Response to the Utah Party Comments on PacifiCorp's 2015 Integrated Resource Plan

Docket No. 15-035-04

1. INTRODUCTION

PacifiCorp filed its 2015 Integrated Resource Plan (IRP) with the Public Service Commission of Utah (Commission) on March 31, 2015. The Company's IRP was prepared in accordance with the Commission's IRP Standards and Guidelines in Docket No. 90-2035-01 and 2013 IRP acknowledgment requirements from the Report and Order in Docket No. 13-2035-01. To be acknowledged, the plan must be deemed reasonable at the time it is presented. As part of its review, the Commission determines whether the IRP adequately adheres to the IRP Standards and Guidelines established under Docket No. 90-2035-01, and takes into consideration the "merit and applicability" of public comments.[1]

As part of the IRP acknowledgment schedule adopted by the Commission for this proceeding, parties filed comments and acknowledgment recommendations by August 25, 2015. The Division of Public Utilities (DPU), Office of Consumer Services (OCS), Utah Association of Energy Users (UAE), Interwest Energy Alliance (IEA), Utah Clean Energy (UCE), Southwest Energy Efficiency Project (SWEEP)[2], Conservation Groups (CG) made up of Sierra Club (SC), Healthy Environmental Alliance of Utah (HEAL Utah), Western Clean Energy Campaign (WCE), Powder River Basin Resource Council (PRBRC) and Idaho Conservation League (ICL) all submitted comments. In addition, there were other public comments posted to the Commission's website from non-intervening parties.

In response to these comments, PacifiCorp submits its reply comments below. Following an executive summary and recommendations section, the Company separately addresses specific comments provided by each of the parties.

2. EXECUTIVE SUMMARY AND RECOMMENDATIONS

PacifiCorp appreciates the parties' comments on the Company's 2015 IRP, and appreciates that its active and engaged stakeholder group recognizes steps the Company has implemented to improve the IRP public process. Many parties raise perceived shortcomings in modeling assumptions that influence resource selection, particularly related to identification and analysis of environmental compliance costs and renewable resources. Below PacifiCorp further clarifies its portfolio modeling assumptions and resource strategy conclusions.

[1] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01), pp. 22 - 23.
[2] SWEEP submitted joint comments with UCE on PacifiCorp's DSM Potential Study. The joint comments were filed as an attachment to UCE's written comments in this docket.

The majority of intervenors either express support for acknowledgement of PacifiCorp's 2015 IRP, or do not expressly oppose acknowledgement. Only one party (UCE) recommends that the Commission not acknowledge the 2015 IRP. The Company strongly disagrees with that recommendation and addresses its reasons below. Compliance with the Commission's Standards and Guidelines as well as the requirements from the Commission's 2013 IRP Report and Order in Docket No. 13-2035-01were carefully considered as the Company develops and finalizes its IRP. In supplying its reply comments, PacifiCorp reminds the parties that the IRP is a planning document that lays out the resource road map, that considers long-term risk and planning uncertainties, and continuously evolves in step with regulatory events and market trends.

PacifiCorp's 2015 IRP meets the Commission's Standards and Guidelines and the 2015 IRP Preferred Portfolio is least cost and least risk. Further, the Preferred Portfolio was selected in a manner consistent with the long-run public interest. Accordingly, PacifiCorp respectfully requests that the Commission acknowledge its 2015 IRP.

3. REPLY COMMENTS: DIVISION OF PUBLIC UTILITIES

In its comments, DPU finds the Company met the requirements identified in the Commission's 2013 IRP Report and Order in Docket No. 13-2035-01. Likewise DPU finds PacifiCorp's 2015 IRP has "reasonably met" the Commissions required IRP Standards and Guidelines included in Docket No. 90-2035-01 and recommends acknowledgement of the 2015 IRP. Nonetheless, DPU offers some suggestions for improvements, as well as additional materials for inclusion in future IRPs.

<u>Actions from Report and Order in Docket No. 13-2035-01</u>

DPU finds the Company's modeling of EPA's draft Clean Power Plan (CPP) 111(d) rule meets the Commission's guidance in the 2013 IRP to address said rule. DPU notes the final EPA rule was recently released and that the regulations continue to be in flux due to legal and political challenges. DPU accurately states that the Company plans to monitor events and update its IRP as necessary. PacifiCorp will provide an update to the 2015 IRP in March 2016, along with a new IRP in March 2017 that will include the current evolution of requirements under the CPP as well as other information related to states' development of their CPP implementation plans.

The Company would like to make a clarification on the discussion of PacifiCorp's 111(d) Scenario Maker model as discussed by DPU. The model calculates rate-based emissions targets for all of PacifiCorp's states containing fossil generation, not just the four states with generation and load. In addition to Utah, Oregon, Wyoming, and Washington the model can analyze rate-based 111(d) targets assumed to be applicable to its generation in non-retail load states, which include Arizona, Colorado, and Montana. Core cases C02, C03 and C04 examined meeting rate-based 111(d) compliance in all states where the Company has fossil generation. The remaining cases focused on meeting emission targets where the Company has both retail load and fossil generation.

Regarding transmission, the Company notes that the Commission was interested in continued discussion with stakeholders on development of tools to address non-modeled benefits of transmission. DPU finds that formation of a System Operational and Reliability Benefits Tool

(SBT) stakeholder group along with the associated workshops held met the Commission's objective. DPU states that any transmission project relying on the SBT will need to be subjected to stochastic risk analysis. As such, DPU recommends that an entire meeting be devoted to the SBT if the Company will rely on it for future analysis. The Company agrees a full discussion on transmission analytical tools would be beneficial in any future IRP that includes action items targeting potential construction of future Energy Gateway (EG) segments.

The DPU recommends acknowledgement of the Wallula to McNary 230 kV single circuit line. As correctly noted, this transmission line is required to meet the Company's obligations under its Open Access Transmission Tariff (OATT). The Company understands acknowledgement is not a prudency finding, which will occur in the ratemaking process.

DPU also raises questions around FERC Order 1000 and associated requirements for cost allocation and interregional planning. The Company will provide information in the 2015 IRP Update and in ongoing IRPs as necessary to explain the interaction of these requirements with any EG project.

In the 2013 IRP Report and Order, the Commission stated it would like to see sensitivity analysis for renewable costs informed by stakeholders. As DPU notes, PacifiCorp made use of a stakeholder feedback form in the 2015 IRP, which was used by stakeholders to submit alternative solar costs. The Company studied these costs in sensitivity case S-12, and therefore, met the Commission's objectives.

DPU finds the Company complied with the Commission's guidance principle on market availability for front office transactions (FOT). This was accomplished through both reduced reliance on FOTs as compared to the 2013 IRP along with core cases examining reduced availability of FOTs at Mona and COB trading hubs. The Company would also point to Appendix J to the 2015 IRP which examined western resource adequacy. The Company's "Acquisition Path Decision Mechanism" discussion in Chapter 9 of the report also discussed the near-term and long-term strategies if the availability of FOTs is limited. Future IRPs will continue to monitor market liquidity and depth as suggested by DPU.

DPU notes the Company performed a planning reserve margin study and concluded that the 13% planning reserve margin met the planning target at the lowest reasonable cost. The Company will update its study in the 2017 IRP.

DPU accurately notes the Company performed a variety of load sensitivity analyses to examine implications under a variety of futures, which include low or high load forecast and low or high penetration levels of distributed generation. In addition, Table 9.3 of the 2015 IRP addresses potential impacts on both near- and long-term resource acquisition should there be either sustained high or low load growth.

The Company discussed stochastic risk modeling at multiple public input meetings, as DPU notes. DPU succinctly captures the Company's stochastic modeling process in its comments. DPU indicates, and the Company agrees, that the requirements in the Commission order were met.

The Company strives for continual improvement in the IRP process. Stakeholder involvement played an important role in the 2015 IRP, especially through the stakeholder feedback form. The Company will continue to implement process improvements to make the public input process more efficient and useful to a wide range of stakeholders. Items will include the potential for further expansion of Table 9.3 on near- and long-term resource acquisition paths and additional information on use of files on data disks submitted in future IRP proceedings. The Company appreciates DPU's comment that the 2015 IRP was "open, engaging and transparent."

The DPU is satisfied the Company met the Commission's requirement to provide the expected capacity contribution to IRP capacity goals in its Energy Efficiency and Peak Reduction Report.

The 2013 IRP Order issued by the Commission required a sensitivity case in the 2013IRP Update, and future IRPs for the Company's Business Plan (BP). Further discussion with DPU clarified that this requirement could be met through the discussions on how the Company's BPs are related to the IRPs and large variances need to be explained. DPU found and the Company agrees that this requirement has been met.

Load Forecast

DPU provides a thorough review of the Company's load and resource balance in its comments and finds the load forecast methodology to be reasonably sophisticated. Included in the review is a comparison of the resource shortfall (prior to any addition of resources) in the 2013 IRP, 2013 IRP Update, and 2015 IRP. DPU determines the load forecast out to 2024 to be reasonable.

Demand Side Management

DPU comments that the Company's 2013 and 2014 Class 2 demand side management (DSM) acquisitions did not achieve the levels identified in the 2013 IRP. First, the Company clarifies that the estimated capacity impact of Class 2 DSM from the 2014 programs is 56.4 MW, as provided on Page 6 of the Company's 2014 Utah Energy Efficiency and Peak Reduction Annual Report. Second, the Company achieved 264 gigawatt-hour (GWh) and 269 GWh of cost-effective Class 2 DSM energy savings in 2013 and 2014, respectively. These acquisitions are above the 2013 IRP Preferred Portfolio Class 2 DSM selections of 235 GWh and 224 GWh for 2013 and 2014, respectively. As described in Appendix 2 of the Company's 2013 and 2014 DSM Annual Reports, the reported capacity impacts of Class 2 DSM are estimates only, based on the methodology presented therein. However, the Company understands DPU's concerns that these capacity estimates fell below the capacity shown in the 2013 IRP Preferred Portfolio and will attempt to better align the methodology used to develop these estimates with IRP reporting, beginning with its 2015 DSM Annual Report.

