PACIFIC POWER
A DIVISION OF PACIFICORP

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April 1, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: LC 70—PacifiCorp's Final Comments

PacifiCorp d/b/a Pacific Power encloses for filing its Final Comments in the above-referenced docket.

Informal inquiries may be directed to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 70

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2019 Integrated Resource Plan	PACIFICORP'S FINAL COMMENTS

I. INTRODUCTION AND SUMMARY

PacifiCorp d/b/a Pacific Power (PacifiCorp) filed its 2019 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on October 18, 2019. On February 5, 2020, PacifiCorp filed reply comments in this proceeding.[1] The following parties filed their final comments on March 4, 2020: Commission Staff (Staff),[2] Renewable Northwest (Renewable NW), Alliance for Western Energy Consumers (AWEC), Citizen's Utility Board of Oregon (CUB), Multnomah County (Multnomah), Northwest Energy Coalition (NWEC), Renewable Energy Coalition (REC), Sierra Club, and the City of Portland (Portland).[3] As discussed in final comments filed by stakeholders, some issues raised in opening comments have been resolved through working groups, additional discussions, and in PacifiCorp's Reply Comments.[4]

[1] The company's reply comments responded to opening comments filed by Staff, Renewable NW, AWEC, REC, CUB, NWEC, the Northwest Intermountain Power Producers Coalition, Sierra Club, and Swan Lake Hydro, LLC filed on January 10, 2020.
[2] Staff filed a motion for leave to supplement their final comments that was granted on March 18, 2020. These comments respond to Staff's final comments including their supplemental comments.
[3] Multnomah and Portland did not file opening comments in this proceeding.
[4] *See*, *e.g.*, PacifiCorp Reply Comments at 56 (modifying Action Item 6b to make clear that the company will bank renewable energy credits in states with renewable procurement standard obligations); *see also* PacifiCorp Reply Comments at 7 (committing to continue evaluating its coal units in future IRPs to ensure that any uneconomic units are identified and retired). *See, generally*, Final Comments of Renewable Northwest (commending the company's efforts in this proceeding and noting several areas of progress since the filing of initial stakeholder comments).

PacifiCorp appreciates the progress that has been made and looks forward to additional discussions with stakeholders and the Commission. The company addresses the issues raised in stakeholders' final comments below but stresses that its preferred portfolio should be reviewed in a holistic manner. The Commission's IRP Guidelines identify four requirements for acknowledgment of an IRP:

- Evaluate all resources on a consistent and comparable basis;
- Consider risk and uncertainty;
- Selects a portfolio of resources with the best combination of expected costs and associated risks and uncertainty for the utility and its customers; and
- Be consistent with the long-run public interest as expressed in Oregon and federal energy policies.[5]

PacifiCorp's 2019 IRP satisfies each of these requirements when the components are considered as a whole. However, if certain of these components were not acknowledged, this piecemeal approach could undermine the integrity of the preferred portfolio and associated Action Plan. When changes are made to Action Plan items, the broader portfolio is impacted; when the broader portfolio is impacted additional changes become necessary and the company's resource portfolio ceases to reflect the least-cost, least-risk modeling performed by PacifiCorp. To avoid this result, the company encourages the Commission and stakeholders to view the 2019 IRP as a comprehensive resource plan when submitting any final recommendations. Through this lens, the PacifiCorp 2019 IRP must be acknowledged under the Commission's guidelines. Further, it will be increasingly important to review IRP filings as "complete packages" to allow utilities the ability to address increasing policy objectives and is particularly important for a multi-state utility like PacifiCorp that must account for differences across its service territory.

[5] Order No. 07-002 Appendix A at 1-2 (corrected by Order No. 07-047).

While the company acknowledges that there are many suggestions for refining the IRP process going into development of the 2021 IRP, none of these suggestions or recommendations should prevent acknowledgment of the 2019 IRP. Development of the IRP will always be an evolving process because state and federal policies continue to change and customer preferences and actions change, but these changes must be implemented while also maintaining a reliable system and avoiding overly burdensome rate impacts. PacifiCorp is confident that its preferred portfolio strikes this balance of progress and stability.

In these final comments, PacifiCorp responds to key issues raised in stakeholders' final comments including the following:[6]

- Responds to questions raised by the Commission at the March 10, 2020 workshop.
- Provides additional clarification regarding the appropriate assumptions used to develop the 2019 IRP, including its coal analysis.
- Provides additional support regarding the identified resource and transmission need set forth in the 2019 IRP and how that need will be met through PacifiCorp's Action Plan and specifically, through the upcoming request for proposals (RFP).
- Responds to questions regarding the transmission action items identified in the 2019 IRP and how these transmission action items will facilitate the interconnection of new renewable resources to PacifiCorp's system.

Consistent with these items, and as discussed in more detail below, PacifiCorp agrees to the following modifications to its IRP Action Items:

[6] The lack of company response on any issue should not be construed as agreement. In addition, many stakeholders comments on the same items or themes. The company has attempted to group its responses by topic rather than providing individual responses to each stakeholder.

- The company agrees to update Action Plan item 2b to reflect the extension of Production Tax Credits (PTC) through December 31, 2024.
- The company agrees to update Action Plan item 4a to include a Class 3 Demand Side Management (DSM) workshop that will occur no less than six months before filing of the 2021 IRP.

II. RESPONSE TO ISSUES RAISED AT COMMISSION WORKSHOP

As referenced above, the Commission held a workshop on March 10, 2020; at the workshop, PacifiCorp was asked to include responses to several inquiries in these Final Comments. These responses are set forth in this subsection with additional information integrated into the responses to written comments that follow.

A. Evaluation of Risk in Development of the 2019 IRP

As detailed in Staff's Final Comments, the 2019 IRP includes assumptions regarding both risks and opportunities.[7] The concept of "risk" was also discussed at the Commission Workshop to offer a better understanding of how PacifiCorp evaluates these risks in development of the IRP. For example, PTCs are currently set to expire on December 31, 2024. Acquiring resources that can leverage these tax benefits will allow the company to procure resources to meet its projected need at a lower cost. Conversely, PTCs could be extended and further reduce the cost of wind resources further out in time. Another risk discussed at length in Staff's Final Comments (and in these comments, below) is the timing associated with the Energy Gateway South (EGS) transmission project.

Consistent with PacifiCorp's treatment of the Energy Vision 2020 Project that was selected in the 2017 IRP, these risks are addressed in multiple ways. During the 2019 IRP

[7] Staff Final Comments at 12-14.

development they were captured in stochastic risk assessment and acquisition path analysis. After a preferred portfolio is selected, these risks are evaluated through selection of a final short list in the RFP process. And finally, these risks will continue to be mitigated through the development of detailed "off-ramp" strategies to mitigate risks associated with specific project details.

In short, the IRP is the beginning of the planning process, providing a robust model-based recommendation to guide the RFP and set the stage for both the Action Plan and detailed contingency planning. As a long-term planning tool dependent on numerous proxies and forecast assumptions, the IRP appropriately assesses risk through the use of sensitivities and stochastic modeling designed to illuminate the impacts of key variations in system conditions. Within the 2019 IRP, risk was assessed through the modeling of stochastic variables which include: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. These variables provide volatility representing unforeseen changes in future system conditions, creating 50 stochastic futures for every portfolio. In addition, these stochastic futures serve as proxies—for example, stochastic load is a proxy for any unforeseen circumstance that would create a variance in the load forecast, or variance in net demand, such as higher-than-expected wind curtailments.

Sensitivities also play a role in evaluating risk by providing the basis for acquisition path analysis accounting for lower and higher loads, lower and higher private generation, high carbon dioxide (CO_2) price with accelerated coal retirements, Jim Bridger and Naughton alternate retirements, low and high market prices, and changes in customer preference resource demand.

With respect to the risks associated with assuming that tax credits will expire in 2024, as currently scheduled, the company ran two hypothetical Tax Credit Extension Cases after the

2019 IRP was completed (and submitted to the Commission) in an attempt to quantify this risk. These additional modeling runs were mentioned during the February Commission Workshop. The first modeling run is a case that assumes a 60 percent wind PTC extension through 2028. The second modeling run is a case that assumes a 60 percent wind PTC extension through 2028, plus the extension of the 30 percent solar investment tax credits (ITCs) extended through 2028.

In the 60 percent wind PTC case, EGS is delayed to 2028.[8] The present-value revenue requirement (PVRR) as reported by the Planning and Risk model (PaR) for the 60 percent wind PTC extension case is lower than the preferred portfolio by approximately $1.1 billion. The 60 percent wind PTC case delays the addition of new wind until 2028, but adds approximately 2,000 megawatts (MW) more wind than the amount of wind in the preferred portfolio. The additional wind displaces nearly 2,000 MW of solar+storage. In the 2024 through 2027 time frame, reliance on market purchases increases significantly—on average, summer front-office transactions (FOTs) over this period are up by over 300 percent relative to those included in the preferred portfolio.

In the 60 percent wind PTC plus 30 percent ITC case, EGS is also deferred to 2028. The PVRR of system costs is about $1.0 billion lower than the preferred portfolio. The portfolio impacts of this case are similar to those from the 60 percent PTC case, where wind is delayed until 2028, with about 2,000 MW of additional wind relative to the preferred portfolio, and less solar+storage. Similarly, reliance on market purchases are up significantly in the 2024 through 2027 time frame, when average summer FOTs are over 400 percent higher than those in the preferred portfolio.

[8] Notably, this is still before the 2030 date supported by Staff, which PacifiCorp addresses at length below.

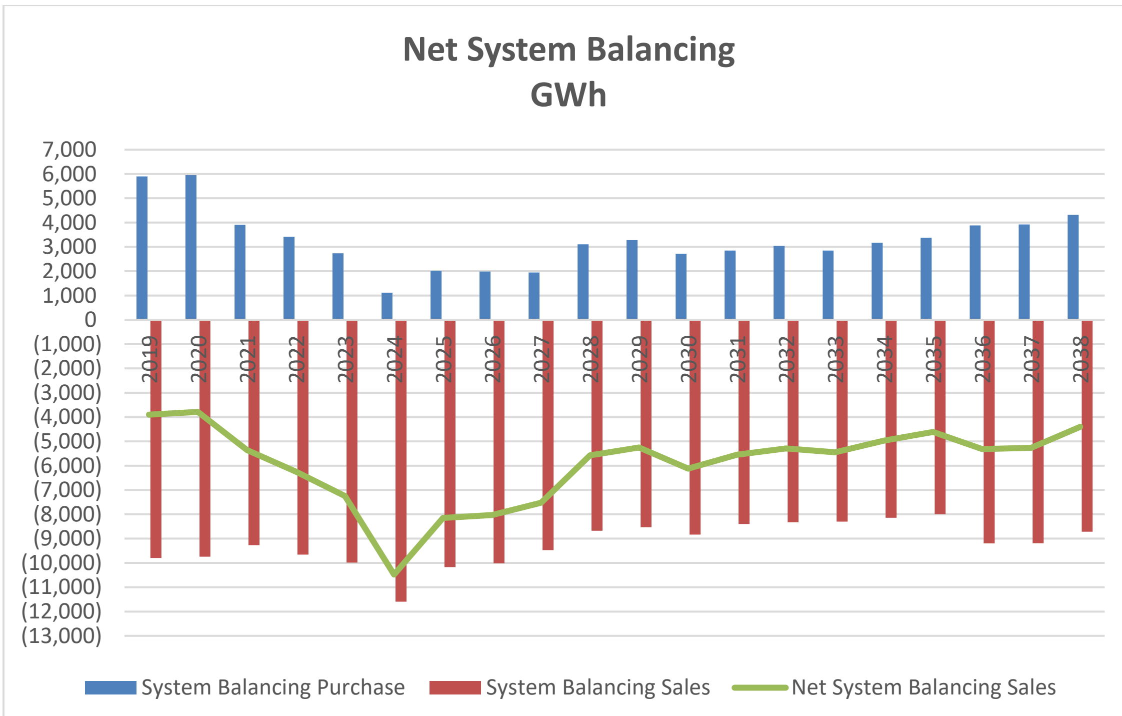
While both of these cases show potential for lower system costs if tax credits are extended through 2028, it is highly speculative to assume that tax credits will be extended, let alone extended for this period of time and at the levels assumed in the analysis. If renewable resources are not procured in a time frame that is consistent with the procurement timing in the preferred portfolio, which reflects the expiration of tax credits that are currently in effect, customers will be more exposed to market purchases and will face a significant risk that the cost of procuring new renewable resources at a later date would come at a substantially higher cost.

