Response to Utah Party Comments on PacifiCorp's 2007 Integrated Resource Plan

(Docket No. 07-2035-01)

INTRODUCTION

PacifiCorp (the "Company") filed its 2007 Integrated Resource Plan ("IRP") with the Public Service Commission of Utah (the "Commission") on May 30, 2007. The Commission then issued an invitation under Docket No. 07-2035-01, opened on June 4, 2007, for interested parties to submit comments on the IRP by July 27, 2007, later extended to August 31, 2007. 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]

Nine parties or groups of parties submitted comments by the August 31, 2007 extended deadline:

- Utah Division of Public Utilities (DPU)
- Utah Association of Energy Users (UAE)
- Utah Committee of Consumer Services (CCS)
- Western Resource Advocates, Utah Clean Energy and The Sierra Club (WRA[2])
- Utah Physicians for a Healthy Environment and Utah Moms for Clean Air (UPHE/UMCA)
- Salt Lake City Mayor, Ross C. Anderson
- Salt Lake County Mayor, Peter M. Corroon
- Park City Mayor, Dana Williams
- Corporate Real Estate Group, LLC, Salt Lake City

To classify the party comments at a high level, they fall into three general categories:

1. The IRP should not be acknowledged because it is not "optimal"; specifically, it is perceived to understate resource need and not adhere to least-cost/least-risk planning principles. The DPU and CCS fall into this category.

2. The IRP should not be acknowledged because the preferred portfolio includes coal plants and fails to adequately assess alternatives to fossil fuel plants. The WRA, UPHE/UMCA, the mayors, and Corporate Real Estate Group fall into this category.

3. The IRP should be acknowledged because it generally meets the requirements of the Commission's Standards and Guidelines. The UAE falls into this category.

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[1] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01), pp. 22-3.
[2] The comments were submitted by WRA on behalf of the other parties.

PacifiCorp contends that the 2007 IRP meets all substantive requirements of the Utah Standards and Guidelines, and that if the acknowledged 2004 IRP is used as the benchmark to determine this, then it follows that the 2007 IRP exceeds this mark due to the numerous modeling and analysis improvements implemented since the last IRP process. For example, this IRP addressed the concerns raised by the Commission in its 2004 IRP acknowledgement order pertaining to "the limited application of both natural gas/electric price risk and climate change policy risk analysis."[3] As outlined in the IRP and described in the reply comments below, the Company implemented enhanced stochastic and scenario analysis covering both market and carbon dioxide regulatory cost risks.

This document provides responses to comments organized by each of the relevant Utah IRP Standards and Guidelines. Guidelines for which substantive issues were not raised by the parties are not cited. Some of the comments also included modeling or process improvement suggestions for subsequent IRP development. PacifiCorp appreciates these suggestions, and addresses some of them here. Others were judged to be more appropriate for discussion with public stakeholders during the project planning phase of the next IRP.

Prior to addressing the specific comments of the parties, the Company first makes some observations on party comments in relation to those received for the 2004 IRP, and given an acknowledged 2004 IRP and the significant modeling and risk analysis strides made by the Company since then. The value of the integrated resource planning and acknowledgement processes for PacifiCorp, in light of the current planning environment, is then discussed.

CHARACTERIZATION OF PARTY COMMENTS

The most conspicuous and troubling development in the progression of comments from PacifiCorp's last IRP to the current one is the DPU's about-face concerning the IRP's adequacy to meet the Commission's standards and guidelines given the numerous portfolio analysis improvements introduced for this IRP. Specifically, the DPU has dramatically increased the guideline compliance thresholds from those applied in its evaluation of the 2004 IRP. In effect, the DPU has disregarded its own compliance evaluation history, and is now applying stricter standards than what has been acceptable to the DPU and the Commission in the past.

For this IRP, PacifiCorp followed the same (or improved) IRP practices and methods for guideline compliance as it did for the 2004 IRP. The DPU generally found the 2004 IRP practices and methods as acceptable, and in their assessment of individual guidelines it judged the IRP to be in compliance with all of them.[4] The Commission also concluded that PacifiCorp's IRP 2004 was generally consistent with its guidelines. For the 2007 IRP, the Company implemented many modeling improvements that directly addressed concerns raised by the Commission, the DPU, and other parties for the 2004 IRP, including: (1) full implementation of its capacity expansion optimization tool, (2) enhanced risk analysis of short-term market

[3] Public Service Commission of Utah, "In the Matter of the Acknowledgment of PacifiCorp's Integrated Resource Plan 2004", Report and Order (Docket No. 05-2035-01, July 21, 2005), p. 20.

