Response to Utah Party Comments on PacifiCorp's 2008 Integrated Resource Plan

(Docket No. 09-2035-01)

Section Number Corrections

1. INTRODUCTION

PacifiCorp (the "Company") filed its draft 2008 Integrated Resource Plan ("draft IRP") with the Public Service Commission of Utah (the "Commission") on April 8, 2009, and filed its final 2008 Integrated Resource Plan ("IRP") on May 28, 2009 including a "redline" version as requested, under Docket No. 09-2035-01. The Commission's criterion for IRP acknowledgment is that the plan is deemed reasonable at the time it is presented. As part of its review the Commission determines if the IRP adequately adheres to the IRP Standards and Guidelines established under Docket No. 90-2035-1, and takes into consideration the "merit and applicability" of public comments.[1]

The Commission issued an Order on April 27, 2009 requesting interested parties to submit comments on the IRP by June 18, 2009. The following six parties submitted comments, with none of them recommending that the Commission acknowledge the Company's IRP:

- Utah Division of Public Utilities (DPU)
- Utah Office of Consumer Services (OCS)
- Western Resource Advocates (WRA)
- Utah Association of Energy Users (UAE)
- Utah Clean Energy (UCE)
- Interwest Energy Alliance (Interwest)

This document first summarizes the Company's views and recommendations then describes the state of the IRP process in Utah. The document then provides responses to comments and recommendations organized by the responding party. In responding to each party, the Company may reference other sections of the document where a reply to a similar comment has been made.

2. EXECUTIVE SUMMARY AND RECOMMENDATIONS

After reviewing the parties' comments, the Company still strongly believes that the Commission should find the IRP to be in compliance with the Standards and Guidelines and grant acknowledgement. In the context of continuous improvement, if the Commission believes the Company should provide additional analysis in the future in certain areas, it should provide the Company specific guidance in those areas for future study while at the same time, acknowledging this plan.

[1] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01), pp. 22-3.

Comments from parties in this docket address a number of issues, but primarily express the view that the plan relies too much on market purchases and discriminates against renewable resources and new technologies. The critical portion of the IRP is the action plan, yet no party addressed the reasonableness of the action plan or suggested changes to the action plan that would address their particular concerns. Such suggestions would have been most helpful in that it could have allowed the Company to consider modifications to its action plan in a manner that would allow parties to recommend acknowledgment of the plan.

3. THE STATE OF THE IRP PROCESS

Parties do not address the reasonableness of the action plan; rather they focus on adherence of the plan to each party's interpretation of the Commission's Standards and Guidelines. In this regard, the bulk of the comments contend that the Company didn't perform enough analysis and didn't provide enough justification for the assumptions and conclusions in the IRP. In no case did the parties identify specific alternative actions the Company could take that would be enough to meet their view of the standard for acknowledgement. The Office of Consumer Services succinctly sums up the situation with the Company's IRP process in Utah:

> The Office also notes that the Company has incorporated numerous modeling upgrades as well as other changes in response to stakeholder comments; yet, an IRP that cannot receive acknowledgement is still the product of those efforts.[2]

The Company believes that the IRP process has reached a tipping point for manageability due to its widening scope and complexity. In its comments, the DPU mentioned that the IRP has become cumbersome. We agree with this assessment. A number of the Utah parties recommend a proceeding or dialogue to discuss the status of the IRP process. The Company supports such a collaborative approach to working out the issues. As part of the dialogue on the IRP, the Company a discussion on ways to improve the efficiency of the IRP process and restructure it so that it becomes a more effective product for all stakeholders.

The remainder of these comments addresses specific issues raised by the parties.

4. COMMENTS AND RECOMMENDATIONS FROM THE DIVISION OF PUBLIC UTILITIES

The DPU filed its report on June 18, 2009, entitled "PacifiCorp 2008 Integrated Resource Plan Report and Recommendations ("DPU Report"). The DPU recommended that the Commission not acknowledge the IRP. The primary reasons given include the following:

- The Company did not align its 10-year Business Plan with its 2008 IRP.
- The Company did not conduct an analysis of different planning reserve margins.
- The Company did not complete its own wind integration study using PacifiCorp wind and cost data.

[2] Office of Consumer Services, "In the Matter of the Acknowledgement of PacifiCorp's 2008 Integrated Resource Plan; Docket No. 09-2035-01", p. 2.

- The Company did not model intermediate purchases as portfolio options that compete with other resource options and then analyze cost and risk.
- The Company manually spread the wind resource quantities relatively evenly across the years from 2009-2018, instead of allowing the System Optimizer to select the timing and resource mix.
- The in-service date for the combined-cycle plant was “randomly” selected to be 2014.
- The Company “hand created” portfolios excluding Lake Side 2 based on the original top-performing portfolios, and these portfolios were not fully vetted.
- The Company created hand-built weighting adjustments for the eight performances measures but did not “explain or show adequate analysis of how these weighting schemes were derived.”

The DPU also recommended that the Commission “revisit the entire IRP process” (DPU report, p. 2), calling for a formal process to manage public meetings, handle information exchange, and provide regulators and intervenors with training for the IRP models.

The Company addresses each of these criticisms, the DPU’s process-related recommendations, and other complaints regarding technical aspects of the IRP.

4.1. The Company did not adequately link its 10-year Business Plan with its 2008 IRP

The DPU makes two related arguments supporting its claim that the Company’s IRP failed to meet procedural requirement no. 9, “The Company’s Strategic Business Plan must be directly related to its Integrated Resource Plan.” First, the Company performed IRP analysis after MEHC board of directors’ business plan approval in December 2008, due to the IRP filing delay caused by the Lake Side II decision. The DPU thus concludes that the IRP could not have informed the business plan. Second, the Lake Side II plant was included in the Company’s 2008 10-year Business Plan, but was not included in the Company’s IRP.

The DPU’s claim that IRP analysis is not directly linked to the business plan disregards the Company’s progress and challenges in aligning the two different and complex planning processes under a difficult set of circumstances. (These circumstances, mentioned in the IRP, include (1) the financial market crisis, (2) rapidly deteriorating economic conditions with consequent impacts on load and price forecasts, and (3) implementation of significant modeling and analysis enhancements to address IRP regulatory requirements.) The Company used its IRP System Optimizer model to develop resource portfolios for business planning support throughout 2008. Focusing on the last several months of IRP analysis in 2009, a period devoted to assessing portfolios without Lake Side II, ignores this key IRP modeling contribution as well as the consultative role that the IRP department played in supporting the business plan.

Regarding the timing of the Lake Side II portfolio impact analysis in relation to business plan approval, to expect that the business plan and IRP must be in exact lock step is unrealistic and implies a level of procedural rigidity that is counterproductive to sound planning. The DPU, in effect, presents the Company with a no-win situation. Had the Company filed the IRP based on its original portfolio analysis, it would have been in compliance with this particular procedural requirement according to the DPU. On the other hand, the Company would have been roundly criticized by the DPU and others for filing an outdated and flawed IRP, and would expect non-acknowledgment by the state commissions because the plan no longer comports with known resource planning information at the time it was prepared.[3]

The Company also points out that it did in fact link the business plan with the Lake Side II decision and the IRP. This linkage was described in Chapter 9 of the IRP document:

> For IRP and business planning alignment purposes, major resource differences between the 2008 preferred portfolio and the 2009 business plan approved in December 2008 were analyzed by PacifiCorp Energy's finance department for rate and financial impacts. This analysis also supported credit rating agency review of the business plan. The major resource changes included deferral of the CCCT to 2014 from 2012, deferral of the IC Aero SCCT to 2016 from 2013, and a modified wind acquisition schedule. (The preferred portfolio includes an additional 450 MW from 2009 through 2018.)[4]

4.2. The Company did not conduct an analysis of different planning reserve margins

The DPU states that the Company did not justify or provide supporting information for selection of a 12 percent planning reserve margin. The DPU also criticized the Company's study scope (comparing portfolios with 12-percent and 15-percent reserve margins at three different CO_2 tax levels) and its use of a three-tiered energy not served (ENS) cost structure, which it views as arbitrarily selected by the Company.

