APPENDIX F

APPENDIX F - ORIGINAL AND REFILED RESOURCE SELECTION AND EVALUATION STEPS

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Overview

PacifiCorp's 2021 CEIP complied with CETA's SCGHG requirements by analyzing Washington-specific resource decisions under SCGHG generation cost assumptions, and then analyzing the resulting portfolio under expected MM conditions. This analysis revealed that the portfolio selections for Washington customers using SCGHG, labeled "P02-SCGHG," were virtually identical to the resource selections in the Company's least-cost, least-risk expected case, labeled "P02-MM," that served as the basis for the 2021 IRP preferred portfolio. This led the Company to use P02-MM as the basis of the preferred portfolio, and incorporate Washington resource selections from the P02-SCGHG portfolio, to arrive at a final CETA portfolio, labeled "P02-MM-CETA."

Using P02-MM as the basis for the preferred portfolio, while still incorporating Washington resources selections from the SCGHG portfolio, provided several advantages. First, resource selections for all other states were not impacted. Second, resources selected for Washington would be represented as dispatched under expected real-world conditions, because at the time the Company filed the 2021 CEIP (and for the foreseeable future), Washington customer rates do not reflect the SCGHG. P02-MM mitigated misrepresenting portfolio performance and operational risk that otherwise would occur under SCGHG. Third, evaluating resources under expected conditions avoided artificially depressing the dispatch of emitting resources, which in turn accelerates and increases the need for additional renewables for real-world CETA compliance and reduces compliance risk.

This means that P02-MM, when adjusted for CETA compliance, was less costly, less risky, and resulted in higher renewable selections for the state compared to P02-SCGHG.

That said, this Revised CEIP presents another reasonable interpretation of CETA, where the entirety of "P02-SC-CETA" is adopted for evaluating dispatch, emissions and incremental costs that result from applying the SCGHG as a dispatch adder. While the resulting preferred portfolio from P02-SC-CETA is largely unchanged from P02-MM-CETA, the assumed operations of resources are different due to applying the SCGHG as a dispatch adder for all purposes. This results in two primary differences between the Company's 2021 CEIP and Revised CEIP: (1) incremental costs are higher in the Revised CEIP, and (2) renewable incremental resources to achieve compliance with CETA targets are reduced in size and delayed in the Revised CEIP.

This means that under P02-SC-CETA, Washington customers have higher costs, receive less renewable resources, and these resources are delayed several years, compared to P02-MM-CETA.

Consistent with the Complaint Settlement, this Appendix F: (1) details the data inputs, outputs, and provides a roadmap for the Company's initial 2021 CEIP P02-MM-CETA portfolio; and (2) details the data inputs, outputs, and provides a roadmap for the Company's 2021 Revised CEIP P02-SC-CETA portfolio.

P02-MM-CETA Data Inputs, Outputs and Roadmap

In this section, the Company details the data inputs, outputs, and provides a roadmap for the Company's initial 2021 CEIP P02-MM-CETA portfolio.

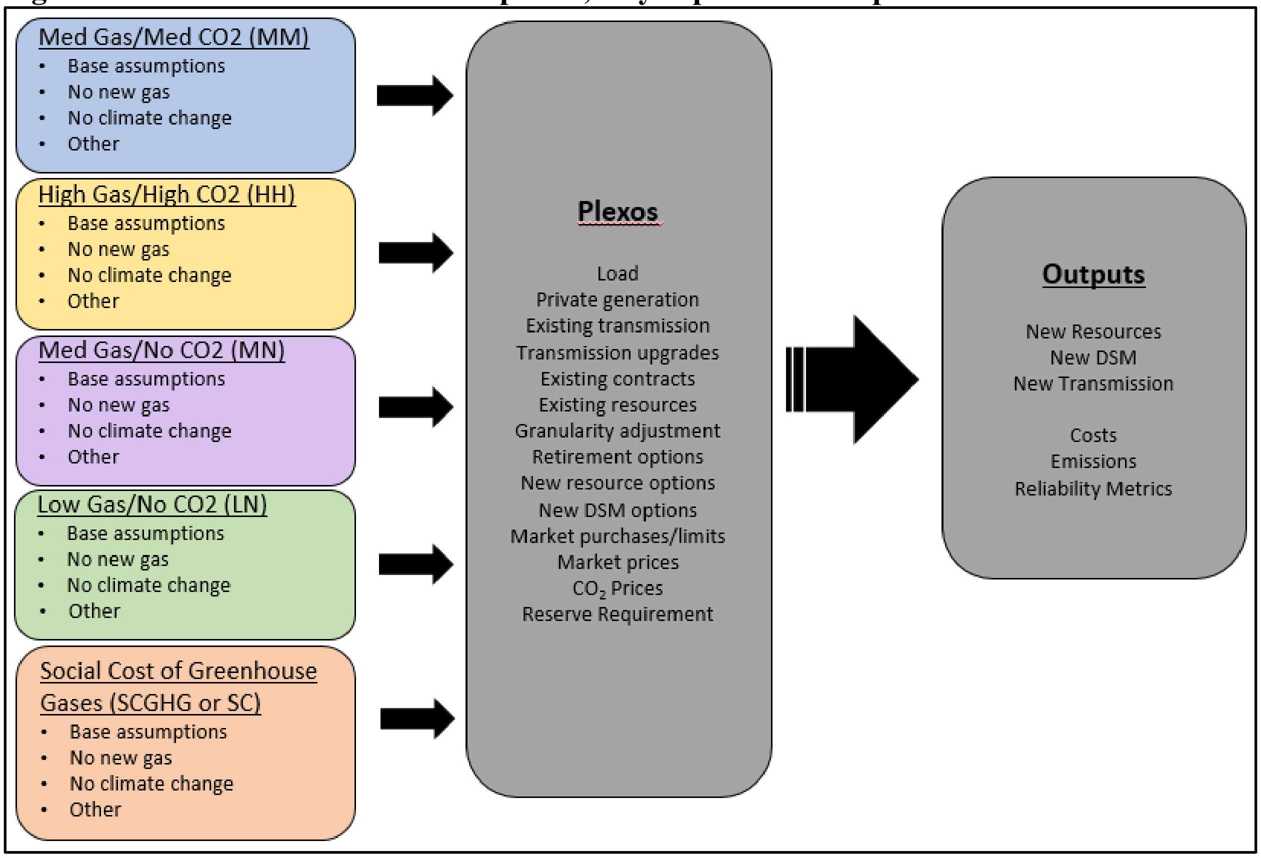
Each portfolio in the 2021 IRP was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three CO_2 price scenarios (zero, medium, high). An additional CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gas (SCGHG) as defined by CETA. Taken together, there were five distinct price-policy scenarios (medium gas/medium CO_2, medium gas/zero CO2, high gas/high CO2, low gas/zero CO2, and the social cost of greenhouse gases). Of the five, two were relevant for the development of the P02-MM-CETA preferred portfolio used for resource selections in both the 2021 IRP and the CEIP: medium gas/medium CO_2, and the SCGHG.

In the naming conventions of the 2021 IRP, each price-policy scenario includes two parts that were carried into the CEIP. As shown below in Figure F.1, "MM" represents Medium Natural Gas and Medium CO_2 cost assumptions. These medium values were the assumptions used in the 2021 IRP "expected" case, P02-MM. SCGHG also constitutes a distinct price-policy scenario, and does not use any other CO_2 price assumptions. Likewise, the MM price-policy scenario uses only the medium CO_2 carbon price adder for MM studies.

The SCGHG price-policy studies in the 2021 IRP coupled the SCGHG carbon price adder with the medium natural gas price component to describe the SCGHG price-policy scenario, whereas the MM price-policy studies in the 2021 IRP coupled the medium carbon price adder with the medium natural gas price component to describe the MM price-policy scenario. These two price-policy scenarios were used to create two unique portfolios called "P02-MM" and "P02-SCGHG." Both of these portfolios were used to create the CEIP portfolio, "P02-MM-CETA."[1]

[1] Supporting workpapers for the P02-MM-CETA portfolio include the LT summary: "210829-PAC-WP-LT 18609 21IRP 20yr P02-MM-CETA-12-31-21 (C).xlsx", ST cost summary: "210829-PAC-WP-ST Cost Summary -P02-MMGR-CETA ST Split Run Cost Data LT 18609 ST 19709 12-31-21 (C).xlsx", and MT cost summary "210829-PAC-WP-MT Cost Summary -P02-MMGR-CETA MT Split Run Cost Data LT 18609 MT 18631 12-31-21 (C).xlsx".

Figure F.1 – 2021 IRP Plexos Assumptions, Key Inputs and Outputs[2]



These model inputs and outputs, a roadmap for how P02-SCGH was incorporated in P02-MM-CETA, how portfolio and resource selections occurred, how identified shortfalls were resolved, and a summary of P02-MM-CETA portfolio development, can be found below.

Model Inputs and Outputs

Base Inputs

All IRP models are configured and loaded with the best available information at the time a model run is produced. Figure F.1 includes the primary base assumptions for Plexos as inputs prior to running models. These inputs, such as load, private generation, existing transmission, etc., vary only for specific sensitivities and variants noted in the 2021 IRP. For the two relevant studies used to develop P02-MM-CETA for the CEIP there are no differences in base assumptions with the exception of the SCGHG price-policy scenario. All model inputs are included in workpapers included with the original filing, and are included again in this refiling for completeness. Additional input workpapers are provided and noted where appropriate below to fulfill on the terms of the settlement. Among the included workpapers is the entire 2021 IRP Plexos database.

Outputs are also provided in workpapers accompanying the 2021 IRP and original CEIP filings. As with inputs, these output files are provided again for completeness.

[2] Figure adapted from materials presented in the 2021 IRP public input meeting held September 17, 2020.

SCGHG Inputs

The Company's initial CEIP applied the SCGHG as a dispatch adder input to the P02-SCGHG portfolio used to select Washington resources in the initial CEIP. Plexos inputs for the SCGHG dispatch adder, extracted directly from Plexos, are provided in the confidential workpaper "210829-PAC-WP-P02-SCGHG ST (30497-Emissions by Generator) 3-13-2023 (C).xlsx" on the "Emissions Results" tab. These inputs are applied to all emitting resources on a dollars per pound basis, where the model calculates the amount of emissions based on fuel usage. The workpaper also illustrates that the reported emissions cost for every resource is directly attributable the SCGHG dispatch adder and no other emissions cost. The same analysis is provided for the P02-MM case in the confidential workpaper "210829-PAC-WP-P02-MMGR Prod Port 20yr ST 4Blk-Mo (19667-Emissions by Generator) 3-13-2023 (C).xlsx", demonstrating that the CO_2 cost under the expected case also ties out exactly to the total emission cost for each resource.

P02-SCGHG Roadmap for Inclusion in P02-MM-CETA

Resource selections for all studies were performed using the Plexos suite of models, all of which contribute to final resource selections. As a backdrop to the portfolio selection discussion to follow, Figure F.2 shows the three types of Plexos models and their uses.

Figure F.2 – Plexos Models used in Resource Selection[3]

