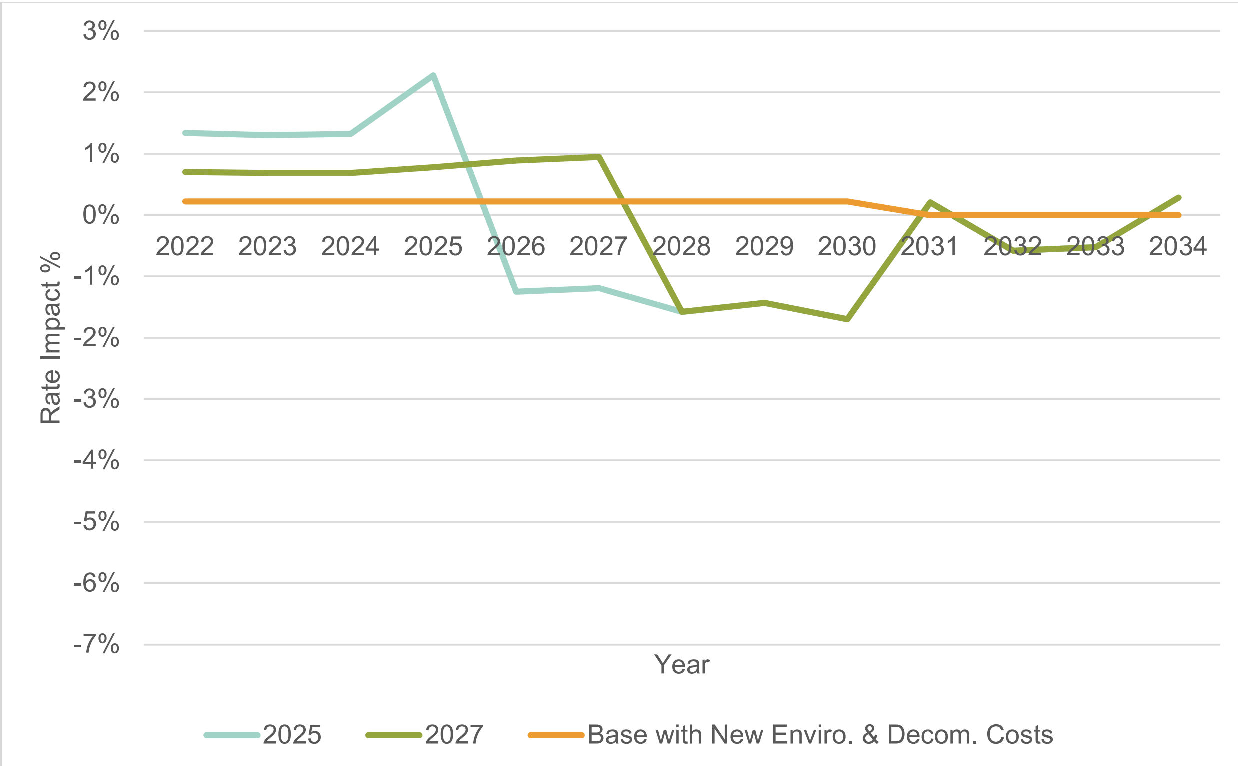
Figure 3: Estimated Price Impact of Extension of the Collection of Environmental and Decommissioning Costs



Carbon Price Assumptions

Colstrip's output is particularly sensitive to carbon pricing due to the high emissions rate of the plant. In scenarios with carbon pricing, Colstrip only dispatches, pursuant to its O&O Agreement, to its contractually required minimum generation level. To provide another perspective, the Company did additional analysis to include Colstrip's dispatch without the impact of carbon pricing. As illustrated in Figure 4 below, the near-term price impacts are similar to those with carbon pricing. The key difference occurs after the scenarios show Colstrip as fully depreciated and removed from customer prices. Since the plant would have been generating more MWhs and operating at a higher cost efficiency, replacing Colstrip with another resource in 2025 or 2027 is not as economic as it is when there is carbon pricing, but it still presents cost savings for customers compared to continued operation of the plant.