In addition to these two hypothetical tax credit cases, PacifiCorp also ran an intergenerational equity case to test the impact of delaying the procurement of all physical generation resources until 2028. The model initially could not solve this case and reported that the scenario was "infeasible" due to insufficient resources to reliably serve load through 2027. Available DSM and FOTs could not supply all of the system capacity needs, even with very high cost tranches of DSM. Thus, PacifiCorp allowed storage additions in 2026 and 2027 to meet reliability requirements and to develop a resource expansion plan that could be analyzed in PaR.

EGS was not allowed until 2028, and was chosen in 2028. The PVRR of this case was approximately $1.8 billion higher than the preferred portfolio. This cost differential includes a $2.3 billion increase in present-value DSM costs, partially offset by a $1.3 billion reduction in present-value capital revenue requirement and fixed operation and maintenance (O&M) costs. Of note, Oregon DSM reaches the $750-$1,000 per megawatt-hour (MWh) bundle level, versus a maximum price of $90-$100 per MWh DSM bundle in the preferred portfolio.

B. Changes in System Balancing Purchases and Sales

During the March 10, 2020 Commission Workshop, Commissioner Tawney asked about changes to the company's net energy position as a result of the addition of renewable resources to PacifiCorp's portfolio. As shown in the 2019 IRP, renewable resources represent 17 percent of the system in 2020 and grow to 50 percent by 2038, the last year of the forecast.[9] In 2021, with the addition of Energy Vision 2020, renewables grow to 26 percent, then continue to grow to 40 percent by 2024 with the addition of transmission upgrades, including EGS, that enable procurement of additional renewable resources and battery storage systems that are eligible for federal tax credits. The addition of these renewable resources influences the level of projected system balancing purchases and sales, as summarized in the figure below.

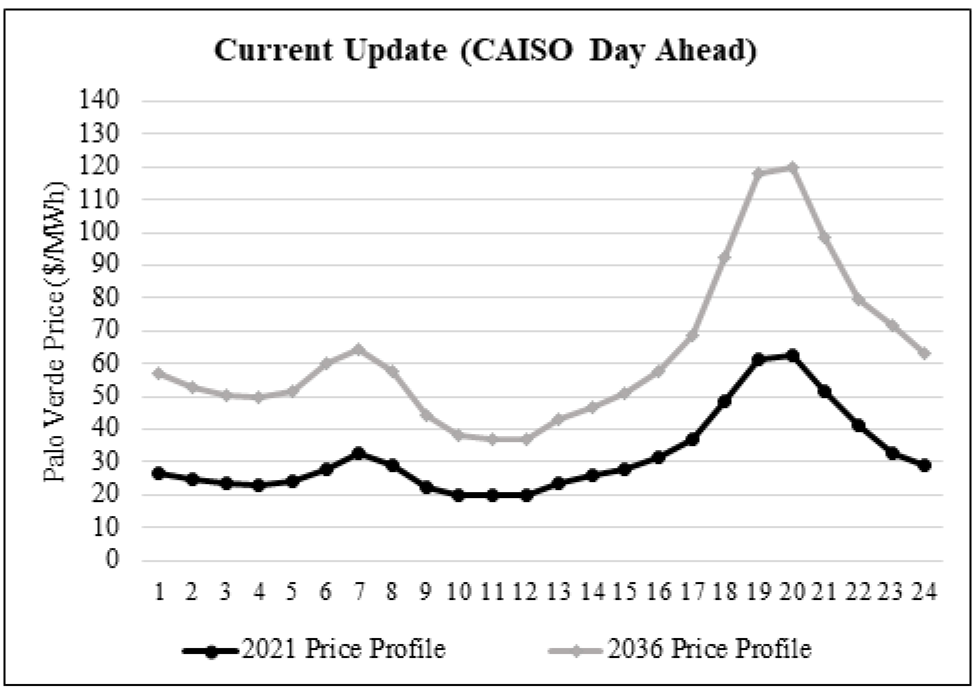


From 2023 to 2024, when a large volume of renewable resources are added to the system, annual purchase volumes decrease by about 1,600 gigawatt-hours (GWh) and annual sales volumes increase by about 1,600 GWh. By 2025, the trend shifts direction, as evidenced by a year-on-year increase in system balancing purchases and a year-on-year decrease in system balancing sales relative to 2024. On average, annual system balancing transactions from 2025 through 2038 reflect a net long position of about 5,800 GWh per year, which is actually less than

[9] See 2019 IRP at 257, Figure 8.44: Projected Energy Mix with Preferred Portfolio Resources.

the 7,250 GWh net long position in 2023, before the relatively large volume of renewable resources are in service in 2024. While the addition of 2024 renewable resources from the preferred portfolio influence system balancing transactions, the impact is relatively short lived. Consequently, PacifiCorp's plan to initiate a procurement process for these resources is not disproportionately driven by an overly optimistic forecast of increased market sales.

These purchases and sales are priced to reflect hourly profiles derived from data available from the California Independent System Operator (CAISO), thereby capturing the impact that renewable resources are having on the shape of market prices within the day. The figure below, which was presented to stakeholders at the September 2018 public-input meeting, shows a representative example of how hourly prices are shaped based on historical CAISO day-ahead market data.



III. REPLY TO PARTIES' FINAL COMMENTS

A. Considerations for Future IRP Development

As noted in the company's Reply Comments, PacifiCorp has already begun the process of developing its 2021 IRP. As part of that development, the company will consider feedback received through comments and other stakeholder input during this proceeding. The company also encourages all interested stakeholders to actively participate in the development of the 2021 IRP through the robust public input process that includes two-day meetings on a near monthly basis beginning in June 2020 and an informal comment/question process facilitated through the company's IRP website that allows stakeholders to submit comments and questions to the company for a response. All responses are then posted publicly on the website. PacifiCorp encourages all stakeholders to take advantage of this process; implementing recommendations during development of the IRP is preferable because it allows a holistic approach that is often not possible when material changes to the preferred portfolio are suggested during the acknowledgement process.

By raising these recommendations through the public input process, stakeholders in all jurisdictions will also be made aware and have the opportunity to weigh in on these recommendations. This increases transparency and allows input from across PacifiCorp's service territories. With the increasing market pressure to reduce reliance on coal, it was helpful during the 2019 IRP development process to allow stakeholders to interact directly through the public input process with the impacted employees operating these coal facilities.[10] These interactions increase the likelihood that the preferred portfolio is representative of all perspectives across service territories.

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[10] *See* NWEC Final Comments at 4 (noting that direct involvement of the workers and communities that will be impacted by coal plant closures as part of the 2019 IRP process was a positive development).

B. PacifiCorp's IRP Assumptions Were Reasonable

1. The company's Coal Study Assumptions are reasonable.

As discussed in the company's Reply Comments, PacifiCorp intends to continue to refine and update its coal analysis.[11] While the company is appreciative of CUB's general support for its coal analysis and scheduled retirements, PacifiCorp continues to disagree with CUB's suggestion that because selective catalytic reduction (SCR) technology was deemed less effective than retirement of coal units as part of the 2017 IRP analysis this conclusion should never be revisited (*i.e.*, that the costs of SCR should simply not be included in future IRP modeling). If SCR technology makes coal units non-economic, this result will be supported by the IRP modeling and analysis. It is not necessary to "stack the deck" against coal units and it would not be appropriate to do so, particularly in circumstances where the underlying assumptions with regard to the life of a coal facility in any given scenario would not be achievable without including the SCR costs required by current environmental compliance obligations.

Instead, as required by the IRP Guidelines, the company evaluated all resources on a consistent basis. For PacifiCorp's coal units, this required inclusion of current environmental compliance obligations like SCR technology.[12] Only when these requirements are changed would it be appropriate to remove the costs associated with SCR from the IRP analysis

[11] *See* Sierra Club Final Comments at 5-7; *see also* PacifiCorp Reply Comments at 7.
[12] *See* PacifiCorp's Reply Comments at 8 (stating that under the State of Wyoming's Regional Haze Implementation Plan that has been approved by the United States Environmental Protection Agency (EPA) SCR is a current legal requirement for the operation of Jim Bridger Units 1 and 2). *See also* PacifiCorp's Reply Comments at 9 (stating that the Regional Haze Federal Implementation Plan that would require environmental compliance technology for the Hunter and Huntington coal units has been stayed by the United States Tenth Circuit Court of Appeals pending reconsideration by the EPA).

performed by the company. PacifiCorp's inclusion of SCR costs was consistent across its IRP modeling and based on current legal requirements.

Sierra Club argues that SCR requirements are a "reasonably foreseeable risk" with respect to the company's Hunter and Huntington units, however, consistent with PacifiCorp's determination to include only the currently legally enforceable obligations these costs were not included in IRP modeling.[13] It is difficult to predict the outcome of legal proceedings and the company's approach is reasonable and can be consistently applied. Attempting to determine the likelihood of a particular outcome on future compliance obligations is especially unnecessary given the IRP cycle that provides for updates every two years.

CUB also asks that PacifiCorp align its preferred portfolio retirement dates for Jim Bridger with dates identified in the integrated resource plan modeling efforts of its co-owner of the Jim Bridger plant and mine, Idaho Power Company (IPC).[14] While PacifiCorp and IPC work to ensure that the input assumptions and data associated with the Jim Bridger plant and mine are consistent between our respective resource planning modeling tools, the system needs, customer loads, and various other modeling parameters for our respective entities are indeed independent and should be expected to result in somewhat unique resource need modeling outcomes. In addition, the regulatory procedural schedules for our independent integrated resource planning efforts across the states we respectively serve can be somewhat overlapping, but often times diverge. Recognizing these differences and the regularity of our respective future integrated resource planning efforts, PacifiCorp and IPC will continue to coordinate to establish prudent

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[13] Sierra Club Final Comments at 6. Sierra Club also points to the company's coal studies developed as part of the 2017 IRP proceeding and alleges that there were inconsistencies based on differences between the assumptions in that 2018 coal study and the 2019 IRP. *See* Sierra Club Final Comments at 7. This argument should be disregarded because the treatment of environmental obligations was consistent throughout the development of the 2019 IRP and need not be consistent with a 2018 analysis. Legal obligations and thus reasonable assumptions will change over time.
[14] See CUB Final Comments at 9-10.

and supportable outcomes for our respective customers and stakeholders pursuant to the terms of the joint ownership agreements that govern our decision making processes for the Jim Bridger plant and mine as critical decision points regarding pending retirement dates approach.

2. PacifiCorp's reliability resource methodology was necessary and produced accurate results.

PacifiCorp strongly disagrees with Sierra Club's assertion that the company's Reply Comments included "misleading" justifications regarding the reliability resource methodology.[15] PacifiCorp, like all utilities, has an obligation to supply electric service as a provider of last resort. The company's Reply Comments provided an explanation in support of its reliability resource methodology including why this methodology is necessarily included to meet reliability and reserve requirements. PacifiCorp has also responded to data requests and answered questions at the March 10, 2020 Commission workshop. As the company explained at the workshop, PacifiCorp cannot guarantee that the preferred portfolio will be a reliable portfolio if this additional reliability resource requirement is not included because not all uncertainties can be captured in the company's hourly reliability modeling.[16] Sierra Club may disagree with the conclusions reached by PacifiCorp, but it is disingenuous to allege that the company is attempting to mislead the Commission or other stakeholders. In fact, Staff confirms in their final comments that the company's conclusion to include some additional reliability resources was "completely justifiable and reasonable."[17]

[15] Sierra Club Final Comments at 3.
[16] PacifiCorp Reply Comments at 11.
[17] Staff Final Comments at 22 (Staff does question the correct amount of reliability resources to include as addressed below).

As noted above, Staff agrees with the company that additional reliability resources are necessary, but Staff questions whether 500 MW is the "right" amount.[18] The company disagrees with Staff's assertion that PacifiCorp's discovery responses fail to support this amount.[19] As explained in the response to Data Request OPUC 191, during the summer of 2018, the company held 536 MW in reserve for contingency needs (that could arise from a forecast error, intra-hour volatility, or peak load conditions) based on its 13 percent planning margin.[20] This explanation is consistent with the company's 2019 IRP, Appendix R which states:

> The 500 MW incremental requirement relative to a deterministic forecast of loads, outages, market prices, and hydro generation was established upon review of operational data and with consideration of operational experience. In operations, capacity held in reserve for contingency, forecast error and intra-hour variability is approximately 16 percent of peak load. In the summer months, additional capacity is held in reserve to mitigate risks associated with high volatility in load and resource availability. In 2018, capacity held in reserve that is incremental to the 13 percent planning margin for contingency, forecast error, and intra-hour volatility totaled 295 MW. In 2018, capacity held in reserve to mitigate risk during peak load conditions in the summer months was approximately 241 MW.