[4] The DPU stated the following in their 2004 IRP comments: "...we are satisfied that the 2004 IRP adequately meets the standards and guidelines as ordered by the Commission." (Division of Public Utilities, "*In the Matter of the Acknowledgment of PACIFICORP Integrated Resource Plan 2004*: Docket 05-2035-01, April 22, 2005, p. 14)

purchases via the assignment of stochastically-modeled prices, (3) the first-time application of supply curves for demand-side management resources, and (4) expansion of CO_2 cost risk analysis.

PacifiCorp also notes that the CCS, WRA, and DPU appear to discount the Company's numerous IRP improvements, and expect ever-increasing modeling sophistication, an expanding scope of research to justify its planning decisions, and quicker response to external events. If IRP acknowledgement was to be made contingent upon meeting these expectations, then, in effect, the Company no longer is in control of its IRP process, and could never obtain an acknowledged IRP in Utah.

THE INTEGRATED RESOURCE PLANNING AND ACKNOWLEDGEMENT PROCESS

As indicated above, acknowledgement in Utah generally means that the Company followed the guidelines set out by the Commission and that the plan is deemed reasonable at the time it is presented. While this was once a relatively simple and straightforward exercise, it has become increasingly complex and less straightforward given the uncertain and rapidly changing planning environment and the divergent views of the IRP stakeholders across the company's various state jurisdictions. For example, during the 18 months over which the company developed the 2007 IRP, there were IRP rule changes in Oregon and Washington, an acknowledgement order for the 2004 IRP in Oregon, renewable portfolio standards enacted into law in Washington, emission performance standards enacted into law in Oregon and Washington, and a baseload request for proposal that was rejected by Oregon and approved by Utah. On May 30, 2007, the day the 2007 IRP was filed, the company announced its transmission expansion plan to build more than 1,200 miles of new 500-kilovolt transmission lines originating in Wyoming and connecting into Utah, Idaho, Oregon and the desert southwest, with completion targeted in 2014. Shortly after filing the 2007 IRP, Oregon enacted legislation on renewable portfolio standards and new legislation was introduced in the federal congress on carbon regulation. As noted by the WRA in their comments, subsequent to filing of the IRP, Utah Governor Huntsman signed an agreement to join the Western Climate Initiative, and Utah embarked on investigation of possible implementation of a renewable portfolio standard. The impact of these policy initiatives on PacifiCorp's resource planning is compounded by significant and rapidly changing load growth in the company's Wyoming service territory as oil and gas prices have dramatically increased.

The IRP development and acknowledgement processes are not designed to keep pace with this change, and we note, as the WRA does, that some of the current events referred to above occurred after the plan was filed. The IRP is by design a snapshot in time. Given the pace of change, the Company finds it increasingly difficult to provide the Commission with an IRP that reflects the current regulatory environment and at the same time meets the parties' increasing demands for more research and analysis.

Based on the comments received, it is clear that the carefully designed, collaborative IRP process is not accomplishing its intended purpose. Despite this, the Company will continue to plan and run its business in a manner that provides customers with low cost electric power in a manner that accounts for risk and is in the public interest. The Company would be interested in opening up discussions with parties to explore alternatives to the IRP process that are a better fit to today's planning environment.

UTAH STANDARDS & GUIDELINES COMPLIANCE

Procedural Issues

5. Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.

The DPU cited the lack of analysis or discussion on particulates as well as societal costs such as increased health care. It called for a more comprehensive treatment of externalities, including quantification where possible. This sentiment was also shared by the WRA, UPHE/UMCA, Corporate Real Estate Group, and the Utah mayors, which variously mentioned such externality topics as regional haze and air pollution, global climate change, water consumption, fly ash and mercury contamination, wildlife impacts, noise, and disruption of Native American religious sites.

<u>Response</u>

For this IRP and past IRPs, PacifiCorp's approach for considering environmental externalities has been in compliance with IRP standards and guidelines for the states it serves, as evidenced by commission acknowledgement of the IRPs. It has sought out stakeholder comments on treatment of externalities as part of the IRP public process and through PacifiCorp's Environmental Forum, consisting of external parties representing a range of stakeholder interests. For example, the method of quantifying expected future costs of air emissions was reviewed with stakeholders during IRP public meetings in 2006.