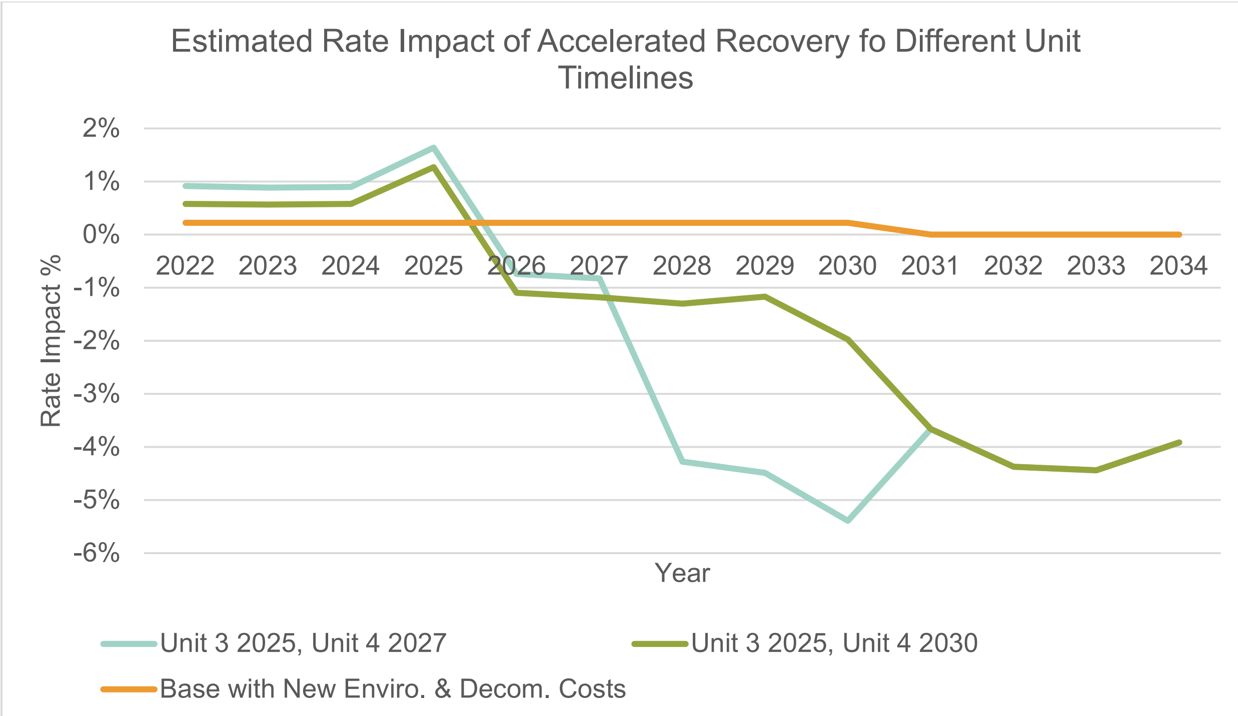
Figure 4: Estimated Price Impact of Acceleration with No Carbon Pricing



Individual Retirement Timelines for each Unit

Colstrip's co-owners have diversity in ownership, business practice, emissions goals, and regulatory processes. As a result, there could be an instance in which units 3 & 4 are removed from PGE's resource mix on different timelines. To investigate this option PGE looked at a scenario in which Unit 3 is depreciated and is removed from PGE's resource mix in advance of Unit 4. At this time the data to accurately estimate the cost of running one unit only is not readily available or easy to calculate due to uncertain impacts on shared and common facilities as well as workforce, so costs were assumed to be evenly split in the instance that one unit leaves PGE's portfolio before another. In practice, it is likely that running only one unit increases the cost of that unit due to lost efficiencies which may make the scenario impractical. Accelerating the capital recover for each unit on different timelines spreads the accelerated depreciation over a longer time horizon resulting in a lower year over year impact to customer prices.

Figure 5: Estimated Price Impact of Accelerated Recovery for Different Unit Timelines



Uncertainties

Overall, the results from all scenarios suggest that accelerating the capital recovery of the Colstrip units will yield price increases for customers that vary between 0.3%-2.4% during the years of the acceleration. Those increases can be reduced by extending the recovery timeframe for the asset retirement obligation and potentially having units removed from PGE's portfolio at different times. However, the figures provided in the Customer Price Impact portion of the study have a high degree of uncertainty because of the period of time examined. This customer price impact analysis relies on five and ten-year budget estimates from Talen, the plant operator. Long-term budgeting is inherently difficult and does not contemplate any unforeseen changes to plant operations or costs during a period of time in which Washington co-owners are legally required to remove Colstrip from their portfolios and other co-owners are anticipating a longer plant life. Additionally, changes in power market conditions and state legislation may change the plant dispatch and impact the cost to maintain.

Portfolio Analysis

As discussed in the Background section above, sensitivities in which Colstrip units 3 & 4 were removed from the PGE Portfolio before the end of 2034 were included in both the 2019 IRP and LC-73 Final Comments. In addition to the expanded set of scenarios considered, this enabling Study also incorporates an update to natural gas price forecasts, which impact wholesale market prices, plant dispatch, and associated GHG emissions. [20]