DPU raises concerns that the amount of Utah Class 2 DSM included in the 2015 IRP Preferred Portfolio may be overly aggressive and not achievable, particularly as compared to the amount contained in the 2013 IRP Preferred Portfolio and the Company's historical DSM acquisition in Utah. The increase in DSM resources flows directly from the 2015 DSM potential study, which shows an increase in potential relative to the 2013 DSM potential study. This increase between studies is largely driven by updated projections of the cost, efficacy, and applicability of solid state lighting technologies. This increase in potential was well documented in the Demand-Side Resource Potential Assessment as discussed in Appendix D of the 2015 IRP. The Company agrees with DPU that the Utah Class 2 DSM projections in the 2015 IRP are aggressive compared to historical program acquisitions, but believes such projections are consistent with the increased lighting opportunities across all six states. The potential will be re-assessed for the 2017 IRP to identify whether any market conditions have changed that would affect the availability and/or cost-effectiveness of Class 2 DSM resources beyond 2017.

In addition to concerns about the achievability of the Utah Class 2 DSM resources identified in the 2015 IRP, DPU is also concerned that the associated acquisition costs may be prohibitive. DPU points to two budget estimates, one provided in Appendix D to the 2015 IRP ($263 million) and the other at the July 17, 2015 technical workshop ($297 million), both of which are estimates of the cost to acquire the DSM resources identified in the Preferred Portfolio. To clarify, the budget provided in the 2015 IRP was a preliminary estimate, a high-level look based on IRP targets and average acquisition costs to provide a rough estimate for the implementation plan. The updated estimate presented at the technical workshop was a “ground-up” number based on detailed program-level forecasts. Neither budget estimate impacts the costs modeled in the IRP, which are structured to ensure that the DSM resources are selected on a consistent basis with supply side resources, incorporating DSM cost credits and average program incentive and administration assumptions. That is, the cost of DSM resources modeled in the 2015 IRP did not change, rather the updated budget is a better estimate of the cost to acquire the resources based on newer and more detailed information.

Further, while the Class 2 DSM budget presented in the July technical workshop may be higher compared to that in Appendix D, these savings are still least-cost and/or least-risk as compared to other supply side resources, as determined by the IRP. The Company will continue to review the status of the DSM balancing account with its DSM Advisory Group and Steering Committee, provide semi-annual funding forecasts, and provide cost-effectiveness information in annual reports, program evaluation reports, and update programs as needed. Through these processes, the Company ensures appropriate funding and spending levels as well as cost-effectiveness of DSM acquisition.

DPU recommends “the Commission direct the Company that the DSM targets must to be both technically and economically achievable in future IRPs in order for the preferred portfolio to remain the least cost, least risk options.” The Company relies on the best information available at the time assumptions are established and independent third-party analysis to determine the technically achievable DSM potential. Moreover, the Company uses a robust IRP modeling framework to determine the amount of that potential that is cost-effective relative to other alternatives. The Company believes its current best practices result in optimal DSM targets, which are both technically and economically feasible, as recommended by DPU.

The Company agrees with DPU that coordination between the Company’s DSM and IRP departments is important in evaluating DSM targets for economic and technical achievability. The two departments have been working closely together on the development and modeling of DSM supply curves in IRPs since 2007. The DSM department regularly attends IRP meetings, manages the DSM potential study development, presents DSM methodology and results at IRP public meetings and technical conferences. The groups work together on supply curve format and modeling methodology, and reviewing DSM selections before the IRP is finalized. This cooperation will continue in future IRPs to ensure that DSM selections in the IRP are based on a best practice methodology, well-understood, and expected to be cost-effective and achievable.

The Company addressed DSM at multiple public meetings during the 2015 IRP process and held a separate Utah DSM technical conference based on requests from stakeholders. DPU recommends the Company hold a similar technical conference in the 2017 cycle, as was done this year. The Company will continue to present relevant DSM material at IRP public meetings during the development of the 2017 IRP and include detailed information in the IRP main body and appendices. If, based on the DSM information provided and 2017 IRP modeling results, stakeholders believe a separate DSM technical workshop would be valuable, the Company will hold such a workshop. However, the Company does not believe the Commission should require a technical workshop to occur, but rather hold it upon stakeholders' request.

Adequacy of the 2015 IRP and Action Plan

DPU provides a summary of the Company's 2015 Action Plan, noting the minimal number of actions. These actions include requests for proposals (RFP) for Renewable Energy Credits (REC) to meet renewable requirements in California and Washington, finalization of negotiation to meet Oregon's Solar Capacity Standards, acquisition of DSM and FOTs, conversion of Naughton Unit 3 to gas, and construction of the Wallula to McNary transmission line. Although DPU has some concerns, it believes the Company's succinct Action Plan conforms to the IRP requirements.

For the first time in the IRP process, Navigant prepared for the Company a study on distributed generation (DG) potential specific to the PacifiCorp service territory. This study examined costs and benefits from a customer economic perspective. DPU believes that the impact of DG should be considered from both the customer perspective and the utility perspective. The study results by Navigant are based on a Fisher-Pry payback analysis to determine market penetration for the Company's service territories with customer rates based on the Company's tariff, which reflects customer-economics. The incorporation of the Navigant study results in the modeling for IRP portfolios reflects the impact of customer-sited distributed generation from the utility perspective. As for modeling DG, the Company did treat energy from DG resources as a reduction to load, but the reduction was consistent with the expected generation profiles of the DG resources during specific hours of a day and in different seasons.

DPU offers two recommendations related specifically to DG. The first is to consider renewables and DG in greater detail as supply-side resources in future IRPs. The second is to provide an updated DG potential study in the 2017 IRP. The Company agrees that DG has the potential to impact future resource decisions and as such will continue to monitor and update assumptions.

DPU also highlights the Company's treatment of energy storage in the 2015 IRP. DPU notes that storage is becoming more cost-effective and expects these economics to continue to improve. As such it suggests the Company examine the way storage is modeled in the 2017 IRP and consider potential changes. Another suggestion is to look at modeling storage and DG combined. In response, the Company will continue to monitor storage developments and incorporate combined technologies as the market dictates. The Company also intends to provide an updated storage screening study as requested and is exploring supplemental evaluation techniques to capture additional benefits of energy storage systems not traditionally captured in IRP models.

Another area of concern is the incorporation of potentially substantial amounts of qualifying facilities (QF) putting energy to the Company's system. DPU cites the potential for 3,692 MW of new contracts as noted by the Company in Docket No. 15-035-53. This surge in QF activity could impact the Company's planning[3], and as such, DPU would like to see sensitivities in the 2015 IRP update for higher level of solar penetration through addition of QFs. The Company will address updates to QF activity in its 2015 IRP and will consider specific modeling recommendations for alternative qualifying facility scenarios.

<u>Summary of Recommendations</u>

DPU presents a summary of recommendations to improve the IRP product and process. Many of these have been covered above, and will not be discussed further; however, the Company addresses some of the recommendations below.

First, the Company did have vendors or consultants available on the day their study was presented to stakeholders. The Company is unaware of any issue in the 2015 IRP process where the study authors were unavailable for questions, and will ensure the same in the 2017 IRP process. If stakeholders have follow up questions after the presentations, they are welcome to submit them via the feedback forms, or through data requests once the formal IRP process begins.

DPU requests to have all state-specific programs, or reports that influence the IRP to be presented to the larger stakeholder group. The Company currently does present all programs, studies, or reports supporting any major IRP assumptions. In some cases the material is presented directly by the originator, in others a subject-matter expert from the Company presents it. The originators are generally in attendance at the meeting (or via phone) to respond to questions from stakeholders. The Company is unaware of any major study that was not presented to stakeholders, but is happy to work with DPU to ensure full information is available as needed.

As discussed above the Company will continue to update studies as needed, monitor developments in such items as storage and DG, and refine IRP-related tools as required. The heavy involvement and work of DPU in this process is appreciated. The Company concurs with DPU's finding that the Commission acknowledge the 2015 IRP.

[3] The system PVRR values referenced by the DPU are from different studies: core case C05-1's value is from the System Optimizer, and the values for sensitivity cases S-05, S-09 and S-12 are from the Planning and Risk model. If all cases are viewed with values from the same model run, System Optimizer (pages 157 and 158 of Volume II) or Planning and Risk (pages 216 and 217 of Volume II), sensitivity case S-05 (without costs of the DG), S-09 and S-12 would all show reduction in the system PVRR from the benchmark case C05-1.

4. REPLY COMMENTS: OFFICE OF CONSUMER SERVICES

In its comments, OCS notes the Company made significant efforts to incorporate stakeholder input throughout the 2015 IRP process. As mentioned earlier, the Company values stakeholder input, and appreciates OCS's involvement. While the OCS recommends finding that the Commission acknowledge PacifiCorp's 2015 IRP, it also raises several issues of concern, which are addressed below.