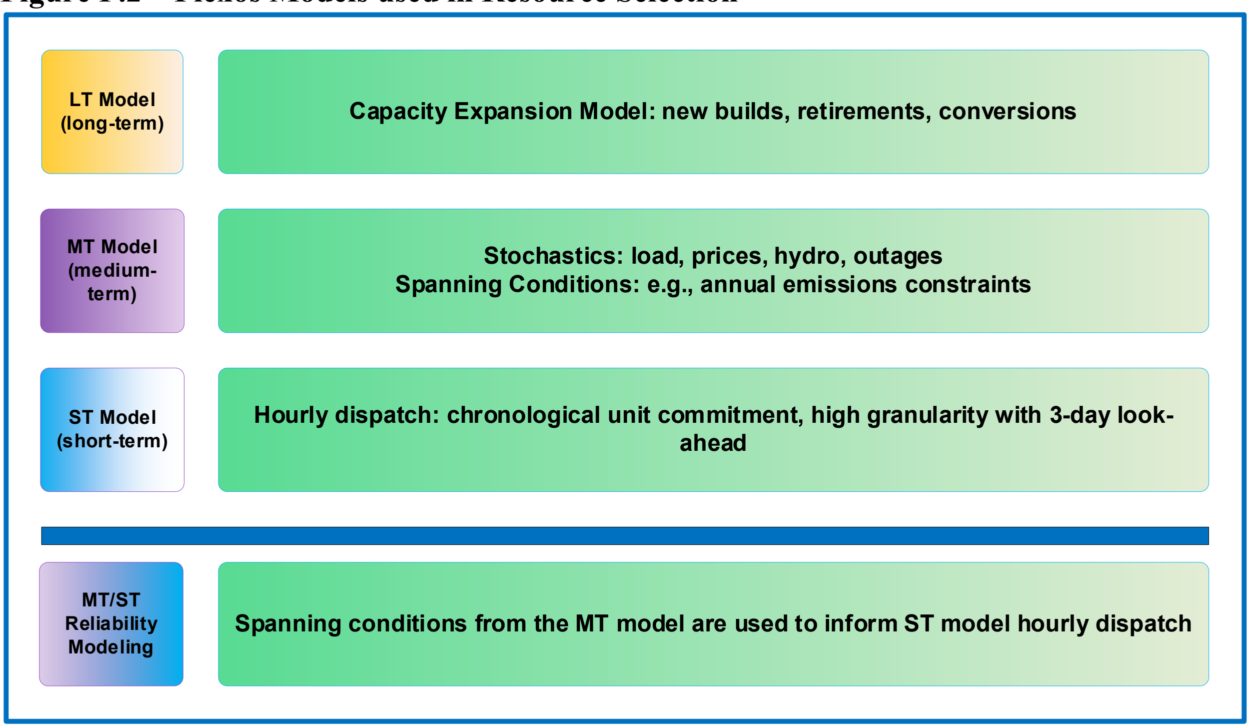
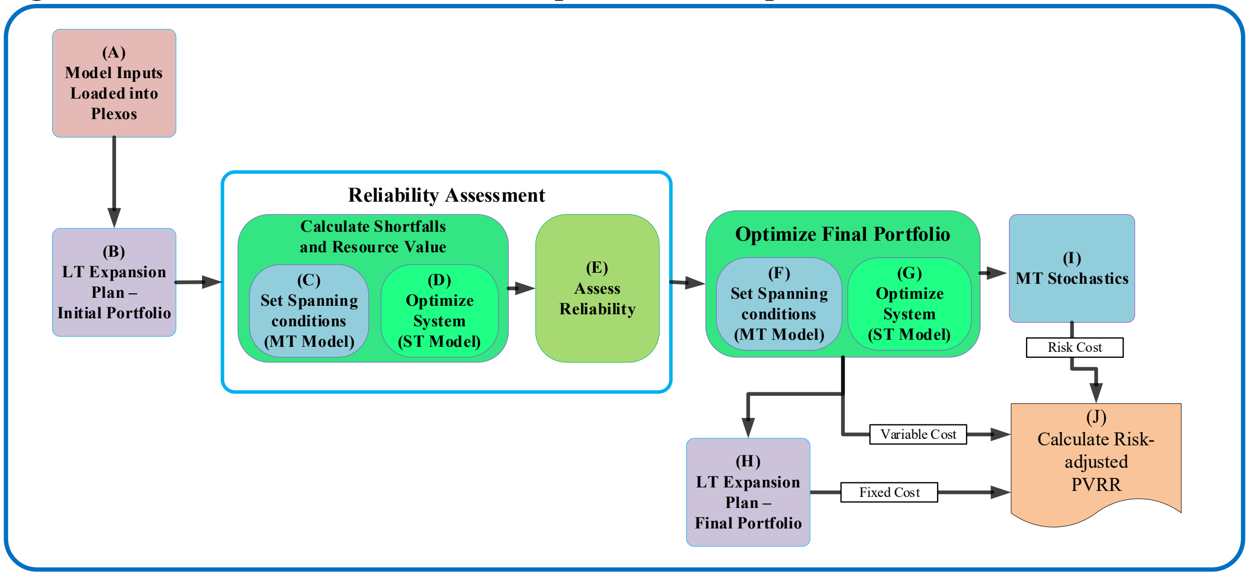


Figure F.3 illustrates the functions of the three Plexos models used to incorporate the SCGHG dispatch adder in the P02-SCGHG portfolio selections in the original CEIP filing. The SCGHG dispatch adder as used for resource selection is applicable in Step B (LT Expansion Plan – Initial Portfolio) and also in Step E (Assess Reliability).

[3] Figure adapted from materials presented in the 2021 IRP public input meeting held June 25, 2021

Figure F.3 – SCGHG in Portfolio Development Roadmap[4]



Each step in P02-SCGHG portfolio development is detailed below, with additional focus provided for steps B and E as directly relevant to CEIP compliance in the original filing through the incorporation of the SCGHG dispatch adder.

Step (A) – Model Input Loaded into Plexos

As noted under the Base Inputs sub-section above, key modeling elements and inputs used in both the CEIP and 2021 IRP include the following:

- Transmission System;
- Transmission Costs;
- Resource Adequacy;
- Granularity and Reliability Adjustments;
- New Resource Options, including demand-side management, wind and solar resources, non-emitting resources, energy storage resources, and market purchases;
- Capital Costs; and
- General Assumptions, including study period and date conventions, inflation rates, discount factors, CO2 price scenarios, and wholesale electricity and natural gas forecasts.

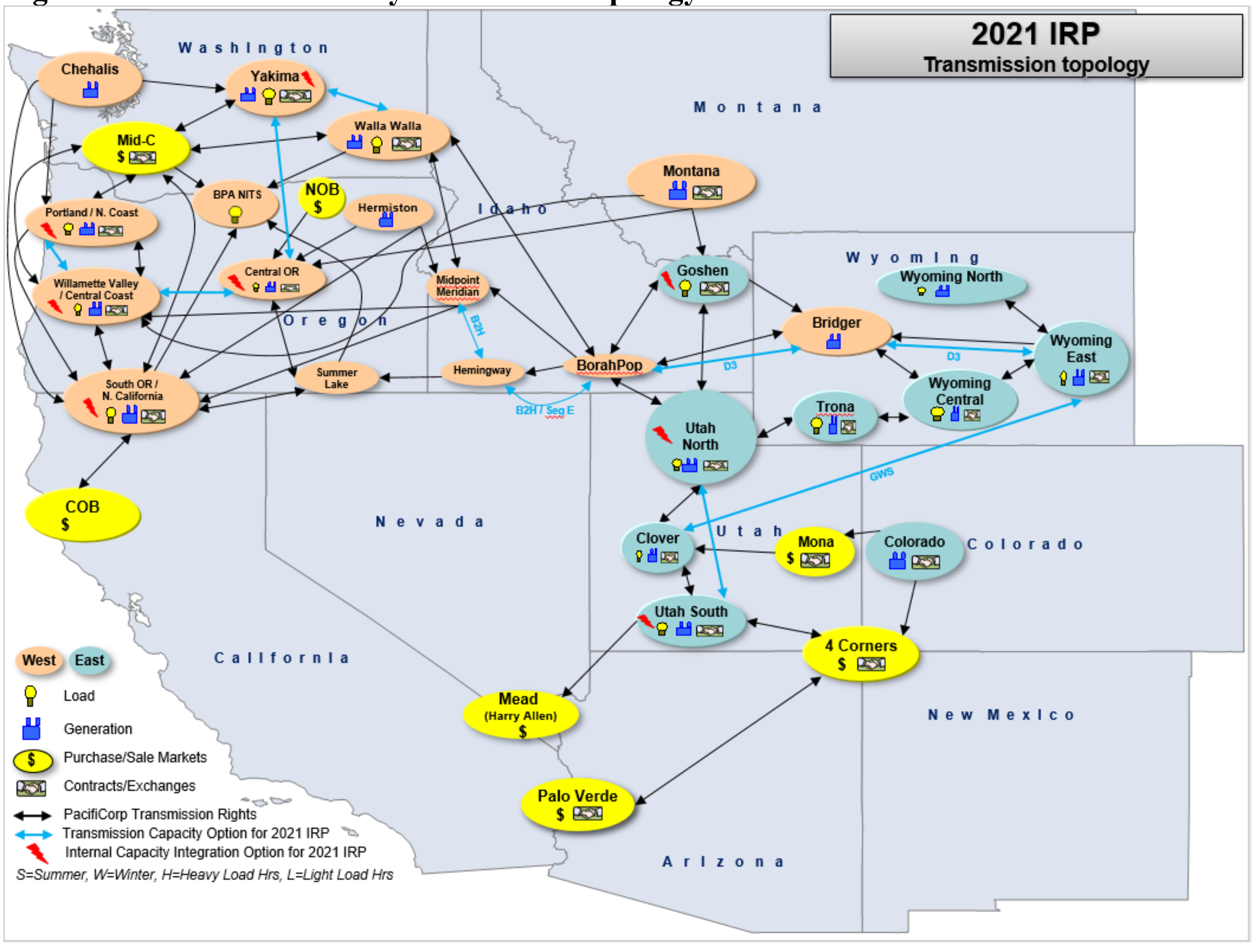
These elements and inputs are discussed from the perspective of the 2021 IRP, because that is where each was developed.

Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

[4] Adapted from Chapter 1, Figure 1.2 – Portfolio Production Process provided in both the IRP and original CEIP.

Figure F.4 – Transmission System Model Topology



Transmission Costs

In developing resource portfolios for the 2021 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and amount of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy

In its 2021 IRP, PacifiCorp established a 13% hourly capacity reserve margin requirement for each topology location containing load in the LT model. The capacity reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. This treatment is an improvement on a traditional planning reserve margin which accounts only for peak load capacity met by an estimated firm capacity contribution. Additionally, the 2021 IRP directly modeled operating reserve requirements in expansion plan model runs, which ensures that expansion resources selected to CRM requirements will also meet operating contingency spin and non-spin reserve requirements. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments

As detailed during the 2021 IRP public-input process, the granularity adjustment reflects the difference in economic value between an hourly 8760 cost calculation in ST modeling, and the four-block per month representation used in the LT model.

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the 4 LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the four-block granularity smooths out many of the storage arbitrage opportunities.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent net load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

As a consequence of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

New Resource Options

New resource options include including demand-side management, wind and solar resources, non-emitting resources, energy storage resources, and market purchases. Each is discussed below.

<u>Demand-Side Management</u>

Energy efficiency (Class 2 DSM) resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response (Class 1 DSM) resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

Wind and Solar Resources

Certain wind and solar resources are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources represent expected monthly generation levels such that half of the time actual monthly generation would fall below expected levels, and half of the time actual monthly generation would be above expected levels assuming no curtailments.

The ability for wind and solar resources, to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio. The use of resource availability to meet requirements in all periods allows the model to endogenously account for declining capacity contribution due to the increasing penetration of resources with similar dispatch patterns.

Non-Emitting Resources

Two non-CO2-emitting thermal resources are considered: advanced nuclear projects and non-emitting peaking units. Advanced nuclear resources are characterized by continuous operation and substantial storage in the form of heat stored as molten salt. In contrast, non-emitting peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The non-emitting peaking resource is assumed to use a non-CO2 emitting fuel such as hydrogen.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period;
- Energy return – energy used to fill (or charge) a storage reservoir; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs (for example, the cost of natural gas for expanding air with gas turbine expanders).

Market Purchases

Market purchases are transactions by the company's front office represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, which differ by delivery pattern and delivery period, that are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process. For capacity expansion optimization modeling, market purchases contribute capacity toward meeting the 2021 IRP's capacity reserve margin and supply energy to meet system needs.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. All capital costs evaluated in the IRP are converted to nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

General assumptions include study period and date conventions, inflation rates, discount factors, CO_2 price scenarios, and wholesale electricity and natural gas forecasts. Each is discussed below.

<u>Study Period and Date Conventions</u>

PacifiCorp executes its 2021 IRP models for a 20-year period beginning January 1, 2021 and ending December 31, 2040. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period.

Inflation Rates

The 2029 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.155 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2021 through 2040, using PacifiCorp's September 2020 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

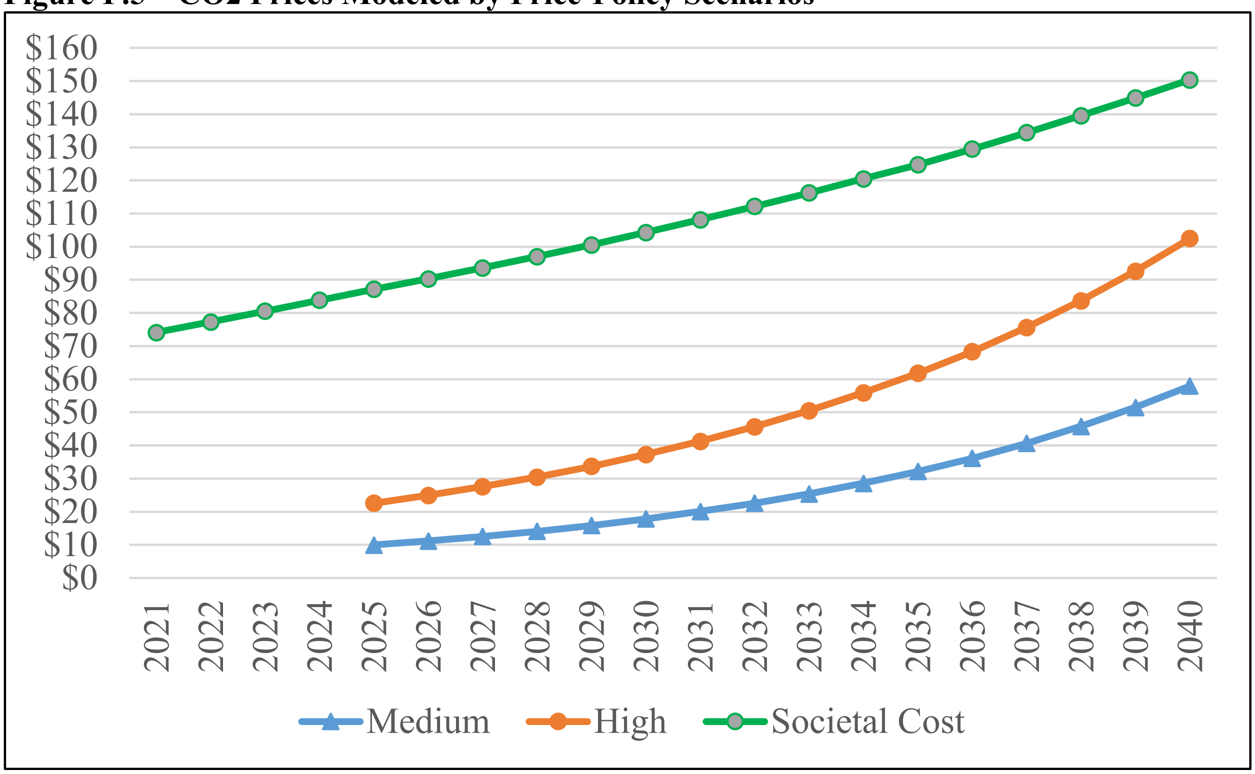
The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2021 IRP is 6.88 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs. PVRR figures reported in the 2021 IRP are reported in 2021 dollars.