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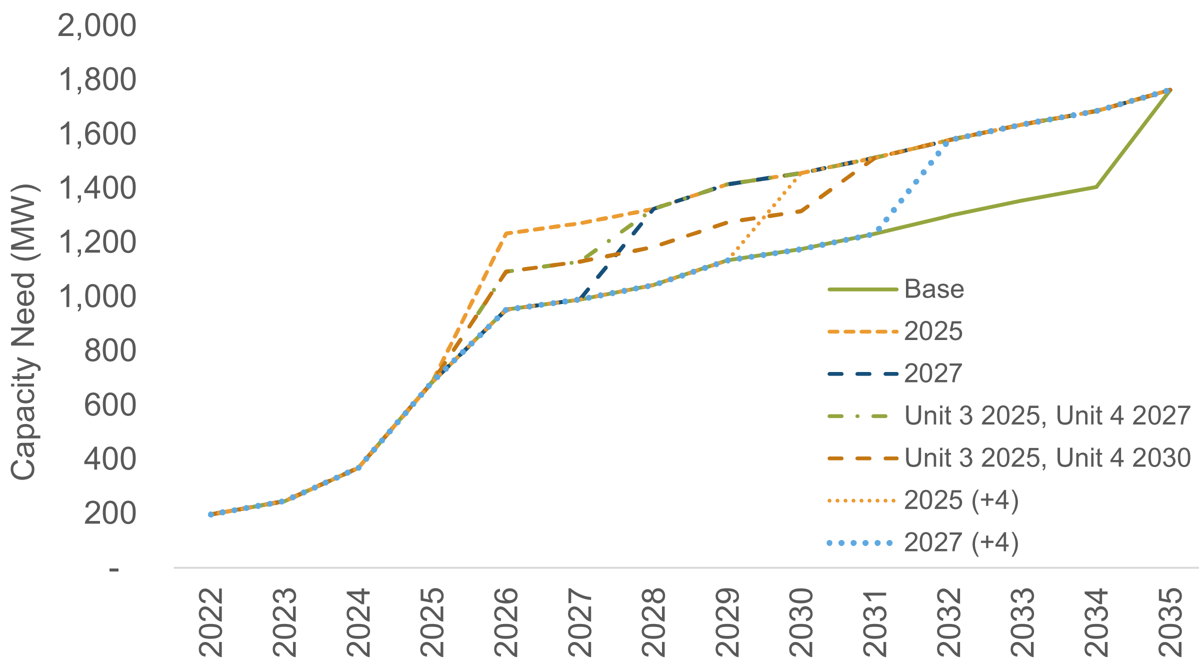
[20] Natural gas prices were updated to the following: PGE 2020 Q1 forward gas trading curve from 2020-2024, Reference Gas Future of Wood Mackenzie 2019 H2 from 2025-2040, High Gas Future of 2020 U.S. Energy Information Agency (EIA) Annual Energy Output (AEO) Low Oil and Gas Supply Case from 2025-2040, Low Gas Future assumes gas prices grow at the rate of

The impact to PGE's capacity need in each sensitivity is shown in Figure 6. The acceleration of Colstrip's removal from PGE's portfolio to an earlier date in scenarios considered brings forward approximately 281 MW[21] of capacity need into the mid-2020's. This is a tangible impact, as this occurs when PGE is likely to experience increased capacity needs due to expiring contracts. Further, it occurs at a time when expected plant retirements will likely increase demand for capacity in the region.

Figure 6: **Capacity Need**[22]



Results

Results from the portfolio analysis consistently suggest that the acceleration of Colstrip's removal from PGE's portfolio lowers long term costs. The updated traditional cost and risk metrics of the preferred portfolio across each Colstrip scenario are shown below in Figure 7 and Table 3 below.[23] Under all scenarios, Reference Case costs are lower relative to the current exit date, as are both risk metrics.

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inflation from 2025-2040. All Gas Futures use 2025 as an interpolation year between the forward gas trading curve and subsequent forecasts. All Gas Futures assume gas prices grow at the rate of inflation from 2040-50. These assumptions are consistent with the 2019 IRP natural gas price treatment but have been updated to more recent forecasts. These prices were included in PGE's most recent avoided cost filing, Order 20-171, Docket UM 1728.

[21] The combined nameplate capacity of PGE's ownership shares in Colstrip Units 3 & 4 is 297 MW, however the estimated capacity contribution to PGE's system (which accounts for forced outage rates) is approximately 281 MW.

[22] The base capacity need used in this analysis is calculated from the filed 2019 IRP. The updated needs assessment filed in December 2019 (available here: https://edocs.puc.state.or.us/efdocs/HAH/lc73hah10211.pdf) slightly increased capacity need. Further updated capacity need information, to include the recently signed contract with Douglas County PUD, will be included in the next IRP Update. However, the magnitudes of the differences between the Base Case and each scenario reflected in this figure will remain the same, as these updates will affect each equally.

[23] For a detailed description of IRP portfolio metrics, please see Section 7.2.1 – Scoring Metrics from the 2019 IRP , available here: https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf

When the two Colstrip units leave PGE's portfolio in different years (e.g. 2025/2027), we see cost and risk metrics fall in between the cases where both units are removed from the portfolio in 2025 or 2027.

Given Colstrip's low forecasted dispatch, the evaluation of its removal from PGE's portfolio primarily involves the tradeoff between the fixed and variable costs associated with its continued operation and maintenance (O&M) and the cost of replacing its capacity. The results shown below are reflective of the fact that Colstrip's O&M costs escalate more rapidly than do the costs associated with replacement. Accordingly, earlier removal consistently leads to higher reductions in both Cost and Risk metrics.