It is clear in the text that the uncertainty requirement is intended to cover an array of possible deficiencies. The company considered the actual holding of capacity on a day-ahead basis if there is a risk of a forced outage due to tube leaks or other items that are scheduled for a later time but that can cause near-term problems. These are not contingency reserves, they are replacement reserves (*i.e.*, they are designed to re-supply contingency reserves in the second hour following a loss of supply). Replacement of reserves can be problematic if there is limited

[18] Staff Final Comments at 22.
[19] Staff Final Comments at 22.
[20] Staff agrees that a 13 percent planning margin is appropriate. Staff Final Comments at 25 (*stating* that the 13 percent planning reserve margin appears reasonable based on Appendix I of the 2019 IRP and commending PacifiCorp for its "excellent" reporting of the analysis that is the basis of this calculation). The company's response to Data Request OPUC 191 was included in Attachment A to Staff's Final Comments.

market liquidity or high prices due to high loads or decreased supply relative to hydro conditions, etc. As the capacity held in reserve "is approximately 16 percent of peak load," the 500 MW requirement is by definition incremental to both reserve and load obligations assumed by the 13 percent planning reserve margin.

To provide additional context for the 500 MW requirement, note that the 13 percent planning reserve margin is based on an analysis with stochastic variations in load, hydro conditions, and thermal outages. This stochastic variation is not present in the deterministic study upon which the reliability analysis is performed. The deterministic study contains median loads, hydro conditions and thermal outages, at levels that are equally likely to be higher or lower than actual conditions. In one year out of two, requirements will be higher than the deterministic analysis indicates, such that absent an incremental requirement, PacifiCorp would face resource shortfalls in 50 percent of years. Based on the stochastic variations in load, hydro, and thermal availability used in the development of the planning reserve margin, the incremental 500 MW requirement would only be sufficient to avoid shortfalls in 70 percent of years.

Put another way, the 500 MW requirement refers to the minimum quantity of unused capacity that is available to PacifiCorp after serving load and meeting operating reserve requirements (spinning, non-spinning, and regulation reserve). The 500 MW requirement is not part of the operating reserve requirements and is calculated from the unused capacity of dispatchable resources (*i.e.*, in excess of generation and allocated operating reserve) and market purchase capacity up to the defined FOT limits plus any market sales. Since market sales represent economic dispatch rather than a long-term commitment, resources available to support market sales would be deployed first to ensure the reliable provision of service to PacifiCorp customers. Non-dispatchable resources also contribute to meeting the requirement, as an incremental MW of non-dispatchable resource output will result in a rebalancing of the system which either reduce dispatchable generation, reduce market purchases, or increase market sales.

In response to Staff's request for clarification regarding whether the 500 MW reliability resource amount is designed to eliminate shortfall (Energy Not Served (ENS)) or ensure that operational reserves are maintained,[21] PacifiCorp would also note that contingency reserves cannot be deployed except in the 60 minutes following a qualified contingency event, so depletion of contingency reserves to forestall ENS is not an option. The regulation reserves modeled in the 2019 IRP are intended to compensate for errors between hour-ahead forecasts and actual output. This does not encompass all of the uncertainty in actual operations. In the event the regulation reserves available are insufficient to maintain the balance of load and resources, curtailment of firm load (*i.e.*, ENS) may be required to avoid violation of the North American Electric Reliability Corporation reliability standards. The uncertainty requirement is intended to cover additional unanticipated emergent needs without pre-selection bias. One reason for this lack of bias is that deficiencies in optimization modeling can be nearly interchangeable due to cost margins between types of deficiencies. While types of requirements are specific, a "missing megawatt" may be assigned in more than one way without a meaningful difference in cost impact to the model. The reliability assessment therefore translates all deficiencies (load, spinning-reserves, non-spinning reserves, and regulating reserves) into a flexible resource capacity shortfall, where a flexible resource can supply capacity to cover any deficiency.

PacifiCorp disagrees with the implied conclusion in Staff's Final Comments that a portfolio with demonstrated operating reserve deficiencies should be considered reliable from the perspective of long term planning.[22] Staff's recommendation implies that the deficiencies

[21] Staff Final Comments at 22.
[22] *See* Staff Final Comments at 22-23.

measured in the reliability assessment must be either load deficiencies or reserve deficiencies. The assessment necessarily measures both, as both load and reserve requirements must be considered in any assessment of system reliability. The reliability assessment examines load and reserve requirements, either or both which may be deficient and either or both of which can be met by flexible capacity.

Nevertheless, consistent with PacifiCorp's Reply Comments, the company commits to revisiting this issue as part of the 2021 IRP development and ensuring that the public input process includes an opportunity for discussion with stakeholders.[23] The challenge in the reliability process stems from modeling deficiencies which have emerged due to the rapid inception of cost-effective renewable and storage resources. Consistent with public input meeting discussion and stakeholder feedback, the company is actively engaged in acquiring new optimization modeling intended to address these deficiencies. Updates on this new modeling will be communicated as part of the 2021 IRP public input process.

3. The correction to the Jim Bridger Coal Mine costs identified by Sierra Club will be included in development of the 2021 IRP.

Sierra Club's Opening Comments identified an error in the company's coal mine costs included in the modeling; PacifiCorp acknowledged the error in its Reply Comments and explained the implications of this error. Sierra Club does not disagree that accounting for this error does not result in any changes to the 2019 IRP Action Plan; instead, Sierra Club argues that this error should result in changes to depreciation schedules because the error would have resulted in selection of portfolio P-48CP where Jim Bridger Units 3 and 4 retire in 2033 instead of 2037 under the preferred portfolio.[24] Whether there may be implications to the depreciation

[23] PacifiCorp Reply Comments at 13.
[24] Sierra Club Final Comments at 5.

schedule is not relevant to this proceeding. Depreciation schedules are determined separately from the IRP acknowledgement process and need not be considered here. In fact, as part of the company's multi-state protocol (MSP), revised depreciation schedules for Oregon were agreed to by the parties to the MSP stipulation.[25] Thus, no additional consideration as part of this proceeding is necessary.

PacifiCorp agrees, however, that it should (and will) ensure that the correct Jim Bridger coal mine costs are included in the 2021 IRP. The company has also considered Staff's recommendation that PacifiCorp should use the coal retirements from portfolio P-48 for its 2020 all source (2020AS) RFP (instead of the coal retirements from the preferred portfolio). PacifiCorp would not expect any material differences to result from this change. To confirm this expectation, however, the company will conduct a sensitivity analysis to the initial short list of bidders that uses the coal retirements from P-48. The company would prefer not to change the RFP documents to reference P-48 because it is concerned that this could cause confusion regarding the relationship between the preferred portfolio (currently referenced in the RFP documents) and the 2020AS RFP. Performing this additional analysis will allow the RFP to account for the updated coal retirement dates without causing confusion.

4. The company has included industry-standard estimates for solar in its analysis.

In addition to raising specific concerns with the company's operation of its coal units, Sierra Club continues to question the solar O&M cost assumptions used in the IRP reflect industry-standard estimates.[26] Sierra Club's arguments are generally repetitive of the arguments raised in its opening comments. As stated in PacifiCorp's Reply Comments, PacifiCorp will

[25] Sierra Club actively participated in the MSP process, signed the 2020 Protocol, and the stipulation supporting adoption in Docket No. UM 1050.
[26] Sierra Club Final Comments at 8.

continue to monitor cost trends for utility scale single-axis tracking photovoltaic solar generation resources in the company's service territory and update those costs in future IRP cycles. The 2020 renewable resource assessment will specifically address differences from the Lazard and National Renewable Energy Laboratory (NREL) studies referenced by the Sierra Club. Staff's Final Comments support this approach[27] and this is consistent with the company's prior commitment to continue to revisit its schedule of coal unit retirements. Nothing in Sierra Club's comments suggest that changes would even be necessary during the Action Plan window. It is therefore appropriate to revisit these issues as part of the 2021 IRP development instead.

5. PacifiCorp's Natural Gas Price Assumptions are reasonable.

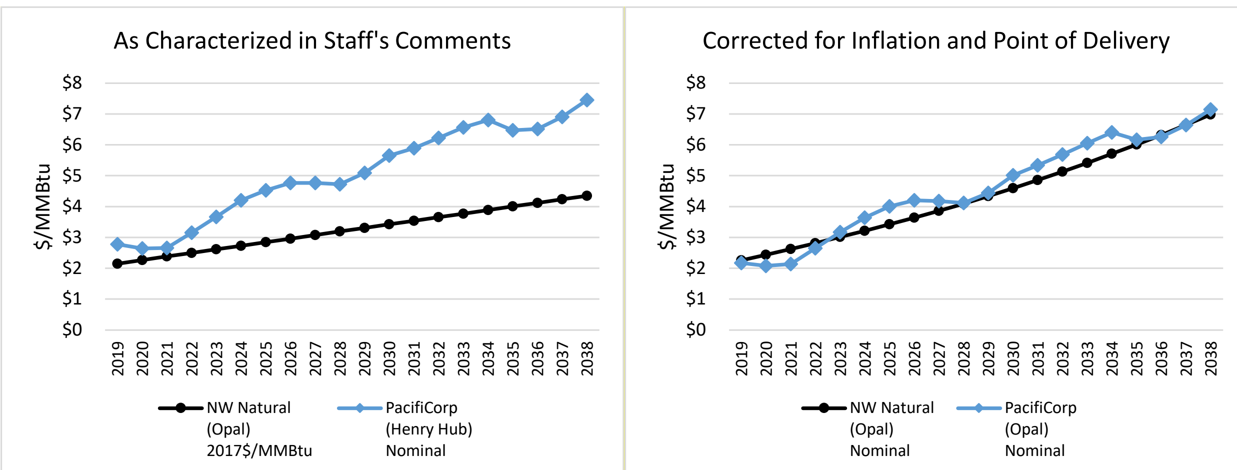
In its discussion of economic risk and uncertainty, Staff notes that if natural gas prices do not increase as projected, that the value of renewable resources will be lower than expected.[28] In raising this risk, Staff presents natural gas price assumptions used in PacifiCorp's 2019 IRP, and to provide perspective, summarizes these assumptions relative to price forecast information from NW Natural's 2018 IRP. The way that Staff presents natural gas price information from PacifiCorp's 2019 IRP relative to the price projections summarized in NW Natural's 2018 IRP is misleading.

First, Staff presents a graph of PacifiCorp's 2019 IRP natural gas price projections for three scenarios—medium, low, and high. This graphic appears to be taken from Figure 7.4 of the 2019 IRP. The title on the figure denotes that the price forecasts are for Henry Hub. The title of this figure in the 2019 IRP, which was omitted from Staff's comments, further notes that the price forecasts are in nominal dollars (*i.e.*, reflecting the influence of inflation over time). Second, when comparing price assumptions from PacifiCorp's 2019 IRP relative to

[27] Staff Final Comments at 38.
[28] Staff Final Comments at 13-14.

NW Natural's price forecast in its 2018 IRP, Staff quotes average price information from PacifiCorp's 2019 IRP for the year 2038 among three different points-of-delivery—Opal, Sumas, and AECO. While not stated, Staff's representation of PacifiCorp's 2038 price information is also in nominal dollars. Staff then compares this information to data presented in NW Natural's 2018 IRP for the year 2038 and concludes that PacifiCorp's price projections are 60 percent higher.

This conclusion is flawed. Staff does not recognize that NW Natural's price forecast is presented in real 2017 dollars (*i.e.*, does not reflect the influence of inflation over time). The following figure summarizes two different graphs.



The graph on the left shows PacifiCorp's nominal price forecast for Henry Hub alongside our representation of NW Natural's 2018 IRP forecast at Opal presented in 2017 dollars.[29] It is not appropriate to infer how these natural gas price projections relate to one another because the forecasts are for two different points-of-delivery with two different representations of inflation.

[29] The NW Natural price forecast referenced by Staff is presented as a graph in NW Natural's 2018 IRP with monthly granularity. In representing NW Natural's 2018 price forecast in these reply comments, the company visually interpreted price data from this graph such that the average annual price at Opal for the year 2019 is approximately $2.15/MMBtu in 2017 dollars and that the average annual price at Opal for the year 2038 is approximately $4.35/MMBtu in 2017 dollars. Prices between 2019 and 2038 were linearly interpolated.

The graph on the right shows PacifiCorp's nominal price forecast for Opal alongside PacifiCorp's representation of NW Natural's 2018 IRP forecast at Opal when presented in nominal terms.[30] As can be seen in this graph, PacifiCorp's price forecast is *not* 60 percent higher than prices presented in NW Natural's 2018 IRP. In fact, PacifiCorp's 2019 IRP prices at Opal are very much aligned with prices assumed by NW Natural.