Demand Side Management

OCS has similar concerns to those of DPU with the achievability and affordability of Utah Class 2 DSM resources selected in the 2015 IRP Preferred Portfolio which the Company has addressed above. OCS also raises concerns about possible cost allocation based on Utah's share of 20-year IRP Class 2 DSM selections relative to its share of system sales. The Company respects OCS's concerns, but believes the supporting analysis oversimplifies how to determine an appropriate cost allocation methodology across states. The Company believes that the subject is best addressed through the Multi-State Process, rather than in an IRP docket.

OCS would like to see more information on "the states, sectors and end uses … that provide a majority of the resources." The Company believes that it has provided such information through public input meetings, and the DSM potential study, filed with the 2015 IRP and referenced in Appendix D. The DSM potential study also includes methodology, sources of key inputs, and explanations of differences relative to the previous study, and the Company believes this is the best place to keep underlying detail supporting the DSM supply curves.

The detailed information as listed in Table 7 of OCS's comments on Class 2 DSM selected by the Preferred Portfolio is not available directly from the IRP studies, as the IRP selects bundles of measures with similar costs, not specific sectors or end uses. The detailed information can be disaggregated based on data from the DSM potential study, but only after the Preferred Portfolio is finalized. The Company is concerned that performing this analysis and preparing this information for publication in the IRP document may not be feasible without jeopardizing its ability to timely file the IRP. The Company will continue to provide available information to stakeholders upon request.

Front Office Transactions

OCS notes that PacifiCorp's Preferred Portfolio continues to show a high reliance on FOTs, albeit down from the levels in the 2013 IRP. OCS notes these levels are significant, and comparable to 2011 IRP levels. OCS reviewed the analysis PacifiCorp provided in Appendix J – Western Resource Adequacy Evaluation which shows there is adequate market depth to meet the Company's FOT assumptions. Based upon review of the Western Electricity Coordinating Council 2014 Power Supply Assessment, OCS concludes, consistent with PacifiCorp, that there is both adequate market depth and liquidity to maintain positive regional reserve margins for several years. OCS concurs with the market liquidity assumptions but cautions the Company to monitor the market and make adjustments as necessary. The Company agrees with OCS that this is a prudent planning approach.

Transmission Projects

OCS understands that justification for new transmission is complex and can serve many purposes including new generation, reliability, or to meet regulatory requirements. The Wallula to McNary line identified in PacifiCorp's 2015 IRP Action Plan is needed to satisfy requirements in PacifiCorp's FERC-approved OATT.

While recognizing the overall cost impact of this line will be small, OCS believes construction of EG West or EG South would have a much larger impact. OCS also notes that the 2015 IRP did not include any new resources to be built in Wyoming, renewable or thermal, throughout the (first 10-year period of the) planning horizon. With these considerations in mind, OCS would like to see a fresh discussion on transmission planning in future IRPs. In response, when proposing new transmission the Company will provide the necessary justification.

Capacity from QFs

OCS takes note of the 816 MW of recently executed QF contracts included in the 2015 IRP Preferred Portfolio. They also note an additional 260 MW of solar QF power purchase agreements (PPA) located in Utah that were executed in March 2015. The OCS recognizes these PPAs were executed as required by federal and state requirements, but is somewhat uneasy about the level of investment made outside of an IRP process that ultimately affects customer costs through retail rates. The Company shares these concerns and supports QF policies that account for cost and risk.

Recommendations

OCS recommends acknowledgement of the Company's 2015 IRP along with three recommendations which were addressed above. Regarding DSM, the Company will endeavor to provide as much detail as possible for the DSM analysis; however, the detailed information desired may not be available until after the IRP is filed. As for an annual technical conference for updates on progress in achieving DSM as forecast, the Company suggests the requested information could be provided as part of the 2017 IRP process, concurrent with presentation of the updated DSM Conservation Potential Study. Finally, the Company will update the transmission discussion, especially in the event of a transmission Action Item.

5. REPLY COMMENTS: UTAH ASSOCIATION OF ENERGY USERS

Conformance with Standards and Guidelines

UAE appreciates the Company's efforts in developing the IRP. They do not oppose Commission acknowledgment of the 2015 IRP as generally consistent with the Standards and Guidelines.

Sensitivity Analysis

UAE notes the Preferred Portfolio relies primarily on DSM and FOTs, especially in the early years with a new, deferrable resource not included until 2028. Due to this heavy reliance, and updated estimates of DSM acquisition costs, UAE would like sensitivities for both FOT market limits and costs of DSM included in future IRPs. The Company notes that there is a core case in the 2015 IRP that examines market reliance. Core cases C09-1 and C09-2 both were developed with the assumption of limited FOT availability under different regional haze scenarios. These cases eliminated FOTs at both Mona (300 MW) and NOB (100 MW) beginning in 2019. This reduction of 400 MW of available FOTs results in higher PVRR costs and accelerated acquisition of a new thermal resource by six years.

UAE raises concerns with the variability of DSM costs, similar to those expressed by DPU. DSM budget variances between the one provided in Appendix D to the 2015 IRP ($262.5 million) and the one presented at the July 17, 2015 technical workshop ($297 million) are explained above. In short, the cost of DSM resources modeled in the 2015 IRP did not change, rather the updated budget is a better estimate of the cost to acquire the resources based on newer and more detailed information.

The Company will work with stakeholders during the 2017 IRP public process on sensitivities to include in the 2017 IRP, similar to the 2015 IRP public process. Many of the sensitivities in the 2015 IRP were a direct result of stakeholder requests, including a solar cost sensitivity (S-12), high CO_2 cost assumptions (S-11), and Restricted 111(d) attributes (S-15)[4] as cited by UAE. A clarifying note on S-15, this sensitivity required state RPS-eligible RECs and 111(d) attributes to be surrendered at the same time.

Preferred Portfolio Selection

UAE is concerned with the selection process for the Preferred Portfolio, assuming it is biased toward the front 10 year of the planning horizon. While many of the graphs are limited to the front 10 years this is more to do with presentation than Preferred Portfolio selection. Chapter 8 of the 2015 IRP goes through the selection process; it is based on total portfolio costs (and risks) for the entire planning horizon (20 years). Finally, as to Figure 8.17, it is simply showing the similarity of top-performing portfolios in resource selection in the front 10 years. It does not imply the ten-year period was paramount to selecting these portfolios.

[4] In sensitivity case S-15, the gas-fired Chehalis unit is shutdown early to meet the assumed 111(d) compliance requirements in state of Washington, as opposed to a coal plant referenced by the UAE.

6. REPLY COMMENTS: UTAH CLEAN ENERGY

UCE submitted comments individually, which are addressed below. UCE also submitted comments with SWEEP which are addressed in Section 7. Finally, UCE was included with CG whose comments are addressed in Section 10 below.

Coal Investment Strategy

UCE initially raises concerns with the Company's litigation approach to avoid installation of Selective Catalytic Reduction (SCR) on coal plants. They are concerned that if the strategy fails customers will have to pay for SCRs or replacement power if the units retire early. With the exception of conversion to natural gas, UCE lists the variety of options available for PacifiCorp's coal fleet, that is, avoidance or installation of SCR, or early retirement. The Company has evaluated regional haze compliance alternatives in Volume III of its 2015 IRP. These analyses support 2015 IRP action items, none of which call for installation of SCR equipment.

UCE also points to additional SCRs assumed in the preferred portfolio as being a concern, combined with ongoing CO_2 risk due to the CPP. The Company's use of different Regional Haze scenarios is informative in potential costs associated with different requirements. As noted throughout the IRP, these scenarios developed for planning purposes, recognize that agency, regulator, and joint owner perspectives on acceptability have not been determined. Likewise, modeling of section 111(d) compliance obligations recognizes potential changes in regulations. Volume III of the Company's 2015 IRP provides more detailed analysis and trade-off of alternative compliance options of specific coal-fired units with compliance decisions required in the action plan time horizon. Future IRPs will continue to incorporate then current policy assumptions and utilize scenarios to evaluate policy uncertainties. Importantly, the 2015 IRP shows that mid- to longer-term policy uncertainties have limited to no impact on near-term resource actions identified in the 2015 IRP action plan. Further, the SCRs included in the Preferred Portfolio will be analyzed in future IRPs prior to making actual compliance decisions.

UCE also raises concerns around the costs associated with units that have shorter depreciable lives in Oregon as compared to other PacifiCorp states. The Company's analyses on whether to install SCR, convert to gas-fired, or retire a unit earlier are performed on total Company basis using the remaining life of the unit as determined in the Company's other five states. The conclusion on whether a certain option is beneficial to the Company's customers in those five states should be irrelevant to Oregon's decision on accelerated depreciation of the unit. UCE listed four units whose depreciable lives in Oregon are shorter than in other states, and would require SCRs at some point in time. As addressed in the Company's 2013 IRP, the Company is a minority owner of Craig Unit 1 and, in essence, was bound by the participation agreement with other owners. The decision to implement any of the options for the other units that UCE referenced has not yet been made. Analyses of final costs and the impact on customers will be completed prior to making final compliance decisions. The Company is aware that there could be implications in cost-allocations; however, this is beyond the scope of the IRP. Cost allocation is better addressed through the Multi-State Process.

Acquisition Path Analysis

UCE raises issues with Table 9.3, Near-term and Long-term Resource Acquisition Paths. Specific issues include lack of costs and who bears any associated risks. UCE is also concerned that construction of new renewables does not appear often enough. In response, Table 9.3 is a qualitative, not quantitative tool. The table is not exhaustive and not intended to capture all potential scenarios that could change the Company's planning approach. Instead, Table 9.3 offers overall guidance on how changes in the planning environment could impact resource selection, as shown in the table. Many of the planning scenarios, to a greater or lesser degree, are captured in sensitivities presented in the Company's 2015 IRP. Regardless, the Company would not proceed with actions outside of the Action Items without thorough analysis, such as the ones performed for Volume III of the Company's 2015 IRP.