Figure 7: Cost and Variability

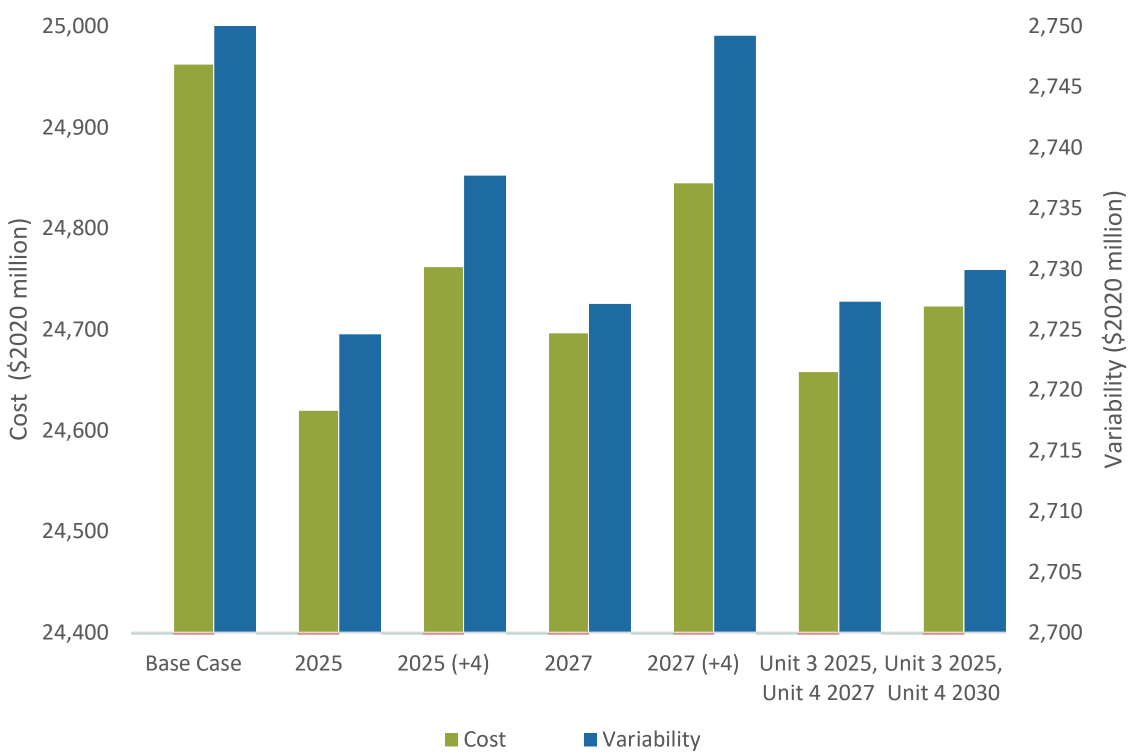
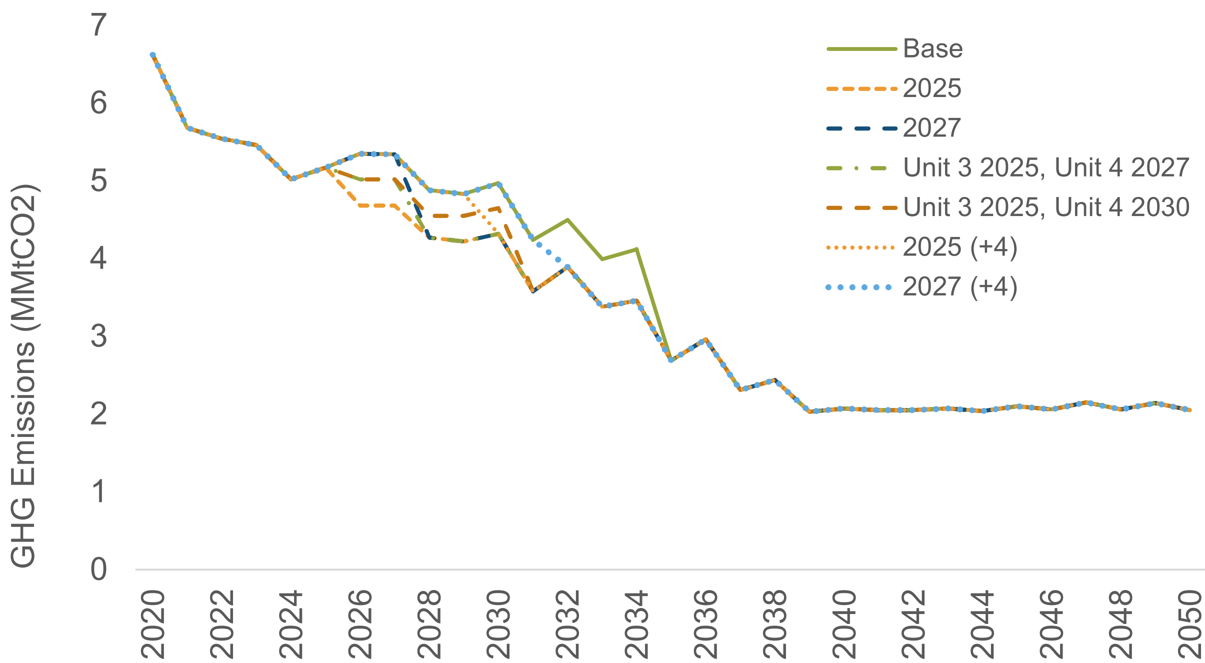


Table 3: Portfolio Scoring Metrics – Difference (Scenario - Base Case)