C. DSM Actions

The company's 2019 IRP separates DSM resources into four classes as follows: Class 1 DSM (DR); Class 2 DSM (energy efficiency); Class 3 DSM (time varying rates); and Class 4 DSM (customer practice adaptation). In opening comments, several stakeholders raised concerns that the preferred portfolio does not include all cost-effective DSM resources. In the 2019 IRP, 23 MW of DSM energy efficiency capacity was selected over the 20-year forecast period which included bundle costs up to $90 per MWh. In response to stakeholder concerns, PacifiCorp committed in its Reply Comments to conduct additional stakeholder workshops on these topics including a workshop specifically focused on demand response (DR). PacifiCorp also committed to working with stakeholders to consider ways to refine its conservation potential assessment (CPA) DR methodology. The company has already held two CPA workshops and has an upcoming workshop scheduled for April 16, 2020.

1. The company has included an appropriate level of Class 1 DSM resources for Oregon.

NWEC, Staff, and CUB all raised concerns with the level of Class 1 DSM (demand response) in the 2019 IRP through opening comments. NWEC's Final Comments acknowledge the steps the company has taken to address these concerns including commitments to improve

[30] The conversion of NW Natural's price forecast from 2017 dollars to nominal dollars is based on the company's inflation forecast used to derive the 2.28 percent annual inflation rate adopted for the 2019 IRP.

modeling for the 2021 IRP, leveraging its affiliate's experience in Utah with the "coolkeeper" program, and engaging in discussions regarding a separate DR RFP.[31] Staff and CUB also acknowledge these efforts but request that a separate DR RFP be memorialized in the Action Plan including a requirement to file a proposal with the Commission and a stakeholder process to discuss a potential future DR RFP.[32] CUB also recommends that acknowledgment of the 2019 IRP include a condition pursuant to which the company would commit to implement more DR pilot programs in Oregon, in the near-term.[33] While it may be premature to commit to conducting a DR RFP or pilot, PacifiCorp reiterates its commitment to conduct additional stakeholder meetings to discuss these proposals and to also evaluate the market. The first of these discussions is scheduled for April 14, 2020. Based on these discussions with stakeholders and the company's market evaluation, PacifiCorp will be able to provide an update to the Commission that would include the company's determination on whether such an RFP is an appropriate option for acquisition of additional Class 1 DSM, including a proposed timeline for any such RFP. The company will also use these discussions to seek clarification regarding the scope, scale and purpose of any potential pilot programs. In the meantime, as noted by NWEC, the company is already working to update the inputs to its CPA with respect to DR based on stakeholder feedback and these updated inputs will inform the 2021 IRP.

While the company is committed to exploring how additional DR can be added to its portfolio, it strongly disagrees with Staff's position that investment in battery deployment should be "disallowed" until PacifiCorp "can demonstrate it has identified, planned for, and implemented all technically achievable demand response that costs less than battery deployment,

[31] PacifiCorp Reply Comments at 18.
[32] Staff Final Comments at 9; *see also* CUB Final Comments at 4.
[33] CUB Final Comments at 4.

or proven that demand response is an invalid solution to the problem in question."[34] The "problem in question" appears to be that Staff disagrees with the company's IRP modeling results. The "solution" suggested by Staff (to "disallow" investment in battery deployment) is neither appropriate for this proceeding nor a solution to the alleged problem.

As Staff concedes in Final Comments, batteries and Class 1 DSM each provide different benefits to the system and are not interchangeable.[35] PacifiCorp's Reply Comments explained how DR is modeled for development of the IRP; this modeling selects economic DR resources based on the ability to compete against other supply-side resources. Thus, Staff's assertion that the company has not fully evaluated DR on a comparable resources is without merit.[36] Staff's attempt to support that argument by reference to a table that attempts to compare the costs of DR with storage resources is similarly not persuasive. The company previously addressed the table and surrounding discussion from Staff's Initial Comments in PacifiCorp's Reply Comments that stated in relevant part:

> The SO model selects economic DR resources based on its ability to compete against other supply-side resources to achieve a least-cost and least-risk portfolio of resources to meet customer needs. The modeling process is robust and continuously improving to ensure the planning process is prudently using the best possible information available at the time of the development of the resource assumptions informing the IRP. Therefore, PacifiCorp's preferred portfolio already identifies the full amount of economic DR within the supply and costs identified in the CPA.[37]

The company also addressed this table in its response to Data Request OPUC 201. PacifiCorp provided the following relevant information in that response:

[34] Staff Final Comments at 20.
[35] Staff Final Comments at 20.
[36] Staff Final Comments at 20.
[37] PacifiCorp Reply Comments at 18.

> Simply stated, the cost and performance attributes of near-term DR alternatives in Oregon are such that a portfolio that would include these resources would yield a higher PVRR from an SO model simulation than a portfolio that excludes them.
>
> While DR resources provide peak capacity, they provide little to no energy value since most are load-shifting in nature, and they are available in a limited number of hours. On an energy basis, the cost of the least expensive Oregon DR resource (OR-Ancillary Services) is $254.58 per megawatt-hour ($/MWh). The cost of an Oregon solar+storage resource added to the system in 2024, which also provides reserves to the system, is $37.81/MWh.

Staff's misleading statement in Final Comments that PacifiCorp was not responsive to its analysis is therefore without merit. Instead, their objection seems to find PacifiCorp's analysis to be unintuitive based on its own analysis which ignores the fundamental differences between DR and storage. Using load-cutting programs (such as irrigation) as an example, during the summer evening peak when solar is falling off and the energy ramp becomes extreme, cutting load through a DR program brings a load reduction benefit in the peak timeframe to offset program cost. Cutting load four hours earlier when the system is flush with solar energy, however, provides no benefit and still carries the program cost. In contrast, storage can absorb the excess solar energy from four hours prior to the evening peak, energy which would potentially be curtailed (wasted), and bring it to bear to not only to supply the sharply rising demand curve, but also to sell into a high-price market, carry reserves, and avoid the expense of cutting load represented by the DR program's cost.

For these reasons, Staff's recommendation to "disallow" investment in battery deployment should be disregarded by the Commission.[38] Instead, the company commits to

[38] The company also disagrees with Staff's recommendation to require a separate index to address DR in the 2021 IRP. Staff Final Comments at 20. PacifiCorp's IRP already clearly explains how the company's modeling *selects* all cost-effective DR by having DR compete against all other supply-side resources on a comparable footing.

continued discussions with stakeholders, including Staff, regarding additional opportunities to implement DR.

2. The company continues to pursue additional cost-effective DSM Class 2 resources and improvements to its system-wide approach to acquisition of these resources.

In opening comments, Staff and NWEC raised concerns with the level of energy efficiency pursued in Oregon relative to the other company jurisdictions.[39] PacifiCorp committed to an April 2020 CPA meeting that would include discussion of the key drivers of energy efficiency potential to facilitate a greater understanding of the challenges faced by the company, including challenges to acquire similar levels of energy efficiency across the company's service territory.[40] PacifiCorp anticipates that its proactive approach to this issue will result in greater transparency for the 2021 IRP. As discussed at the March 10, 2020 Commission Workshop, it is not clear that it would be appropriate to not acknowledge the Class 2 DSM action item based on inequities in energy efficiency acquisition across service territories because the requirements for energy efficiency acquisition are determined on a state-by-state basis. These state specific requirements are then incorporated into the IRP; for example, in Oregon the Energy Trust of Oregon is responsible for developing the Class 2 DSM potential. Any concerns regarding other states' failure to acquire adequate Class 2 DSM should be addressed in those states; similarly, any concerns regarding inequitable rate impacts for Oregon customers are better addressed in a cost recovery proceeding.

[39] Staff Initial Comments at 40-41; NWEC Opening Comments at 4.

[40] *See* PacifiCorp Reply Comments at 20 (explaining that disparities exist across its service territory due to different requirements and differences in potential).

3. Additional Class 3 DSM pilot programs should be addressed in PacifiCorp's next general rate case.

Staff's Final Comments recommend that the Action Plan be updated to include a new outside expert study and a full stakeholder workshop for Class 3 DSM in the next IRP cycle.[41] Staff's suggestion to hold a workshop on this topic is consistent with the company's commitment in its Reply Comments and PacifiCorp agrees to the timeline suggested by Staff (*i.e.*, that the workshop would occur no less than six months prior to the filing of the 2021 IRP); however, it is not clear that an a new outside expert study is necessary at this time. PacifiCorp suggests that this be discussed as part of the stakeholder workshop.

D. Acquisition of New Resources and Transmission Upgrades

On February 24, 2020, PacifiCorp filed its application to open a proceeding to select an independent evaluator (IE) to oversee the request for proposals identified as Action Plan item 2b.[42] The RFP results from a capacity need identified in the 2019 IRP and intends to take advantage of the tax credits currently scheduled to expire at the conclusion of 2023 (for solar) and 2024 (for wind). The company appreciates the thoughtful consideration of stakeholders regarding whether there is a resource need, including recent discussions at the Commissioner workshop on March 10, 2020. As an initial matter, the company is amenable to updating Action Plan item 2b for consistency with the RFP that seeks resources that can achieve commercial

[41] Staff Supplemental Final Comments.

[42] The Commission has opened a proceeding, docketed as UM 2059. Staff's Final Comments assert that the company's filing in UM 2059 fails to include sufficient time for a transparent and thorough analysis of the RFP scoring and modeling details. PacifiCorp strongly disagrees with this statement and notes that Staff's vague reference to the proprietary pricing model used to evaluate RFP bids is both misleading and fails to support Staff's position. Staff Final Comments at 11. As Staff is well-aware, the company always relies on a propriety pricing model in its evaluation of resource RFPs. Further, Staff is familiar with such model because it has been shared with Staff in prior RFP proceedings. Nevertheless, PacifiCorp agrees with Staff that the appropriate proceeding to resolve any concerns with the procedural schedule for the RFP is docket UM 2059 and the company looks forward to continued discussions in that proceeding.

operation by 2024 to account for the extension of PTCs through December 31, 2024.[43] The company also does not object to limiting its 2020AS RFP capacity acquisition to be consistent with the amount identified in the preferred portfolio and indicated this would be the target amount in its filing with the Commission in docket UM 2059.[44] PacifiCorp does not agree, however, that the types of resources should be limited.[45] While the company expects renewable resources to be the most competitive, an all-source RFP is the only way to confirm this hypothesis.[46] Gathering these data points also helps inform future IRP inputs to ensure that the company is using the most accurate data.[47]

1. The 2019 IRP has identified a resource need.

In final comments, AWEC continues to assert that the 2019 IRP has failed to identify a resource need other than an "economic need" and that the company can use FOTs to satisfy any resource need during the Action Plan time period.[48] Staff echoes these misguided arguments.[49] As discussed at the Commission workshop on March 10, 2020, FOTs are a modeling tool used to represent how much capacity the company wishes to leave "open" or not firm.

Accounting for committed resources, expected incremental procurement of energy efficiency, and planned early retirements; PacifiCorp's "firm" capacity falls short of its expected

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[43] Staff Final Comments at 11. PacifiCorp finds that cost is an inappropriate limit for the RFP; the modeling proposed for evaluation of the RFP will determine whether bids are economic and therefore additional pricing constraints are unnecessary.
[44] *See* PacifiCorp's Application filed on February 24, 2020, in Docket No. UM 2059; *see also* CUB Final Comments at 5-6.
[45] *See* Portland Comments; *see also* Multnomah Comments at 3.
[46] The company is also conducting this RFP to acquire resources for its entire system, including the Rocky Mountain Power d/b/a PacifiCorp side of the system where the Utah regulatory commission has determined that failure to issue an RFP undermines the ability to determine whether the most cost-effective resources are being selected.
[47] *See* Staff Final Comments at 11 (requesting that real bid data be used to inform future IRPs).
[48] AWEC Final Comments at 3.
[49] Staff Final Comments at 10.

obligation in 2024 by over 950 MW.[50] This is in addition to the FOTs already accounted for in the IRP modeling; the 2019 IRP includes 1,425 MW of market capacity. The amount of "firm" capacity from new generating resources being contemplated in the RFP, based on preferred portfolio resource selections, totals just over 730 MW. Thus, the company is not procuring resources ahead of a capacity deficit and it cannot be argued that the 2020AS RFP is not the result of a capacity need identified in the 2019 IRP.[51] The 2020AS RFP will procure resources to reduce PacifiCorp's capacity deficit during the Action Plan timeframe.[52] If the company does not acquire additional resources through the 2020AS RFP it risks meeting its reliability obligations.