CO2 Price Scenarios

PacifiCorp used four different CO2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party multi-client "off-the-shelf" subscription services. Both scenarios apply a CO2 price as a tax beginning 2025.

PacifiCorp also incorporated the social cost of greenhouse gas in compliance with RCW 19.280.030. Social cost of greenhouse gas emissions are assumed to start in 2021.

Figure F.5 – CO2 Prices Modeled by Price-Policy Scenarios



Wholesale Electricity and Natural Gas Forward Prices

For 2021 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

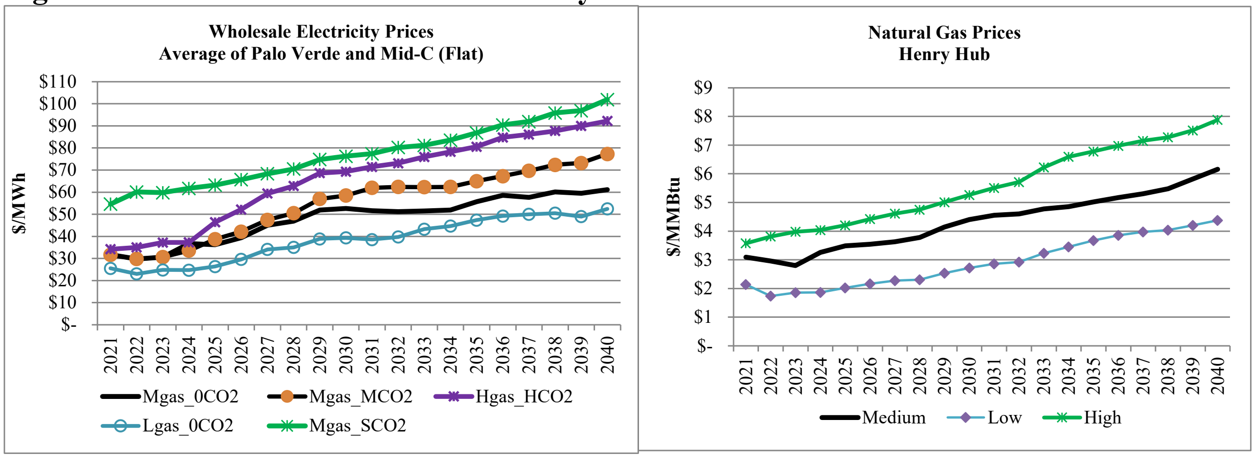
At the time PacifiCorp's 2021 IRP modeling inputs were prepared, the March 2021 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day. As such, these 36 months are market forwards as of March 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAXMP (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios pairing medium gas prices with alternative CO2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a pure fundamentals forecast. Scenarios using high or low gas prices, regardless of CO2 price assumptions, do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party multi-client "off-the-shelf" subscription services.

PacifiCorp's OFPC for electricity and each of its five scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four CO2 price scenarios. The OFPC used in the 2021 IRP does not assume any CO2 policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2021 IRP "medium case" price forecast is not the OFPC but a scenario that couples medium gas with a medium CO2 price, applied for forecasting purposes as a tax. Thus, the 2021 IRP medium case differs from that of the March 2021 OFPC by assuming a medium CO2 price starting in 2025. This medium CO2 price serves as a proxy for a potential future CO2 policy.

Figure F.6 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2021 IRP.

Figure F.6 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Step (B) – LT Expansion Plan (Initial Portfolio)

The PLEXOS Long-Term planning model (LT model) is used to produce optimized resource portfolios with sufficient capacity to be reliable on a 20-year aggregated granularity basis. As discussed under inputs, the LT model uses all relevant loaded inputs to mathematically minimize operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints.

These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

The initial resource portfolio employs operating reserve requirements, including contingency reserves, which are calculated as 3% of load and 3% of generation. The capacity reserve margin in the CEIP was set at a “floor” of 13% at each load area in the topology, as provided in Figure F.4, above.

In the event that an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp’s transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

The social cost of greenhouse gases is applied such that the price for the SCGHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SCGHG dispatch adder to determine optimized dispatch for SCGHG price-policy studies, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

Plexos's core functionality inherently applies the CO_2 emission cost that has been input into the model on a dollars-per-pound basis as a factor in determining an optimal portfolio. In the P02-SCGHG case, the CO_2 emissions cost is the SCGHG dispatch adder cost[5]. In PO-SCGHG study, this dispatch adder costs effectively replaces the expected medium CO_2 cost. As a consequence of this core model functionality, Washington resource selections are made with the SCGHG dispatch adder incorporated throughout the P02-SCGHG price-policy study. Note that while the P02-MM price-policy study does not include the SCGHG dispatch adder as its CO_2 cost, it is combined with the P02-SCGHG study to analyze Washington resources to arrive at the P02-MM-CETA preferred portfolio.

Step (C) – Set Spanning Conditions (Initial Portfolio)

After completion of the LT initial portfolio, the MT and ST models are run consecutively in order to evaluate any LT model reliability shortfalls.

The MT model serves two significant functions in 2021 IRP modeling. The first is to set "spanning conditions" for use in the ST model, and the second is to generate stochastic risk analysis. The first of these two functions is addressed in Step (C).

Spanning conditions are constraints that must be observed across periods of time that extend beyond the ST model's ability to "see" as it chronologically optimizes several days of hourly data at a time (e.g., an annual emissions limit). The MT model is able to determine for each month how each spanning condition is allocated for the ST model's use. The result is that even though the ST model is focused on hourly details and cannot simultaneously account for limitations that span across every hour in a year, the model is nonetheless incented to appropriately adhere to an annual constraint.

The spanning conditions result of Step (C) is automatically transmitted to the ST model for Step (D) when the MT model completes.

Step (D) – Optimize System (Initial Portfolio)

The ST model uses the same common input assumptions described for the LT model with additional spanning condition data provided by the MT model. The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability needs of a particular study (e.g., a particular sensitivity or price-policy scenario). In this step, the ST model is run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls

[5] Refer to the workpaper "210829-PAC-WP-ST Cost Summary -P02-SCGR ST -SCGHG Only in Emissions 3-13-2023 (C).xlsx" for SCGHG as modeled in Plexos.

by hour, and 2) the value of every potential resource to the system. These two pieces of information serve as the basis of the reliability assessment in Step (E).

Step (E) – Assess Reliability

When assessing reliability, the Company examines shortfalls, resource values, portfolio refinements, and applying reliability assessment workpapers. Each is described below.

Shortfalls

The ST model data generated in Step (D) is used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. Shortfalls are calculated for the P02-SCGHG and P02-MM portfolios based directly on model outcomes and are summarized annually in the workpapers "210829-PAC-WP-Shortfalls - P02-SC 2025_ST_output_3980 3-13-2023 (C).xlsx" and "210829-PAC-WP-Shortfalls - P02-MM 2025_ST_output_3700 3-13-2023 (C).xlsx" respectively.[6]

Resource Value

Plexos calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. Plexos also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. Plexos then multiplies these prices by a generator's energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated and marginal prices will again reflect the variable cost of an available resource.

The calculation of net value[7] can be seen in workpapers titled "210829-PAC-WP-Resource options and Granularity_3632 MMGR 3-13-2023 (C).xlsx" and "210829-PAC-WP-Resource options and Granularity_3632-SCGR 3-13-2023 (C).xlsx" for the MM and SCGHG cases respectively.

[6] All years from 2025-2040 have been provided for reference. MM shortfalls include files with the final four numbers from 3684-3700. SCGHG files include those from 3980-3995.
[7] Measured in cost/kW-year

Portfolio Refinements

While a large number of resource options are evaluated, new generation resources are mostly restricted to two circumstances: replacement resources at retiring generators, and new resources at locations with interconnection or transmission upgrade options.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. For this reason, the modeling of combined solar and storage resources now reflects storage with capacity equal to 100% of solar nameplate, and four-hour duration—up from 25% of solar capacity in the 2019 IRP, and 50% of capacity as discussed early in the 2021 IRP public-input process. This allows a collocated solar resource to shift more energy accumulated during periods of high solar radiance, increasing its effective capacity contribution.

Applying Reliability Assessment Workpapers

The Reliability Assessment leverages two different data sources from the LT and ST model runs. The first source for reviewing reliability is the hourly shortfall data provided by ST Runs. These runs provide annual hourly shortfall data, which is then reviewed and processed to assess system level reliability. The hourly shortfall results for the MM and SCGHG initial cases can be found in the provided workpapers as noted above. These sets of analysis provide the IRP group with the maximum annual shortfall on the system in any given hour. These figures are reviewed both in aggregate (looking at monthly or annual maximum shortages) and more granularly (reviewing the number of consecutive hours of shortfall) to determine the best course of action to address resource adequacy issues.

The next data source leveraged to determine reliability additions or adjustments is a review of the economics of each possible resource which could have been included in any portfolio to determine which set of options represents the lowest cost, least risk, and feasible, grouping of resources. The economic results for the MM and SCGHG cases can be found in the provided workpapers as noted above. Where at all possible, the lowest cost resource is selected to replace either a higher cost resource, or to be included in the portfolio should there be the ability to add additional resources at a given location, limited by interconnection limits and other constraints.

Reviewing the reliability adjustments for the MM case, the first data set shows shortfalls occurring in 2034, then starting again in 2037 and extending through the end of the study horizon. A snapshot of MM reliability adjustments can be seen on the "Final MM Vs. Initial MM" tab of the "210829-PAC-WP-Pre-Reliability to Reliability Summary workpaper 3-13-2023 (C).xlsx" workpaper. On this tab, one significant change includes the selection 402 MW of Non-Emitting Peaker in 2033 supplanting 218 MW of Utah North Solar Plus Storage. The economics in this case show that the average cost of the Non-Emitting Peaker in Utah North is $96/kw-Year, versus $93/kw-Year for the Solar plus Storage resource. Given the relative equivalence of these two resources, shortfall duration became the deciding factor between the two. In the 2038-2040 timeframe, where the east side of the system had a maximum hourly shortfall of 3,124 MW, shortfalls lasted up to 16 hours, with a number of those hours during the nighttime. As such, the ST model data demonstrated a greater need for firm capacity, long duration resources and given the generally equivalent economics, the Non-Emitting Peaker was determined to be the best option for a least cost, most reliable resource. Utah North Nuclear can be seen on the above referenced tab to be the most expensive option, and 4-hour storage, while the least expensive option, did not adequately contribute to long duration shortfalls in the later periods of the study.

The same type of analysis was completed for the major 2038 and 2040 changes. In 2038, Jim Bridger Solar plus storage is supplanted by Non-Emitting Peaker and Nuclear. While the Solar Plus Storage resource was economically stronger than the other options, duration and size of shortfalls again necessitated larger firm resources to replace Solar and Storage items.

The Social Cost of Greenhouse Gas (SCGHG) portfolio underwent the same process as above. On the "Final SC vs. Initial SC" tab in the above referenced workpaper, the resource changes, shortfalls and relative economics are shown. Ultimately, in the SCGHG case, the major adjustments were to include Non-Emitting Peaker, Stand Alone Storage and Solar Plus Storage resources instead of Wind resources. Additional reliability determinations prompted delays in the timing of Coal retirements and the inclusion of those associated resources. Shortfalls begin in 2025 in this case and continue through the remainder of the horizon. Due to the timing of shortfalls and the company's ongoing RFP process, no new, non-RFP resources were allowed to be included prior to 2026. As such, resolving 2025 shortfalls necessitated delaying coal plant retirements, and for this IRP cycle, the coal plants which were initially selected to retire in this time frame were only eligible to continue to the end of their life in 2028. Additionally, A significant amount of Wind in 2026 was replaced by Solar plus Storage resources. A review of the economics shows that the Wind resources were somewhat stronger than the Solar Plus Storage options. Again, as in the MM case, a review of the duration and timing of shortfalls was necessary here. A combination of multiple hours of shortfall, and timing which would coincide with solar radiance led to Solar Plus Storage presenting a stronger reliability addition than other options in this period.

Other major adjustments in the SCGHG portfolio include a shift in timing of nuclear resources from 2029 to later and the removal of a geothermal option, which are based on updated assumptions provided to the IRP team after the initial run was completed. The assumed start date of geothermal resources moved from 2026 to 2030, and costs were adjusted. Nuclear options were initially assumed to all begin in 2028 with the Natrium demonstration project, but further data from the developer led to any additional nuclear options beginning no earlier than 2030. The addition of Wind, a Non-Emitting Peaker and Solar plus Storage in 2030, and the addition of Solar Plus Storage in 2037 is again related to shifts in timing of Coal plant retirements as discussed above. Similar to the MM Case, 2038 adjustments were related to the Jim Bridger plants and options, and in this case the Nuclear Plant under SCGHG assumptions was the most economic option.