Scoring metrics (million 2020$)			
Scenario	Cost	Variability	Severity
2025	-343.0	-33.4	-370.8
2025 (+4)	-200.5	-20.3	-219.9
2027	-266.1	-30.9	-291.7
2027 (+4)	-117.5	-8.8	-129.2
Unit 3 2025, Unit 4 2027	-304.6	-30.7	-330.7
Unit 3 2025, Unit 4 2030	-239.5	-28.1	-261.3

Updated GHG emissions from the Colstrip sensitivities are included in Figure 8. Under Reference Case conditions, an early removal of Colstrip from PGE's portfolio continues to result in a reduction of GHG emissions relative to the Base Case.[24]

Figure 8: Emissions



Discussion

Beyond the portfolio costs and price impacts to customers, Colstrip has many subjective or non-quantifiable complexities and risks that require further discussion when determining the best balance of cost and risk for customers, the company, the town of Colstrip, Montana and the employees who work at the Colstrip plant who were integral in delivering many years of reasonably priced and reliable power to our customers.

Greenhouse Gas Emissions

The state of Oregon has set economywide greenhouse gas (GHG) emission reduction goals. HB 3543 (2007) established a 10% GHG reduction below 1990 levels by 2020 and 75% GHG reduction below 1990 levels by 2050. Executive Order No. 20-04 from Gov. Brown (March 2020) addressing climate change expanded these GHG reduction goals to at least 45% below 1990 levels by 2035 and at least 80% below 1990 levels by 2050. The Executive Order directs all state agencies to exercise their broad statutory authority to reduce GHG emissions and specifically directs the PUC to “Prioritize proceedings and activities, to the extent consistent with other legal requirements, that advance decarbonization in the

[24] The base case refers to the preferred portfolio estimated with the inputs and assumptions from the filed 2019 IRP and does not include any changes that have been made since then (such as the PPA with Douglas County PUD). These values will be updated in the next IRP Update.

utility sector." These actions demonstrate the state's commitment to reduce GHG emissions on an economywide basis and in the electric sector specifically. However, Colstrip and the removal of coal from Oregon utility customer prices is only explicitly addressed in SB 1547, which establishes the current framework for investment recovery (2030) and removal from customer prices (2034).

Accelerating the removal of Colstrip from PGE's portfolio certainly advances the state's GHG emissions reduction agenda and may reduce customer risk in a variety of future scenarios. Oregon has seen bills in the Oregon Legislature that would introduce a cap-and-trade program in the state, but the lack of a quorum in the last two legislative sessions has caused these bills not to advance. There is also conversation about a clean energy standard being advanced in the state as either a ballot initiative or introduced at a future Oregon legislative session. If either of these frameworks were to move forward it will increase the costs to run Colstrip once implemented. While the analysis presented in this Study does include some level of carbon cost, the exact details and timing of any future regime are unknown. For this reason, our analysis does not include specific costs or risks associated with the GHG emissions of Colstrip, however this will likely be an increasingly relevant consideration.

Customer Preferences

The Customer Insights Study, which was an enabling study from the acknowledgement of the 2016 IRP, illustrated that our customers, both residential and business customers, expect the Company to transition our resource mix towards more renewable resources. The study also found that coal was the least preferred resource for both PGE residential and business customers surveyed[25].

In addition to surveys to gain insights into our customer preferences, the Company has also seen an increase in local municipalities taking action to address the climate emergency. Of the 51 municipalities in our service territory, 12 have adopted climate action and/or sustainability plans, with other municipalities in active discussions of plan or goal development. Although these plans differ in scope and desired goals and outcomes, all seek to reduce greenhouse gas emissions from municipal operations and/or community-wide emissions. Of the plans and resolutions adopted to date within our service territory, the following municipalities have the most aggressive electricity decarbonization goals:

- Beaverton has committed to achieve net zero emissions for electricity by 2035;
- Milwaukie has committed to achieve net zero emissions for electricity by 2030;
- Portland has committed to meet 100% of community-wide electricity needs with clean, renewable energy by 2030; and
- Multnomah County has committed to meet 100% of community-wide electricity needs with clean, renewable energy by 2035[26].

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[25] https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/msi-customer-insights-study-rt-18-1-2018-02-14.pdf?la=en

[26] Beaverton: Page 32, https://www.beavertonoregon.gov/DocumentCenter/View/27980/Beaverton-Climate-Action-Plan---2019

Milwaukie: https://www.milwaukieoregon.gov/sustainability/climateaction

Removing coal from PGE's resource mix on an accelerated timeframe would be a key step for PGE to help its municipal customers achieve their clean energy goals.

Operational Considerations

The cost to operate and maintain the plant into the future remains uncertain. Material changes to the assumptions in the analysis can occur for a variety of reasons including post- 2025 coal supply costs, the impacts of unexpected repairs and maintenance costs, and increased costs from lost efficiencies upon unit closures.

As previously discussed, the current Coal Supply Agreement's term ends December 31, 2025. The Rosebud mine, the plant's current mine-mouth coal supply, is likely to reevaluate their cost structure, including potentially high cost access to new coal seams, and negotiate increased pricing with the co-owners. An alternative supply of coal would likely introduce additional plant investments and supply chain logistics resulting in higher overall operational costs.