2. Treatment of Long-lead Time Resources in the 2020AS RFP.

In its Reply Comments, PacifiCorp stated that it would consider bids that include long-lead time resources in response to the 2020AS RFP.[53] The company stated that if a determination was made that such a resource was feasible and could provide economic benefits, the resource bid would be removed from the 2020AS RFP and pursued subject to a waiver request under the Commission's competitive bidding rules.[54] In response to this proposal, Staff recommends that the company conduct a separate RFP for up to 200 MW of flexible capacity scheduled to come online after 2024 but before 2027.[55] Staff makes this recommendation

[50] *See* 2019 IRP Volume I, Chapter 5 (Load and Resource Balance), page 115, Table 5.12 – Summer Peak – System Capacity Loads and Resources without Resource Additions and line System Position.
[51] *See, generally*, AWEC Final Comments.
[52] Because PacifiCorp has identified a capacity need in the 2019 IRP sufficient to justify its 2020AS RFP there is no need to address the remainder of AWEC's Final Comments.
[53] PacifiCorp Reply Comments at 28.
[54] PacifiCorp Reply Comments at 29.
[55] Staff Final Comments at 10.

because it does not support affording a waiver of the competitive bidding rules to allow consideration of these long-lead time resources.[56]

A separate RFP for long-lead time resources is unnecessary. The company has considered this issue further and determined that with some adjustments it could consider bids received for long-lead time resources under the same process as all other bids and therefore no waiver should be necessary.[57] If long-lead time bids are received in response to the 2020AS RFP that are otherwise in conformance with the RFP requirements, the company's analysis of those long-lead resources would be conducted in the manner within the RFP process. For example, a pump storage hydro bid would be evaluated and ranked in a separate resource type by topology in the initial shortlist phase, similar to how other resource types like wind or solar are evaluated and ranked. These pools of bids will then be subject to an economic analysis using the IRP models to determine the initial shortlist. Long-lead time resources that are selected to the initial short list will then proceed together with the other initial short-list resources to the interconnection transition cluster study, if applicable, subject to the same level of review, including review by the IE. Out of the interconnection transition cluster study, the long-lead resources along with the other initial shortlist bidders, would be asked to update their bid including interconnection costs. Those bids would then be re-evaluated by the IRP models for the final shortlist. Under this proposal there should be no concerns that long-lead time resources are being provided with any special or biased treatment because there will be the same level of scrutiny and oversight. This also allows consideration of these resources consistent with Staff's

[56] Staff Final Comments at 9-10.
[57] The company's reference in Reply Comments to necessity of a waiver was premised on the idea that these long-lead time bids would be reviewed on a case-by-case basis as non-conforming bids because they would not be able to achieve the requested commercial operation date.

determination that greater consideration should be given to non-emitting flexible capacity resources.[58]

3. Improvements to the RFP process

Staff Final Comments requested that the company "report" in these comments on whether "real bid data" could be used in development of the 2021 IRP.[59] PacifiCorp already uses real project and industry data to inform updates to the IRP inputs. The company agrees with Staff that using actual data as often as possible results in the most accurate IRP modeling and PacifiCorp strives to include this actual data whenever available. NWEC also suggests that improvements to the RFP process may be necessary to accommodate the "magnitude and pace of the change in each utility's resource mix."[60] NWEC acknowledges the complexities that exist with undertaking sequencing and alignment issues associated with the relationship between the IRP and RFP processes. These complexities are consistently apparent during discussions regarding the proposed schedule for the RFP and the company encourages all stakeholders to remain mindful of the challenges faced by the company as it adapts to the ever-changing resource acquisition policies at both the state and federal level. PacifiCorp is appreciative of NWEC's recognition of these challenges but does not recommend adopting its suggestion to use a request for quotations. To be meaningful, responses to a request for quotations would need to be developed with the same level of detail as responses to a request for proposals. As a result, bidding entities are unlikely to participate in such an exercise where there is no opportunity to be awarded a contract. In fact, issuing requests for quotations could diminish the company's competitive position in the market because bidders may become less likely to provide bids if

[58] Staff Final Comments at 10.
[59] Staff Final Comments at 11.
[60] NWEC Final Comments at 2.

PacifiCorp's "seriousness" is uncertain. Bidders do not have unlimited resources and will focus on submitting bids to utilities with a proven track record of developing projects.

4. PacifiCorp's reply to parties' comments on transmission resources.

PacifiCorp's 2019 IRP Action Plan also includes several transmission action items, including new transmission resources EGS, Boardman to Hemingway (B2H), and Energy Gateway West and several transmission reinforcement projects. As an initial matter, the company responds to Staff's request for the total transmission investment cost associated with the Action Plan. The current estimated costs are $2.2 billion.[61]

Regarding Energy Gateway West, Sub-segment D.1, the company agrees with Staff that this segment could be chosen based on bids received in response to the 2020AS RFP. However, at the time of the October 18, 2018 filing of the 2019 IRP, the Company's D.1 action item was limited to "continued permitting" on the basis of information known at that time.[62] The Company is unable to speculate on the odds of segment D.1 being required as a result of the 2020AS RFP, but will continue permitting to facilitate implementation should that be the case.

Finally, the company directs Staff to its Reply Comments in response to Staff's question about how PacifiCorp's transmission plans are consistent with regional planning priorities. Contrary to Staff's assertion, the company's Reply Comments did provide an explanation for why there are differences between the priorities identified by the North Tier Transmission Group (NTTG) process and PacifiCorp's planning process (PacifiCorp's planning process is narrowly tailored to its specific needs).[63] Staff appears to be misconstruing *different* priorities for inconsistent priorities and this is not the case. The 2018-2019 NTTG Regional Planning process

[61] As noted by Staff, the company has previously responded to requests for this information through discovery but provides the total estimated cost again for clarity and convenience. *See* Staff Final Comments at 7.
[62] Staff Final Comments at 8; *see also* 2019 IRP Volume 1, Chapter 9 at 284.
[63] PacifiCorp Reply Comments at 33.

evaluated projects that were initially submitted by the funding members to determine if the projects are least cost or most effective for the NTTG footprint. Because of the scope and nature of the Energy Gateway project, the project was submitted in segments, separating projects east of Populus from projects west of Populus or for south of Aeolus. Additionally, as the Energy Gateway West – Subsegment D.2 project was currently under construction, it was considered in-service for purpose of the evaluation. After a thorough review by NTTG, the following Energy Gateway segments were included in the NTTG 2018-2019 Regional Transmission Plan:

› Windstar–Aeolus 230 kV

› Aeolus–Clover 500 kV

› Aeolus–Anticline 500 kV

› Anticline–Populus 500 kV

› Populus-Cedar Hill–Hemingway 500 kV

› Borah–Midpoint 345 kV to 500 kV conversion

While the NTTG analysis identified a different set Energy Gateway segments than were selected in PacifiCorp's 2019 IRP, which included the Windstar – Aeolus 230 kV line and the Aeolus – Clover 500 kV line, it is important to remember that the two analyses had different goals and purposes. The NTTG regional planning analysis is a reliability analysis performed for the NTTG footprint to meet the regional planning requirements of Federal Energy Regulatory Commission (FERC) Order 1000, and evaluated long-term planning projects (and a fixed set of generation resources) submitted by PacifiCorp, Idaho Power, Northwestern Energy, Deseret Power, and Avista. The PacifiCorp 2019 IRP, however, was intended to evaluate the long-term resource needs of PacifiCorp and to identify major transmission projects that are required to support PacifiCorp's specific identified resources needs.

While the NTTG planning process included a broader selection of the Energy Gateway project segments in the Regional Transmission Plan than what was included in the PacifiCorp 2019 IRP, the key difference between the two processes is that the NTTG process assumes a fixed set of generation resources in its evaluation, taking into account generation unit retirement, whereas the IRP process evaluates generation needs based on projected performance of each generation unit. Although PacifiCorp 2019 IRP selected Energy Gateway projects that were a subset of the NTTG project, the timing of when the Energy Gateway projects will be constructed will based on the economics of the resource evaluation identified in the IRP.

a. **Energy Gateway South should not be delayed.**

PacifiCorp provided additional details regarding the relationship between the transmission items identified in the Action Plan and the 2020AS RFP resource acquisition in response to opening comments from AWEC, NWEC, Staff and Sierra Club that raised concerns regarding the sequence of determining transmission need. Specifically, stakeholders have questioned how the company can be sure that the EGS project, in particular, is necessary before selecting resources through the 2020AS RFP. These concerns are echoed in final comments.[64] Staff suggests that given the uncertainties associated with EGS that it may be appropriate to delay the project until at least 2030 to allow customers to realize those savings.[65]

i. EGS is consistent with the least-cost, least-risk preferred portfolio.

Staff's first argument against moving forward with EGS is its assertion that even without EGS, the company's system can accommodate up to 3,350 MW of new resource interconnection.[66] Staff supports this assertion based on its assumption that there is an

[64] *See* Staff Final Comments at 33.
[65] Staff Final Comments at 5-6.
[66] Staff Final Comments at 4.

abundance of wind interconnection that is available outside of Wyoming (*i.e.*, wind interconnection that would not use EGS) that could avoid the need for the investment in EGS. However, Staff's comparison of these non-EGS projects with EGS projects does not take into account the estimated cost for transmission to support those non-EGS projects. The estimated costs for transmission to support the non-EGS projects *were* captured as part of the 2019 IRP's transmission option modeling.

Fourteen non-EGS transmission projects outside of Wyoming were also selected by the capacity expansion model on the basis of economics, enabling the selected resources, with costs appropriately considered.[67] EGS was consistently selected in 2024 by the capacity expansion model in more than 70 cases, including these additional investments and considering the estimated costs and capabilities of both EGS and non-EGS enabled resources. The capacity expansion model selected EGS, therefore, not instead of other transmission and system investments but in addition to other investments in six states, selecting the type and quantity of resources that would deliver the least-cost portfolio.

To the extent that there are transmission options that were not selected by the IRP, the costs of those projects and their interconnection capabilities were not competitive with the EGS project, nor other selected transmission projects. This makes sense, as all other factors being equal, Wyoming wind is the highest quality wind in the nation making the selections of the 2019 IRP preferred portfolio intuitive. While the 2019 IRP was not published in a timeframe to consider legislation allowing for 60 percent PTCs, the superiority of Wyoming wind would remain undisputed.

[67] See 2019 IRP, Chapter 8, Tables 8.16 and 8.17.

The interconnection assumption in the map referenced on page 4 of Staff's Final Comments is for the purpose of establishing an initial shortlist of bids in the 2020AS RFP. The bids will carry no transmission costs at this phase (prior to the interconnection cluster study) and except for EGS are elevated to 1.5 times the resource interconnection indicated by the 2019 IRP. These rating are 50 percent higher than in the 2019 IRP (at no interconnection cost) to gather sufficient bids to account for withdrawals and exclusions that may occur throughout the process, and also to allow the bid selection model the opportunity to assess system interactions that might escape a more simplistic market-based analysis. While there may indeed be an abundance of wind projects at non-EGS locations, they will be represented in the bids received, selectable in the RFP, account for the higher PTC rate where appropriate, and will likely not achieve the capacity factor ratings of Wyoming wind. In the RFP, the $1.8 billion EGS project with enabled projects will be in competition with non-EGS transmission projects and any enabled bids.

ii. EGS provides customer benefits and should not be delayed.

Staff then asserts that there is a $335 million savings to customers if EGS is simply delayed from 2024 until 2030.[68] Based on this assumption, Staff asks what resources would have been selected by the SO model if EGS had not been made available until 2030. The company's stated benefits for the preferred portfolio are net of costs accounting for the comparative deferral value implicit in counterfactual cases. The company conducted and provided several studies that are responsive to this question in the Utah 2019 IRP docket.[69] These studies confirmed that moving forward with EGS provides greater benefits than waiting as proposed by Staff.

[68] Staff Final Comments at 5.
[69] *See* PacifiCorp d/b/a Rocky Mountain Power's response to Data Request OCS 2.1 in Utah Docket No. 19-035-02; this data request response is provided in Attachment A of these comments.

In further support of its argument that savings could be realized for customers if EGS is delayed until 2030, Staff requested that the company report on the possibility and costs of renewing the Bureau of Land Management (BLM) permit in 2022 to maintain the relevance of the permit. PacifiCorp already addressed through discovery the issue of whether it is feasible to seek renewal of the permit. As explained in the response to Data Request OPUC 206, due to the passage of time the data used in the original Environmental Impact Statement could be determined to be stale.[70] Such a determination would result in the need to perform a new analysis and such analysis takes between eight and 12 years. The costs associated with this process are $10-$15 million.