Nevertheless, in response to stakeholder recommendations to treat environmental externalities more comprehensively, PacifiCorp tasked Quantec LLC to conduct an externality study as part of the multi-state DSM potentials study.[5] The purpose of this externality study was to (1) review and synthesize literature on including externalities in utility resource planning, valuation methods, and ranges for their values, (2) determine the ranges of likely externality values (including monetary, where possible) and (3) assess the sensitivity of IRP outcomes to probable ranges. For this study, the Company identified a set of externalities for evaluation not previously covered in past IRPs. These included impacts on water use and water quality, impacts on land use, environmental effects of wind generators (focusing on bird and bat populations as the main wildlife impact), effects of global climate change on the hydroelectric system, and carbon sequestration.

Although this study was not intended as a comprehensive externality assessment, it provides a useful basis with which to determine how PacifiCorp can feasibly address externality analysis in future IRPs given available research, corporate scientific expertise, the overall IRP workload, and PacifiCorp and stakeholder analytical priorities.

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[5] See Appendix G, "Treatment of Externalities," in Quantec LLC, Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources: Appendices, Final Report, Volume 2 (July 11, 2007).

6. The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.

PacifiCorp was widely criticized by most of the parties for not modeling energy efficiency measures (Class 2 DSM) in a manner comparable to other resources, and for representing renewables with a single generic "proxy" resource. A few parties thought that "pre-screening" of certain resources to exclude them from detailed production cost simulation and risk analysis was inappropriate. On the adequacy of the Class 1 and Class 3 DSM proxy supply curves, the CCS and WRA state that expression of these resource types as fixed for a single cost and amount is improper. For example, the CCS states that the curves used for the Capacity Expansion Module (CEM) were "pre-selected by PacifiCorp and therefore do not provide an opportunity for the CEM to select from the full range of DSM resource available."[6]

Response

The Company's responses to parties' criticisms on the handling of Class 2 DSM programs and renewable resources are addressed under Guidelines 4.b, 4.b.i, and 4.b.ii below.

Regarding the CCS and WRA criticism on the proxy supply curves for Class 1 and Class 3 DSM, the formulation of proxy supply curves was addressed by the Company at the DSM Technical Workshop held on February 10, 2006. PacifiCorp sought guidance from participants on how to best represent all Class 1 and Class 3 DSM resources in a sufficiently compact manner so as to be practical from a modeling perspective. Program attributes (size and cost) were addressed, as well as the characterization of appropriate groupings. The Company adopted suggestions by meeting participants, and as a consequence implemented a DSM supply curve scheme that was reasonable to the Company and met most of the meeting participant's concerns.

In response to the specific argument that the proxy supply curves do not capture design flexibility, PacifiCorp and Quantec LLC agree that the general proposition that market acceptance is to some extent positively related to the offer price (for example in demand bidding or real-time pricing) or incentive levels (such as for direct load control). Therefore, the DSM potentials might be more accurately represented as a "range" rather than a point estimate. However, there is limited data available to support an analysis of the slope of such supply curves for many of the demand response options that were analyzed by Quantec. Moreover, the elasticity of load response with respect to prices (or incentives) tends to be small. For example, small elasticity estimates were reported in a comprehensive analysis of real-time pricing programs.[7]

9. The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.

Two of the parties, the DPU and CCS, are concerned that the PacifiCorp business plan or other outside influences may have driven the IRP process, resulting in plan components and resource

[6] CCS Comments, p. 5.

[7] Chuck Goldman, et al, *Does Real-Time Pricing Deliver Demand Response, A Case Study of Niagara Mohawk's Large Customer RTP Tariff*, Lawrence Berkeley National laboratory, LBNL-54974, August 2004.

choices whose merits were not supported by IRP analysis. (The DPU cites the "determination to go with a 12 percent Planning Reserve Margin, adjustments to the load forecasts, adoption of the expanded use of front office transaction[s]" as examples of such plan components.[8]) They also believe that the intent of the Commission is to have the IRP drive the Business Plan.