Unit closures will continue to remove efficiencies from the operations of common and shared facilities making continued operations more expensive and potentially uneconomic.

The plant is over 35 years old and may experience outage events requiring repairs in excess of current and future budgets. These costs are not contemplated in the analysis and may be significant if incurred. With differences in co-owner cost recovery timelines and mechanisms, there may not be alignment in the appropriate level of maintenance, capital replacement or both.

Capacity and Resource Adequacy

The above portfolio analysis, consistent with PGE's acknowledged 2019 IRP, illustrates the material capacity need PGE forecasts beginning in the mid-2020's. While many of the assumptions are subject to change, including load projections and contract renewal status, an acceleration of the removal of Colstrip from PGE's portfolio increases needed capacity at a time when the resource adequacy of the region is in question. The analysis assumes replacement of the capacity using the IRP proxy resource but capacity constraints in the region and rapid technological change mean that there is significant uncertainty in future costs for capacity. There is value to customers in minimizing exposure to those uncertainties and there is value in having optionality as conditions change.

Reducing uncertainties will require a PGE commitment to replace the capacity that Colstrip has provided PGE's system for close to four decades[27]. This could be achieved through one or more actions and should contemplate leveraging the existing transmission rights from Colstrip to PGE's system to access high capacity renewables such as Montana wind for PGE customers. Montana wind represents a renewable resource that contributes more capacity to PGE's system (37% ELCC) than Gorge wind

Portland: Page 9, https://www.portlandoregon.gov/auditor/article/763389
Multnomah County: Page 3, https://multco.us/node/34287

[27] The needs associated with Colstrip exiting the portfolio are beyond the current IRP Action Plan and would require additional actions

projects (24% ELCC) or a solar and storage project (20% ELCC[28]) providing a unique opportunity to meaningfully address PGE's capacity need at the same time as acquiring low cost carbon free energy. A second action may require a commitment to a dispatchable resource to be able to ensure reliable supply for PGE customers. Consistent with the findings of the most recent IRP, PGE may consider existing dispatchable capacity or new non-emitting capacity resources, such as battery storage or pumped storage, to meet remaining needs.

Additionally, SB 1547 included a mechanism that allowed for recovery of non-capital costs beyond the date that it will be fully depreciated. With any change to the recovery of depreciation, continuing this mechanism allows optionality for customers to continue to access the plant's benefits helping to provide a capacity option to maintain a reliable power supply if needed.

Exit from PGE Portfolio vs Exit from Plant

As discussed above, the O&O Agreement does not provide any co-owner the ability to unilaterally decide when the plant closes and does not eliminate a co-owner's obligations to pay for fuel and operations until the plant closes. PGE's options for exiting the plant are limited given the plant's age, fuel source and location. The two main vehicles for a potential PGE exit from the plant are:

- Plant Sale - Innately challenged by having to recover remaining investment in plant through purchase price, legacy environmental obligations, and pension obligations. The current co-owner group are the most likely candidates for a purchase and the three Washington co-owners are precluded from recovering the costs of a coal plant beyond 2025.
- Plant Closure - A shutdown of either unit, or both, will require the approval of the co-owners and different recovery mechanisms, operational needs, and policy realities can make consensus on a certain year challenging. Additionally, the closure of one unit may significantly increase the operating cost of the remaining unit making the option challenging.

Commitment to the Colstrip Community (Transition Funds)

Transition funds are common for long-lived assets with large impacts to local communities. To date, Avista has committed $3 million and PSE $10 million[29] to help the people of Colstrip mitigate the economic impact of the plant's eventual closure.

In addition to the jobs that decommissioning and remediation obligations provide, PGE commits to do the right thing for the plant workers and the Colstrip community to address the implications our exit from Colstrip will have on the community that supported PGE and its customers for many years. It will be critical to partner with stakeholders, including labor and the Colstrip Community Impact Advisory Group, to explore options that balance the interest of workers at the plant, the local community and our

[28] See 2019 IRP, Section 6.2.3 – Capacity Value: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2019-integrated-resource-plan.pdf?la=en

[29] https://dojmt.gov/colstrip-receive-minimum-10-million-community-impact-result-rate-case-settlement/

customers. When exploring those options PGE will consider the Colstrip agreements and the impacts that decisions related to Colstrip could have on communities in Montana.

Conclusion

This Study analyzed the impacts to PGE customers on both an overall portfolio cost and customer price impact basis and found that an acceleration of the removal from PGE's portfolio resulted in long-term portfolio cost savings but with near-term customer price impacts. Updates made to the environmental and decommissioning cost estimates since the last GRC will further increase those near-term price impacts. Extending the recovery of the decommissioning and environmental costs to more closely reflect the expenditures is one way to mitigate the price increase customers would experience with an acceleration action. Additionally, retiring each unit over different timeframes mitigates near-term price impacts but is challenged by needing unanimous co-owner approval[30] and may have costly operational realities.

While an acceleration action does advance the state's GHG emissions reduction agenda, it does so at a time when the resource adequacy of the region is in question and PGE is forecasted to have a significant capacity need.