Modeling Issues

UCE raises several issues related to modeling in the IRP. The first of these is load forecasting, which it believes does not sufficiently capture "impacts of changing climate." In support of this they point to the year 2013 which experienced an 8% increase in peak as compared to 2012, while the energy amount remains unchanged from the prior year. Using a single data point as evidence is problematic. In fact, the coincident peak in 2013 was not driven by high peak day temperatures in Utah, as UCE claims. Instead, an unusually high level of coincidence in the jurisdictional peaks drove this record peak event in 2013. Hot temperatures across the western half of the United States caused all six states to peak close to the same time, resulting in a PacifiCorp coincident system peak on July 1, 2013, the same day as the jurisdictional peak in Utah. The load forecast for the 2015 IRP utilizes normalized peak forecast that reflects an average level of coincidence**.** To address the impact of potential changes in load forecast, for this IRP, the Company prepared sensitivity studies with different levels of load forecast besides the expected medium forecast: low (S-01), high (S-02) and 1-in-20 (S-03) load forecasts.

Loss of load probability, and its impact on setting capacity values for renewables is another area of concern for UCE. UCE cites its testimony in Docket No. 14-035-140 stating that the loss of load events in the Wyoming area during winter time were due to the Company's transmission constraints, and, therefore, not appropriate to be used to set the capacity value for renewable resources located outside Wyoming. The Company responded to the issue raise by UCE in that docket. Loss of load events occur only after available local resources and imports are exhausted. Eliminating all loss of load events that are influenced by transmission limits could eliminate most if not all loss of load events across most if not all hours, which is unrealistic and would eliminate the very purpose of loss of load studies. This argument suggests that wind and solar resources only contribute to the reliability of the local load area in which they are sited which is inconsistent with resource planning principals and completely ignores the reliability benefits of the Company's transmission system.

UCE states resource decisions in the out year will impact QF prices. This may be correct but it is irrelevant in the selection of the Company's Preferred Portfolio. The portfolio exhibiting the least cost/ least risk is selected as the Preferred Portfolio regardless of impact on QFs. That is, the planning process is agnostic as to the impact on QFs.

The Company is disappointed that UCE does not believe the 2015 IRP process was improved and with their finding that the "2015 process was less transparent that (sic) past IRP planning process..." Other parties have found the reverse to be true, with positive comments on an improved process,[5] and positive comments on increased transparency.[6]

Conclusions and Recommendations

UCE's summary includes multiple recommendations, many of which the Company disagrees with. First, and foremost, the Company believes the Commission should disregard UCE's recommendation to not acknowledge PacifiCorp's 2015 IRP. UCE base this recommendation on results of the Synapse report, something the Company does not find persuasive in any manner. Worth noting is the fact that Synapse's own report shows in Table 3 that PacifiCorp's Preferred Portfolio was lower cost than the Synapse portfolios. Other issues with the report, including the constraints raised here by UCE are discussed in Section 9.

As to the recently released CPP rule, PacifiCorp will update modeling consistent with assumptions based on the final rule. The 2015 IRP Update and future IRPs will look at the current evolution of requirements under the CPP as well as incorporate information as states begin to develop their CPP implementation plans.

Finally, Table 9.3 in the Company's 2015 IRP will continue to evolve in future IRPs. The current version is expanded from the prior version; the Company would expect this trend to continue. However, the Company is not sure what UCE is asking for with the request for analysis on "who bears the risk of having to pursue different acquisition paths." The Company addresses treatment of customer and investment risk in Chapter 9 (page 247). A brief summary of that discussion is below.

The group who primarily bears the associated risk will vary depending on the risk considered. Chapter 9 address stochastic risk, capital cost risk, and scenario risk. Stochastic risk considers variables such as retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise.

Capital cost risks, such as a Commission determining imprudence in construction of a new generating plant, would be borne by shareholders. If there are variances in costs that are deemed prudent, this would be a customer risk.

[5] See DPU comments, page 3, "The Division has participated in this biennial cycle of the IRP process as an active and engaged stakeholder and recognizes and commends the Company for the steps it has implemented to improve the IRP public process."
[6] See IEA comments page 1, "This progress provides increased transparency and relevant analysis of a variety of potential regulatory futures."

Scenario risk is an abrupt or fundamental change to a variable, or variables. In the current environment this could involve a fundamental shift in regulations around CO_2. To address these risks, PacifiCorp's IRP evaluation uses a range of CO_2 policy assumptions. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

7. REPLY COMMENTS: UTAH CLEAN ENERGY & SOUTHWEST ENERGY EFFICIENCY PROJECT

UCE and SWEEP submitted joint comments addressing PacifiCorp's Demand Side Potential Assessment study and the 2015 IRP model selections. The Company responds to these comments below.

Class 2 DSM Achievable Technical Potential

UCE/SWEEP notes that in the Company's 2015 DSM potential study, Utah has the highest achievable technical potential of any state[7] for Class 1, 2, and 3 DSM resources and suggests that this is a result of differences in how cost-effectiveness is assessed in each state. On the contrary, cost-effectiveness has no impact on the *achievable technical* potential estimated in the DSM potential study. Utah's achievable technical potential is larger than other states in absolute terms because it represents the Company's largest service territory in terms of retail sales. As shown in Table 4-2 of Volume 2 of the 2015 DSM potential study, achievable technical potential as a percent of baseline sales is estimated to be highest in California due to the relatively low share of industrial sales in that state.

Class 1 DSM Emerging Technologies

UCE/SWEEP states that the 2015 DSM potential study considered only existing Class 1 DSM programs. However, as discussed on page 2-10 of Volume 3 of the 2015 DSM potential study, AEG (the study vendor) did consider "emerging" Class 1 resources for inclusion in the study, but only quantified potential for well-understood technologies with reliable information on impacts and costs. The quantification of potential includes both expansion of the Company's current Class 1 DSM programs and potential new programs such as Commercial Curtailment.

UCE/SWEEP would like to see additional Class 1 DSM options assessed in the next IRP, either as specific programs or a proxy for emerging technologies that may become available over the course of study period. In future studies, the Company will continue to review the state of Class 1 DSM resources to determine which options have sufficiently reliable information on impacts and costs to justify inclusion in resource planning. However, these inputs will need to be based on specific offerings available in the market, as creating a generic "emerging technology" resource with hypothetical impacts and costs could create an unanticipated resource deficit if the resource does not materialize at the assumed magnitude or cost.

Acquiring Class 3 DSM resources through Advanced Metering Infrastructure

[7] DSM potential in Oregon is estimated through a separate study conducted by the Energy Trust of Oregon.

UCE/SWEEP suggests the Company should consider deploying an advanced infrastructure in new residential developments as pilot programs to acquire and refine Class 3 DSM programs. PacifiCorp analyzed the potential for Class 3 DSM in the 2015 IRP in sensitivity S-14. This sensitivity assumed Class 3 DSM resources, generally assumed non-firm due to the voluntary nature of customer response to price signals, can be treated as firm resources and were modeled as such. The analysis results showed a reduction in portfolio costs as compared to the benchmark case (C05-1). However, the sensitivity did not include the costs of the necessary advanced metering infrastructure (AMI) that would be required. Incremental costs to deploy AMI would include the field hardware and installation of meters and the communication network, engineering design and management, and most significantly costs around information and technology to handle the billing interface and dynamic pricing schemes. In light of the costs the Company does not currently have plans to conduct a pilot at this time. However, the Company continues to monitor costs and potential and expects to re-evaluate the feasibility of pilot in the next couple of years.

Class 4 DSM resource neglected in the 2015 DSM Potential Assessment

UCE/SWEEP correctly states that Class 4 DSM resources are excluded from the 2015 DSM potential study and the 2015 IRP, but incorrectly states that this also applies to "behavioral change-oriented programs such as Home Energy Reports and support for energy managers." The referenced programs are considered Class 2 DSM resources, as stated on page 68 of the 2015 IRP, and are included in the Class 2 DSM potential study and the IRP. As described on page 69 of the 2015 IRP, the Company uses the term "Class 4 DSM" to refer to non-incented behavior-based savings achieved through broad energy education and communication efforts where savings may not be easily quantified. Impacts of such efforts may not be explicitly treated in the resource planning process, however, are captured naturally in actual sales and forecasts of future loads.

Residential Class 2 DSM IRP Selections in Utah by IRP Preferred Portfolio

Based on the relatively large share of residential cooling potential identified in the 2015 DSM potential study, UCE/SWEEP suggests the Company "should explore the opportunity to promote and/or modify their existing wattsmart programs and incentives for residential cooling…" and makes specific reference to evaporative cooling. The Company recognizes the opportunity for, and value of, cooling resources and has a long track record of aggressively pursuing opportunities to cost-effectively target these loads, including offering incentives to residential and non-residential customers to encourage evaporative cooling technologies. The Company also runs one of the largest air conditioner direct load control programs in the nation. As part of regular DSM program management, the Company and its implementation contractors monitor market conditions, new technologies, comprehensiveness of offerings, and cost-effectiveness and will continue to do so to ensure DSM programs are being optimized for its customers and to meet Company resource planning objectives.