During the 2021 IRP cycle, assumptions were made which restricted the nameplate capacity of resource additions to the nameplate capacity of retiring coal units, or the maximum allowable transmission capacity of a given line. This assumption meant that additional surplus resources were not eligible to be added behind the meter at existing locations, and that resources could only be added in the exact configurations provided to the IRP team. This is being adjusted in the 2023 IRP, so that resource additions are constrained by actual generation instead of nameplate capacity added. This will enable the model to more flexibly meet reliability needs on an initial basis and give the model a larger set of resource combinations from which to select.

Step (F) – Set Spanning Conditions (Final Portfolio)

The MT model is then run again with the modified portfolio to establish a new set of optimized spanning conditions for use by the ST model. There is no difference in the execution of the MT model in this step as opposed to Step (C), above. Only the post-reliability assessment portfolio is different.

Step (G) – Optimize System (Final Portfolio)

The ST model is then run again with the modified portfolio to calculate an initial PVRR. This initial PVRR is risk-adjusted on the basis of stochastic modeling using the results of Step (I), below. There is no difference in the execution of the ST in this step as opposed to Step (D), above. Only the post-reliability assessment portfolio is different.

Step (H) – LT Expansion Plan (Final Portfolio)

The LT model is then run again with the modified post-reliability portfolio locked-in. The portfolio is not re-optimized. This step is performed to generate a comprehensive dataset from the LT model for portfolio reporting and to establish the fixed costs of the portfolio for use in the final risk-adjusted PVRR.

Step (I) – MT Stochastics

The MT model uses the same common input assumptions described for LT and ST models with additional data provided by the LT and ST model results (e.g., the capacity expansion portfolio). While the LT and ST models supply an optimized portfolio for each case, the MT model is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies. While deterministic ST system cost results are the most precise available due the hourly granularity, the MT model provides the necessary data to calculate a stochastic risk metric for each case, which is then added to the ST system cost outcomes to produce the risk-adjusted PVRR for each case. These include cost and risk analyses; stochastic model parameter estimations; and stochastic portfolio performance measures. Each of these are detailed below.

Cost and Risk Analysis

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed with the MT model.

The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

The stochastic parameters used in the MT model for the 2021 IRP are developed with a short-run mean reverting process, whereby mean reversion represents a rate at which a disturbed variable returns to its expected value. Stochastic variables may have log-normal or normal distribution as appropriate. The log-normal distribution is often used to describe prices because such distribution is bounded on the low end by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average. Unlike prices, load generally does not have such skewed distribution and is generally better described by a normal distribution. Volatility and mean reversion parameters are used for modeling the volatilities of the variables, while accounting for seasonal effects. Correlation measures how much the random variables tend to move together.

Stochastic Model Parameter Estimation

Stochastic parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to hover around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter- variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The stochastic parameters are used to drive the stochastic processes of the following variables:

- Representative natural gas prices for PacifiCorp’s east and west balancing authority areas;
- Electricity market prices for Mid-C, COB, Four Corners, and Palo Verde;
- Loads for California, Idaho, Oregon, Utah, Washington and Wyoming regions; and
- Hydro generation.

Volume II, Appendix H – Stochastic Parameters discusses the methodology for developing the stochastic parameters for the 2021 IRP.

For unplanned thermal outages, PacifiCorp assumes a uniform distribution around an expected rate. For existing units, the expected unplanned outage rates by unit are based on its historical performance. For new resources, the unplanned outage rates are as specified for those resources as listed in the 2021 IRP supply-side resource table in Volume I, Chapter 7 – Resource Options. Table F.1 through Table F.8 summarize updated stochastic parameters and seasonal price correlations for the 2021 IRP.

Table F.1 – Short-Term Load Stochastic Parameters

Short-Term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2021 IRP	0.045	0.041	0.038	0.023	0.052	0.016
Spring 2021 IRP	0.039	0.038	0.066	0.030	0.039	0.018
Summer 2021 IRP	0.043	0.059	0.057	0.051	0.053	0.017
Fall 2021 IRP	0.041	0.037	0.045	0.033	0.042	0.018
Short-Term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2021 IRP	0.154	0.165	0.177	0.281	0.147	0.226
Spring 2021 IRP	0.214	0.242	0.258	0.519	0.157	0.272
Summer 2021 IRP	0.197	0.265	0.148	0.307	0.212	0.234
Fall 2021 IRP	0.290	0.277	0.198	0.202	0.234	0.241

Table F.2 – Short-Term Gas Price Parameters

Short-Term Volatility	East Gas	West Gas
Winter 2021 IRP	0.115	0.166
Spring 2021 IRP	0.091	0.203
Summer 2021 IRP	0.099	0.131
Fall 2021 IRP	0.101	0.171
Short-Term Mean Reversion	**East Gas**	**West Gas**
Winter 2021 IRP	0.061	0.031
Spring 2021 IRP	0.160	0.140
Summer 2021 IRP	0.503	0.287
Fall 2021 IRP	0.046	0.022

Table F.3 – Short-Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid-Columbia	Palo Verde
Winter 2021 IRP	0.132	0.163	0.198	0.121
Spring 2021 IRP	0.172	0.288	0.630	0.138
Summer 2021 IRP	0.220	0.339	0.260	0.202
Fall 2021 IRP	0.174	0.173	0.160	0.150
Short-Term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2021 IRP	0.089	0.070	0.090	0.086
Spring 2021 IRP	0.180	0.258	0.461	0.151
Summer 2021 IRP	0.312	0.395	0.196	0.146
Fall 2021 IRP	0.197	0.178	0.120	0.163

Table F.4 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.413	1.000				
COB	0.377	0.620	1.000			
Mid - Columbia	0.320	0.540	0.757	1.000		
Palo Verde	0.492	0.791	0.586	0.564	1.000	
Natural Gas West	0.344	0.235	0.302	0.288	0.248	1.000

Table F.5 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.197	1.000				
COB	0.141	0.339	1.000			
Mid - Columbia	0.102	0.424	0.638	1.000		
Palo Verde	0.223	0.630	0.327	0.276	1.000	
Natural Gas West	0.563	0.195	0.215	0.168	0.097	1.000

Table F.6 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.066	1.000				
COB	0.161	0.224	1.000			
Mid - Columbia	0.116	0.233	0.797	1.000		
Palo Verde	0.056	0.440	0.453	0.542	1.000	
Natural Gas West	0.674	0.035	0.103	0.075	-0.003	1.000

Table F.7 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.207	1.000				
COB	0.251	0.289	1.000			
Mid - Columbia	0.225	0.279	0.596	1.000		
Palo Verde	0.165	0.609	0.401	0.435	1.000	
Natural Gas West	0.359	0.129	0.203	0.226	0.160	1.000

Table F.8 – Hydro Short-Term Stochastic

	Short Term Volatility	Short-Term Mean Reversion
Winter 2021 IRP	0.274	0.722
Spring 2021 IRP	0.189	0.433
Summer 2021 IRP	0.210	1.149
Fall 2021 IRP	0.298	0.368

Figures F.7 and F.8 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for Mid-C and Palo Verde market hubs based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Mid-C electricity prices, differences between the first and 99th percentiles range from \$27.18/MWh to \$69.57/MWh during the 20-year study period. For Palo Verde electricity prices, the difference between the first and 99th percentiles range from \$31.08/MWh to \$88.59/MWh.

Figure F.7 – Simulated Annual Mid-C Electricity Market Prices

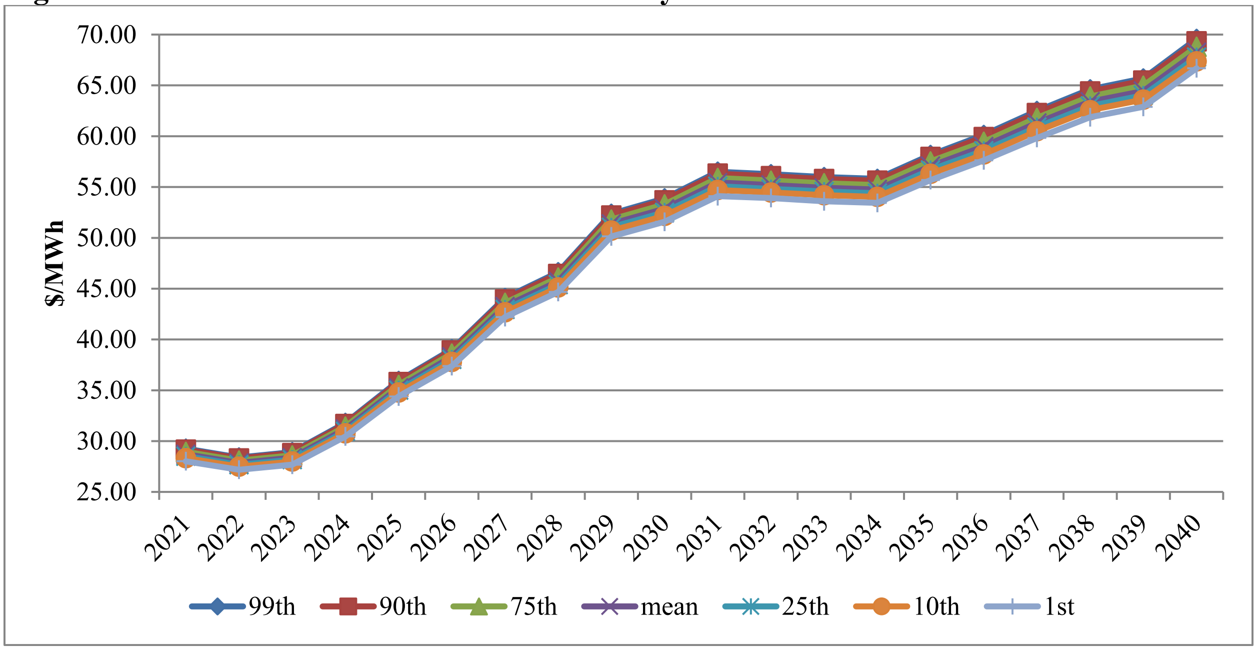


Figure F.8 – Simulated Annual Palo Verde Electricity Market Prices

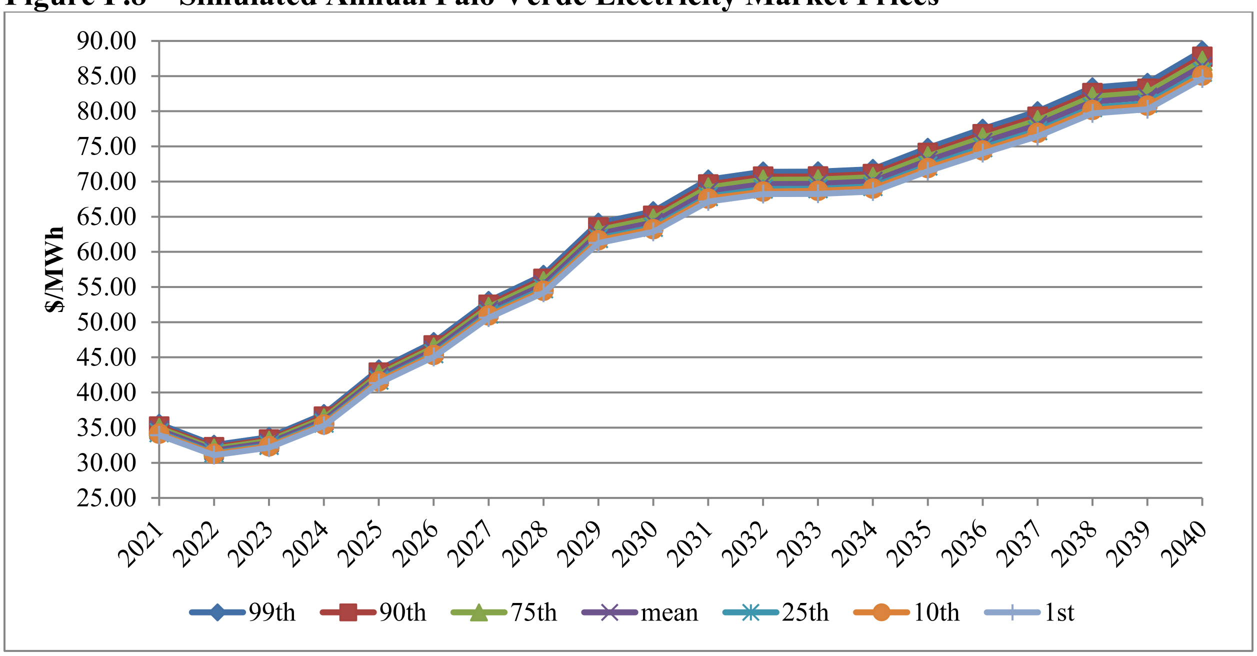


Figure F.9 and Figure F.10 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99th percentiles range from $2.71/ Million British thermal units (MMBtu) to $5.25/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99th percentiles range from $2.61/MMBtu to $6.01/MMBtu.