PGE believes the optimal regulatory construct to provide the flexibility for the removal of Colstrip from PGE's portfolio given the multiple complexities to be a two-part solution. Flexibility to act is important but does not guarantee an exit from the plant.

1. **Acceleration of capital recovery to the end of 2025.** Analysis suggests the removal of Colstrip from PGE's portfolio in 2025 provides customers the greatest reduction in the IRP portfolio metrics of cost and risk. This date also aligns with Washington's CETA legislation and the current coal contract, better aligning PGE with several co-owners. Beyond 2025 the uncertainty at the plant materially increases and having the asset fully recovered by this date allows PGE and customers the most flexibility to be able to accommodate any future. This added flexibility will also allow PGE to pursue Montana wind projects that can leverage the Colstrip Transmission System in a more optimal timeframe.
2. **Recovering environmental and decommissioning expenses through the end of 2052.** Acceleration of capital recovery comes at the expense of near-term customer price impacts. Extending the recovery of the environmental and decommissioning expenses mitigates some of these price impacts and better aligns cost recovery with actual expenditures.

[30] Unanimous co-owner approval required for a closure of one or both units.

https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101

Allowances acquired for speculative purposes and identified as such in contemporaneous records at the time of purchase shall be accounted for in Account 124, Other Investments.

B. When purchased allowances become eligible for use in different years, and the allocation of the purchase cost cannot be determined by fair value, the purchase cost allocated to allowances of each vintage shall be determined through use of a present-value based measurement. The interest rate used in the present-value measurement shall be the utility's incremental borrowing rate, in the month in which the allowances are acquired, for a loan with a term similar to the period that it will hold the allowances and in an amount equal to the purchase price.

C. The underlying records supporting Account 158.1 and Account 158.2 shall be maintained in sufficient detail so as to provide the number of allowances and the related cost by vintage year.

D. Issuances from inventory from inventory included in Account 158.1 and Account 158.2 shall be accounted for on a vintage basis using a monthly weighted-average method of cost determination. The cost of eligible allowances not used in the current year shall be transferred to the vintage for the immediately following year.

E. Account 158.1 shall be credited and Account 509, Allowances, debited so that the cost of the allowances to be remitted for the year is charged to expense monthly based on each month's emissions. This may, in certain circumstances, require allocation of the cost of an allowance between months on a fractional basis.

F. In any period in which actual emissions exceed the amount allowable based on eligible allowances owned, the utility shall estimate the cost to acquire the additional allowances needed and charge Account 158.1 with the estimated cost. This estimated cost of future allowance acquisitions shall be credited to Account 158.1 and charged to Account 509 in the same accounting period as the related charge to Account 158.1. Should the actual cost of these allowances differ from the estimated cost, the differences shall be recognized in the then-current period's inventory issuance cost.

G. Any penalties assessed by the Environmental Protection Agency for the emission of excess pollutants shall be charged to Account 426.3, Penalties.

H. Gains on dispositions of allowances, other than allowances held for speculative purposes, shall be accounted for as follows. First, if there is uncertainty as to the regulatory treatment, the gain shall be deferred in Account 254, Other Regulatory Liabilities, pending resolution of the uncertainty. Second, if there is certainty as to the existence of a regulatory liability, the gain will be credited to Account 254, with subsequent recognition in income when reductions in charges to customers occur or the liability is otherwise satisfied. Third, all other gains will be credited to Account 411.8, Gains from Disposition of Allowances. Losses on disposition of allowances, other than allowances held for speculative purposes, shall be accounted for as follows. Losses that qualify as regulatory assets shall be charged directly to Account 182.3, Other Regulatory Assets. All other losses shall be charged to Account 411.9, Losses from Disposition of Allowances. (See Definition No. 30.) Gains or losses on disposition of allowances held for speculative purposes shall be recognized in Account 421, Miscellaneous Nonoperating Income, or Account 426.5, Other Deductions, as appropriate.

22. Depreciation Accounting.

A. Method. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

B. Service lives. Estimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.

C. Rate. Utilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property to the service life of the property. Where composite depreciation rates are used, they should be based on the weighted average estimated useful service lives of the depreciable property comprising the composite group.

23. Accounting for other comprehensive income.

A. Utilities shall record items of other comprehensive income in account 219, Accumulated other comprehensive income. Amounts included in this account shall be maintained by each category of other comprehensive income. Examples of categories of other comprehensive income include, foreign currency items, minimum pension liability adjustments, unrealized gains and losses on available-for-sale type securities and cash flow hedge amounts. Supporting records shall be maintained for account 219 so that the company can readily identify the cumulative amount of other comprehensive income for each item included in this account.

B. When an item of other comprehensive income enters into the determination of net income in the current or subsequent periods, a reclassification adjustment shall be recorded in account 219 to avoid double counting of that amount.

C. When it is probable that an item of other comprehensive income will be included in the development of cost-of-service rates in subsequent periods, that amount of unrealized losses or gains will be recorded in Accounts 182.3 or 254 as appropriate.