The Company believes that it conducted a sufficiently robust stochastic cost analysis of portfolios with different planning reserve margins as requested by the Commission. This study incorporated portfolios developed with different CO_2 cost scenarios as recommended by OCS staff at the June 26, 2008 public meeting. (The Company notes that it received no indication of dissatisfaction with the Company's study design or selection of planning reserve margin levels from DPU staff at this meeting or at other public meetings held for the IRP.) The Company also introduced a measure that identified the opportunity cost of reducing each megawatt-hour of ENS for given portfolios developed with the 12 and 15 percent planning reserve margins. The Company clearly identified the costs associated with selecting a 12 percent margin versus a 15 percent margin in the IRP (pp. 218-221) given the three CO_2 cost levels included in the study, and found no basis to change the reserve margin assumption for IRP preparation based on these cost comparisons. The economic recession and its impact on load growth would also support the view that moving to a higher planning reserve margin is not warranted at the present time.

Regarding the tiered ENS cost methodology adopted for this IRP, the impact on the planning reserve margin study is negligible since the same costing methodology is applied for all stochastic simulations, and is handled as an out-of-model / post-processing adjustment to the total portfolio PVRR. The Company also strongly disagrees that the tiered ENS cost methodology is arbitrary. This methodology accounts for how the Company would respond in practice to persistent and large ENS levels over a long planning horizon. The Company provides the following rationale for adopting the tiered cost approach in the IRP:

[3] For example, one of the Public Utility Commission of Oregon's criteria for acknowledgment is that the plan "seems reasonable based on information available at the time".
[4] 2008 Integrated Resource Plan (May 28, 2009), pp. 263-4.

> In previous IRPs, PacifiCorp applied a single ENS cost for the PaR model, using the FERC price cap as a reasonable cost proxy for acquiring emergency power. PacifiCorp recognizes that, in practice, the planning response to significant ENS is different for short-run versus long-run ENS expectations. In the short-run, the Company would have recourse to few remedial options, and would expect to pay a large premium for emergency power. On the other hand, the Company has more planning options with which to respond to long-term forecasted ENS growth, including acquisition of peaking resources. Consequently, a tiered pricing scheme has been applied to ENS quantities generated by the Planning and Risk model. The ENS cost is set to $400/MWh (real dollars) for the first 50 GWh/yr of ENS, $200/MWh for the next 100 GWh/yr, and $100/MWh for all quantities above 150 GWh/yr. For large forecasted ENS quantities that occur in the out years of the study period, the acquisition of peaking generation would become cost-effective, with the $100/MWh reflecting the long-run all-in cost for such generation.[5]

With the above explanation, the Company believes that it has adequately explained why the tiered costing methodology represents a superior approach for valuing ENS.

4.3. The Company did not complete its own wind integration study using PacifiCorp wind and cost data

The DPU is mistaken that the Company did not provide its own wind integration study in the IRP (as Appendix F). PacifiCorp used the Portland General Electric wind integration cost as a proxy value until it could complete its own study and publish the results in the final IRP filed with the Commission on May 28, 2009. Appendix F describes the Company's own study, not that of Portland General Electric. The Company has therefore complied with the Commission's scheduling order to include its wind integration study in the final IRP.

The DPU also references wind integration cost studies that cite comparable or lower cost values relative to those published in the Company's 2007 IRP. Section 5.4 has comments on similar findings described by the OCS.

4.4. The Company did not model intermediate purchases as portfolio options that compete with other resource options and then analyze cost and risk

The Company is puzzled as why this criticism appears in the DPU's comments document, since the requirement comes from the Public Utility Commission of Oregon's 2007 IRP acknowledgment order. It appears in the Executive Summary, but not in the body of the comments document. If it was inserted by mistake, the Company requests that the DPU verify this. If it was included intentionally, then the Company requests that the DPU explain why another Commission's IRP requirement serves as the basis for determining whether the IRP complies with the Commission's own standards and guidelines. The Company would have a justifiable concern that the DPU is not assessing the IRP on a fair and objective basis.

[5] PacifiCorp 2008 Integrated Resource Plan, pp. 173-4.

Regardless of the disposition of this matter, the Company explained in the IRP (Chapter 6, page 132 of the final IRP) that insufficient data was available from the market to adequately distinguish intermediate-term purchase prices from those of other purchase types. The Company also has insufficient experience in acquiring such purchases and formulating them into resources that can be modeled with reasonable confidence. Finally, the Company notes that it included an action item in the IRP Action Plan that addresses this resource type: "Continue to investigate the formulation of satisfactory proxy intermediate-term market purchase resources for portfolio modeling, contingent on acquiring suitable market data."[6]

4.5. The Company manually spread the wind resource quantities relatively evenly across the years from 2009-2018, instead of allowing the System Optimizer to select the timing and resource mix

The Company allowed the System Optimizer to select optimal amounts and timing for wind resources in all the portfolios modeled as directed by the Commission in its 2007 IRP acknowledgment order. Resource portfolios were evaluated for relative cost-effectiveness, risk, and reliability on this basis. In fixing the timing of wind amounts in the preferred portfolio only, the Company is recognizing that a smooth wind acquisition pattern is a good procurement, regulatory risk, and cost management policy. This is a post-modeling determination, and some of the key reasons for specifying such a smooth acquisition pattern are described in Chapter 8 of the IRP (p. 240). The Company could have formulated constraints in the model to achieve such a smooth acquisition pattern, but that would have resulted in the same portfolio outcome. The action plan addresses the approach for procuring wind resources which will ultimately determine the actual timing of wind resource quantities. Such procurement is not limited by the timing of the wind resource quantities in the preferred portfolio.

4.6. The in-service date for the combined-cycle plant was "randomly" selected to be 2014

The DPU claim that the combined-cycle combustion turbine (CCCT) was randomly fixed in 2014 for the case "B" portfolios is unfounded and incorrect. As noted in the supply-side resource table on page 102 of the IRP (Table 6.2), the earliest in-service date for a new CCCT is 2013. This date presupposed that an acquisition decision is made by late 2009 for such a resource. Since a new competitive procurement timeline would push out the acquisition by another 6 to 12 months, 2014 is now the earliest reasonable year for commercial operation. A review of the capacity load and resource balance, and consideration of uncertainty in predicting the impact of an economic recovery, supported a 2014 in-service date. As noted in the action plan chapter, the Company expects the near-term resource plan to require adjustment in response to changing planning conditions, with such adjustments to be reflected in the 2010 business plan and 2008 IRP Update.

The Company also provided the rationale explaining why a CCCT needed to be fixed in the two portfolios that assumed acquisition of a large gas resource:

[6] PacifiCorp 2008 Integrated Resource Plan, Table 9.2.

> The rationale for fixing CCCTs in System Optimizer is that this model does not account for resource optionality and reserve holding value captured through stochastic production cost modeling, and tends to favor SCCTs over CCCTs for meeting capacity planning reserve margins as a result.[7]

This is a model comparability issue. The Company intends to investigate cost adjustments to System Optimizer resources that would put them on an equal footing with the comparable resources modeled with the stochastic production cost model. If successful, this would avoid the need to manually fix CCCT resources in System Optimizer portfolios. In any event, fixing the CCCT in 2014 resulted in a better outcome for customers, and therefore should not be a reason for non-acknowledgement of the IRP.

4.7. The Company "hand created" portfolios excluding Lake Side 2 based on the original top-performing portfolios, and these portfolios were not fully vetted

The DPU implies that portfolios developed without Lake Side II were all "hand-built" by fixing a CCCT in 2014 as well as the wind resources, and faults the Company for not conducting the Commission's recommended deterministic risk assessment for these portfolios. The DPU also stated that the Company failed to meet Commission requirements by not properly vetting the Lake Side II portfolio analysis with the public.

The Company points out that the CCCT was fixed in only two of the 10 portfolio developed without Lake Side II, and section 4.6 above explained the need for fixing a CCCT in at least one of these portfolios. The Company also notes that no wind resources were fixed in the case B portfolios; only after preferred portfolio selection were the wind resources spread out to reflect a practical procurement schedule as outlined in the IRP and described in section 4.5.