Figure F.9 – Simulated Annual Western Natural Gas Market Prices

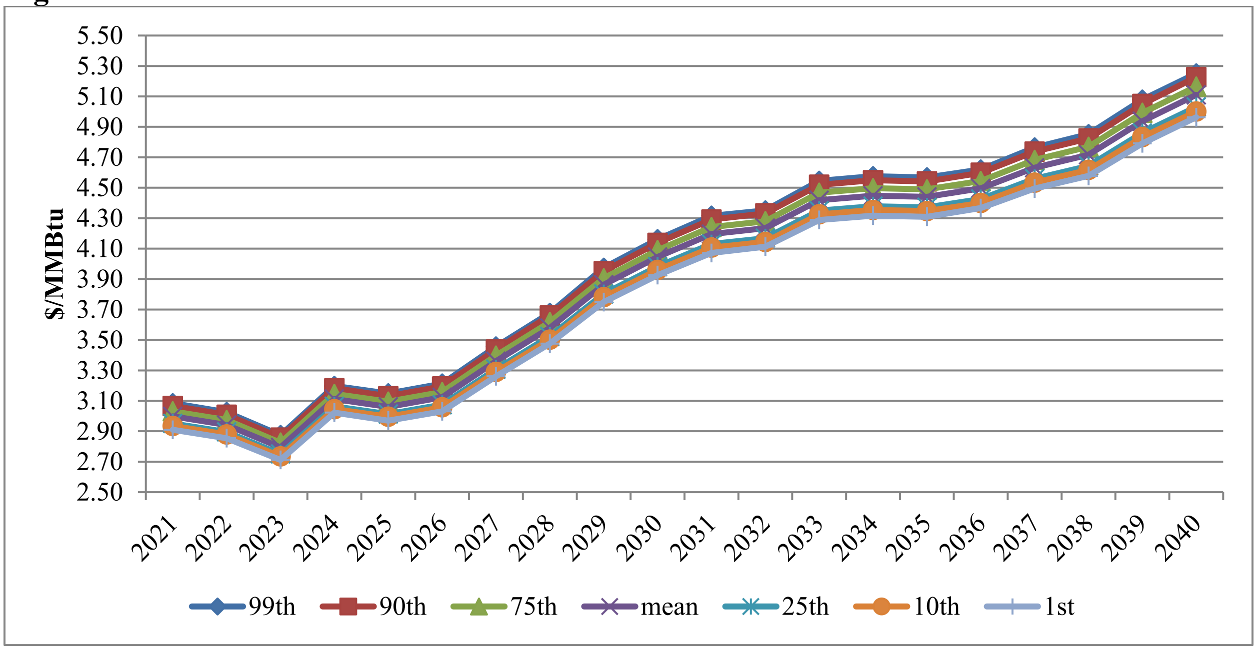
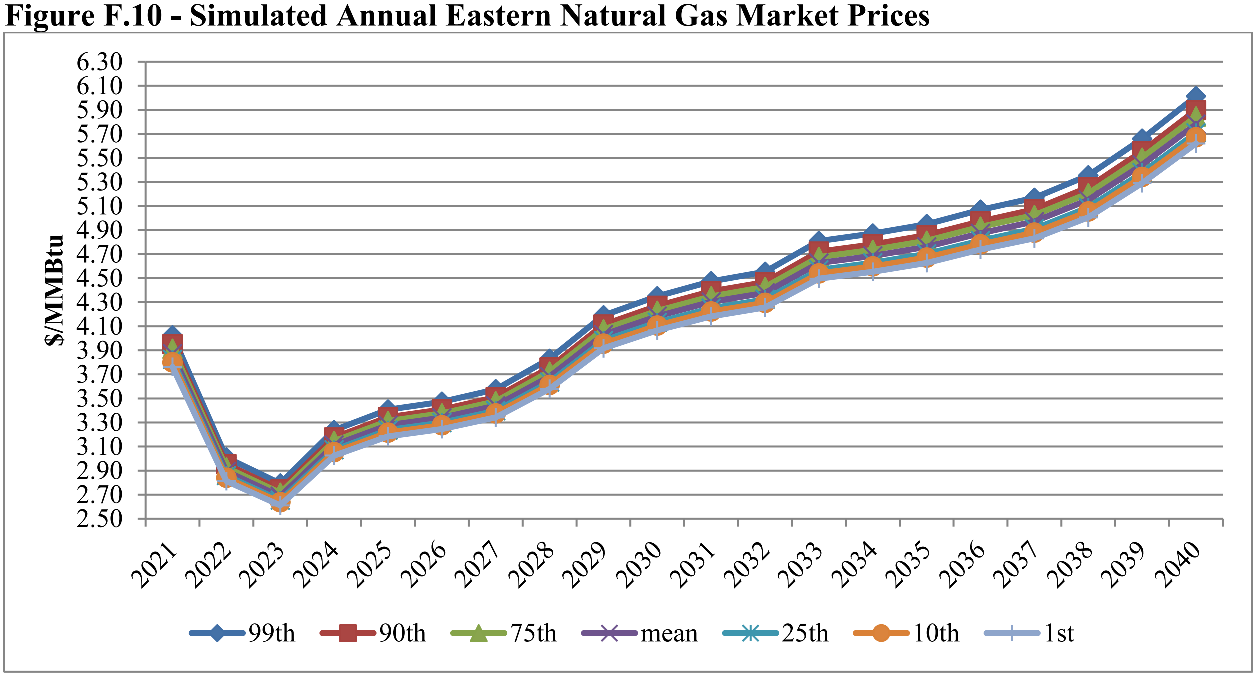


Figure F.10 - Simulated Annual Eastern Natural Gas Market Prices



Figures F.11 through F.17 show annual loads by load area and for PacifiCorp's system at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Idaho load, the annual differences between the first and 99th percentiles range from 154 gigawatt-hours (GWh) to 165 GWh. For Utah load, the annual difference ranges from 830 GWh to 1,069 GWh. For Wyoming load, the annual difference ranges from 150 GWh to 177 GWh. For Oregon load, annual differences range from 423 GWh to 545 GWh. California load, annual differences range from 27 GWh to 29 GWh

For Washington load, the annual difference ranges from 160 GWh to 187 GWh. For PacifiCorp's system load, the annual difference ranges from 1,430 GWh to 1,731 GWh.