24. Accounting for derivative instruments and hedging activities.

A. Utilities shall recognize derivative instruments as either assets or liabilities in the financial statements and measure those instruments at fair value, except those falling within recognized exceptions. Normal purchases or sales are contracts that provide for the purchase or sale of goods that will be delivered in quantities expected to be used or sold by the utility over a reasonable period in the normal course of business. A derivative instrument is a financial instrument or other contract with all of the following characteristics:

(1) It has one or more underlyings and a notional amount or payment provision. Those terms determine the amount of the settlement or settlements, and, in some cases, whether or not a settlement is required.

(2) It requires no initial net investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors.

344 - Wind Plant Retirements

Sum of Activity Cost	Column Labels		
Row Labels	**2020**	**2021**	**Grand Total**
34400-Generator Other Prod	**(221,133)**	**(7,383,551)**	**(7,604,684)**
Biglow Canyon Wind Farm	(149,861)	(5,574,327)	(5,724,188)
Tucannon Wind Facility: 3466	(71,272)	(1,809,224)	(1,880,496)
Grand Total	**(221,133)**	**(7,383,551)**	**(7,604,684)**

"Depr Group Depr Group"	"Major Location Major Location"	"Gl Account Gl Account"
34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
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34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
34400-BIGLOW	Biglow Canyon Wind Farm	1010001 Electric Plant in Service
34400-TUCANNON	Tucannon Wind Facility: 3466	1010001 Electric Plant in Service
34400-TUCANNON	Tucannon Wind Facility: 3466	1010001 Electric Plant in Service
34400-TUCANNON	Tucannon Wind Facility: 3466	1010001 Electric Plant in Service
34400-TUCANNON	Tucannon Wind Facility: 3466	1010001 Electric Plant in Service

"Utility Account Utility Account"	Vintage	"Work Order Control Ldg Work Order Description"
34400-Generator Other Prod	2010	Biglow Canyon Phase 3
34400-Generator Other Prod	2007	Biglow Phase 1 Turbine P-I-S Costs
34400-Generator Other Prod	2007	Biglow Canyon Wind Farm Phase 1
34400-Generator Other Prod	2009	Biglow - Install Avanti Climb Assis
34400-Generator Other Prod	2010	Biglow Canyon Phase 3
34400-Generator Other Prod	2007	Biglow Canyon Wind Farm Phase 1
34400-Generator Other Prod	2007	Biglow Phase 1 Turbine P-I-S Costs
34400-Generator Other Prod	2007	Biglow Phase 1 Turbine P-I-S Costs
34400-Generator Other Prod	2009	Biglow Phase 2 Inservice
34400-Generator Other Prod	2007	Biglow Canyon Wind Farm Phase 1
34400-Generator Other Prod	2010	Biglow Canyon Phase 3
34400-Generator Other Prod	2009	Biglow Phase 2 Inservice
34400-Generator Other Prod	2014	Tucannon: Construct Wind Farm
34400-Generator Other Prod	2014	Tucannon: Construct Wind Farm
34400-Generator Other Prod	2014	Tucannon: Construct Wind Farm
34400-Generator Other Prod	2014	Tucannon: Construct Wind Farm

"Cpr Ledger Ldg Work Order Number"	"Func Class Func Class"	"Ferc Activity Code Ferc Activity Code"	Month Nu	"Cpr Activity Gl Posting Mo Yr"
0000024943	Other Production	Retirement	202102	Feb-21
0000025034	Other Production	Retirement	202105	May-21
0000023993	Other Production	Retirement	202102	Feb-21
0000025983	Other Production	Retirement	202007	Jul-20
0000024943	Other Production	Retirement	202103	Mar-21
0000023993	Other Production	Retirement	202006	Jun-20
0000025034	Other Production	Retirement	202102	Feb-21
0000025034	Other Production	Retirement	202006	Jun-20
0000026263	Other Production	Retirement	202102	Feb-21
0000023993	Other Production	Retirement	202103	Mar-21
0000024943	Other Production	Retirement	202011	Nov-20
0000026263	Other Production	Retirement	202105	May-21
1000003455	Other Production	Retirement	202103	Mar-21
1000003455	Other Production	Retirement	202105	May-21
1000003455	Other Production	Retirement	202102	Feb-21
1000003455	Other Production	Retirement	202006	Jun-20

Activity Qu	Activity Cost	Average Cost	Second Financial Cost
0	($1,050,955.20)	$0.00	$0.00
0	($252,407.02)	$0.00	$0.00
0	($1,870,377.00)	$0.00	$0.00
-1	($4,847.09)	$4,847.09	$0.00
0	$0.00	$0.00	$0.00
0	($48,130.80)	$0.00	$0.00
0	($930,493.92)	$0.00	$0.00
0	($49,025.00)	$0.00	$0.00
0	($1,584,368.89)	$0.00	$0.00
0	$200,090.68	$0.00	$0.00
0	($47,858.41)	$0.00	$0.00
0	($85,815.57)	$0.00	$0.00
0	($487,705.26)	$0.00	$0.00
0	($101,224.83)	$0.00	$0.00
0	($1,220,293.74)	$0.00	$0.00
0	($71,271.71)	$0.00	$0.00

203