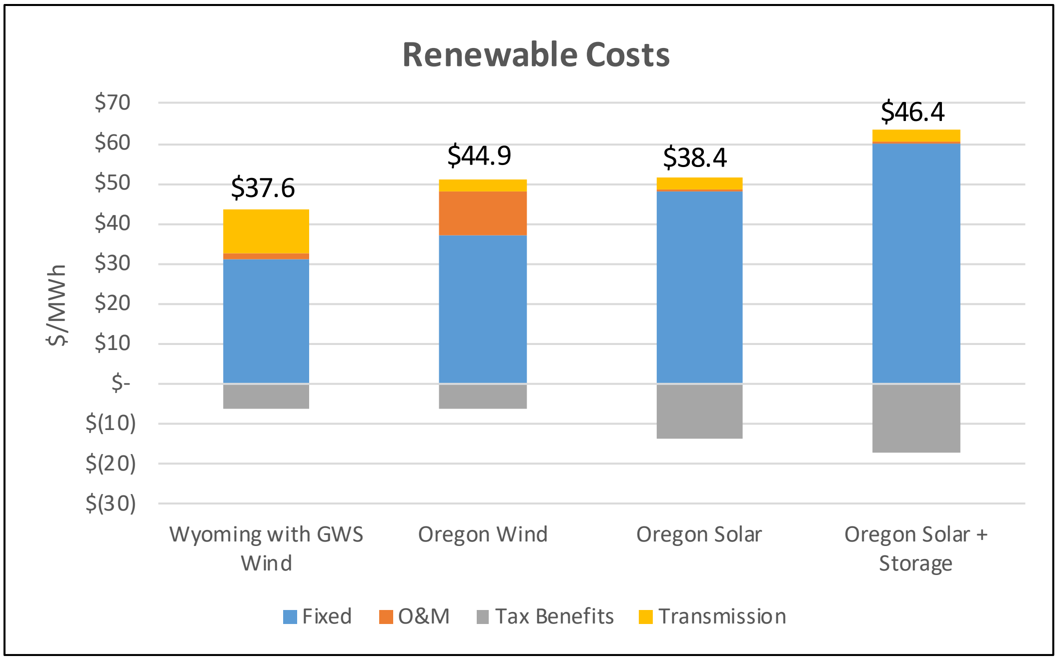
Staff has also requested that the company identify any additional savings that could be realized for other Energy Gateway projects including B2H and Segment E through use of lower-cost guyed-V towers.[71] This question is posed by Staff in response to the cost-estimate reduction performed before filing of the 2019 IRP for EGS.[72] While PacifiCorp will continue to try to identify cost savings for all transmission line projects, the company was unable to apply a similar cost reduction for Segment E because BLM did not allow the consideration of guyed towers of any type for Energy Gateway West during the Environmental Impact Statement and Record of Decision process. Therefore no guyed towers are being used for Segment E. With respect to B2H, Idaho Power is the project manager on the B2H project and as such has the primary responsibility of reviewing possible cost saving measures. PacifiCorp, as a party to the permitting agreement, has an opportunity to provide lessons learned to Idaho Power and will provide information if PacifiCorp remains a participant in the construction phase of the project,

[70] The company's response to Data Request OPUC 206 is included in Attachment A to Staff's Final Comments.
[71] Staff Final Comments at 7.
[72] See Staff Final Comments at 6.

but the decision to incorporate any lessons learned will be in agreement with parties involved in the project moving forward.

A related question arose at the March 10, 2020 Commission Workshop; specifically, the company was asked whether renewables could be added at less cost on the west side of its system to avoid the transmission cost of EGS on the east. The following figure compares the levelized cost of Wyoming wind with EGS with Oregon wind and Oregon solar plus storage. The data are presented in 2018 dollars. The figure shows that including the transmission cost of EGS is still cheaper than adding renewables in the west. Further, if transmission upgrades were required on the west side of the company's system, only a portion could be completed in time to meet a December 31, 2024 deadline for PTC's, as right of ways would need to be secured, delaying the project and risking the loss of PTC's. EGS currently has the right of way approved that would allow the project to move forward sooner. If west renewables were built without transmission, the resource would be considered non-firm and not dependable to meet peak load demands, and so would not be considered beneficial to customers.

There are many factors that layer into the total project costs and benefits. All must be considered to build or acquire a resource. These factors include resource siting and location, transmission, asset life, capital investment, capacity factor, tax benefits, turbine size, variable O&M, fixed O&M, wheeling and so on. All other factors being equal, Wyoming wind is the highest quality wind available in the west.



Finally, Staff attempts to capture the alleged savings associated with delaying EGS until 2030 by recommending that any future RFP conducted by the company include a condition requiring PacifiCorp to demonstrate that final shortlist selections requiring EGS will provide specific benefits that outweigh the $335 million cost of construction associated with building EGS in 2024 versus 2030.[73] This additional condition is unnecessary and redundant. The IRP modeling employed by the RFP will include costs and benefits leading to any transmission and resource selections. This is the model's purpose and is built-in. In all studies prior to the availability of 40% PTCs was determined, EGS selection was allowed in any year from 2025 to 2032. The model consistently selected EGS in 2032. Once the availability of 40% PTCs was determined, all studies consistently selected EGS wind in 2024, producing net benefits above and beyond deferral value. PacifiCorp also conducted additional studies in response to data requests that continue to support the ubiquitous selection of EGS.[74]

[73] Staff Final Comments at 7.
[74] See Rocky Mountain Power d/b/a PacifiCorp's response to Data Request OCS 2.1 in Utah Division of Public Utilities Docket 19-035-02; this response is provided in Attachment A to these comments.

iii. EGS satisfies federal transmission requirements while providing these customer benefits.

In addition to the modeling and analysis that supports building EGS for 2024, there are legal requirements that would require the company to move forward. Staff's Final Comments acknowledge this possibility and request additional information regarding the legal requirements to construct transmission facilities in eastern Wyoming.[75] The company gave a brief overview of this issue at the March 10, 2020 Commission Workshop. As PacifiCorp explained at that workshop, federal policy requires transmission providers to expand their transmission systems as necessary to grant either requests for FERC-jurisdictional transmission service[76] or FERC-jurisdictional interconnection service.[77] Both PacifiCorp's interconnection queue and its separate transmission service queue currently contain FERC-jurisdictional requests for service that are contingent upon EGS being constructed. Therefore, as PacifiCorp has previously explained,[78] it would be unrealistic to assume that PacifiCorp transmission would not be obligated to construct *any* transmission system upgrades out of eastern Wyoming to accommodate FERC-jurisdictional Open Access Transmission Tariff (OATT) requests. In addition, PacifiCorp has executed interconnection agreements granting interconnection capacity on EGS facilities. As a result, in response to Staff's question, PacifiCorp's legal requirements to

[75] *See* Staff Final Comments at 6.

[76] *See, e.g.*, PacifiCorp's OATT, Section 13.5 (stating that the transmission provider will be obligated to expand or upgrade its transmission system if it cannot provide the requested firm transmission service without degrading or impairing the reliability of service to other firm transmission customers or interfering with the transmission provider's ability to meet prior firm contractual commitments).

[77] *See, e.g.*, PacifiCorp's OATT, Sections 41-48 (containing comprehensive rules for interconnecting new generators, including the identification and construction of new network upgrades if necessary to grant the request and containing no tariff authority to refuse an interconnection request because it would require new network upgrades).

[78] The company provided this information previously in response to Data Request OCS 2.1 in Utah Division of Public Utilities Docket 19-035-02. This data request response is provided in Attachment A of these comments.

construct transmission facilities in eastern Wyoming stem from FERC's open access transmission policies and PacifiCorp's contractual obligations.

One approach in the face of legal requirements driving the construction of transmission facilities would be to allow those requirements to stand alone, without any additional justifications. PacifiCorp has not chosen that route, and has instead analyzed the estimated costs and benefits associated with EGS using traditional planning and modeling metrics—metrics that continue to demonstrate its selection is justified by economics (regardless of any legal requirement drivers). The costs of EGS, as proposed, satisfy the company's legal requirements and provide benefits to retail customers.

iv. Federal policy limits cost allocation options for EGS.

As part of Staff's inquiry related to the legal requirements for EGS, Staff asked the company to provide funding options for EGS. Consistent with the discussion above, the company's cost allocation options will be limited by federal policy and contractual terms. By way of background, transmission system upgrades necessary for granting FERC-jurisdictional transmission service are paid for upfront by the utility and rolled into transmission rate base. For interconnection service, FERC requires interconnection customers to pay upfront for the network upgrade costs that would not be needed "but for" their interconnection request, and requires utilities to reimburse the generator for those network upgrade costs once the generator commences operation and transmission service began.[79]

The "but for" aspect of FERC's interconnection policies is an important factor for cost allocation. A new transmission upgrade triggered by the need to grant a specific interconnection request would be an upgrade that would not have been identified "but for" the interconnection

[79] *See, e.g.*, FERC Order No. 2003 at PP 693-95.

request and, therefore, should be upfront funded by the requesting generator under FERC's policies. Transmission upgrades that the transmission provider was planning to build and later identifies (*e.g.*, in an interconnection study) as a requirement to granting a specific interconnection request would have been identified even *absent* the interconnection request. Therefore, those planned upgrades should not be upfront funded by the requesting generator under FERC's policies. Transmission upgrades that the transmission provider was already planning to build may include those triggered by a higher-priority service request or those identified in the transmission provider's long-term transmission plan.

As a result, PacifiCorp has not required any interconnection customer to upfront fund the cost of EGS, as reflected in the interconnection studies and executed interconnection agreements granting interconnection service on the EGS facilities. Therefore, in response to Staff's question about cost allocation options,[80] PacifiCorp would need FERC approval to deviate from federal policies to implement alternative funding options and then to modify the executed contracts to implement any cost allocation change.

Staff next turns to the benefits of EGS and concludes that it cannot recommend acknowledgment because it is not clear that the benefits outweigh the risks of constructing the project prior to 2030.[81] Staff reaches this conclusion based on its assertion that EGS will not provide sufficient benefits to Oregon customers. Despite the costs of EGS, there are benefits associated with EGS in nearly every case included in the 2019 IRP. The benefits accrue when the value to the system exceeds the high costs, which it does, time and time again. Because PacifiCorp operates as a single system and develops one IRP for the entire system, customer benefits include benefits to Oregon customers.

[80] Staff Final Comments at 6.
[81] Staff Final Comments at 31-34.

The company also does not agree with Staff's determination that EGS will be "underutilized" because the goal is for resources to be *optimally* utilized, not for resources to experience high usage around the clock. The average utilization of a transmission path is unrelated to the need for its full capacity. Unless the path is tightly constrained there will be hours of high usage and hours of low usage, these usage patterns are dependent on the demand curve, generation from wind facilities, solar radiance, outages, etc. Evaluating transmission paths using load will result in a finding that transmission paths across the system are likely to be underutilized every day during early morning hours and more heavily utilized during the high-ramping evening peak. This fluctuation in usage is expected and does not mean that a transmission path is not needed.

b. Endogenous Transmission Modeling

Staff's initial comments expressed support for the company's endogenous transmission modeling[82] but request an explanation in their Final Comments for why the B2H transmission line cannot be modeled endogenously as a simple connector between the Hemingway bubble and the Bonneville Power Administration (BPA) Network Integration Transmission System (NITS) bubble in the IRP topology.[83] While PacifiCorp could model Hemingway to BPA NITS, the favorability of B2H relies on B2H's ability to move energy from east to west. To meaningfully capture the value of B2H, a continuous path rating increase must be modeled between Borah and points west. Without this capability a new renewable resource modeled at Borah would have no commensurate increase in capability to reach Hemingway and therefore, additional points west. A new resource, or existing resources that would benefit from B2H, would effectively be trapped behind the same transmission constraints currently applicable in the absence of B2H. The

[82] Staff Initial Comments at 44.
[83] Staff Final Comments at 31.

continuous path that gives B2H its value cannot be modeled with an increase to just one transmission link path rating between two nodes, which is why B2H could not be modeled endogenously in the 2019 IRP.

E. Inclusion of Qualified Facilities (QF) in the Preferred Portfolio

PacifiCorp's Reply Comments explained that because the company cannot require a QF to renew its contract at the conclusion of the contract term, PacifiCorp does not include a forecast for QFs in the IRP analysis that assumes contract extensions (similarly, the company's analysis does not include a forecast of new QF contracts). In response to PacifiCorp's Reply Comments, Staff has refined its position on this issue to recommend that even a forecast relying on the lowest amount of annual new QF contracts over the prior four-year period would be preferable to PacifiCorp's practice of including only contractually certain QF capacity amounts.[84] Staff asserts that this is reasonable in light of the average of approximately 300 MW of QF capacity that came online over the four-year period of 2015-2019.[85]

PacifiCorp is open to providing sensitivities to help demonstrate the potential impacts of new and renewing QF contracts, and provided REC with a sensitivity to the 2019 IRP that assumed all existing QFs renewed at the end of their current contract terms. However, PacifiCorp disagrees that any level of assumed new or renewing QF contracts should be imputed in the preferred portfolio. The preferred portfolio identifies proxy resource types and locations that are aligned with system needs and it is assumed that these resources could be added to PacifiCorp's portfolio either as an owned asset or as a power purchase. To the extent new or

[84] Staff Final Comments at 37. Sierra Club's Final Comments also weigh in the company's forecast of QF capacity in the IRP, arguing that some level of QF capacity should be included. Sierra Club Final Comments at 8.