Regarding the duplication of the Commission's deterministic risk assessment for the case B portfolios, the Company did not have time to conduct this analysis given the need to run dozens of System Optimizer simulations and compile results. Such a study would not alter conclusions for the top-performing portfolios based on the findings of the original risk assessment study; however, it would have resulted in further delay in filing the IRP. Similarly, fully vetting the post-Lake Side II portfolio analysis approach in public would have resulted in even more delay, which the Company viewed as unacceptable based on filing schedule requirements in Utah.

4.8. The Company created hand-built weighting adjustments for the eight performances measures without showing adequate analysis of how these weighting schemes were derived

The Company provided an explanation for the selection of measure importance weights in the IRP (Chapter 7, pp. 175-6). However, the DPU finds this explanation insufficient, and criticized the Company for not providing "analytical discussion of the exact weight percentages it used in looking at the top-performing portfolio selections, as well as why cost and risk measures are not equally weighted." (DPU Report, p. 32). The DPU also criticized the Company for not presenting "a wider variety of selection criteria and weightings in order to demonstrate how portfolios perform under different valuation scenarios."

[7] PacifiCorp 2008 Integrated Resource Plan, Chapter 8, p. 235.

The purpose of the measure importance weights and portfolio preference scoring was to explicitly show how the Company ranks portfolios by combining a diverse set of performance evaluation measures. This approach was intended to address past Utah party complaints that the selection of the preferred portfolio was insufficiently transparent and not quantitatively well supported using the various comparative portfolio performance measures.

While the Company sought and acted upon recommendations regarding the portfolio preference scoring approach, the importance weights themselves reflect the Company's subjective view on what measures are most relevant and important for its integrated resource planning process. Contrary to the DPU's expectations, there is no deeper analysis to support the selection of the importance weights. The Company is also well aware that different weighting schemes can change portfolio-ranking results. Therefore, it conducted two separate sensitivity studies using different weighting schemes for portfolio ranking. The first, documented in Chapter 8 on page 228, was based on comments and recommendations made by participants at PacifiCorp's February 2, 2009 public meeting. The second sensitivity study, documented in Volume II (Table B.23 on p. 215), shows the impact of ranking the ten case B portfolios when using and heavily weighting the upper-tail mean PVRR risk measure. While such sensitivity studies are informative, it is the Company's prerogative as the developer and owner of the IRP to apply a single weighting scheme that best represents its resource planning objectives.

Finally, the Company disagrees with the DPU's view that cost and risk measures should be weighted equally for portfolio evaluation purposes. First, none of the IRP standards and guidelines in Utah or any other state enforce such a rigid analytical requirement. Second, risk measures imply a probability of specific (adverse) events or costs occurring, which is a qualitatively different concept than a straight cost measure. Hence, there is no coherent reason why cost and risk measures need to be weighted equally.

4.9. Response to the DPU's recommendations for formalizing information exchange and public meetings

The DPU recommends an overhaul of the IRP process, focusing solely on additional administrative procedures for the Company to follow. These procedures consist of (1) placing the entire IRP development cycle under a docket with all IRP materials to be filed with the Commission, (2) making all stakeholder information requests and PacifiCorp responses universally available, (3) establishing a formalized public meeting format that includes submission of reports both before and after each meeting, and (4) extensive model training for regulators and intervenors. As the rationale for recommending these additional administrative procedures, the DPU notes that the IRP process has become cumbersome and marked by chronic delays as of late. Also, in the transmittal letter accompanying the DPU report, the following factors are cited.

> The Division is additionally concerned with the apparent inability of the Company to satisfy the Commission's IRP requirements. The PacifiCorp IRP's increasing complexity along with the apparent need to satisfy multiple

> interests are likely contributing to the IRP's declining usefulness and lack of compliance with Commission guidelines.[8]

The Company agrees with the DPU that the IRP process for Utah needs to be revisited. This sentiment was expressed in the Company's Utah party reply comments for the 2007 IRP. In these reply comments, the Company noted that the increasing complexity and scope of the IRP process, combined with the pace of regulatory and market change and continued regulatory uncertainty, resulted in an IRP process that was no longer accomplishing its intended purpose.[9] The Company began to address this concern by adopting the IRP and business plan alignment strategy in 2008, an initiative that is still undergoing implementation and evolution. The Company has also expressed its desire to continuously improve the IRP public process and resource decision-making transparency, and will continue to work with stakeholders on ways to accomplish this. However, the Company strongly disagrees with the DPU's proposed solution. This solution narrowly focuses on administrative procedure and takes the IRP in the wrong direction: towards the formality of a rate case proceeding.

Rather than making the IRP process less cumbersome—which is one of the DPU's stated goals in provide its recommendations—it would have the opposite effect of making it more complex, arduous, and less conducive to collaboration. The Company currently needs to comply with over 160 individual state IRP requirements, and can expect more at the conclusion of the 2008 IRP acknowledgment process. Requiring the Company to file all IRP-related materials, prepare multiple reports for every public meeting, manage a formal data request/response process for the duration of the IRP cycle, and "allow parties to access any data or other models used by the Company in its planning process", would increase the IRP department's workload to an unsupportable level. (The IRP department consists of a total of five employees that develop the IRP and support the business planning and procurement processes.) In response to this workload increase, the Company would be forced to cut back on the number of meetings and reduce other IRP support activities to the overall detriment to the IRP process.

Regarding the recommendation to provide stakeholders with model training, the Company believes that an IRP model workshop with simulation demonstrations has merit. The Company does not advocate hands-on training, particularly for the Planning and Risk (PaR) model. The PaR model is a complicated client-server system; operational access for multiple simultaneous users is not feasible, and one-day training is not sufficient to understand or be able to operate this system effectively. While the System Optimizer is more amenable to hands-on training, the Company does not have the computing equipment needed to support a training session for a large group of people.[10] Finally, the Company questions the utility of a training session unless parties intend to use the models on a regular basis. This would entail the purchase of annual software licenses, acquisition of compatible hardware, and time invested for more thorough training.

4.10. Response to the DPU recommendations for PacifiCorp's IRP Filing Schedule

[8] DPU transmittal letter, June 18, 2009, p. 2.

[9] PacifiCorp, "Response to Utah Party Comments on PacifiCorp's 2007 Integrated Resource Plan" (Docket No. 07-2035-01, October 17, 2007), pp. 3-4.

[10] It is not clear if the DPU intends the training sessions to be held exclusively for Utah parties. The Company assumes that such training would need to be available to all IRP participants.

On May 28, 2009, the Company filed a statement with the Commission outlining its rationale for a March 31, 2009 IRP filing deadline. This date was selected to ensure sufficient time to complete the IRP given the modeling and coordination processes involved in aligning the IRP and business plan, as well as to address state IRP guidelines and acknowledgment order directives tied to the preferred portfolio. In response to the Company's statement, the DPU found it "incredulous" that the Company needed an additional three months to complete and file the IRP for acknowledgment after the business plan approval by the MidAmerican Energy Holdings Company (MEHC) board of directors in December (DPU Report, page 11). The DPU then provided IRP scheduling recommendations contingent on Commission acceptance of the March 31, 2009 IRP filing date. The DPU would require the Company to "substantially complete"[11] the IRP by the time the MEHC board of directors reviews the business plan in December and to file the draft IRP at that time, as well as provide the Commission with an IRP/business plan variance report and the approved business plan within 30 days after filing the draft IRP.

The Company's IRP scheduling statement mentions that October and November are devoted to developing resource portfolios to support resource decisions made for the final version of the business plan. Modeling assumption and input updates occur prior to, and during, this portfolio modeling and analysis period. The DPU's scheduling recommendations disregard this critical stage of the IRP and business plan alignment process, and would force the Company to redirect IRP staff away from business planning support activities to focus on preparation and filing of the draft IRP. The result is that the IRP and business plan will diverge rather than be synchronized as recommended by the DPU (DPU report, p. 10). Additionally, valuable time will be spent preparing a report that describes IRP and business plan differences that could have been avoided to begin with by not requiring substantial completion of the IRP by December.

Regarding the amount of time needed to complete the IRP after MEHC board review of the business plan, the three months allotted time accounts for activities tied to an *approved* preferred portfolio - action plan development, acquisition path analysis, and CO_2 compliance scenario analysis for the Oregon commission - as well as the potential need for additional portfolio analysis triggered by MEHC review of the final business plan or last-minute external events. While it is the Company's intention to file the IRP as soon as possible after business plan approval, it is prudent to allow for such contingencies in the IRP schedule.