Figure F.1 - Simulated Annual Idaho Load

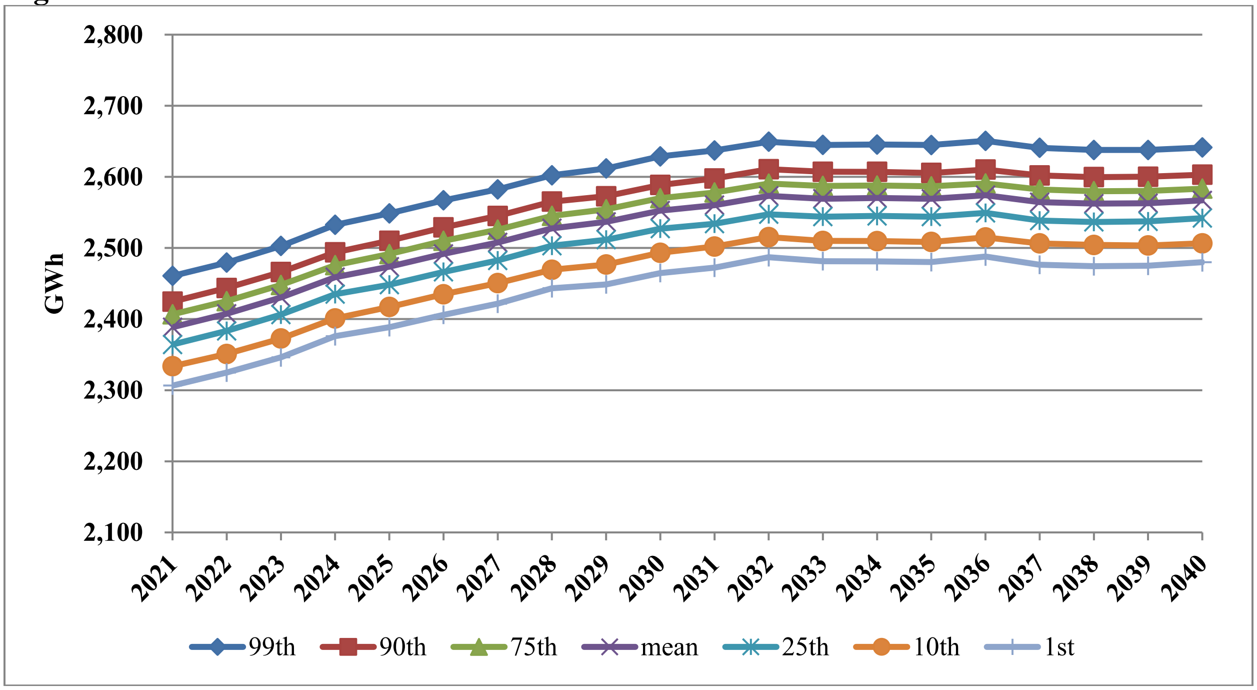


Figure F.2 - Simulated Annual Utah Load

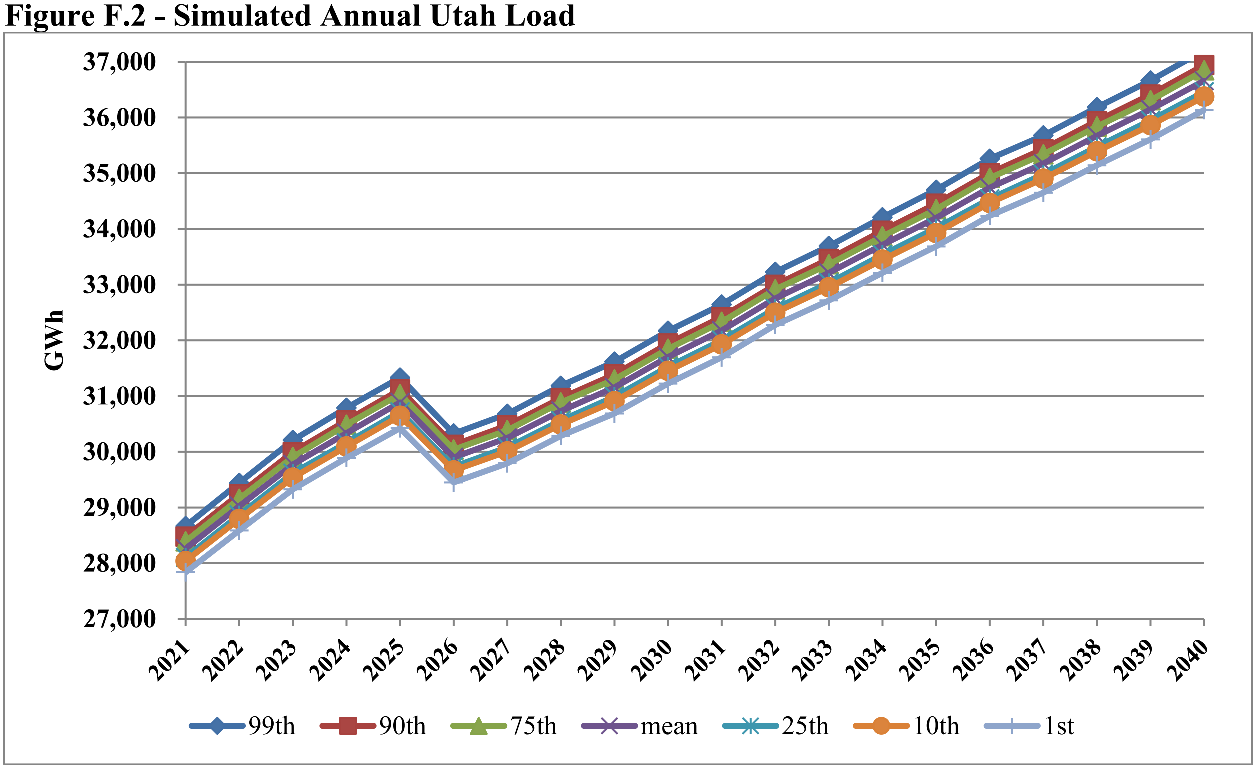


Figure F.3 - Simulated Annual Wyoming Load

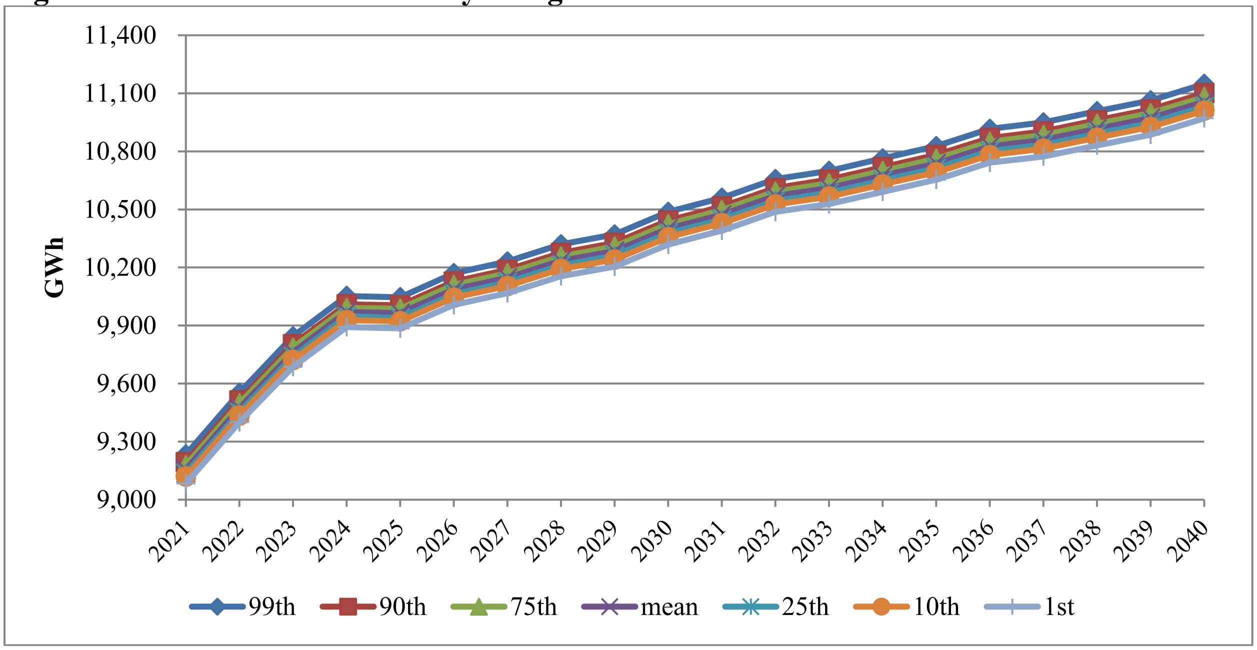


Figure F.4 - Simulated Annual Oregon Load

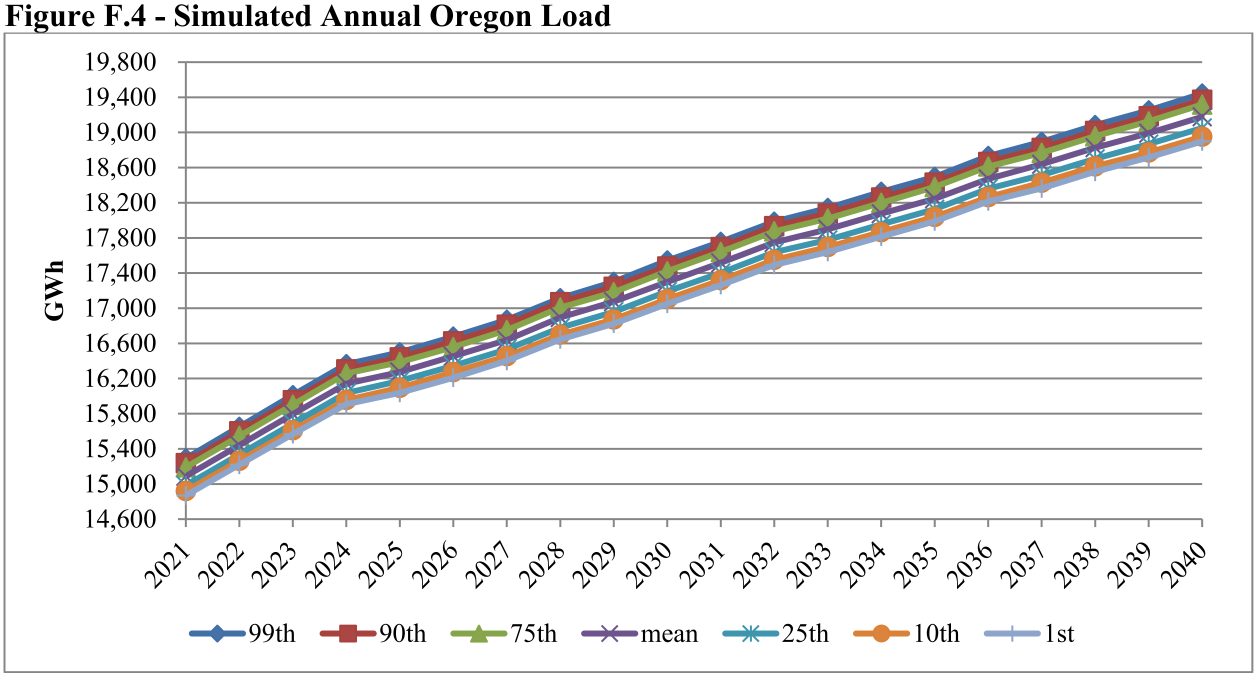


Figure F.5 - Simulated Annual Washington Load

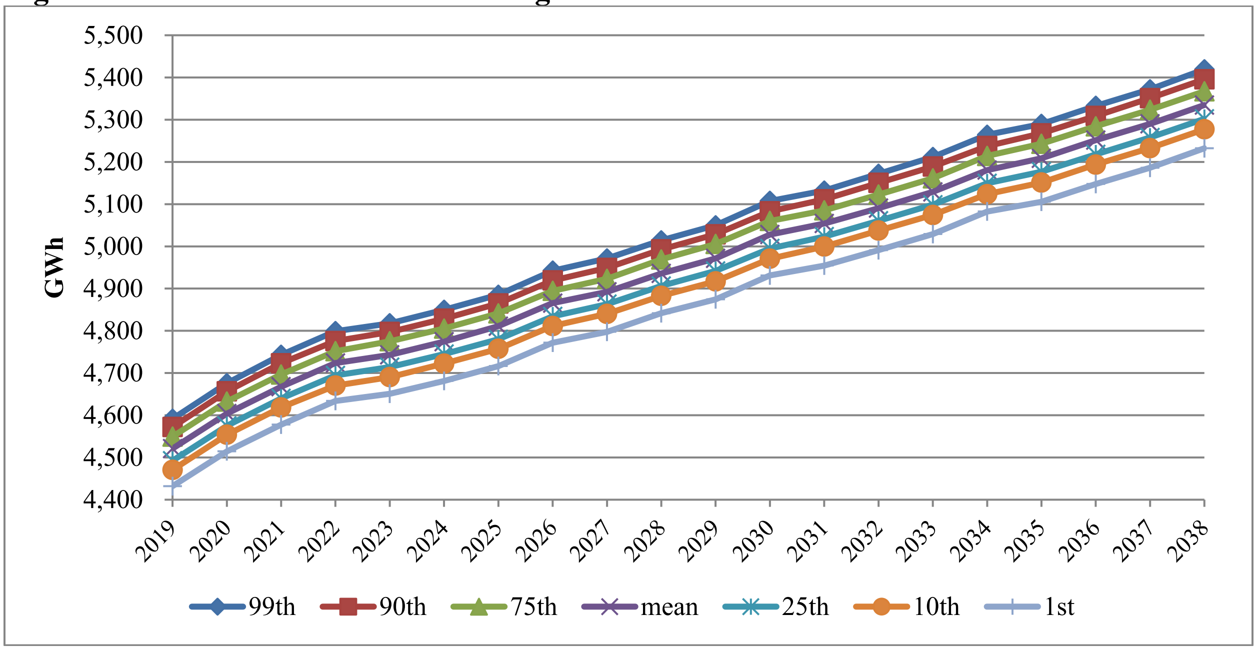


Figure F.6 - Simulated Annual California Load

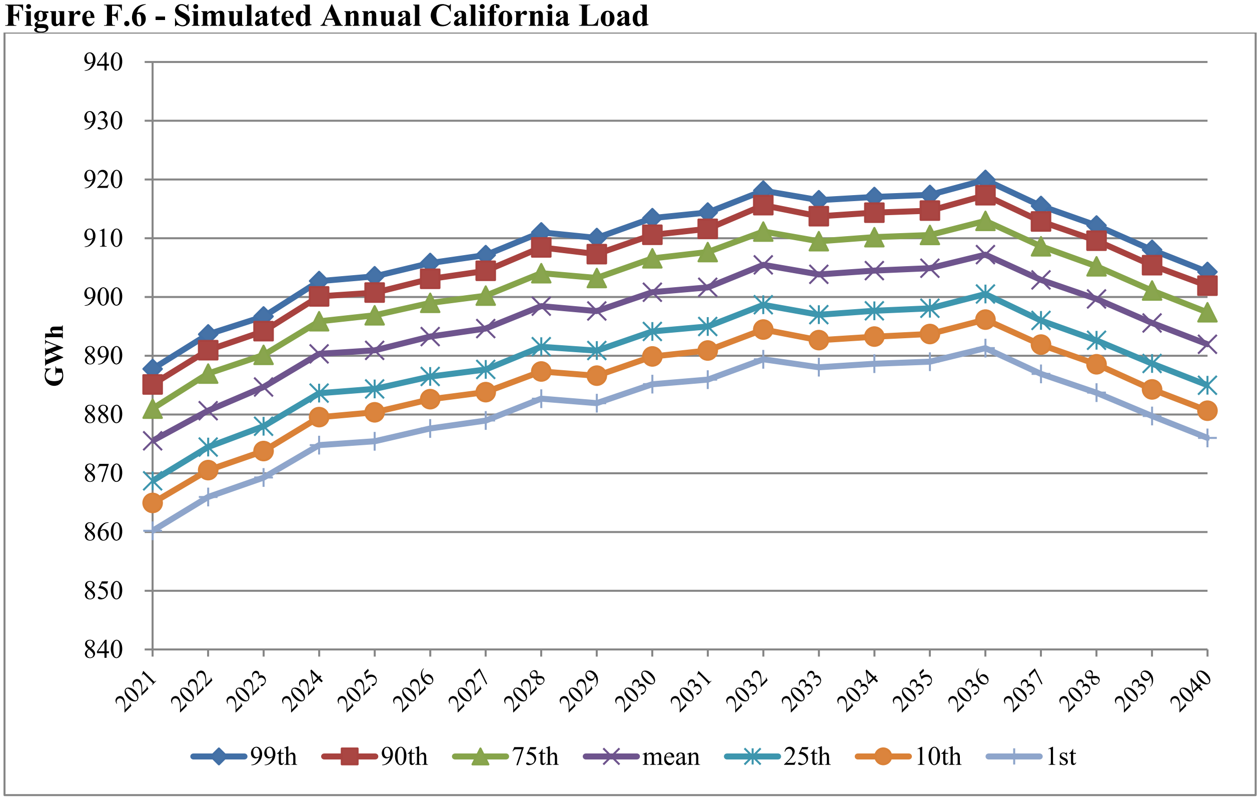


Figure F.7 - Simulated Annual System Load

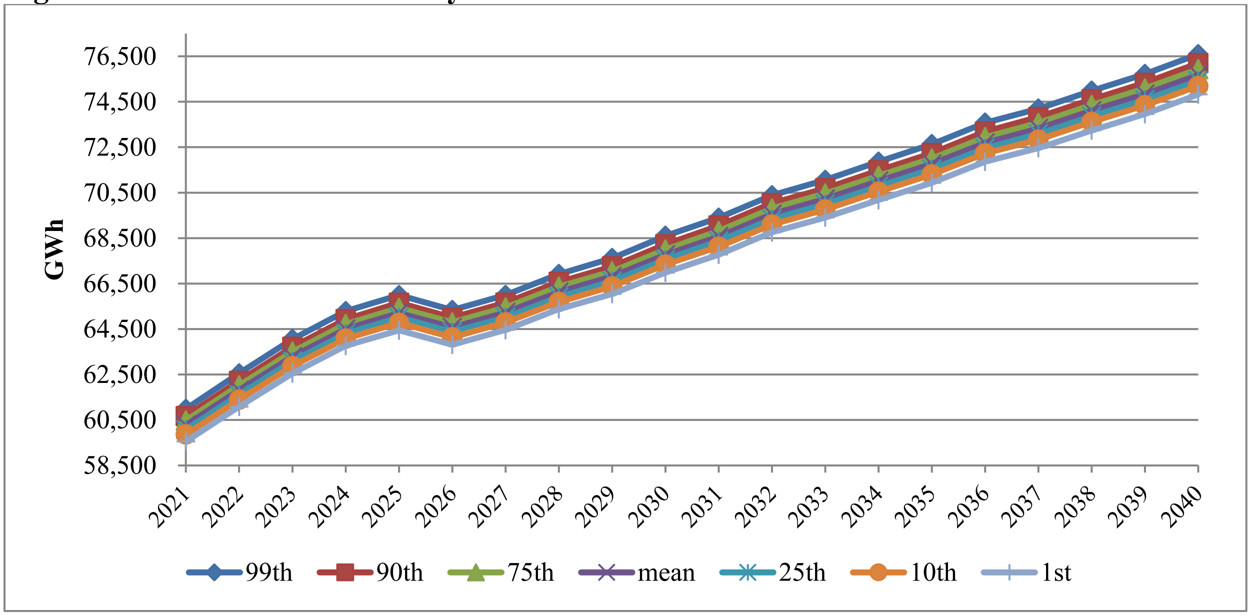
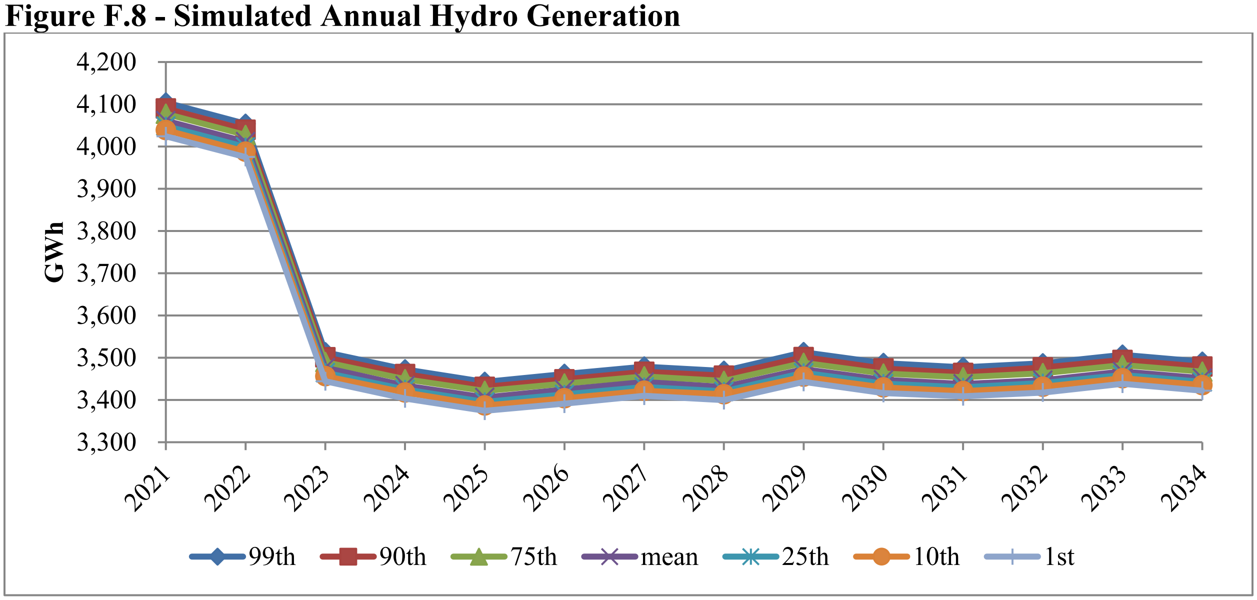


Figure F.18 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters developed for the hydro stochastic process approximate the volatility of hydro conditions as opposed to variations due to dispatch. The drop in 2021 is due to the assumed decommissioning of the Klamath River projects. Annual differences in hydro generation between the first and 99th percentiles range from 68 GWh to 80 GWh.