Utah Residential Direct Load Control in the IRP Preferred Portfolio

UCE/SWEEP comments that the amount of Utah Residential Direct Load Control in the 2015 IRP Preferred Portfolio remains constant at 115 MW over the 20-year planning period, which is incorrect. While the existing program impacts are assumed to continue at 115 MW in each year, the Preferred Portfolio includes an incremental 4.9 MW beginning in 2033, as shown in Table 8.7 of the 2015 IRP. Incremental potential for Utah Direct Load Control was available as input to the 2015 IRP studies beginning in 2016 and its lack of selection until 2033 indicates that the value of incremental participation in the near term is not sufficient to justify the cost when compared to other resource alternatives.

DSM Cost Curve Inputs

As presented at the July 18, 2014 IRP public meeting and again at the July 17, 2015 IRP technical conference, the Company determines the levelized cost of Class 2 DSM measures differently across states to align with state-specific guidance on cost-effectiveness criteria and prudency of DSM acquisition costs. UCE/SWEEP believes that the inclusion of participant costs in states that rely on the Total Resource Cost (TRC) test unfairly burdens these resources as compared to supply-side resources and proposes an alternate modeling methodology where supply curves in TRC states would first be screened for cost-effectiveness at various incentive levels, but then modeled based on utility costs in the IRP.

First, the Company notes that TRC costs are not always higher than Utility costs. This can occur for several reasons, including:

1. Some measures, such as evaporative coolers, have a negative incremental cost, meaning the TRC cost is less than the incentive and administrative costs counted in the Utility Cost Test.
2. Some states include non-energy benefits in the TRC tests, which can represent significant reductions to a measure's total cost. Examples include water savings from clothes washers and avoided bulb replacements over the longer life of an LED bulb.
3. Washington and Oregon apply an additional 10 percent benefit to the TRC results to account for unquantified environmental benefits.

Second, the Company is concerned that UCE/SWEEP's proposed methodology would create a disconnect between IRP modeling and state-specific guidance on DSM program implementation.

Class 2 DSM Acquisition Goals

UCE/SWEEP recommends that PacifiCorp consider the DSM resources selected in the 2015 IRP as a "floor" and work to acquire all cost-effective DSM, setting a goal to achieve two percent electricity savings as a percentage of retail sales. As UCE/SWEEP noted earlier in its comments, the IRP model did not select all of the achievable technical Class 2 DSM potential offered to it, indicating that acquiring levels of Class 2 DSM above the IRP selections is sub-optimal. The Company also modeled two cases with accelerated Class 2 DSM supply curves, neither of which was selected as the Preferred Portfolio, indicating that acquiring higher levels of Class 2 DSM would not be cost-effective in the short term. For additional explanation of the considerations in comparing acquisitions as a percent of retail sales across utilities and services territories, see the Company's responses to the CG comments.

8. REPLY COMMENTS: INTERWEST ENERGY ALLIANCE

IEA commends portions of PacifiCorp's IRP, such as participation in energy imbalance market (EIM), reduced reliance on coal generation and inclusion of wind and solar qualifying facility (QF) contracts of 816 MW. They also note that the Company does "…incorporate Clean Power Plan ("CPP") scenarios in its modeling, consistent with stakeholder comments." Treatment of transmission was also viewed favorably with potential benefits associated with entry into the EIM.

Conversely, IEA faults PacifiCorp for not planning to add more renewables, as well as for the Company's continued reliance on fossil generation. IEA also provides several recommendations for the Commission's consideration. The Company's reply to these comments is provided below.

<u>Renewable Costs in 2015 IRP</u>

IEA faults PacifiCorp's cost estimates associated with new renewables. The capital cost estimates for new wind generation in the 2015 IRP range between $2,135/kW and $2,188/kW, depending upon the location of the resource. PacifiCorp estimates the cost of proxy IRP resources based on a feasible commercial in-service date considering all activities associated with developing, permitting, constructing and commissioning for each type of resource. The cost estimates in the 2015 IRP rely upon the Company's knowledge of costs incurred during previous wind construction projects, tax costs in specific states and market prices for goods and services.

IEA references the 2013 Wind Technologies Market Report (WTMR) prepared by Lawrence Berkeley National Laboratory (LBNL) as the source for capital costs for wind of $1,630/kW in 2013. The $1,630/kW price estimate, however, is subject to three vulnerabilities that are mentioned in the report: (1) limited data sources, (2) unequal credibility of data sources, and (3) a small sample size of 2013 projects. The authors of the WTMR indicate collecting wind turbine price data is a challenge because many of the contracts are not publically released. The creditability of pricing data is difficult to verify because services covered in wind turbine transactions can vary and press releases might only reveal certain project costs. The report cautions that the limited sample size of 11 projects making up a total of 650 MW in 2013 could have influenced the weighted average for that year. The WTMR states the 2013 turbine costs are more than $300/kW lower than 2012 costs and approximately $120/kW lower than the projected 2014 capital costs for 16 projects totaling more than 2,000 MW. IEA seems to have chosen the year with the lowest possible costs, despite warnings that the sample size for that year could make it a statistical outlier and the availability of more recent information for 2014 that showed higher wind capital costs.

While the project costs in the WTMR have limits, the report is a good source of information for wind turbine price trends during the past 15 years. Market demand for wind turbines in the United States has fluctuated during the past 10 years, often impacted by the availability of production tax credits (PTCs). Page 47 of the WTMR details market forces such as manufacturer profitability and strong demand growth that caused turbine prices to rise between 2002 and 2008. The WTMR also describes the reversal that has occurred since 2008 as market conditions changed.

When preparing the cost of wind resources for the 2015 IRP, PacifiCorp spoke with a number of key wind turbine generator manufacturers about the costs of future wind turbine generators between 2015 and 2020. By and large, these manufacturers did not predict lower capital costs for wind turbine generators. The wind turbine generator costs PacifiCorp used to prepare the 2015 IRP are within the cost range of $900 to $1,300 cited in the WTMR. PacifiCorp cannot know with certainty which wind project costs were included or excluded in the WTMR, but the Company is confident the price estimates in the 2015 IRP represent reasonable market rates for complete wind project capital costs.

Amount of Renewables in 2015 IRP

There is a misconception that the lack of renewables in the Preferred Portfolio is because PacifiCorp is "in a holding pattern" and "awaiting the outcome of litigation contesting the coal upgrade requirements... to determine the best path forward." In looking at potential outcomes of litigation, PacifiCorp examined four different regional haze scenarios. Additionally Volume III of the 2015 IRP is focused on potential actions related to different regional haze litigation outcomes. Final resolution of litigation is not germane to resource decisions that need to be made in the near-term. Such resolution will only impact decisions that must be made in the 2017 IRP or future IRPs.

IEA points to levels of renewable penetration of other utilities, and states that PacifiCorp could "effectively integrate more wind and solar energy." It is IEA's belief that increased renewables will not raise integration costs. Further, IEA claims that wind and solar energy can provide "valuable flexibility and reliability support to the grid."

PacifiCorp will not question the veracity of any of the statements at this time. Rather, what is important to note is the Preferred Portfolio relies on DSM and FOTs in the front years of the planning horizon. In fact there are no major generation assets selected until 2028 when a CCCT is added. Simply stated, the 2015 IRP shows that incremental renewable resources, beyond the 816 MW of QF renewable resources expected to come online by the end of 2016 are not needed in the near-term. PacifiCorp will continue to evaluate the need for renewable resources with changes in the planning environment, whether driven by reduced renewable costs or development of state and federal policies. Likewise, the integration costs related to renewable resources are relatively small and are not a barrier to the resource selection.

IEA notes that the renewable percentages fall through the planning horizon. This is driven by the fact that other resource alternatives and fuel types, such as DSM resources and natural gas resources, take on a more prominent role in the 2015 IRP generation mix as coal generation levels decline. Resource selection in IRP modeling is driven by the least cost approach to meeting load obligations that meet known and assumed state and federal policies. For the 2015 IRP, FOTs and DSM proved to be the most cost effective alternative, given current planning assumptions, to meet PacifiCorp's incremental resource needs in the front two to four years of the planning horizon, a period in which 816 MW of incremental renewable QF resources are assumed to come online.

PacifiCorp prepared sensitivities to examine issues that could impact long-term planning. Two such sensitivities examined potential changes in the drivers of renewable resource selection. Sensitivity S-09 examined a world in which the PTCs are assumed to be extended indefinitely, Sensitivity S-12 incorporated stakeholder solar cost assumptions. Both of these sensitivities show an increased amount of renewable generation installed as compared to the benchmark case (C05-1). This is not surprising, as these assumptions lead to decreases in the cost of renewable generation. If these events do occur, the Company will re-evaluate its resource plans in subsequent IRPs and IRP Updates.

Resource sections made in the IRP are not made in a vacuum, and not locked down for the entire planning horizon. Table 9.3 in the 2015 IRP contains potential impacts to near- and long-term planning due to some of the main uncertainties in the 2015 IRP. The table incorporates information gleaned from sensitivity runs like the two listed above. It provides guidance on how resource procurement plans might evolve with changes in some of the variables analyzed. PacifiCorp revisits long-term planning every two years with each publication of its IRP. IEA misinterprets the table when suggesting PacifiCorp needs to add more renewable because states will set 111(d) emission rate targets. The planning scenario for that trigger event is related to targets applied to PacifiCorp generation in states where the Company has no load (AZ, CO and MT) without any relief. It is not simply driven by the fact that 111(d) targets will be set in individual states.

IEA also discusses potential savings from use of resources with zero fuel costs. IEA points to a study purporting to show energy prices were lower in a two-day period of a polar vortex in January 2014 for the PJM market. Without fully reviewing the study this conclusion does not seem surprising. Theoretically, spot-market prices are set by marginal units, if sufficient amount of zero-cost, must-run units are added to the mix they will push the highest cost marginal units out of the needed resource stack. PacifiCorp's IRP however incorporates the full cost of resources, fuel and capital. The IRP by design considers the potential savings offered by renewable resources because it considers the variable costs of the resources as well as capital investment and other fixed costs.