[85] Staff Final Comments at 37 (Staff's Final Comment's support a QF forecast based on historical trends but is willing to accept a forecast based on the lowest amount over the four-year term). In final comments, REC recommends a forecast of QF capacity based on historical data consistent with the position taken in REC's opening comments. *See* REC Final comments at 1-2.

renewed QFs that are not yet contracted are imputed as part of the preferred portfolio, PacifiCorp's capacity shortfall will be reduced, but PacifiCorp cannot compel QFs to contract with the company. For example, a number of QFs on PacifiCorp's system have recently chosen to take advantage of higher rates available elsewhere and wheel their power to other utilities. Under Staff's proposal, those QFs would have been imputed into the preferred portfolio but ultimately cannot be relied on by the company.

One of the key outcomes of the IRP process is the Action Plan. Under Staff's proposal, PacifiCorp's Action Plan would not include acquisition of the right amount of capacity. If the forecasted QF capacity failed to come to fruition, PacifiCorp would be left to scramble to identify incremental resources. Staff suggests that 60 to 300 MW of new QF capacity per year should be assumed as of PacifiCorp's 2019 IRP preferred portfolio. Over the 20 year IRP planning horizon this would amount to 1,200 to 6,000 MW of new QF capacity – this is comparable in magnitude to all of the renewable resources added over the IRP study window, implying that more than half of all of the wind and solar resources identified in PacifiCorp's 2019 IRP preferred portfolio could be QFs procured outside of a competitive solicitation process.

It is likely that competitive procurement processes would provide access to more cost-effective and targeted resources, resulting in higher customer benefits than a scenario in which those same resources were acquired based on a proscriptive avoided cost methodology that is unlikely to incorporate the most recent information available to bidders and/or developers. Moreover, it is not clear how PacifiCorp should determine the mix of resources that should be represented in this new QF capacity. It is likely that QF development will correspond to changes in avoided costs over time, such that the most cost-effective resource types will be most prevalent. The most cost-effective resources are the ones identified in the IRP preferred portfolio. PacifiCorp could designate some percentage of the preferred portfolio renewable resources as QFs to correspond to the levels identified by Staff, but this would have no bearing on the overall composition of the preferred portfolio or the IRP Action Plan. For these reasons, the company finds that its conservative approach (not including capacity over which it has no control) is appropriate for planning purposes.

To the extent the Commission finds merit in Staff's recommendation to include qualifying facilities in the IRP preferred portfolio, PacifiCorp would caution that qualifying facility contracts and pricing are state-jurisdictional, and the energy and capacity benefits associated with new and renewed QF contracts are expected to be situs-assigned to the customers of each state. Significant analysis of state-specific resource portfolios and allocations will be conducted as part of the 2021 IRP, so it may be premature to apply a blanket QF assumption across PacifiCorp's multiple jurisdictions at this time. If imputed QFs are to be included in IRP preferred portfolio for Oregon, PacifiCorp recommends that this treatment only apply to Oregon QFs. PacifiCorp would also reiterate that it is straightforward to identify existing Oregon QFs with expiring contracts, all or a portion of which could be assumed to be renewed, while the quantity, type, and location of future QFs is undetermined. A survey of existing QF owners whose contracts will expire during the IRP Action Plan window could inform the renewal assumption used in the IRP, but this information would be likely to complicate the determination of avoided cost pricing, as discussed below, and contract renewal decisions are likely to be dependent on the level of pricing offered by PacifiCorp and other off-takers.

PacifiCorp is appreciative of Staff's recognition of its concerns regarding the cost implications of including a forecast of QF capacity based on historic data.[86] In response to these concerns, Staff suggested that QF renewals could be included in the company's load resource balance study and preferred portfolio, but that a separate calculation could be used to determine system costs without these forecast QF renewals to determine QF costs. PacifiCorp suggests that this two tier approach to QF capacity is better discussed in one of the Commission proceedings currently pending; specifically, this topic appears to fall within the Commission's Investigation into the Treatment of QFs in the IRP process (docket UM 2038).[87] This would allow additional time for the company to consider this proposal and allow for broader stakeholder input (including input from other utilities in Oregon to allow consistent treatment of QFs across the state).

F. Responses to Individual Party Comments

In the sections above, the company has provided responses to categories of topics that were raised by multiple parties. In the section below, the company provides responses to the remaining issues presented in opening comments.[88]

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[86] Staff Final Comments at 37.

[87] In final comments, REC argues that moving the discussion of QF contract renewals to Docket No. UM 2038 would result in allowing PacifiCorp to avoid compliance with the IRP guidelines by failing to account for uncertainty. The company, however, does account for the uncertainty associated with QF contracts by not including a forecast of new or renewed QF contracts in its analysis. More specific directives to address the uncertainty associated with QF contracts should be specifically addressed with all stakeholders and all utilities through the Commission's pending investigation. Without a holistic approach there is a risk that QFs connecting to different utility systems will be treated differently resulting in inequitable results.

[88] The company's silence with respect to an issue raised in initial comments should not be viewed as agreement with a party's position; as noted above, the company anticipates that some issues will be resolved through workshops or additional discussions between the parties and PacifiCorp.

1. ***Load Forecast Methodology.***[89]

Staff requests that the company reexamine its peak load forecast to incorporate the electric vehicle (EV) forecast that was filed with the Commission on February 3, 2020, as part of PacifiCorp's Oregon Transportation Electrification Plan.[90] Staff argues that this is necessary because the peak load forecast is based on historical data that would not likely account for current trends in EV adoption.[91] PacifiCorp declines to reexamine its peak load forecast. As discussed in the company's Oregon Transportation Electrification Plan, PacifiCorp performed an analysis of the local impacts of the EV adoption forecast.[92] The study did not indicate a need to update the peak load forecast at this time.

The company is also concerned with Staff's implication in its Final Comments that PacifiCorp's Reply Comments were inaccurate or misleading. Staff's Final Comments imply that PacifiCorp should have provided an updated peak load forecast with its Reply Comments because "[a] forecast of EVs in PacifiCorp's territory is available." Staff's Final Comments make no reference to the discussion in PacifiCorp's Reply Comments that confirmed that an EV forecast was being developed (and was provided to the Commission just two days before its Reply Comments filing deadline) and that such EV forecast would be incorporated into future IRPs.[93] Consistent with the company's Reply Comments this EV adoption forecast, subject to further refinement, will be included in the energy and peak forecast that inform the 2021 IRP.[94]

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[89] Staff also suggested that providing raw data would improve the documentation and information sharing associated with development of the load forecast. Staff Final Comments at 26-27. In response, PacifiCorp agrees to provide this raw data on a going forward basis.
[90] Staff Final Comments at 28; *see also* PacifiCorp's Initial Filing in Docket No. UM 2056.
[91] Staff Final Comments at 28.
[92] Docket No. UM 2056, PacifiCorp Oregon Transportation Electrification Plan, Attachment 5.
[93] PacifiCorp Reply Comments at 45.
[94] PacifiCorp Reply Comments at 45.

PacifiCorp also notes that preliminary load forecast results are currently scheduled to be presented in July as part of the 2021 IRP public input process.

2. Private Generation

Staff's Final Comments request that the company modify its load resource balance to reflect PacifiCorp's high private generation (PG) forecast scenario asserting that PacifiCorp is likely understating the ability of PG resources to meet a portion of its needs in the near-to-mid term by up to 22 percent over the planning horizon.[95] The company declines to make this modification because the company already runs a high PG sensitivity to test what changes that would drive into the preferred portfolio.

Further, as explained in the company's response to Data Request OPUC 189,[96] the NREL study referred to by Staff uses a market penetration curve that is from an old Navigant report (a report from 2008). Navigant has refined that analysis over time and determined that the older curves were generally overestimating market behavior of PG customers and required modification.[97] For the analysis results to be consistent with actual observed adoption over time smoothing of the curves was needed. This "smoothing" addresses unrealistic jumps in the adoption results. The current Navigant analysis (relied on by PacifiCorp for the 2019 IRP) has a proven track record of accurately forecasting adoption solar and other PG technologies in PacifiCorp's service territory and other utilities' service territories across the country. For this reason, the more refined model is the appropriate model for the 2019 IRP.

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[95] Staff Final Comments at 41. Staff's Final Comments recommended in lieu of this modification to the load resource balance that the company provide an updated PG forecast that reflects NREL assumptions regarding customer adoption and a "reasonable" assumption that some level of PG incentives will continue. However, as discussed in the company's Reply Comments, PacifiCorp's PG study already included existing customer incentives and other reasonable assumptions. *See* PacifiCorp Reply Comments at 46.
[96] The company's response to Data Request OPUC 189 is provided in Attachment A of Staff's Final Comments.
[97] *See* PacifiCorp's response to Data Request OPUC 189 provided in Attachment A of Staff's Final Comments.

In response to Staff's recommendations to facilitate leveraging PG and customer storage, PacifiCorp will consider Staff's modeling recommendation as part of its development of the 2021 IRP. The company will also continue to evaluate whether and when a residential storage pilot might be appropriate. PacifiCorp is currently updating the CPA and adding both commercial and residential storage as a Class 1 DSM resource. This update is part of the company's overarching goal of updating PacifiCorp's modeling around the potential benefits of DR resources, generally. The company has already hosted two workshops recently to discuss this effort and has scheduled an additional workshop for April 2020.

Storage has the potential to offer numerous system benefits including load shaping for seasonal peaks. These potential benefits are determined by the storage resource itself and not the source of the energy. PacifiCorp d/b/a Rocky Mountain Power, currently has a residential storage pilot operating in Utah (the Soleil Project). The Soleil Project will test the ability to get benefits through utility control of customer sited storage equipment. That project has sufficient capacity and dispatch flexibility to test many different use cases for residential storage that can be leveraged in Oregon. The company has also modified its PG rate schedule in California from a traditional net metering format to a time of export net billing format.[98] That new rate schedule goes into effect on April 1, 2020, and will allow customers to capture off-peak (daytime) solar and use it on-peak (early evening) to reduce their load at a time that benefits the system. This will allow the company to determine if Class 3 DSM economic drivers impact customers' choices around the installation of solar and solar plus storage. If PacifiCorp determines that a pilot with a different configuration could provide an additional learning opportunity, the company may seek to develop an additional residential storage pilot program.

[98] *See* The Public Utilities Commission of California, Docket A.19-04-013.

3. Economic Opportunity

Staff makes certain recommendations to ensure that economic opportunity is incorporated to protect customers: (a) that the full value of PTCs projected in the IRP be provided to customers; (b) that an updated economic analysis be conducted with the request for acknowledgement of the final shortlist for PacifiCorp's 2020AS RFP; and (c) that the risk of proceeding with the 2020AS RFP resource acquisition remain with PacifiCorp until a prudence review is conducted by the Commission and cost recovery is approved.[99] The company interprets the first recommendation as a recommendation for customers to receive the full benefits of PTCs received by PacifiCorp, not a proposal for a guaranteed level of PTCs based on the IRP forecast. With this interpretation, the company does not disagree with these recommendations; in fact these recommendations are supported by PacifiCorp's filing in docket UM 2059 (the pending 2020AS RFP docket) and Commission precedent.[100]

4. Distributed Standby Generation

In response to PacifiCorp's Reply Comments stating that the company plans to work towards development of a program design that can be communicated to customers to gauge their potential level of participation in a distributed standby generation program, Staff has requested a timeline for this program design including when a report could be submitted to the Commission.[101] As noted in PacifiCorp's Reply Comments, the company is still in the research phase associated with this program and therefore any timeline may change as the process moves forward. The company is unable to provide a timeline; PacifiCorp continues to evaluate the

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[99] Staff Final Comments at 14.
[100] These recommendations are supported by Commission precedent with the exception of any suggestion to require a PTC floor. As noted above, the company interprets this recommendation to be that customers receive the full benefits of PTCs received by the company and *not* a proposal for a guaranteed level of PTCs based on the IRP forecast."
[101] Staff Final Comments at 26.

potential development of a dispatchable standby generation program. However, recent changes in state and federal air quality rules have added significant uncertainty into processes and requirements for securing air quality permits for standby generating units that participate in utility demand response programs. The company is reluctant to discuss a potential program with customers until a clearer understanding of the impacts of these regulatory changes on program participation are known.