Figure F.8 - Simulated Annual Hydro Generation



Monte Carlo Simulation

During model execution, the MT model makes time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the MT model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the MT model include:

- Stochastic mean PVRR
- Upper-tail Mean PVRR
- 5th, 90th and 95th percentile PVRR
- Standard deviation
- Risk-adjustment (5% of the 95th percentile)

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 50 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, limited by performance constraints of the MT model, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's fixed costs, taken from the LT model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 50 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 2021 through 2040. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The MT model outcomes of the 50 stochastic samples are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 50 Monte Carlo simulations for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Step (J) – Calculate Risk-adjusted PVRR

As illustrated in Figure F.3, the calculation of the final PVRR for any study is performed by adding together the fixed costs from the LT model run in Step (H), the stochastic risk-adjustment from the MT model in Step (I), and the ST hourly granularity resulting PVRR from Step (G).

Portfolio and Resource Selections

Overview

The company incorporated the SCGHG dispatch adder in its Plexos modeling in the case identified as “P02-SCGHG” in Steps (B) and (E) as detailed above. The results of this study were compared to the results of the expected case, “P02-MM,” which was the least-cost, least-risk initial portfolio. Because both portfolios contained resource selections for all states, and because the resources allocated to Washington were 95 percent,[8] for Washington resource selections regardless of whether the analysis began with P02-SCGHG and removed non-Washington factors or started with P02-MM for the system and added Washington factors. regardless of whether the analysis began with P02-SCGHG and removed non-Washington factors or started with P02-MM for the system and added Washington factors.

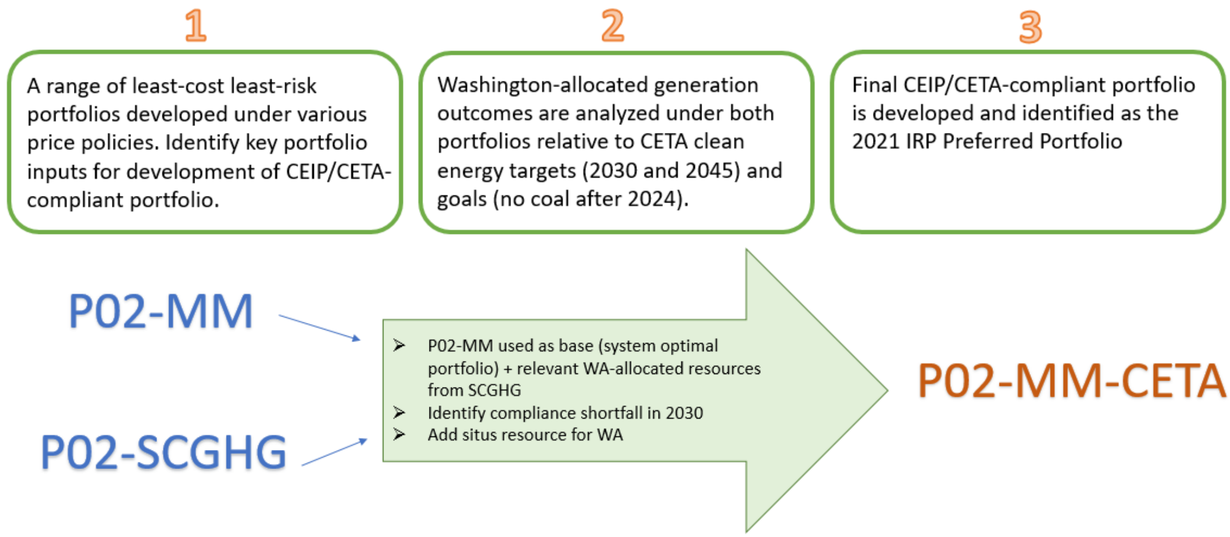
Incorporating P02-SCGHG into P02-MM-CETA

P02-MM entered the final evaluations as the top-performing portfolio for preferred portfolio selection on a systemwide basis. As Washington benefits from PacifiCorp’s systemwide optimization, and five other states would use P02-MM’s non-Washington allocated resource selections, PacifiCorp elected to label its preferred portfolio P02-MM-CETA once all CETA requirements had been met. Washington resource selections included in the preferred portfolio to meet CETA compliance included P02-SCGHG demand-side and supply-side resources, with only minor adjustments to meet identified CETA target deficiencies and improve portfolio

[8] Refer to workpaper for a comparison of Washington-allocated installed capacity of resources between P02-MM and P02-SCGHG “10829-PAC-WP-Compare - P02-SC vs P02-MM WA Allocated Capacity 3-13-2023.xlsx”.

diversity. Figure F.18 illustrates the integration process transforming the completed P02-MM and P02-SCGHG portfolio into the 2021 IRP preferred portfolio, which was also the CETA-compliant portfolio in the original CEIP filing.

Figure F.18 – Development of CETA-Compliant Portfolio[9]



P02-MM was subsequently evaluated using the targets established by CETA. While P02-MM was evaluated for compliance shortfalls, this was done with both P02-SCGHG demand-side resource selections and P02-SCGHG supply-side resources as a necessary step in creating P02-MM-CETA. The reason the modified P02-MM was evaluated against CETA targets and not P02-SCGHG is because PacifiCorp's intent was to evaluate compliance with CETA targets under expected operational conditions, which cannot be done using the P02-SCGHG study.[10]

CETA establishes specific targets for utilities serving customers in Washington including:

- By 2025, utilities remove coal-fueled generation from Washington's allocation of electricity;[11]
- By 2030, Washington retail sales are carbon-neutral;
    - 80 percent from long-term system resources;[12] and
    - 20 percent from alternative compliance using purchase of Unbundled Renewable Energy Credits (RECs);[13]

[9] Adapted from presentation materials developed for the October 5, 2022 technical conference, see supporting file file "210829-PAC SCGHG Settlement Workshop FINAL (C).pdf".
[10] This is evident in the 2021 IRP description of how the CETA compliance shortfall was identified for year 2030. Please refer to the 2021 IRP, Chapter 9 – Modeling and Portfolio Selection Results, page 290, paragraph 5, "This shortfall includes lower capacity requirements from incremental demand-side management resources specific to Washington identified from the P02-SCGHG portfolio." The purpose of this statement was to make clear that the only material difference between the PO2-MM and PO2-SCGHG portfolios of Washington-allocated resources was included in PO2-MM prior to assessing the shortfall. While PO20-SCGHG resources were also included, the differences were not material.
[11] RCW 19.405.030(1)(a).
[12] RCW 19.405.040(1)(a)(ii) (requires utilities to "use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utilities retail electric loads over each multiyear compliance period.").
[13] RCW 19.405.020(38).

- By 2045, Washington's retail sales are 100 percent renewable and non-carbon-emitting

Evaluating P02-MM against these targets required certain modeling assumptions to account for uncertainties related to the future of interjurisdictional cost allocation among the PacifiCorp states and resolution of outstanding CETA implementation issues. PacifiCorp currently allocates costs and benefits, including resource costs and benefits, to Washington according to the Washington Inter-Jurisdictional Allocation Methodology (WIJAM). The WIJAM expires December 31, 2023, and negotiations are underway among all six states to determine the next inter-jurisdictional allocation methodology. In addition to future inter-jurisdictional uncertainty, certain CETA implementation issues remain unresolved.[14]

In addition to assumptions regarding how energy is allocated across PacifiCorp's six-state system, PacifiCorp also made assumptions regarding the amount of renewable and non-emitting resources that is eligible to apply toward the 80 percent "primary" compliance obligation. For purposes of meeting primary compliance, PacifiCorp assumed that eligible generation was limited to energy generated from long-term resources located on PacifiCorp's system where both the energy and RECs were: 1) acquired at the same time; and 2) allocated to Washington customers under the applicable interjurisdictional allocation mechanism.

By 2025, PacifiCorp will remove all coal-fired generation from Washington's allocation of electricity. By 2030, the Chehalis natural gas-fueled plant is the only Washington-located thermal resource operating on the system; all other existing and new resources in the P02-MM top-performing portfolio are renewable or non-emitting. Thus, all system energy allocated to Washington from a renewable or non-emitting resource contributes to meeting the CETA targets.[15] This includes the renewable and non-emitting resources in the P02-MM top-performing portfolio as well as the energy efficiency and renewable Washington resource selections indicated by P02-SCGHG.

Identified Shortfalls

Upon evaluating the 2030 CETA target, a shortfall of roughly 69 MW of annual capacity was identified in 2030 (the highest shortfall year), with significantly smaller shortfalls identified in the years between 2030-2033. Under a four-year compliance window for the time period 2030 – 2033, an average annual shortfall of 49 MW was identified. This shortfall was addressed with a Washington-situs assigned 160 MW wind and solar resource co-located with storage located in Yakima, Washington.[16]

This shortfall also included lower capacity requirements from incremental demand-side management resources specific to Washington identified from the P02-SCGHG portfolio and the

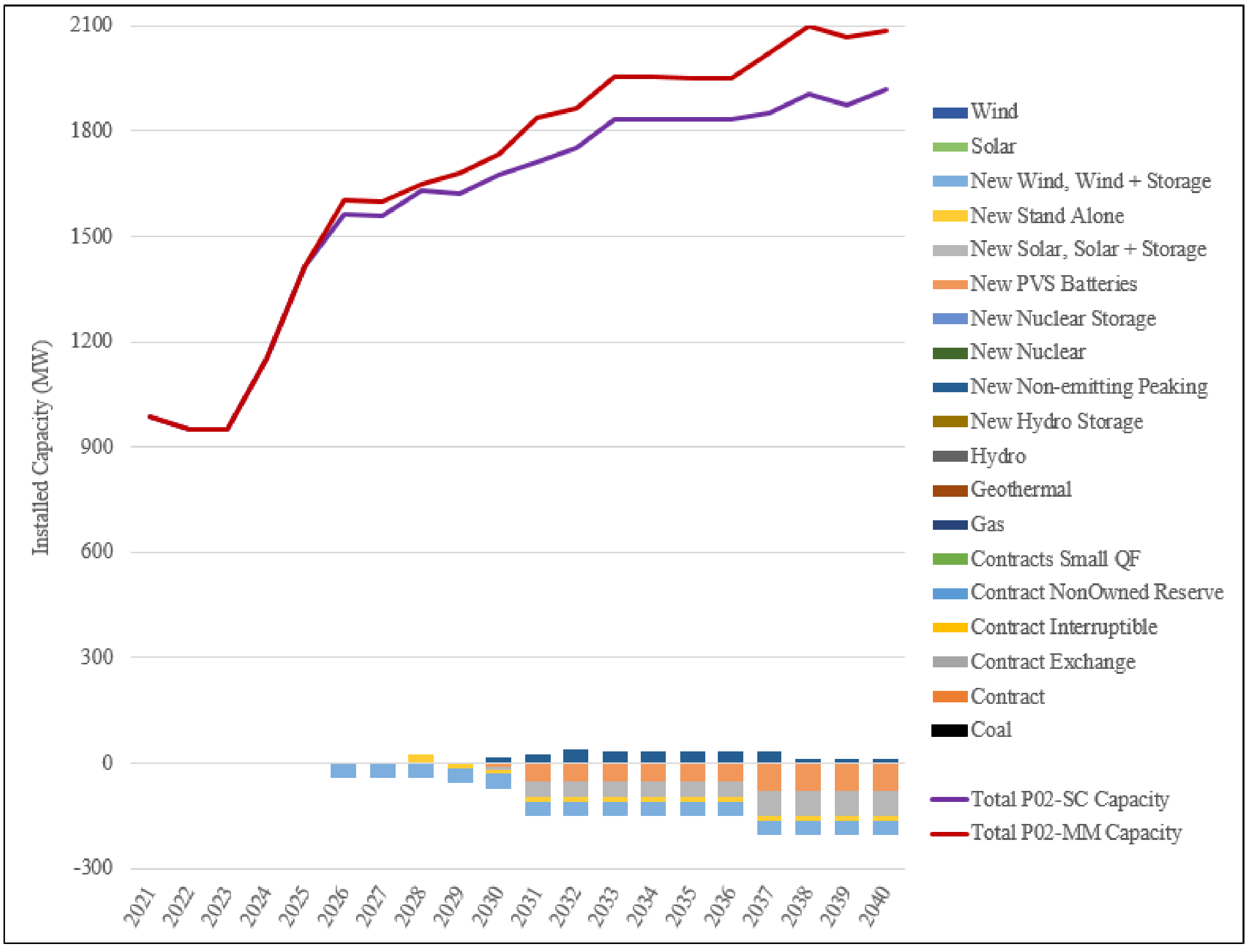
[14] For existing resources and new resources added through the end of 2023, the energy from system resources was allocated to states consistent with the 2020 Protocol and Washington Inter-Jurisdictional Allocation Methodology. For resources added to the system in 2024 and beyond, assignment of energy, costs and benefits followed a potential framework, subject to the ongoing Multi-State Process discussions, that enables compliance with CETA (and Oregon law) through reassignment of certain thermal resources. These resource allocation assumptions are used to assess the generation and allocation of Renewable Energy Credits (REC) state Renewable Portfolio Standard (RPS) compliance.
[15] This is limited to system energy where Washington is also allocated the associated RECs.
[16] Supporting confidential workpaper is "210829-PAC-WP-P02-MM Initial WA Resource Alloc 3-13-2023 (C).xlsx".

dispatch under the medium gas, medium CO_2 price-policy assumption of Washington selected resources identified in P02-SCGHG. In 2030, there was a reconfiguration of 160 MW of system solar collocated with storage located in Yakima, Washington in P02-MM, the top-performing portfolio, to become a Washington-situs assigned 160 MW resource that also includes wind, collocated with the solar and storage resource. This Washington-situs assigned resource maximizes usage of transmission interconnection availability at this location.