Response

The parties' claim that the IRP was driven by PacifiCorp's 2006 10-year business plan is incorrect. Both the 2007 IRP and 2006 business plan were under development concurrently given that the business plan is conducted on an annual cycle. Initial IRP modeling results informed the selection of the generation capital additions assumed for the business plan, which was finalized and approved in December 2006. As the IRP process was still continuing after this point, PacifiCorp updated certain resource assumptions made early in 2006 to maintain consistency with the business plan, as well as used the most recent load forecast (March 2007). These assumptions are documented in the 2007 IRP report on page 179.

The IRP portfolio analysis conducted in 2007 was not a product of the business plan; rather, regulatory and public policy developments (and other factors cited at the IRP public meeting on February 1, 2007) prompted the Company to reassess whether a preferred portfolio with four supercritical pulverized coal plants could ever get acknowledged by all of the state commissions.[9] This reassessment, made after the completion of the 2006 business plan, led to the decision to model portfolios with only two proxy coal plants rather than four. This change of course reflected a resource policy decision that was fundamentally part of the overall corporate planning process of which the IRP is a part, but naturally was not a model-driven decision.

Similarly, the handling of front office transactions was not dictated by the 2006 business plan. As clear evidence of this, compare the amount of front office transactions in risk analysis portfolio RA13 with the amount in the other Group 2 portfolios. (Recall that RA13 was designed with the business plan generation resources, and served the role of a reference portfolio). For RA13, the average annual quantity of front office transactions is 1,317 MW for 2010 through 2016, reflecting this portfolio's coal- and market-intensive resource strategy. In contrast, RA14 only averages 501 MW per year, while RA17, which relies on additional front office transactions to meet forecasted load, averages just 897 MW.

Finally, in response to the issue of what planning process—IRP or business plan—drives the other, and what degree of consistency there should be between the two, the Company is doing its best to keep them consistent to the degree permitted by their respective development cycles, functions, and data dependencies. For example, because the business plan attempts to project utility costs as accurately as possible, it requires more precise cost estimates and more frequent assumption updates than the IRP. If the Company was held to the exact standard advocated by the DPU and CCS, then the business plan would be forced to use IRP inputs, assumptions, and a resource strategy that could be at least a year old.[10] Given the rapidly changing planning

[8] Memorandum to the Utah Public Service Commission, August 31, 2007, p. 9.

[9] For example, one of the new IRP Guidelines issued by the Public Utility Commission of Oregon states: "The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies." (Order No. 07-002, p. 7).

[10] For example, assume that an IRP preferred portfolio is selected in October of a given year. The final analysis for the subsequent year's business plan would take place in October, a full year later.

environment and its implications to customer rates and system reliability, the Company does not believe it is in anyone's best interests to be bound by the constraints of the IRP in this regard. A similar point was voiced by the DPU back in 1992. As pointed out by the Commission in its IRP Standards and Guidelines Order, the DPU "cautioned against unequivocal enforcement [of the directive to have the Company's Strategic Business Plan be directly related to the Integrated Resource Plan] that would inhibit the pursuit of prudent resource acquisitions that were not included in the plan."[11]

As a practical solution to IRP/business plan linkage issues, PacifiCorp is using its IRP models and portfolio analysis methodology as an integral tool set for developing a refreshed preferred portfolio and associated planning scenarios in support of the Company's business planning efforts.

Standards and Guidelines

1. Definition:
Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.

The DPU and CCS put forth a number of arguments as to why they believe the IRP does not comply with some of the basic tenets of integrated resource planning, and therefore should not be acknowledged by the Commission. Each of these arguments is summarized below, followed by PacifiCorp's response.

The Company substituted the Commission's definition of "optimal set of resources" with its own—the concept of portfolio robustness

This argument was made by the DPU. In Chapter 2 of the IRP, PacifiCorp makes the following statement:

> [T]he emphasis of the IRP is to determine the most robust resource plan under a reasonably wide range of potential futures as opposed to the optimal plan for some expected view of the future.[12]

The DPU asserts that PacifiCorp has replaced part of the Commission's definition of the IRP—"The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty"—with its own, and thereby does not comply with the Standards and Guidelines.

[11] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01, June 18, 1992), p. 11.
[12] PacifiCorp 2007 IRP, p. 13.

Response

PacifiCorp is perplexed by the DPU's claim that the Company has somehow redefined the IRP by using robustness as a decision criterion for determining plan optimality under risk and uncertainty. The IRP does not permit mathematical optimality under a single objective function as suggested by the DPU. Instead, the IRP is a multi-objective and partly qualitative decision framework. (In the former case, an optimal solution can be found given deterministic assumptions and disregarding risk.)