5. Long-Term Planning Topics

In Section 11 of their Initial Comments, Staff made several requests for additional information related to topics they identified as "long-term planning" including climate adaptation.[102] PacifiCorp's Reply Comments suggested that further discussions on what was meant by a climate adaptation plan were necessary.[103] In their Final Comments, Staff point to Portland General Electric's IRP development and requests that the company address planning for future climate conditions in the 2021 IRP including a comprehensive report on climate change planning activities.[104] Without committing to specific action items at this time, PacifiCorp will evaluate how the items identified by Staff could be incorporated into the next IRP cycle. As noted earlier in these comments, development of the 2021 IRP has commenced and the company looks forward to further discussions on this topic with Staff through the public input process.

IV. NEXT STEPS

On February 24, 2020, PacifiCorp filed its application to open a docket for selection of an IE to oversee the 2020AS RFP. The current schedule in that proceeding (docket UM 2059) anticipates Commission selection of the IE on April 7, 2020. Following selection of the IE, the

[102] Staff Initial Comments at 69.
[103] PacifiCorp Reply comments at 56-58.
[104] Staff Final Comments at 42-43.

2020AS RFP will be drafted and submitted to the Commission for approval. The final 2020AS RFP approved by the Commission will include a schedule for the resource acquisition identified in the 2019 IRP. Further, as noted in these comments, the company has already commenced development of the 2021 IRP with conservation potential assessment workshops. The public input process is currently scheduled to commence in June 2020 with the first two-day meeting. Following the Commission's determination on the 2019 IRP the company will begin incorporating any refinements to the IRP process that have resulted from this proceeding.

V. CONCLUSION

PacifiCorp's 2019 IRP complies with the Commission's standards and guidelines. The 2019 IRP includes robust portfolio modeling and prudent planning assumptions that led to selection of a least-cost, least-risk preferred portfolio. The 2019 IRP also includes an action plan that is consistent with the long-term public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group and continues to support stakeholder participation throughout the IRP development process to foster constructive dialogue.

PacifiCorp respectfully requests that the Commission acknowledge the 2019 IRP and the 2019 IRP Action Plan.

Respectfully submitted this 1st day of April, 2020.

Etta Lockey
Vice President, Regulation
PacifiCorp d/b/a Pacific Power

Attachment A

OPUC Data Request 201

Demand Response - Please provide an explanation of PacifiCorp's understanding of the reasons why System Optimizer does not choose near-term demand response in Oregon, despite several DR resources being lower cost than other supply side resources, as shown in table 6.6 in the 2019 IRP, and in Table 4 in Staff's reply IRP comments.

Response to OPUC Data Request 201

The company assumes "near-term" is in reference to a period that would support a specific action item to procure demand response (DR) resources in the 2019 Integrated Resource Plan (IRP) action plan. Based on the foregoing assumption, the company responds as follows:

The System Optimizer (SO) model makes resource selections based on the cost and performance attributes of available supply-side and demand-side resource alternatives. The SO model does not make its resource selections based entirely on the relative cost of these resource alternatives.

The performance attributes of any resource alternative (i.e., dispatch restrictions and the type and level of reserves a resource can provide) and the location of a given resource within the system affect the value of that resource in meeting load, supplying reserves, or facilitating market sales that can reduce system costs. The SO model simultaneously assesses the relative costs of resources, accounting for the performance characteristics of those resources, when determining the least-cost mix of resources needed to meet load and provide reserves over time. Functionally, the SO model achieves this by finding the combination of available resource alternatives that minimizes the present value of revenue requirements (PVRR) while meeting load requirements and maintaining and adequate level of reserves over a 20-year period. Simply stated, the cost and performance attributes of near-term DR alternatives in Oregon are such that a portfolio that would include these resources would yield a higher PVRR from an SO model simulation than a portfolio that excludes them.

While DR resources provide peak capacity, they provide little to no energy value since most are load-shifting in nature, and they are available in a limited number of hours. On an energy basis, the cost of the least expensive Oregon DR resource (OR-Ancillary Services) is $254.58 per megawatt-hour ($/MWh). The cost of an Oregon solar+storage resource added to the system in 2024, which also provides reserves to the system, is $37.81/MWh.

OCS Data Request 2.1

Case P-45CNW without Gateway South. Please run a case based on the parameters of P-45CNW but remove Gateway South as a resource selection. Please provide the resulting resource portfolio, stochastic mean PVRR (benefit)/cost and risk adjusted PVRR versus P-45CNW.

Response to OCS Data Request 2.1

Throughout the 2019 Integrated Resource Plan (IRP) modeling process, Energy Gateway Segment F (Gateway South or GWS) was endogenously selected by the System Optimizer model (SO model) in nearly every resource portfolio. In the preferred portfolio, the year-end 2023 in-service date enables 1,920 megawatts (MW) of new wind capable of qualifying for 40 percent of the full value of production tax credits (PTC) before they expire. The persistence of the SO model selection of GWS in nearly every portfolio obviated the need for a counterfactual case that eliminates GWS from the preferred portfolio. Nonetheless, PacifiCorp recognizes there is broad stakeholder interest in understanding how the preferred portfolio and system costs might be impacted if GWS is assumed to be removed from the preferred portfolio. Consequently, in response to this data request, PacifiCorp has produced a range of cases to evaluate portfolio and system cost impacts when GWS is removed as a resource option.

<u>Case 1 (Counterfactual with Third-Party Firm Transmission):</u>
The first counterfactual case eliminates GWS as a resource option. However, even if GWS is not constructed, it is unrealistic to assume that PacifiCorp transmission would not be obligated to construct *any* transmission system upgrades out of eastern Wyoming to accommodate Federal Energy Regulatory Commission (FERC) jurisdictional requests for open access transmission tariff (OATT) interconnection service and transmission service. Indeed, both PacifiCorp's interconnection queue and its separate transmission service queue currently contain requests for service that are contingent upon GWS being constructed. Even conservatively examining only the transmission service (not interconnection service) queue, only third-party requests for service out of eastern Wyoming, and assuming no additional third-party request for transmission service will be submitted, PacifiCorp transmission would need to identify a non-GWS alternative to granting a request for 500 MW of FERC-jurisdictional OATT firm point-to-point (PTP) transmission service. Based on preliminary, high-level estimates only, granting that PTP request without GWS would trigger the need for a 230 kilovolt (kV) transmission line by the end of 2023, at a minimum. Therefore, this counterfactual case includes the cost of a 230 kV transmission line at the end of 2023, net of incremental wheeling revenue.

PacifiCorp has conservatively been assuming that 12 percent of system transmission costs are recovered by third-party transmission customers. A review of PacifiCorp's transmission usage relative to the usage of third-party transmission customers since 2012 shows that third-party usage has been increasing each year. In 2018, third-party usage was nearly 19 percent of the total. The table below shows the present value revenue requirement differential (PVRR(d)) for the counterfactual case, inclusive of the estimated transmission upgrades to accommodate the queued 500 MW PTP request. Results are shown assuming 12 percent and 19 percent of system transmission costs are recovered by third-party customers. Please refer to Attachment OCS 2.1 for the counterfactual resource portfolio.

Study	Stochastic Mean ($m)			Risk Adjusted ($m)		
	Pref. Port. PVRR	Case 1 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)	Pref. Port. PVRR	Case 1 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)
12% Third-Party Revenue	$23,207	$23,474	($267)	$24,376	$24,657	($282)
19% Third-Party Revenue	$23,018	$23,369	($350)	$24,178	$24,548	($371)

Case 2 (No New Natural Gas Resources):
The counterfactual case described above accelerates the addition of new natural gas-fired capacity. Considering the risk that future policy developments such as a price on carbon emissions may increase the costs of operating these resources in the future, PacifiCorp developed an additional counterfactual case that assumes no new natural gas-fired resources can be added to the portfolio. As described above, this case also includes estimated transmission service request (TSR)-driven costs associated with a queued 500 MW request for firm PTP transmission service. This counterfactual is compared to Case P-29, which includes GWS but similarly eliminates new natural gas-fired capacity as a resource option. The table below shows the PVRR(d) for the second counterfactual case relative to Case P-29. Results are shown assuming 12 percent and 19 percent of system transmission costs are recovered by third-party customers. Please refer to Attachment OCS 2.1 for the counterfactual resource portfolio.

Study	Stochastic Mean ($m)			Risk Adjusted ($m)		
	P-29 PVRR	Case 2 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)	P-29 PVRR	Case 2 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)
12% Third-Party Revenue	$23,328	$24,077	($750)	$24,503	$25,293	($791)
19% Third-Party Revenue	$23,145	$23,958	($813)	$24,311	$25,170	($859)

Case 3 (Alternative Renewables):
Considering that the level of renewable energy is reduced in the first counterfactual case and considering strong customer interest in ensuring more renewable resources are added to the system, PacifiCorp also conducted a counterfactual case that includes renewable energy at levels that are similar to those in the preferred portfolio. Note: PacifiCorp was unable to include renewable energy levels that match the preferred portfolio, because without GWS, there are insufficient transmission upgrades available across the system to achieve a comparable level of renewable resources as the 2019 IRP Preferred Portfolio.

Consequently, this counterfactual case includes renewable resources that represent just 74 percent of the renewable nameplate capacity and just 77 percent of the renewable energy in the preferred portfolio. As described above, this case also includes estimated TSR-driven costs associated with a queued 500 MW request for firm PTP transmission service. The table below shows the PVRR(d) for the third counterfactual case relative to the preferred portfolio. Results are shown assuming 12 percent and 19 percent of system transmission costs are recovered by third-party customers. Please refer to Attachment OCS 2.1 for the counterfactual resource portfolio.

Study	Stochastic Mean ($m)			Risk Adjusted ($m)		
	P-29 PVRR	Case 2 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)	P-29 PVRR	Case 2 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)
12% Third-Party Revenue	$23,207	$24,186	($979)	$24,376	$25,403	($1,027)
19% Third-Party Revenue	$23,018	$24,057	($1,038)	$24,178	$25,269	($1,092)

<u>Conclusions:</u>
The results above show that quantified benefits from GWS and associated new wind range between $267 million and $1.09 billion. These benefits are conservative as they do not include the non-quantified benefits associated with the new transmission line, which include (also listed at page 75, Volume I of the 2019 IRP):

- Adding a parallel path to the Gateway West Sub-Segment D.2 project (Aeolus-to-Bridger/Anticline), which will improve the reliability of the 230 kV system in Wyoming for the loss of either 500 kV line.

- Strengthens the PacifiCorp transmission system (increased fault duty) by interconnecting the geographically drivers areas of eastern Wyoming and southern Utah together, allowing additional generation resources to be connected.

- Improves grid reliability by providing better operational control of the backbone transmission system by interconnecting two areas of the PacifiCorp transmission system that are abundant in two different forms of renewable resources, specifically wind rich eastern Wyoming with the solar rich areas of southern Utah.

- Provides anticipated improvements in eastern Utah reliability by providing a potential future high voltage source and power delivery option to meet the projected oil expansion and corresponding load growth (Ashley, Vernal).

- Improves the southern Utah transmission system reliability by providing congestion relief on the 345 kV lines during outage conditions.

- Supports PacifiCorp's North American Electric Reliability Corporation's (NERC) TPL-001-4 transmission system reliability efforts, which are necessary to improve grid reliability performance.

- Assists PacifiCorp in meeting its OATT obligations to identify and construct the transmission system upgrades necessary to accommodate FERC-jurisdictional requests for interconnection service and transmission service.

ATTACHMENT OSC 2.1 HAS BEEN PROVIDED ELECTRONICALLY

OCS Data Request 2.1

Case P-45CNW without Gateway South. Please run a case based on the parameters of P-45CNW but remove Gateway South as a resource selection. Please provide the resulting resource portfolio, stochastic mean PVRR (benefit)/cost and risk adjusted PVRR versus P-45CNW.

1st Revised Response to OCS Data Request 2.1

Further to the Company's response to OCS Data Request 2.1 dated December 4, 2019, the Company has become aware of a labeling error on the study names associated with the information provided in the original response for Case 3 (Alternative Renewables), specifically the provided table. Please refer to the corrected table provided below, which corrects the second column study name from "P29" to "Pref. Port. PVRR" and "Case 3" in the third column from being labeled as "Case 2" to accurately reflect the cases being compared, which are the Preferred Portfolio to Case 3:

Study	Stochastic Mean ($m)			Risk Adjusted ($m)		
	Pref. Port. PVRR	Case 3 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)	Pref. Port. PVRR	Case 3 (No GWS) PVRR	(Benefit)/ Cost of GWS PVRR(d)
12% Third-Party Revenue	$23,207	$24,186	($979)	$24,376	$25,403	($1,027)
19% Third-Party Revenue	$23,018	$24,057	($1,038)	$24,178	$25,269	($1,092)

Note: all other information / attachments provided with the Company's original response to OCS Data Request 2.1 remain unchanged and valid.