In summary, contrary to the desire of the Commission and the DPU itself, the DPU's recommended filing schedule will effectively prevent the Company from maintaining a direct link between the IRP and business plan, and will undo the Company's progress made to date in aligning the IRP and business planning processes.

4.11. Responses to Other DPU Criticisms

4.11.1. The Company understates the potential geothermal resources in its resource portfolio modeling

[11] Draft versions of the preferred portfolio, action plan, and acquisition path analysis are to be included in the December draft IRP filing.

The DPU asserted that the Company understated the geothermal resource potential for its IRP, and subsequently underrepresented geothermal resources in its capacity expansion modeling. (DPU Report, p. 30).

The 105 MW of geothermal plant capacity included in the capacity expansion model reflects a reasonable assessment of commercially available project opportunities, particularly in the near term. The Company notes that it received no geothermal resource bids in its recent renewable Requests for Proposals, which supports the Company's view that such commercial opportunities are rather limited.

4.11.2. The Company is biased against new technologies

The DPU states that the Company "tends to underestimate or undervalue other available new technologies, such as IGCC, concentrating solar, fuel cell, and nuclear." (DPU report, p. 30). In the case of fuel cells, the DPU asserts that the model is either flawed or that the Company is "hardwiring" results because the capacity expansion model rarely selects this resource even though it has a lower cost than many other supply-side resources. It also points to the Company's decision to screen out resources below small capacity thresholds (such as rooftop photovoltaic systems) as further evidence of a bias against new technologies.

The Company does not have a systematic aversion to new technologies. The Company commissioned an independent analysis (conducted by WorleyParsons in 2008) on solar thermal, geothermal, and biomass generation characteristics to ensure that the Company's resource costs were reasonable. The Company included an action item in the IRP action plan that commits the Company to investigate and acquire cost-effective solar and "emerging technologies" within the next ten years. The Company also made an extensive effort to capture available government financial incentives in renewable and distributed generation resource costs.

The Company does believe that new technologies present added risks, and, as evidenced by the Company's efforts to go forward with the Blundell 3 project, that it is difficult to obtain engineer, procure and construct (EPC) contracts from the marketplace that adequately protects the Company and its customers against such risks. This fact - combined with the lack of Company or extensive utility commercial experience with such technologies and wide ranges in estimated costs - prompts the Company to take a conservative stance when defining cost values to use for IRP modeling purposes. This is consistent with prudent utility practice and the IRP regulatory requirement to acquire the least-cost resource mix considering risk and uncertainty. While the DPU and other Utah parties may disagree with this policy, the Company does not see it as a failure to meet the Commission's IRP standards and guidelines.

Regarding the example of the model's handling of fuel cells as a potential error or bias, the DPU's assertion that the capacity expansion model should have selected this resource because it appears as a low-cost resource on a 20-year, levelized basis, is incorrect and oversimplifies what drives resource selection behavior in the model. The impact of including a CCCT by 2014 is the key factor influencing the selection of fuel cells and other resources early on in the simulation period. (The DPU should note that System Optimizer selected fuel cells in six of the eight "B" series portfolios that excluded a fixed CCCT.) With the CCCT included as a fixed resource in the model, other resource selection factors come into play as the model addresses remaining resource requirements. Fuel cells compete not only with the utility-scale supply-side resources, but with DSM, distributed generation, and front office transactions as well. The Company's response to DPU data request 1.61 discusses the importance of natural gas prices in determining resource economics. Also, the CO_2 cost associated with a natural gas price scenario will affect fuel cell cost-competitiveness with respect to other resources that are not similarly impacted (for example, renewables and DSM). Finally, the interplay between resource size, the magnitude of the capacity need, and resource availability, also help determine if and when resources are selected by the model.

Finally, the Company reemphasizes that the reason for applying a capacity size threshold for distributed generation resources with a tiny regional market potential is to help maintain a manageable model size. To allay stakeholder concerns regarding this strategy, the Company conducted a sensitivity model run where the size constraints on the resources in question were relaxed (rooftop solar PV and water heaters). The model did not select these resources. This sensitivity study is described in footnote 30, page 119, of the IRP.

4.11.3. The Company over-relies on wholesale purchases

The DPU expressed their concern that the Company is putting ratepayers at risk based on the level of front office purchases included in the IRP preferred portfolio, and is ignoring the risks in formulating its resource strategy:

> If the risk and uncertainty are so onerous that PacifiCorp, with its relatively low cost of capital and its substantial financial backing, is unwilling to assume the risks of ownership, then it may be that third parties are unwilling to assume them as well. That is, perhaps no one will build generation capacity because the cost, risk, and uncertainty are too high. This is one of the concerns the Division has with respect to the Company's long-term reliance on the wholesale market. The Company appears to simply assume away this issue apparently based upon its observations of the current wholesale markets under current conditions.[12]

The Company responds to the issue of reliance on market purchases and associated risk analysis in Section 5.7, where it addresses similar comments made by the OCS.

4.11.4. There is no discernable path analysis related to transmission

DPU suggests there is no discernable path analysis related to transmission:.

> "The implication seems to be that the Company intends to build or otherwise acquire these transmission lines "come what may." If that is the case, then the Company needs to explicitly state or, alternatively, discuss how significant forecast changes affect the timing or the desirability of transmission acquisitions." (DPU Report p. 19)

Over the past decade, numerous regional studies have been issued that have documented the urgent need for new transmission in the Western United States. As early as 2002, the Department

[12] DPU Report, p. 33.

Of Energy National Transmission Grid Study identified the Wyoming-Idaho interface as a major constrained interface, and found, under optimal conditions, the Wyoming-Northern Utah interface to be congested during 50 percent or more of the hours during the year. The 2004 Rocky Mountain Area Transmission Study reached similar conclusions, the results of which was a recommended expansion of the 345 kV transmission lines connecting the Bridger substation to points south and west as critically needed improvements. In addition, the Department of Energy's 2006 National Electric Transmission Congestion Study identified several constrained transmission paths in the west, including lines used to deliver electricity from generation plants in Wyoming to loads in Utah and Oregon. Specifically, the DOE congestion study illustrated that the expansion of the Bridger West facility is critical for alleviating congestion from Wyoming to Northern Utah, and Wyoming to Idaho. Similarly, the Western Interconnection 2006 Congestion Assessment Study, identified areas of congestion in the Rocky Mountain states, and projected that based on 2005 load and resource forecasts and a production model, many of the paths associated with the various segments of the Energy Gateway project were forecasted to be heavily congested. Lastly, reports initiated by the Western Governor's Association also show certain paths in PacifiCorp's service territory to be constrained. The Gateway project was designed to help alleviate many of the key bottlenecks consistent with PacifiCorp's long-term operational goals and obligation to provide customers with cost-effective, safe and reliable electric service.

The timing necessary to complete permitting and construction of transmission expansion projects can exceed 5 to 7 years and is typically longer than the time it takes to permit and build new generation resources, particularly wind. As such, the Energy Gateway project was designed as a system-wide transmission expansion program to link "hubs" of resource areas to load centers. The project will enable interconnection and improved economic dispatch of existing and resources, link PacifiCorp's east and west balancing areas, enhance accessibility to location-constrained renewable energy sources, reduce congestion in the transmission-constrained Western Interconnection, improve the reliability of the system, and help PacifiCorp to continue to provide reliable, cost-effective electric service to its customers. To the extent that the configuration of the Energy Gateway project changes, or the timing of individual segments changes, those modifications will be reflected in subsequent IRPs and IRP updates.

PacifiCorp is obligated to balance its "overall system" planning based on short term (5 to 10 years) and the longer term (10 to 25 years) when making Transmission Program investments. This means PacifiCorp can not solely focus on IRPs resource mix and timing but, it must also be prudent in permitting, siting and justifying new corridors, substation sites, and minimizing current and future environmental impacts. Additionally, the company is expected to gain lowest cost delivery that comes with economies of scale for large bulk transmission systems. PacifiCorp's Energy Gateway Program was, by design, planned to provide options by use of segmented line projects, scaleable over time to make prudent use of new corridors and permits and to provide lowest overall transport costs under a range of uncertain and highly variable generation build and market purchase options. The Energy Gateway project was also intended to provide an improved level of information and some increased certainty to all resource developers/bidders who respond to our resource RFPs as transmission location, access and availability can significantly influence the proposed cost of new resources. Historically, this has been a high risk assumption aspect of RFP submittals to PacifiCorp.