These additions to P02-MM to achieve CETA requirements resulted in P02-MM-CETA.[17] As CETA establishes a target in 2045 that retail sales are 100 percent renewable or non-emitting that is outside of the 20-year IRP planning horizon, extrapolation was done that shows the P02-MM-CETA preferred portfolio meets the requirements. The P02-MM-CETA results in a PVRR(d) relative to P02-MM of $164m.

P02-SCGHG and P02-MM (including DSM imported from P02-SCGHG) are identical during the current CEIP period from 2022-2025, as illustrated in Figure F.19.[18]

Figure F.19 – Washington Installed Capacity for P02-SCGHG less P02-MM



[17] Original CEIP targets established for P02-MM-CETA can be found in supporting confidential workpaper "210829-PAC-WP-P02-MM-CETA WA Allocation Target Development 3-13-2023(C).xlsx".
[18] Source data and figure can be found in workpaper "210829-PAC-WP-Compare - P02-SC vs P02-MM WA Allocated Capacity 3-13-2023.xlsx".

As explained during 2021 IRP and CEIP development and narrated in the CEIP executive summary, this is primarily because in the near-term PacifiCorp had already taken significant actions overwhelmingly aligned with CETA in the current CEIP panning window, and remains aligned until the year 2030 even without consideration of the SCGHG dispatch adder. While this holds true for Washington resources, the selection of non-Washington resources show greater disparity between the P02-MM and P02-SCGHG cases. This is because while PacifiCorp has in recent IRPs only added non-emitting resources and has retired coal resources, virtually all of the remaining emitting resources which would be impacted by the application SCGHG are allocated to states other than Washington. For reasons of this non-Washington applicability, the need to meet final targets and also to address diversity needs under conditions of systemwide coal retirement analysis, the Company also adopted a small number of portfolio changes in P02-MM-CETA. Table F.9 lists these final adjustments made for P02-MM-CETA.

Table F.9 - P02-MM-CETA Supply-side Resource Changes from P02-SCGHG[19]

In P02-MM-CETA, not in SCGHG	In P02-SCGHG, not in P02-MM-CETA
Yakima hybrid solar addition[1]	Dave Johnston Non-emitting[2]
Yakima hybrid wind addition[1]	Willamette Valley Non-emitting[2]
Yakima hybrid storage addition[1]	Southern Oregon Wind[3]
Hunter PVS solar[4]	
Hunter PVS storage[4]	

1 - Driven by need for final adjustment to meet targets
2 - Driven by reliability needs under heavy coal retirement
3 - Driven by reconciliation and diversity under heavy coal retirement
4 - Timing change driven by heavy coal retirement

Summary of P02-MM-CETA Portfolio Development

PacifiCorp's compliance strategy in the original CEIP flowed directly from the 2021 IRP preferred portfolio strategy. The company continues to believe that this interpretation of Washington SCGHG authorities was both reasonable and beneficial to Washington customers. Much of the explanation of this strategy was provided in the 2021 IRP, and not in the originally filed CETA document. This decision to leave much of the detail for portfolio development in the IRP was based on the notion that as the CEIP aligns with the IRP, and the IRP included the required precursor CEAP, and the IRP/CEAP preceded the CEIP in timing, including comprehensive detail in the CEIP was unnecessary and would run counter to the goal of filing a CEIP that would be accessible to the public. PacifiCorp chose instead to devote the majority of its attention to other elements of the CEIP, using the already established IRP preferred portfolio as a starting point.

P02-SC-CETA Data Inputs, Outputs and Roadmap

In this section, the Company details the data inputs, outputs, and provides a roadmap for the Company's 2021 CEIP P02-SC-CETA portfolio.

[19] Source data and table can be found in workpaper: "210829-SCGHG Settlement Workshop Portfolio Compares - Graph 3-13-2023.xlsx".

There are few differences between the development of P02-MM-CETA and the P02-SC-CETA portfolios. However, these slight differences have ramifications for eventual CETA target compliance and costs to PacifiCorp's Washington customers: Washington customers receive smaller renewable resources, several years later, compared to P02-MM-CETA.

Each of the settlement requirements for the new P02-SC-CETA portfolio is detailed below, including references to any identical sections of the roadmap narrative already described above.

P02-SCGHG Portfolio as the Basis of the CEIP Portfolio

PacifiCorp removed P02-MM-CETA as the basis for the CEIP portfolio, and replaced it with the P02-SC-CETA portfolio.

This is a new portfolio that was not developed for the 2021 IRP. While the company developed the P02-SCGHG portfolio in the initial CEIP, the additional steps which result in appending "-CETA" to the study names were not performed. Appending "-CETA" indicates that the portfolio has been adjusted for final CETA target compliance beyond the resource selections occurring as part of the roadmap illustrated in Figure F.3. P02-SCGHG is a price-policy study that fully incorporated the SCGHG dispatch cost adder in all resource selections. However, as with the P02-MM study, final CETA target compliance could not be achieved without additional resource considerations. As with P02-MM, in order to reach the "-CETA" status of full compliance, additional resources were required to be added in 2030 and beyond. That said, P02-SCGHG and P02-MM (including DSM imported from P02-SCGHG) are identical during the current CEIP period from 2022-2025.

Model Inputs and Outputs

Base Inputs

All IRP models are configured and loaded with the best available information at the time a model run is produced. Noted in Figure F.1 are the primary base assumptions for Plexos as inputs prior to running models. These inputs, such as load, private generation, existing transmission, etc., vary only for specific sensitivities and variants noted in the 2021 IRP. For the single relevant study used to develop P02-SC-CETA for the refiled CEIP there are no differences in base assumptions compared to any other study with the exception of the SCGHG price-policy scenario. All model inputs are included in workpapers included with the original filing, and are included again in this refiling for completeness. Additional input workpapers are provided and noted where appropriate below to fulfill on the terms of the settlement. Among the included workpapers is the entire 2021 IRP Plexos database which contains the P02-SCGHG study that serves as the basis for P02-SC-CETA.

Outputs are also provided in workpapers accompanying the 2021 IRP and original CEIP filings. As with inputs, these output files are provided again for completeness. As P02-SC-CETA is a new study, all of the appropriate additional workpapers, such as model report output files for the LT, MT and ST models, have been included in workpapers.

SCGHG Inputs

As detailed in section (1a) Model Inputs and Outputs - SCGHG Inputs, Plexos inputs for the SCGHG dispatch adder, extracted directly from Plexos, are provided in the workpaper "210829-PAC-WP-P02-SCGHG ST (30497-Emissions by Generator) 3-13-2023 (C).xlsx" on the "Emissions Results" tab. The critical component of this workpaper is provided here in Table F.10. As shown in this table, emissions costs for each Washington resource are derived entirely from the SCGHG dispatch adder, ensuring that there are no conflating emissions costs applied.

Table F.10 - SCGHG Dispatch Adder Applied to Thermal Resource Emissions Cost

	Production (ton)	Model Reported Cost ($000)	Emissions cost/lb	Emissions cost per ton	Calculated Emission total cost ($000)	Delta
Washington Emitting Resources	31,411,009	3,257,125	0.0451	90.2	3,257,125	0
Percentage of emissions cost accounted for by SCGHG dispatch adder						100%

P02-SCGHG Roadmap for Inclusion in P02-SC-CETA

PacifiCorp used the P02-SCGHG study as the basis for Washington resources in its P02-MM-CETA preferred portfolio, and does so again for the new P02-SC-CETA portfolio. The roadmap in Figure F.3 describing the application of the SCGHG dispatch adder in P02-SCGHG initial study, and therefore in the P02-SC-CETA final CEIP portfolio, is therefore unchanged. The application of the roadmap steps to the development of the P02-SCGHG portfolio is likewise identical. For this reason, the roadmap Steps A-J are not repeated here.

Instead, this section picks up where the roadmap leaves off, and identifies remaining CETA target shortfalls in the P02-SCGHG study and explains the resolution of those shortfalls through additional renewables added to the portfolio in 2030 and beyond.

Identified Shortfalls

P02-SCGHG does not result in a CETA compliant portfolio: the portfolio is 14 MWs short of annual capacity for the 2030 CETA target, and 28 MWs short of annual capacity for the 2045 CETA target.[20]

Due to the SCGHG dispatch adder's inevitable depression of CO2 emissions, shortfalls are lower in the P02-SCGHG than in P02-MM, leading to a reduced need for renewables over the 20-year study period. As a consequence, while shortfalls are smaller overall, they are distributed in a way that leads to breaking up CETA-target resource additions over multiple years. This distribution of target deficiencies results in net smaller renewable additions and a delay in achieving 100% CETA target compliance. In the P02-MM-CETA portfolio, the addition of a 160 MW renewable

[20] Supporting confidential workpaper is "210829-PAC-WP-P02-SCGHG WA Initial Target Development 3-13-2023 (C).xlsx".

resource in 2030 resolved all subsequent deficiencies and achieved 100% emissions reduction by the year 2038. In the P02-SC-CETA study, additions are made of the following type, location, size and timing as summarized in Table F.11.[21]

Table F.11 – P02-SC-CETA Resource Additions for CETA Compliance

Incremental Resource	Fiscal Year	Build Capacity (MW)
Yakima hybrid solar addition	2030	80
Yakima hybrid wind addition	2030	80
Yakima hybrid storage addition	2030	80
Yakima hybrid solar addition	2040	55
Yakima hybrid wind addition	2040	55
Yakima hybrid storage addition	2040	55

As can be seen in refiling Chapter 1, Figure 1.1 – Interim Targets, 100% compliance is instead achieved in year 2040, as there are cost savings associated with optimizing resource size according the schedule of deficiencies.

In 2030, there was a reconfiguration of 80 MW of system solar collocated with storage located in Yakima, Washington in P02-MM, the top-performing portfolio, to become a Washington-situs assigned 80 MW resource that also includes wind, collocated with the solar and storage resource. This Washington-situs assigned resource maximizes usage of transmission interconnection availability at this location. There is an additional reconfiguration of 55 MW in 2040 to bring the total installed capacity of the Washington-situs assigned wind, collocated with solar and storage resource to 135 MW.

These portfolio differences to P02-SCGHG to meet the requirements of CETA result in the CEIP Portfolio, P02-SC-CETA. As CETA establishes a target in 2045 that retail sales are 100 percent renewable or non-emitting that is outside of the 20-year IRP planning horizon, extrapolation was done that shows the P02-SC-CETA CEIP portfolio meets the requirements. The P02-SC-CETA results in an incremental cost relative to P02-SCGHG of $2.56 million on average annually.

Conclusion

The development of the P02-SC-CETA portfolio simplifies portfolio analysis compared to the 2021 IRP preferred portfolio by eliminating the steps of integrating Washington's resources with the rest of the system, and by retaining the SCGHG price-policy scenario throughout the analysis. While more straightforward, this approach increases the margin of error for CETA compliance under real-world conditions expected to prevail, and invites the risk identified in the 2021 IRP:

[21] Supporting data can be found in workpaper "210829-PAC-WP-P02-SC-CETA Installed Capacity 03-13-2023.xlsx".

> Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).[22]

P02-SC-CETA presents another reasonable interpretation of Washington's SCGHG authorities, and the identified impacts lie outside of the current four-year CEIP window. The Company looks forward to additional feedback and the continued discussion for how to best apply the SCGHG dispatch adder.

[22] 2021 IRP, Chapter 8 – Modeling and Portfolio Evaluation Approach, page 226