Recommendation for Future Reports

IEA makes several recommendations for future IRPs. The first recommendation is to incorporate the endogenous determination of early retirement dates for coal plants when selecting portfolios. This option would be problematic as there are many details to consider when assessing the cost for early retirement. Coal contract constraints, fixed costs, impacts on fixed and operating costs of other coal units at multi-unit plants, and other variables influence the economics of early retirement decisions. Resource expansion and dispatch models are not able to dynamically reflect changes to these important cost variables when endogenously calculating early retirement alternatives. PacifiCorp's current approach, which analyzes alternative coal unit retirement scenarios, is more robust because the impact of early retirements on other units and system fixed costs is explicitly captured.

In its recommendations, IEA questions the use of RECs to meet renewable portfolio standard (RPS) requirements in Oregon and Washington and using a 111(d) attribute from the same generation to meet 111(d) requirements in other states. Given the level of uncertainty around the proposed rule and how the proposed rule will ultimately interact with state law, the Company's assumptions regarding RECs are reasonable. In the proposed rule, the EPA requested comment on what would consist of duplicative counting of attributes. One pointed to a duplicative standard as:

> An example of a duplicative emission standard would occur where recognition of avoided CO_2 emissions from, for example, a wind farm, could be applied in more than one state's CAA section 111(d) plan.

PacifiCorp's 111(d) modeling did not allow the same CO_2 emission reductions to be counted in multiple states. With respect to non-duplicative standards renewable energy generation, the proposed rule indicated that renewable generation may meet more than one requirement:

> This does not mean that measures in an emission standard cannot also be used for other purposes. For example, if a state wished to take credit for CO_2 emissions avoided due to electric generation from a new wind farm, those avoided emissions could be considered non-duplicative and included for purposes of CAA section 111(d), even if electric generation from that wind farm was also being used to generate renewable energy certificates (RECs) to comply with the state's RPS requirements.

The proposed rule makes clear that a single megawatt-hour of renewable generation can be used for both 111(d) and RPS compliance. Both the proposed rule and current state law are silent as to whether renewable generation could be used for both 111(d) compliance and RPS compliance in separate states. Both the proposed rule and state law are similarly silent as to whether a REC must be retired when the underlying renewable generation is "used" for 111(d) compliance. Given the proposed rule's intent to leverage state RPS programs and allow renewable generation to be used for both purposes, it would not have been reasonable to assume that current state law would preclude this outcome. The Company acknowledges that there is lack of clarity regarding the interaction of 111(d) and state RPS requirements. In light of this lack of clarity, the Company's assumptions were reasonable at the time they were made.

IEA also suggests changes in modeling to recognize the value of hard assets when meeting RPS requirements in Oregon and Washington. The Company has done this. The analysis for pursuing an unbundled REC strategy found a nominal levelized unbundled REC price of $18/REC would yield break-even economics to a hard asset alternative. Unbundled REC prices are currently well below this break-even level, and therefore, customers will benefit from an unbundled REC strategy as documented in the 2015 IRP. As such, there is no need for additional modeling.

Finally IEA suggests the Commission request modification to the preferred portfolio to force additional renewables into the preferred portfolio, or update the IRP modeling once the CPP rule is finalized. PacifiCorp does not believe either recommendation is appropriate in terms of the 2015 IRP as filed. Lack of additional renewable generating resources by itself does not attest to the objectivity of PacifiCorp's 2015 IRP. In fact, requiring any specific resource to be included would show lack of objectivity.

As to an IRP update concurrent with the final CPP rule, PacifiCorp will update modeling consistent with assumptions based on the recently released final CPP rule. The Commission however should not require an update of the IRP at this time. PacifiCorp will provide an update to the 2015 IRP next year, along with a new IRP in 2017. These future filings will look at the then-current evolution of requirements under the CPP as well as incorporate information as states begin to develop their CPP implementation plans.

9. REPLY COMMENTS: CONSERVATION GROUPS

CG submitted joint comments from SC, HEAL Utah, WCE, PRBRC and ICL. CG comments on a wide range of issues, along with inclusion of a Synapse report that ostensibly develops alternative portfolios for the Company's system. CG also state they consider PacifiCorp's 111(d) modeling flawed, and overly complex. They find the coal plant retirement options included in the modeling to be deficient. They further claim that Class 2 DSM is also underestimated. The Company responds to these issues below.

Class 2 DSM

CG finds projection of annual incremental energy savings in PacifiCorp's 2015 IRP to be overly conservative. They believe that Class 2 DSM is understated for three reasons which are addressed below.

First, CG claims that potential studies inherently rely on current commercially available technologies and lack information on savings from future efficiency measures. The Company's DSM potential studies are performed by independent, third-party contractors and utilize industry best practice methodology. Supply curve development for an IRP requires quantification of savings potential and associated cost. As such, supply curves can only include measures with reliable estimates of cost and potential. DSM potential studies do not attempt to predict what technologies might emerge over the study period and their associated costs, beyond identifying emerging technologies with reasonably reliable projections available. Where available and reliable, the Company's studies do account for projected changes in costs and savings; most notably, the Company's 2015 DSM potential study assumes increasing efficacy and declining costs for LED lighting based on work published by the Department of Energy. A list of all included emerging technologies, as well as those excluded and the accompanying rationale can be found in Appendix D in Volume 4 of the 2015 DSM potential study.

Second, CG claims the projection of annual incremental energy savings in PacifiCorp's 2015 IRP is lower than what leading states and utilities have achieved in the past or are planning to achieve in the near future. The Company appreciates CG's efforts to compare the identified potential to historical achievements of other states and utilities and is also is aware of these metrics. However, there are several reasons to use caution when using these metrics to assess the validity of a utility's DSM potential study or IRP:

- A utility's IRP process focuses on identifying cost-effective demand-side resources and assessing their economic value to inform appropriate levels of program delivery. Resource need and value will vary between different utility/program administrator service territories.
- EE program and market successes coupled with differences in building codes and equipment efficiency standards can have large impacts on forecasted potential relative to historical activity.
- Accurately comparing historical achievements or forecasted potential for different utilities is even more difficult due to factors such as:
    - Differences in housing stock, industry mix, and climate

- o Differences in cost-effectiveness metrics and avoided cost
- o Differences in electricity use per customer and/retail rates
- o Prior program activity and current efficient measure saturations
- o How and when savings are updated to reflect improved codes and standards
- o Presence of high savings niche end use opportunities, such as pool pumps
- o Possible fuel-switching initiatives for dual-fuel utilities

While the lure of such comparisons across jurisdictions and time periods is understandable, given the possible multitude of differences, such comparisons are at best a starting place for further discussions not basis for making conclusive statements regarding a utility's performance or planning analysis.

Third, CG claims the projected annual energy savings significantly decrease year by year. As illustrated in CG's Figure 1, system-level DSM selections increase annually from 2015 through 2019. Selections decrease in 2020 as the lighting backstop provision of the Energy Independence and Security Act of 2007 takes effect, but then increase year-on-year through 2024. Annual selections begin to decline in 2025 as many discretionary opportunities are assumed to be fully captured in the first 10 years of the planning horizon.

CG states that PacifiCorp should seek to accelerate energy efficiency programs in the near term to capture cost-effective savings illustrated in the potential study. The Company's 2015 DSM Potential Study included an assessment of the feasibility and cost of accelerating Class 2 DSM acquisition (Chapter 6 of Volume 3). The findings of this analysis were used to develop a set of accelerated supply curves, which were modeled in two of the core cases for the 2015 IRP, C11-1 and C11-2. As neither of these core cases showed lower cost/risk than the preferred portfolio, the Company has no information to suggest that the value of accelerating acquisition outweighs the additional cost.

Synapse Study

The analysis provided by Synapse is critical of PacifiCorp's approach to 2015 IRP modeling. Synapse is concerned with PacifiCorp's use of a rate-based approach to meeting EPA's draft section 111(d) rules. The Company believes that the rate-based approach sets a maximum emission rate target (expressed as pounds of CO_2 per MWh) consistent with EPA's draft proposal. While Synapse may believe a mass-based approach is a preferable modeling approach to studying EPA's draft 111(d) rule, there was very little guidance in the draft rule indicating how states would develop and adopt mass-based targets, let alone information to suggest that such an approach would be adopted by all states. However, the Company in fact looked at both rate-based and mass-based approaches in the 2015 IRP.

Synapse further raises concerns that portfolio modeling does not allow for endogenous determination of early retirement dates for coal plants. The Company did not model endogenous retirements because this modeling option would be problematic as there are many details to consider when assessing the cost for early retirement. As Synapse points out, "(i)n the years leading up to a unit's phase-out, it would (be) unreasonable to incur major capital expenditures." For this, Synapse made the assumption to reduce major capital expenditures because "in the two years prior to a unit going offline, retirement is known and major capital expenditures can be avoided." Aside from issues related to the assumptions about the length of the time period, the amount of the adjustments and when the two-year period begins, since the retirement dates are unknown in an endogenous modeling approach, there are other costs that should be considered. For example, coal contracts and fixed costs shared by multiple units of a plant, or even multiple plants, would need to be captured correctly when one of the units retires early. Resource expansion and dispatch models are not able to dynamically reflect changes to these cost variables when endogenously calculating early retirement alternatives. PacifiCorp's current approach, which analyzes coal units' specific alternative retirement scenarios with specific costs for the scenarios, is more robust because the impact of early retirements on other units and system fixed costs is explicitly captured. Synapse's approach on the other hand ignores these impacts.