5. COMMENTS AND RECOMMENDATIONS FROM THE OFFICE OF CONSUMER SERVICES

The OCS submitted a number of documents to the Commission constituting its comments. The documents that are the subject of these reply comments include the following:

- Review of Compliance with Utah Public Service Commission Standards and Guidelines for Integrated Resource Planning and Commission's Order on PacifiCorp's 2007 IRP ("OCS Compliance Review")
- Critique of Modeling Issues ("OCS Modeling Critique")
- Evaluation of PacifiCorp's Load Forecast, prepared by GDS Associates ("OCS Load Forecast Report")

The following sections address each of the criticisms, issues, and recommendations outlined in these documents. Many of the comments offered by the OCS mirror those provided by the DPU. In such cases, the Company references the DPU response sections that address the comments and adds elaboration as appropriate.

5.1. The Company does not provide additional support for the use of its portfolio preference weighting structure

The OCS provides criticism of the Company's measure importance weights along the same lines as the DPU: "The Company has not provided additional support for the use of this particular weighting structure." (OCS Modeling Critique, p. 2). The Company addresses this criticism in Section 4.8.

The OCS requests Commission guidance on this issue for future IRP filings. The Company also looks forward to the Commission's perspective on the use of a portfolio preference scoring approach, the associated measure weights applied by the Company, and suggestions for improvement. However, the Company points out to the Utah parties that the purpose of the measure-weighting scheme is not to reflect the resource policies of individual stakeholders, or to capture some sort of policy consensus among multiple stakeholders. Rather, it should reflect the Company's own planning principles and priorities at the time the IRP is being produced. If the measure-weighting scheme ends up deviating from this, then the IRP is considerably weakened as an effective planning tool for the Company.

5.2. With the use of a tiered ENS costing approach, the Company appears to have biased the results in its cost-risk analysis

The OCS provides criticism of the Company's tiered ENS costing approach along the same lines as the DPU. It also refers to the Company's attitude towards ENS in general as "cavalier", and suggests that the Company would prefer to accept ENS rather than invest in resources to prevent it.

The Company discusses the rationale behind the new ENS costing methodology in Section 4.2, and states why it is a superior approach to the single value used in past IRPs. The Company points out that ENS quantities grow over time in the Monte Carlo simulations as a result of long-run volatility parameters that widen the spread of the Monte Carlo draws for such variables as loads. This is a statistical phenomenon intended to capture the effects of growing uncertainty as one looks farther into the future. Consequently, large ENS amounts—quantities that would be subject to the lower cost levels—occur in the out years of a portfolio simulation.

The Company makes the case that a high ENS cost value makes sense for near-term ENS events where there is no recourse except making emergency power purchases. However, applying that same high ENS cost over-estimates the Company's true cost of avoiding ENS occurring far into the future. As explained in the IRP and section 4.2 above, the reason is that the Company would have foresight and the lead-time to acquire other resources to prevent the ENS from occurring. Such resources would be significantly less expensive than emergency power. Since the stochastic production cost model cannot simulate this real-world planning behavior easily, using tiered ENS costs serves as a reasonable and transparent method for more realistically representing ENS costs for the stochastic simulation.[13]

Regarding the OCS comment on the Company's attitude towards ENS, the IRP objective for changing its ENS modeling approach is to more accurately simulate the planning environment and portfolio costs, not downplay the importance of system reliability or the costs in maintaining that reliability. The OCS is also misinterpreting the meaning and implications of the ENS avoidance premium. The premium cited by the OCS ($659/MWh) indicates that there are cheaper options to eliminate ENS than to acquire the incremental mix of resources selected by the System Optimizer to meet a 15 percent planning reserve margin. For example, assuming that the stochastic average simulation results represented the real future outcome, the Company would find it economic to acquire, *when needed*, gas resources or even high-priced emergency power to eliminate the forecasted ENS. In other words, targeted investment to address potential ENS events is cost-effective relative to a portfolio optimized to meet a 15-percent reserve margin on a long-term basis.

5.3. The OCS believes that a better approach needs to be used in the evaluation of the reserve requirement

The OCS makes the following recommendation for improving capacity reserve requirements analysis:

> For example, the Company could compare the costs and risk profile of the portfolio – including appropriate costs assigned to ENS – with another portfolio with identical input assumptions designed as a capacity expansion for the higher target level of 15% reserve requirements.[14]

The Company conducted precisely this type of analysis for the IRP. It used the System Optimizer to develop sets of two portfolios with identical input assumptions but differing planning reserve margin constraints, and conducted stochastic simulations for these portfolio pairs (The portfolio pairs reflected different CO_2 tax assumptions).

[13] As an alternative approach, the Company could devise "emergency stations" with different availabilities and costs to simulate long-run planning efforts for avoiding ENS. It is not clear if such an approach would work as intended.
[14] OCS Modeling Critique, p. 3.

The OCS also recommends that another Loss of Load Probability (LOLP) study be performed to determine the target planning reserve margin, citing the Public Service Company of Colorado's recent reserve margin study as an example. The OCS then castigates the Company for waiting so long to refresh the study conducted for the 2004 IRP.

The OCS comments give the impression that the Company has done nothing on the LOLP front since the 2004 IRP. The Company reminds the OCS that it implemented an LOLP analysis methodology for the 2007 IRP. This same methodology was used for the current IRP, and the associated LOLP statistics serve as one of the performance measures for portfolio evaluation. (See page 174 of the IRP for a description of the methodology.) While not the same thing as a study geared towards identifying a reserve margin based on a specific reliability target, this methodology applies the same LOLP concepts as that used for the Public Service Company of Colorado study performed by Ventyx, and extends them for portfolio comparison purposes.

Regarding the specific type of LOLP study cited by the OCS, it is a time-intensive, resource-intensive, and complex exercise as evidenced by the need for the Public Service Company of Colorado to hire a consultant to perform the work. The Company cannot be expected to perform such a study on a regular basis given the current scope of the IRP effort. The Company also questions the usefulness of re-doing the 2004 IRP reserve margin study given its known limitations and the considerable controversy it originally generated among stakeholders. For example, the reserve margin study assumes, up-front, an appropriate target LOLP, and does not address the economics of maintaining the target LOLP and its associated planning reserve margin. A criticism from a number of parties was that the planning reserve margin study did not account for variations in resource mix, since it uses a single resource type—a simple-cycle combustion turbine—as the proxy resource for presenting incremental reserve increases. The Company's LOLP analysis addresses this criticism.

5.4. The Company's artificial limits on wind resources are not adequately supported

The OCS states the Company inappropriately handled the application of the annual wind constraints:

> The Company places annual limits on wind capacity in the System Optimizer model such that annual wind additions are capped at 500 MW in years prior to 2014 and 750 MW in 2014 and thereafter. If this limit had been greater or even eliminated, then the model may have selected more wind in certain portfolios. This kind of artificial limit must be described and justified by the Company. If exogenously imposed constraints (such as this limit on wind resources) produce significantly different results, the Company should pursue additional runs as a sensitivity analysis to examine the potential lost benefits associated with the constraint.[15]

The Company applied these constraints to ensure that an unrealistic amount of wind capacity is not added in any given year. These constraints do not limit the amount of total capacity added by the model, but rather have the effect of spreading wind quantities over several years. The constraints were developed in consultation with the Company departments responsible for wind

[15] OCS Modeling Critique, p. 5.

acquisition and construction. Considerations such as market availability of wind turbines, transmission constraints, and procurement regulatory requirements, were accounted for in defining them. The Company finds no added value in conducting sensitivities for such constraints since the overall quantity of wind is not impacted. Even if the total wind amount was impacted, there would be no rationale for selecting an alternate set of constraints given that the original values reflect the best judgment of the Company's wind acquisition experts.

The OCS also criticizes the Company for using a wind integration cost that is significantly higher than other published values without providing additional support. The Company notes that the OCS is citing older studies. Utilities have made recent, significant advancements in their understanding of the impacts and associated costs of integrating wind. As a consequence, wind integration costs have generally trended upwards over the last few years. The Company provides a sample of wind integration cost values from more recent studies than the ones mentioned by the OCS.

- Bonneville Power Administration, Within-Hour Balancing Service Rate, energy-based: \$6.2/MWh to \$12.5/MWh (2008)
- Northwest Power and Conservation Council, 6th Power Plan: \$8.6 MWh to \$10.9/MWh (December 2008)
- Idaho Power wind integration study: \$10.72/MWh (2007)
- PacifiCorp wind integration study: \$9.96/MWh to \$11.85/MWh (May 2009)
- Portland General Electric wind integration study: \$11.75/MWh (2008)

5.5. The Company did not sufficiently defend its decisions to fix certain resources in the model

The OCS voiced two concerns regarding resources fixed in portfolios. First, the Company did not provide "strong, defensible reasons" why it fixed the CCCT and SCCTs in the preferred portfolio. Support for fixing the CCCT is provided in Section 4.6. Regarding the SCCT, this resource was not fixed in the preferred portfolio or any other portfolios for that matter. We refer the OCS to Chapter 8, Table 8.37, for the fixed resource set-up for the 10 case "B" portfolios.

Second, the OCS requests confirmation that the 201 MW eastside PPA was treated in the portfolio optimization runs as a fixed resource, and how the sensitivity runs were defined and used to support fixing this resource. The Company confirms that the east-side PPA was treated as a fixed resource in the portfolio optimization runs, but that it also conducted sensitivities with multiple case definitions to support placement in 2012.

5.6. The Company has placed "extremely low" capacity limits on geothermal resources in the System Optimizer Model

The OCS claims that the Company has likely understated geothermal potential for capacity expansion modeling, and recommends a study be conducted. The response to the DPU's similar comment is provided as section 4.11.1.

5.7. The Company's reliance on front office transactions is too high, and did not adequately address the risks associated with the high levels of front office transactions

In its IRP comments transmittal memo to the Commission, the OCS made the statement that the Company "has a significant reliance on market power without providing adequate evidence that the liquidity of the market is sufficient to guarantee supply".[16] In the OCS Modeling Critique, the high volume of front office transactions in the west is specifically cited as an unreasonable expectation.

The Company first notes that the preferred portfolio is not intended as a rigid resource acquisition strategy where the Company must match when it seeks to acquire the resources, through RFPs or other means, at future points in time. This is stated in the introduction section of Chapter 9 in the IRP:

> However, it is important to recognize that the resources identified in the plan are proxy resources and act as a guide for resource procurement. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost, and location. Evaluations will be conducted at the time of acquiring any resource to justify such acquisition.

We make this point because the OCS apparently has the impression that the IRP preferred portfolio represents a fixed and unchanging commitment to acquire specific resources well into the future at a specific point in time. As stated in previous IRPs, the IRP represents a planning snapshot based on available information at the time it was prepared. As the Company acquires new information and reassesses market conditions and other factors, which may change the plan. This is why the Company agrees that an annual IRP update is prudent. In the case of the near-term outlook for reliance on front office transactions and other market purchases, the Company's confidence is high that it will be able to acquire FOT volumes and other market purchases to address near-term short positions resulting from the deferral of the planned CCCT resource. It bases this claim on its familiarity and daily dealings with the market, and its experience in managing its operational planning position. The economic recession and dampening of forward market prices serve to bolster the confidence that market purchases will be sufficiently available and economic for meeting resource needs in the near term at this point in time.

On the other hand, as one considers resource needs farther out the planning horizon, obviously the confidence in acquiring specific volumes of market purchases or any other specific resource declines, and therefore resource acquisition risk increases. We thus acknowledge the importance of comprehensive resource risk analysis which is addressed in part through the stochastic analysis in the IRP process. In the theme of continuous improvement, the Company is open to discussing with stakeholders ways to augment its current risk analysis process in a fashion that is sensitive to the Company's IRP workload and schedule constraints. For example, the Company, Commission, and Utah parties could agree on scaling back or eliminating IRP requirements that are a lower priority in order to make room for enhanced resource risk analysis.

[16] Office of Consumer Services, "In the Matter of the Acknowledgement of PacifiCorp's 2008 Integrated Resource Plan; Docket No. 09-2035-01", p. 2.

Nonetheless, we believe this IRP, is in compliance with Standard and Guideline 4h and welcome any guidance from the Commission for future IRPs.

5.8. The Company inappropriately applied its 12-percent capacity planning reserve margin to front office transactions

The OCS cites the following passage from Chapter 6, page 134 of the draft IRP (Page 132 of the final IRP):

> For example, a 100 MW front office transaction is treated as a 112 MW contribution to meeting PacifiCorp's load obligation plus a 12 percent planning reserve margin, with the selling counterparty holding the reserves necessary to make the product firm.

The OCS interprets this statement as meaning that the Company is applying a capacity reserve credit of 12 percent on top of the avoided reserve requirement due to the counterparty holding the reserves. The OCS correctly points out that applying an additional 12-percent capacity reserve credit would be incorrect. However, the Company is not making this mistake. Rather, the statement is being misinterpreted. A better-worded version of the statement is as follows:

> For example, a 100 MW front office transaction is treated as a 112 MW contribution to meeting *PacifiCorp's resource need, consisting of its load obligation plus a 12 percent planning reserve margin*, with the selling counterparty holding the operating reserves necessary to make the product firm. [Emphasis added]

5.9. Capacity factors of natural gas plants reported for the System Optimizer model runs appear low

The OCS points out that the annual average capacity factors for the Company's gas plant fleet, reported in Table 8.3 of the IRP, appear low in the 2009-2013 timeframe before CO_2 regulations start. The OCS requests an explanation.

Capacity factors for gas-fired power plants are primarily the result of the relationship of the cost of natural gas that is delivered to each plant, the heat rate of the gas-fired power plant, and power market prices. This relationship is commonly referred to as the spark spread. If the spark spread narrows, then the plants will dispatch less often and vice versa.

5.10. The Company did not include a range of forecasts of load growth in compliance with Commission Standard and Guideline 4a

The OCS claimed that that IRP is non-compliant with respect to Commission Standard and Guideline 4a because it did not include a range of peak load forecasts based on different scenarios. The Company notes that the OCS did not make this criticism for the 2007 IRP. For past IRPs, the understanding has been that the use of a "low-medium-high" load forecast scenario approach for portfolio development (which incorporates both energy and peak loads as capacity expansion model variables), combined with Monte Carlo simulation using load growth as a stochastic variable, met the requirement for incorporating a range of load forecasts in the IRP. According to the OCS, this strategy no longer meets the Commission's requirement.

Given that the OCS changed its compliance requirement for this guideline after the IRP was completed, we fail to understand how the OCS can now claim that the Company is non-compliant, and use that to support its IRP non-acknowledgment recommendation.

5.11. The OCS requests reconciliation of Class 1 Demand-side Management amounts reported in the Main IRP Document and Appendix 2 ("Procedural Issue 6")

The OCS requested that the Company reconcile the quantities of Class 1 DSM reported in Tables 8.1 and 8.2 of the IRP with the quantities reported in the detailed portfolio resource tables provided in Appendix A. The OCS pointed out about a 200 MW difference between the reported quantities.

The reason for the capacity difference is that Tables 8.1 and 8.2 report the incremental Class 1 DSM capacity additions selected by the capacity expansion model, whereas the tables in Appendix A include the Cool Keeper program incremental expansion targets that are treated as planned resources in the IRP. The Cool Keeper expansion ramps up to 205 MW by 2018, and the year-by-year resource additions are shown as a separate Class 1 DSM line item in the detailed portfolio tables.

5.12. The Company fails to comply with the guideline for directly linking the IRP and strategic business plan ("Procedural Issue 9")

The OCS provides comments similar to those from the DPU, specifically having to do with the timing of the IRP analysis with respect to business plan preparation and approval. The Company's response regarding the linkage between the IRP and business plan is provided in Section 4.1. The Company also notes that the OCS conclusion that the business planning process helped shape the 2008 process is correct; the IRP and business plan alignment strategy was never intended to be a one-way flow of information and influence. It is equally as true that the IRP planning process helped shape the business planning process. This is made clear on pages 19-21 of the IRP.