Synapse believes that "(a)llowing the model to choose to retire units optimally results in a lower cost plan than when retirements are guessed by planners."[8] However, its own analysis shows PacifiCorp's preferred portfolio to be less costly than those generated by Synapse. Below is Table 3 in Synapse's report that summarizes the costs of PacifiCorp Preferred Portfolio and the costs of Synapse's cases:

Costs (M$ NPV)	PAC Preferred	Synapse Case A	Synapse Case B	Synapse Case C
PVRR (2015-2034)	$28,095	$36,233	$36,363	$36,323
PVRR (CO_2 cost excluded)	$28,095	$28,137	$28,678	$28,720
Difference from PAC Pref.		$42	$541	$583

In addition, Synapse states that it uses the reference case regional haze scenario and assumes that PacifiCorp does not prevail in its Wyoming litigation to roll back the requirements. It is not clear if Synapse incorporated environmental investment costs as required in the reference regional haze case or potentially, both capital and environmental costs for units that continue to operate beyond what is assumed in the Preferred Portfolio. Such costs would drive the presented PVRRs higher than what Synapse shows in Table 3. It is unclear why Synapse models a CO_2 price as opposed to using the mass-cap approach when it states that "(t)he mass-based approach is far simpler" and the System Optimizer (SO) model can be "readily configured to determine a least-cost plan for mass-based compliance."

In Section 2.4 of its report, Synapse questions the capital costs of new wind and solar resources in the 2015 IRP. They compare PacifiCorp's wind and solar capital costs to those recommended by UCE. The source document for UCE's recommended wind capital costs is the United States Department of Energy's (USDOE) publicly available Wind Vision Report. The portions of the Wind Vision Report referenced by Synapse do not have any costs that directly align with the UCE's recommended costs. Comments and costs provided by UCE provide no basis for determining exactly how their cost estimates were created. PacifiCorp's wind capital costs are based upon wind turbines that are matched to specific wind regimes within PacifiCorp's service territory, price estimates from the wind turbine manufactures for purchase two to three years in the future, and development, construction and owner's costs of actual projects within PacifiCorp's service territory.

[8] Synapse report, page 6.

The Wind Vision Report indicates the capital costs for installed wind projects in the United States have been volatile during the past 35 years, falling from $5,000/kW in the early 1980s to $1,300/kW in 2004 and then moving up to approximately $2,230/kW in 2009. Between 2012 and 2014, the report indicates average wind capital costs ranged from approximately $1,930/kW in 2012, to $1,630 in 2013, and to $1,750 in 2014. Changes in technology, market conditions and legislation can significantly increase or decrease wind project capital costs. The Wind Vision Report also illustrates how costs can vary by project, as costs within the report for projects built in calendar year 2013 varied between approximately $1,400/kW to $4,500/kW. The difference between the Company's capital cost estimate range of $2,135/kW to $2,188/kW and UCE's recommended cost range of $1,747/kW to $1,800/kW could be due to wind turbine costs differences based upon what year the sales contract is signed and site specific variations in costs for wind turbines and construction.

Wind turbines need to be matched to the exact wind regime of a site and wind regimes vary tremendously across the country. PacifiCorp's wind capital costs are based upon modern wind turbines that manufacturers determined are suited to the wind regimes at sites within specific states. The costs of these turbines are within the range of $1,000 to $1,300/kW that is cited in the Wind Vision Report. PacifiCorp's capital costs include balance of plant costs based upon actual project construction costs and include costs for development, land, sales taxes (where applicable), transmission interconnection, overheads and allowance for funds used during construction (AFUDC). It is not clear to what extent, if any, UCE's recommended cost figures include these additional costs. PacifiCorp's wind capital cost estimates are well within the costs shown in the Wind Vision Report and differences in turbine and project costs for specific sites can vary greatly due to market conditions.

Synapse cites the 2014 US Solar PV Capital Costs and Prices report by the consulting firm IHS as the basis for the UCE's recommended solar costs. PacifiCorp only has access to two charts of the IHS report and does not know exactly what costs are included in the UCE cost estimate. The two charts in the IHS report show capital costs of just under $\$2/W_{DC}$ which roughly matches UCE's recommended solar capital costs of $1,717/kW to $2,000/kW. UCE's recommended capital costs are likely lower than PacifiCorp's costs for two reasons:

- They are reported on a Direct Current (DC) basis instead of an Alternating Current (AC) basis (i.e. available capacity that can be delivered to the grid)
- The costs in the IHS report only reflect the lowest cost quartile of project costs.

PacifiCorp's 2015 IRP solar capital costs for 50.4 MW_{AC} projects are based upon project designs prepared by Black & Veatch for Milford, UT and Lakeside, OR. These resources have relatively high inverter loading ratios (ILRs) or DC to AC design ratios because they were designed to provide the lowest cost of energy by maximizing panel capacity to inverter capacity that results in the lowest cost of energy. The inverter loading ratios used in PacifiCorp's 2015 IRP are consistent with recommended values/assumptions used in E3's "Capital Cost Review of Power Generation Technologies – Recommendations for WECC 10 and 20 Year Studies (March, 2014)." The E3 study was based on ILRs of 1.3 and 1.4 for utility scale single axis and fixed tilt systems, respectively. PacifiCorp's ILRs were between 1.33 and 1.38 for 50.4 MW_{AC} sized projects. UCE's recommended capital costs are adjusted to an AC basis and compared to the Company's 2015 IRP costs in the table below. UCE's adjusted capital costs are lower since the IHS data on which they are based only reports costs for projects in the lowest quartile. (A note on each IHS chart that is available to PacifiCorp indicates the "commercial capital costs reflect the average of the least-cost quartile of project costs," which means 75% of all PV projects have higher costs and were eliminated from consideration in IHS's cost report). It is likely PacifiCorp's capital costs would be well within IHS's cost range if IHS reported all resource costs, not just those in the lowest quartile. It is also unknown to what extent the costs reported in the IHS study include owner's costs, land, transmission interconnection, allowance for funds used during construction, etc.

50.4 MW PV Resource	UCE Proposed Cost, $/kW_{DC}$	Inverter Loading Ratio (DC to AC) factor	UCE Cost, $/kW_{AC}$	PacifiCorp 2015 IRP Capital cost, $/kW_{AC}$	E3 Report (Table 23), $/kW_{AC}$
Fixed 26.5% CF,UT	$1,717	1.373	$2,358	$2,546	$3,080
SAT 31.6% CF, UT	$1,873	1.339	$2,508	$2,702	$3,380
Fixed 25.4% CF,OR	$1,830	1.344	$2,459	$2,659	$3,080
SAT 29.2% CF, OR	$2,000	1.339	$2,679	$2,829	$3,380

Given the discussion above, claims that the renewable costs incorporated in the Company's 2015 IRP are, "not indicative of commonly held costs" should be viewed with a healthy dose of skepticism. This statement is not supportable by the information provided by Synapse.

After reducing the costs of renewable resources, the outcome from Synapse's model did not lead to addition of more renewable resources as Synapse expected. Instead of studying the Company's needs for renewable resources, contribution to peaks and cost-effectiveness of the alternative resources, Synapse seems to take issue with the constraints used in the Company's setup in the SO model. As Synapse correctly states, "System Optimizer is a highly complex modeling structure that allows extensive flexibility, yet also allows layers of constraints to dictate outcomes." For its 2015 IRP, the Company performed studies for 34 core cases and 15 sensitivity cases, each of which has a distinctive set of inputs. The inputs are prepared utilizing the flexibility that the SO model offers. Synapse is also correct in that it points out the complexity in modeling of the Company's system. The "nearly 20 scenarios" that Synapse references for the setups of the Company's studies are to select appropriate inputs for the specific cases, such as load forecast, level of Class 2 DSM potentials, market prices and assumptions for Energy Gateway transmission. The "technology groups" are to maintain the relationship of different aspects of the Company's system. For example, the amount of new resources that could be built at the Dave Johnston site in a year is dependent upon when the Dave Johnston plant would retire. Also, the maximum amount of renewables by location (pages 114-115 of the Company's 2015 IRP) is not for any specific resource, but for a group of potential resources. That is, it is not appropriate to simply point to the complexity of a model as the culprit when the outcomes of the model are unexpected.

PacifiCorp's Preferred Portfolio is least-cost in comparison to all of the Synapse cases. This cost differential is likely understated as the Synapse cases with endogenous coal unit retirements disregard any incremental costs not captured in the SO model, as discussed above.

PacifiCorp also appreciates that Synapse has concluded the preferred portfolio meets the required 111(d) mass-based targets. In comparing the final CPP to the draft Synapse states:

> PacifiCorp's Preferred Portfolio appears to comply with the final mass-based goals, based on PacifiCorp's pro-rata share of emissions in Arizona, Colorado, Montana, Oregon, Utah, Washington, and Wyoming, (shown in 1.3 Why Mass-Based Compliance and Economic Coal Retirement Matters), it does not show that the plan represents a least-cost pathway towards compliance.

In short, Synapse has demonstrated the PacifiCorp 2015 IRP Preferred Portfolio is the least cost approach to meeting Synapse's interpretation of the revised EPA 111(d) rules. While there are other issues with the Synapse report they are only discussed briefly given the report's results.

10. REPLY COMMENTS: SIERRA CLUB

In addition to joint comments, SC submitted initial comments on storage on April 20, 2015. The following address those comments.