6. COMMENTS AND RECOMMENDATIONS FROM WESTERN RESOURCE ADVOCATES

Western Resource Advocates filed its comments on June 18, 2009, and recommended that the Commission not acknowledge the IRP. The reasons given include the following:

- PacifiCorp's IRP fails to adequately position the Company for carbon regulation and fuel price risk.
- PacifiCorp's IRP is biased in favor of fossil-fueled resources and market transactions.
- Demand-side resources are not assessed properly or comparably with supply-side resources
- Storage technology is effectively precluded by the Company's assumptions.
- PacifiCorp's transmission planning is not integrated with its other resource assessments.
- PacifiCorp's reliance on market purchases presents extraordinary risk to its customers.

Responses to each of these criticisms are provided in the following sections.

6.1. PacifiCorp's IRP fails to adequately position the Company for carbon regulation and fuel price risk

WRA makes the argument that the case 8 portfolio is superior to the case 5 portfolio that served as the basis for the Company's preferred portfolio. The Company noted in the IRP that these two portfolios were virtually equal as far as the portfolio preference scoring was concerned (for the initial 21 portfolios that excluded the Lake Side II gas resource). The main concern that the Company had with the case 8 portfolio was the large incremental capital cost impact of the additional wind, as well as the Company's ability to acquire and integrate that much wind on a sustained basis (over 300 MW/year from 2012 through 2018). For the final 10 portfolios developed and evaluated for preferred portfolio selection, the three variants that used case 5 input assumptions outperformed the case 8 portfolio based on the preference scores (See Table 8.41).

WRA also claims that adopting the case 8 portfolio ("8B") as the preferred portfolio, and using the case 5 portfolio (5B_CCCT_Wet) as the acquisition planning backup, is better resource risk management for the Company's customers than applying the reserve strategy (i.e., using portfolio 8B as the backup as indicated in the IRP). The support behind this view is limited to a comparison of the stochastic mean PVRR for each portfolio. As indicated above, the Company must use other criteria to assess particular resource strategies, and it has done so selecting case 5B_CCCT_Wet as the basis for the preferred portfolio.

WRA claims that the Company assesses the "wrong carbon risk by measuring carbon intensity rather than absolute emissions". The Company does not use carbon intensity as a metric for portfolio performance assessment. The CO_2 intensity graphs included in the IRP are for informational purposes only.

Another criticism is that the Company's "modeled CO_2 costs do not comport with a realistic planning environment" (WRA Comments, p. 5-6). As directed by the state commissions, the Company uses a least-cost standard for IRP development that must account for risk and uncertainty. We have incorporated a CO_2 risk assessment framework in the IRP that meets this standard and addresses to the Company's satisfaction the need to account for regulatory CO_2 cost risk in its resource planning activities. The Company believes that a realistic planning environment is currently characterized as the existence of considerable uncertainty regarding the final form of the CO_2 regulatory framework and associated CO_2 costs. We addressed this uncertainty by applying a probability-weighted portfolio cost methodology based on stochastic simulations with CO2 costs of $0, $45, and $100 per ton. This methodology generated portfolio cost comparisons spanning expected CO2 tax values from $15/ton to $70/ton.

WRA claims that procedural issue 9 from the Standards and Guidelines ("The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan") is violated by the large difference between the carbon price assumptions used in the IRP and the 2009 business plan. First, the Company used a range of CO_2 price assumptions in its IRP portfolio analysis as required by commission IRP rules, ranging from $0 to $100 per ton in 2008 dollars. The Company did not adopt a base or expected-cost CO_2 cost value. In contrast, the business plan has a 10-year planning horizon, and requires expected-value cost inputs because the preparation of financial statements is a key output of the business planning process. The carbon price assumptions used for the 2009 business plan were considered reasonable given that none of the potential CO_2 regulatory schemes under consideration in 2008 had been developed with sufficient detail to develop more accurate costs for the 10-year planning horizon. Obviously with its focus on long-term planning and risk analysis, the IRP is not restricted in this way.

6.2. PacifiCorp's IRP is biased in favor of fossil-fueled resources and market transactions

The WRA makes the following statement: "At almost every juncture, the modeling assumptions, constraints and characterizations appear biased in a manner that prefers conventional fossil-fueled resources to renewable energy and energy efficiency." (WRA Comments, p. 7). Please refer to Sections 4.11.1 and 4.11.2 for the Company's response on similar comments made by the DPU. We note that a considerable effort went into developing the resource characterizations for this IRP. The Company faced significant technical and schedule challenges in doing so, given the shear number and variety of resources covered. The Company will continue to refine these characterizations, and has documented its commitment to investigate and acquire solar and emerging technologies in the action plan.

6.3. Demand-side resources are not assessed properly or comparably with supply-side resources

WRA criticizes the Company's handling of DSM on two fronts. First, it claims that the load adjustment to account for future expansion of existing energy efficiency (Class 2 DSM) programs fails to meet Standard and Guideline 4b ("consistent and comparable treatment for demand-side and supply-side resources") because it penalizes DSM with respect to fossil fuel plants. Second, WRA claims that the administrative cost adder for Class 2 DSM is excessive.

Regarding the DSM-related load adjustment, its effect is to allow the capacity expansion model to select DSM from the supply curves to reach the higher load levels. If the model finds the incremental DSM uneconomic, then it will select other resources. In this case, the forecasted DSM is not reached, but the model has nevertheless closed the resource gap. The intent of this approach was to actually treat DSM and other resources on a comparable basis; an alternative approach would have been to treat the DSM as fixed resources. We note that this adjustment was not applied to the November 2008 load forecast, which was used to develop the preferred portfolio.

With respect to the 15 percent administrative cost adder, the Company responded to a DPU data request asking for more details on assumptions supporting the adder. The following was extracted from the response:

> The 15% is a planning estimate of annual administrative costs for all DSM and supplemental type resources identified in the Quantec study and is believed to be conservative. For example the utility administrative costs may include 5% for program evaluation, 5% for measurement and verification, and another 10% on average for marketing/recruitment, customer meetings, interconnection

coordination, scheduling and enrollment, etc. This amount would however exclude any system related costs.[17]

6.4. Storage technology is effectively precluded by the Company's assumptions

WRA criticizes the Company for its selection of in-service dates for such technologies as compressed air energy storage (CAES) and pumped hydro, suggesting that these dates could be moved up since the resources have been technologically demonstrated. Technology availability is the starting point, not the end point, for determining feasible earliest in-service dates. For generic technologies represented in the IRP, we believe that the selected earliest in-service dates are realistic based on discussions with project developers and the Company's experience with the procurement and regulatory approval processes.

WRA also advocates that the Company pursue hybrid renewable/storage technologies to hedge against carbon, fuel price, or market electricity price risk. We agree that such technologies should be investigated in the context of the IRP.

6.5. PacifiCorp's transmission planning is not integrated with its other resource assessments

WRA states that the Company's treatment of transmission resources in this IRP is a "significant shortcoming", specifically pointing to the fact that the Energy Gateway project was included as part of the base topology for the IRP models and not investigated as a resource option to determine its resource dispatch impacts.

The Company made the decision to go forward with the Gateway project in 2007. Key segments of the project are under construction and additional segments are in the rating and permitting phases. As such, as a planning component, this project has been appropriately treated as an existing resource for purposes of IRP modeling. To the extent that the configuration of Energy Gateway changes, or the timing of individual segments changes, those modifications will be reflected in subsequent IRPs and IRP updates. The IRP team's role with the Energy Gateway project has been to support planning efforts by providing estimates of long-term power cost benefits using its stochastic production cost model.

6.6. PacifiCorp's reliance on market purchases presents extraordinary risk to its customers

The Company responds to the issue of reliance on market purchases and risk analysis in Section 5.7, where it addresses similar comments made by the OCS and the DPU.

7. COMMENTS AND RECOMMENDATIONS FROM THE UTAH ASSOCIATION OF ENERGY USERS

The Utah Association of Energy Users filed its comments on June 18, 2009, and recommended that the Commission not acknowledge the IRP. The reasons given include the following:

[17] Response to DPU Data Request 1.32.

- The collection mechanism for DSM expenses in Utah has become burdensome and unwieldy and needs to be revisited.
- The preferred portfolio continues to rely heavily on Front Office Transactions.
- There are concerns with the portfolio preference scoring approach, and it requires more thorough vetting in public meetings.
- The Company has not sufficiently identified or addressed the adequacy of long-term baseload supplies in the IRP.
- The Company should review its modeling execution to better manage the tradeoffs between using updated information, long modeling times, and time for stakeholders to review and perform analyses.

In addition, the UAE also again recommends that the Company use different models that are "less cumbersome and more transparent and available IRP models that are more adapted to a fast changing environment."

Responses to each of these criticisms and recommendations are provided in the following sections.

7.1. The collection mechanism for DSM expenses in Utah has become burdensome and unwieldy and needs to be revisited

The Company does not believe that DSM cost recovery policy is applicable to the IRP. The UAE mentions that it will "address these concerns in an appropriate docket."

7.2. The preferred portfolio continues to rely heavily on Front Office Transactions

This concern is similarly voiced by the DPU, OCS, and WRA. See Section 5.7 for the Company's response to concerns regarding reliance on front office transactions and treatment of risk analysis.

7.3. There are concerns with the portfolio preference scoring approach, and it requires more thorough vetting in public meetings

The UAE summarizes some of the issues with the preference scoring approach. For example, it questions why fuel source diversity has not been given a weight and included as a preference measure. It also questions why the difference in wind resources between the case 5 and case 8 portfolios, as a concern to the Company, was not somehow captured in the scoring. Finally, it questions why the CO_2 cost exposure measure received a large weight, even though part of this risk is captured in the production cost standard deviation.

Regarding fuel source diversity, the Company found it difficult to quantify it in a meaningful way for portfolio ranking purposes. For example, diversity could mean that a portfolio has (1) a wide variety of different resource types, (2) that incremental resources are different from the dominant ones in the Company's existing portfolio, thereby helping to equalize the overall resource mix, or (3) a combination of these meanings. The Company therefore decided to treat fuel source diversity as a subjective concept that should be considered outside of a quantitative scoring system.

With respect to the issue of the wind quantity difference for the case 5 and case 8 portfolios, the Company treated this as a qualitative distinguishing factor for the top-performing portfolios, rather than a quantitative measure to be applied to all portfolios. To implement the latter approach most effectively, we could have applied a constraint in the model reflecting the maximum achievable wind additions per year. The Company would be interested in getting stakeholder reaction to applying such a constraint.

Regarding CO_2 cost exposure versus the production cost standard deviation, CO_2 cost exposure is intended to capture the value of avoiding an extreme cost outcome, whereas production cost standard deviation is intended to capture the value of avoiding cost volatility. These two measures have independent decision value and are thus desirable to include in the preference scoring.

7.4. The Company has not sufficiently identified or addressed the adequacy of long-term baseload supplies in the IRP

The UAE states that it supports the acquisition of nuclear or clean coal resources, and that the Company did not analyze these resources sufficiently. It also uses the example of a 20-year simulation period as not being adequate to support the analysis of nuclear in particular.

The Company needs more detail from the UAE regarding what aspects of the portfolio analysis it views as insufficient with respect to baseload resource analysis. The Company will continue to refine its treatment of out-year resources due to the need to capture the long-run impacts of CO_2 and renewable generation regulatory requirements.

Regarding the appropriateness of a 20-year simulation period, the Company applies the real levelized amortization method to address end-effects bias associated with long-lived assets. This method is built into the System Optimizer model. Unfortunately, it is not practical to extend the IRP simulations beyond 20 years without resorting to significant scale-back of resource options in the models, reducing the number of Monte Carlo iterations, or moving to less granular data.

7.5. The Company should review its modeling execution to better manage the tradeoffs between using updated information, long modeling times, and time for stakeholders to review and perform analyses

The Company expects to move to a version of the modeling system, likely in 2010, which has the System Optimizer and Planning and Risk models integrated into the same platform. This will help with model execution and management.

Regarding the UAE’s recommendation to adopt different models, the Company periodically assesses other model packages for better capabilities, user-friendliness, portability, and life-cycle costs. Converting to another modeling system would likely be a major undertaking..

8. COMMENTS AND RECOMMENDATIONS FROM UTAH CLEAN ENERGY

Utah Clean Energy Association of Energy Users filed its comments on June 18, 2009, and recommended that the Commission not acknowledge the IRP. (Although it stated partial acknowledgment would be preferable for "regulatory assurance for rate recovery of prudent and timely acquisition of certain needed resources.")

UCE's non-acknowledgment recommendation is based primarily on the view that the Company's preferred portfolio does not have the optimal amount of renewable energy and DSM resources, and therefore does not meet the condition outlined in Standard and Guideline 1: "The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty."

UCE, WRA, and Interwest all levy the same criticism regarding the Company's preferred portfolio selection: that the case 8 portfolio is superior to the case 5 portfolio. (The Company response to this criticism is provided in Section 6.1.) In lieu of the preference scoring results, these parties focus selectively on the cost statistics that support their policy position. UCE also claims that the preferred portfolio does not comply with Senate Bill 202, the Energy Resource and Carbon Emission Reduction Initiative. The Company developed its renewable portfolio standard requirement accounting for the Utah RPS rules. With the Renewable Energy Credit (REC) and banking provisions of the Bill, the preferred portfolio becomes fully compliant.

UCE had earlier requested that the Utah Solar Incentive Program be modeled for the IRP, and mentioned in their comments that the Company failed to do so. We note that distributed solar resources were already incorporated as options in the System Optimizer model. Including another resource as a proxy for the Incentive Program participants reflects double-counting, and would not generate meaningful results with a capacity size of 0.06 MW. Additionally, to be consistent with the costing approach used for DSM and distributed generation technologies, the Company would apply the Total Resource Cost concept, which is reported in Table 6.10 of the IRP.

9. COMMENTS AND RECOMMENDATIONS FROM INTERWEST ENERGY ALLIANCE

Interwest Energy Alliance filed its comments on June 18, 2009, and recommended that the Commission not acknowledge the IRP unless acknowledgment was conditioned on the Company accepting the case 8 portfolio as its preferred portfolio.

Interwest shares the same belief as WRA and UCE that the Company picked the wrong portfolio as its preferred portfolio. (Again, we refer to Section 6.1 for the Company's reply comments.) We note two aspects of Interwest's argument in support of the case 8 portfolio. First, like WRA and UCE, Interwest selects the cost statistics that support portfolios with more wind, rather than looks at the totality of cost and risk measures the way that the Company does. Second, the least-cost argument that Interwest uses to support the higher wind acquisition is applied to the original 21 portfolios rather than the final 10 portfolios that reflect model topology updates and the deferral or removal of a CCCT resource.

Interwest, like most of the other Utah parties, criticized the Company's wind integration results, citing other wind integration studies that reported significantly lower values. To provide a balanced view, there are other recent studies that report wind integration costs more in line with what the Company produced. (See Section 5.4 for examples of such studies.) The Company points out that until the utility industry adopts a standardized cost estimation methodology, simple comparisons of cost values produced by different companies at different times can be misleading.

Interwest also makes a bold statement claiming that the Company violates Utah state policy by not adhering to the SB 202 rules. The Company accounted for these rules in developing system-wide renewable portfolio standard constraints for the capacity expansion model. These RPS constraints are enforced for all portfolios developed using this model, and account for the Utah rules allowing for WECC-wide REC trading/transfers and banking.

Finally, we respond to a curious comment: "PacifiCorp does not sufficiently address the need to plan for transmission for the long term." (Interwest Comments, p. 14.) We believe we have sufficiently addressed this issue in IRP Chapters 4 and 10, which summarize the Company's transmission planning efforts and transmission expansion plan, respectively.

10. CONCLUSION

The Company strongly believes that the Commission should find the IRP in compliance with the Standards and Guidelines and grant acknowledgement. In the context of continuous improvement, if the Commission believes the Company should provide additional analysis in the future in certain areas, it could provide the Company specific guidance in those areas for future study while at the same time, acknowledging this plan.