<u>Storage</u>

There is an extensive discussion of storage provided by SC in its letter submitted in April. However, the Company disagrees with the premise the storage was not included in the 2015 IRP. Storage was included as a supply-side resource option as shown in Table 6.1 and Table 6.2. There were several different types of storage including pumped hydro, compressed air energy storage (CAES), flywheels, and three types of batteries, lithium-ion, sodium-sulfur, and vanadium redox. There were also sensitivities that incorporated storage. Sensitivity S-06 forced a west side 400 MW pumped storage plant in 2024, while S-13 forced an east-side 300 MW CAES plant in 2024.

PacifiCorp is very interested in identifying economic applications for energy storage within the Company's network. There has been significant progress within the past year related to energy storage including reduction of battery costs, estimating and forecasting battery system costs and the development of models for quantifying the economic benefits of battery storage. PacifiCorp is closely following this progress, investigating the impacts of new information and seeking ways to apply it for our customers' benefit.

The Company continues to look for sites where multiple value streams can be stacked, including value streams in the EIM. Development of a company-wide standardized process for evaluation is underway. To this end, PacifiCorp is working to obtain a newly developed battery storage evaluation tool. Once the process is refined, it may be used to evaluate battery storage as an option for all applicable capital investment projects.

Currently, of the possible sites that have been identified, none of them has been determined as economically competitive to implement a battery storage solution. As penetration of variable generation grows, energy storage will become more attractive as an option to provide high quality, reliable service. In the near future, PacifiCorp will consider both the Oregon Request for Grant Applications for utility-scale, electrical energy storage demonstration projects and Washington's Clean Energy Fund grant for an energy storage and/or renewable project. The Company will also explore options to procure an energy storage system of at least 5 MWh by January 1, 2020, as required by Oregon House Bill 2193.

11. ADDITIONAL COMMENTS

Several non-intervening parties submitted comments in Docket 15-035-04; the Company will respond to some, but not all of these submittals. The fact that the Company does not respond to individual comments, claims, or suggestions does not imply that the Company agrees with the statements therein.

Many of the comments submitted appeared to be a form letter with a general concern of coal plant investments of $1.3 billion dollars over the next decade. Here the commenters assume incorrectly that the Preferred Portfolio as modeled is static for the next 20 years. This is a basic misunderstanding of the IRP process. While the IRP looks at a planning horizon of 20 years, resource decisions are not locked at this point for the foreseeable future. This is the reason PacifiCorp repeats the IRP cycle every two years, to ensure any resource investment decisions are made with the most current information and assumptions.

Several of the email comments also express support for renewables, specifically wind and solar. The comments mention wind as being the cheapest form of electricity and costs of solar falling. Here again the commenters may not fully understand the IRP modeling process and broad considerations of both cost and risk. That is, all costs for all resources are incorporated in the System Optimizer portfolio optimization process. The Company also examined the impact of factors that may impact the selection of solar resources, such as infinite extended production tax credit in sensitivity case S-09, lower solar costs as requested by stakeholders in sensitivity case S-12, restricted 111(d) attribute to incent the selection of renewables sensitivity case S-15, as well as sensitivity cases on Energy Gateway, cases S-07 and S-08, that would allow more wind resources be built in Wyoming and delivered to the Company's system.

The Company addresses two of the public commentators below. One provides more extensive comments, and covers multiple issues as compare to the general public comments. The second is somewhat more typical of the general public comments.

Utah Physicians for a Healthy Environment (UPHE)

UPHE submitted comments to the Commission on August 25, 2015 followed by an erratum on August 31, 2015. Their impassioned submittal belies an understanding of IRP planning principles and procedures. As a small example, their initial sentence suggests the Company faces a peak load of "8,412 Megawatts (MW)" when the forecasted value for 2015 is actually 10,368 MW as shown on page 62 of PacifiCorp's 2015 IRP.

UPHE further considers the 20-year planning horizon to be static. The Company has not locked in resource decision for the next 20 years as a result of the modeling assumptions included in the Preferred Portfolio. Rather these will be revisited on a two-year cycle going forward, with investment decisions based on the timing of the necessary actions.

UPHE also misunderstands the basic regulatory compact between regulators and the companies they regulate. PacifiCorp's Preferred Portfolio does "internalize" environmental costs via the 111(d) modeling of the CPP. This is what is required in a least-cost, least-risk portfolio. The Commission may be hard-pressed to acknowledge an Action Plan that exceeds such guidelines at a higher cost.

Another area UPHE misunderstands is the contribution to peak of renewable resources. They correctly cite that renewables currently have a capacity contribution to peak of 3% as cited in Table 5.2 of the 2015 IRP. However, they overlook Table 5.13 which shows the value assumed for the peak contribution to capacity of wind and solar which is much higher, up to 39% for solar and 14.5% for wind on the east side of PacifiCorp's system. UPHE incorrectly states the 13% planning reserve margin value is due to fossil generation's need for "maintenance, repair, and retrofitting." In fact the stochastic variables that go into the development of the PRM are: load, hydro generation, and thermal unit outages.

UPHE compares the relationship of PacifiCorp to its regulators with the relationship of German utilities to their regulators and the results are unsurprising: German utilities carry out their responsibilities within the framework that has been established by their regulators just as PacifiCorp carries out its responsibilities within the framework that has been established by its regulators. German regulators established a framework that requires certain environmental goals be met by electric utilities. Similarly, the US federal government and state commissions have established goals for electric utilities within the US. There are significant differences in the regulations that have been established by individual states within the US, by the US federal government and by regulators in Germany. PacifiCorp works diligently to meet the responsibilities it has been given by the many government agencies that create its regulatory framework and will work to accommodate any future changes to the regulatory framework in ways that best meet the needs of its customers while minimizing risks and costs.

On page 10 UPHE questions PacifiCorp's assumption that wind and solar capital costs will stabilize in the coming years. The capital costs for wind and solar projects in PacifiCorp's 2015 IRP are based upon all-inclusive costs for new resources. Turbines make up a significant portion of the capital costs for new wind resources and determine capacity factors for the sites. In preparation for the 2015 IRP, PacifiCorp received pricing and capacity factor estimates for modern turbines at wind regimes similar to existing wind farms. Pricing information remained stable compared to the 2013 IRP, but technological improvements led to higher expected capacity factors for wind resources in Wyoming. As a result, capacity factors for Wyoming were increased to 43% in the 2015 IRP. Stable capital costs and higher capacity factors result in lower wind energy costs for Wyoming wind resources.

The capital costs for 50.4 MW_{AC} solar PV systems in the 2015 IRP are inclusive of development and owner's costs, are listed on an AC basis rather than a DC basis, and are based upon designs to produce the lowest cost of energy by maximizing the relationship of panel capacity to inverter capacity. There are published costs for solar PV systems that are lower than PacifiCorp's 2015 IRP capital costs, but these prices are often listed on a DC basis or have other caveats that make them appear artificially low.

PacifiCorp provided a declining cost estimate for solar PV resources, which is unique within the IRP, but PV panel prices have declined to the point that they make up less than 40% of the price of a new resource. Any further declines in the price of PV panels will have less of an impact to overall solar project costs than they had in the past. In addition, PacifiCorp's research determined there were several factors that could put upward pressure on the cost of new solar resources in the United States, including financial stress of some solar panel manufacturers, economic uncertainty in China and import tariffs on Chinese panels being imported into the United States.

As PacifiCorp updates its IRP plan every two years, changes to capital costs and capacity factors will be incorporated into the energy cost assumptions that are used to develop the IRP.

UPHE claims that the Company's modeling of environmental costs "is far too narrow" as it deals with, "complying with the EPA's Regional Haze Rule, its Clean Power Plan, other Federal clean air and clean water regulations, and state RPS mandates." Given that this is what all IRP guidelines call for, the Company disagrees. In addition, the Company did provide core cases, and additional sensitivities looking at 111(d) compliance plus CO_2 taxes, see core cases C14-1, C14-2, C14a-1, C14a-2 as well as sensitivity case S-11.

The bottom line is while impassioned, UPHE is factually wrong on many aspects of the IRP process. They misinterpret what the Preferred Portfolio represents, a potential path forward given current information, that will re-evaluated on a regular two-year cycle. Decisions made today are limited to actions that will take place in the next two-four years. Given UPHE's lack of understanding, the Commission should disregard their comments and recommendations.

Breathe Utah

While Breathe Utah submitted comments to the Commission on August 25, 2015, it is unclear if they reviewed PacifiCorp's 2015 IRP or the 2013 IRP. Similar to UPHE they make several factual errors. Breathe Utah states the 2015 IRP determined accelerated acquisition of energy efficiency, "resulted in a cheaper, less risky energy portfolio." This is not the case. Core cases C11-1 and C11-2 focused on accelerated EE. These cases were higher cost than the Preferred Portfolio. Another factual error, Breathe Utah cites 2024 as the year the Preferred Portfolio builds utility-scale renewable resources; that is the year for construction as included in the 2013 IRP, not the 2015 IRP. The Commission should give Breathe Utah's comments little heed given the fact it is unclear which of PacifiCorp's IRPs they are discussing.

12. CONCLUSION

PacifiCorp believes its 2015 IRP reasonably adheres to the Commission's Standards and Guidelines, and should therefore, be acknowledged. PacifiCorp further believes its 2015 IRP reflects a balanced consideration of customer interests, and is well-supported by portfolio modeling and prudent planning assumptions leading to selection of a least cost Preferred Portfolio consistent with the long-run public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group, and continues to urge stakeholder participation throughout the IRP development process to foster constructive debate throughout it.