PacifiCorp has defined "robust" in this IRP as an individual resource or portfolio that performs well under a range of alternative futures (in the context of modeling with the CEM) or stochastic simulations based on different CO_2 cost scenarios. PacifiCorp submits that the concept of portfolio robustness is the only appropriate optimality decision criterion that can be applied to account for risk and uncertainty as directed by the Commission, and challenges the DPU to come up with an alternate optimality criterion that does the same. A review of other utility IRPs will show that using portfolio "robustness" as the key determinant of the least-cost/least-risk resource portfolio is a standard practice.

PacifiCorp's preferred portfolio is not the optimal set of resources based on the Company's cost/risk tradeoff analysis

The CCS contends that PacifiCorp cannot justify the preferred portfolio (labeled "RA14") as the least cost/least risk resource mix given its cost, risk and reliability performance relative to all the other risk analysis portfolios evaluated. In making this claim, the CCS discounts the Company's decision to formulate a new set of portfolios based on state resource policy developments. Additionally, the selection of RA14 over the other group 2 portfolios is not justified based on a comparison of stochastic risk values.

The DPU believes that the Company did not sufficiently explain its selection of the final five portfolios (Group 2 risk analysis portfolios) for risk analysis with the public, and feels that the Company inconsistently applied its computer models.

Response

Comparing the performance attributes of the Group 2 risk analysis portfolios (RA13 - RA17) with those of the Group 1 portfolios (RA1 – RA12) is not valid because of the use of different load forecasts for each set of portfolios; both forecasted coincidental peak load and energy are higher for the Group 2 portfolio analysis. There are other differences between the two portfolio groups that affect the comparison, such as an accelerated wind investment schedule for the group 2 portfolios to account for new state renewable portfolio standards. These differences are documented on pages 179-180 of the IRP report.

Aside from the portfolio comparability issue, PacifiCorp takes issue with the CCS conclusion that risk exposure should dominate the cost-risk trade-off analysis because of the greater magnitude of risk exposure relative to expected cost. The CCS makes the explicit assumption that a dollar of risk reduction is approximately worth a dollar of expected cost. This assumption represents an extreme "risk averse" position. PacifiCorp does not assume a level of risk-aversion in judging the relative importance of risk exposure and expected cost due to the subjective and controversial nature of such an assumption.

In response to the DPU's concerns regarding the handling of the group 2 portfolios, the Company provided in the IRP (pages 179-186) a detailed explanation of the portfolio design goals, what resource strategies were being evaluated, and all the development specifics. Without the DPU being more specific in its assertions that the portfolios were not sufficiently explained, PacifiCorp does not know what other information could have been provided.

Pertaining to the consistency of model application, the Company used the same process for developing the group 2 portfolios as it did with the group 1 portfolios. This process is described, and graphically shown, on pages 128-129 of the IRP report. (In short, for both portfolio groups, the CEM was first used to initially screen resources and ensure that there is sufficient capacity to meet planning reserve margin constraints. Based on the screening results, the Company then manually crafted a set of portfolios to test alternative resource strategies.) The overall approach used to develop portfolios will be revisited for the next IRP based on (1) experience in using a capacity expansion optimization model, (2) what was learned from assimilating the results of two models with distinctly different analysis objectives, and (3) vendor improvements to both models.

As for vetting the group 2 portfolios with the public, the main impetus for developing these portfolios was to address new state resource preferences not accounted for in the design of the Group 2 portfolio analysis. Addressing such state resource preferences is an explicit IRP requirement in two of PacifiCorp's states[13], and the Company's intent to proceed to analyze portfolios that account for such preferences was announced at the IRP public meeting held on February 1, 2007. The Company saw little need for additional public discussion on resource decisions driven by such a specific IRP regulatory requirement. Also, opening such resource decisions to public debate would have resulted in another filing delay of indeterminate length, an outcome that the Company, and possibly other state commissions, would not find acceptable.

The preferred portfolio is overly reliant on short-term market purchases

The DPU and CCS believe that PacifiCorp has not adequately documented its evaluation of wholesale market liquidity to support the level of front office transactions cited in the preferred portfolio for 2013 and beyond. The CCS also contends that including additional front office transactions in the portfolio yields an unacceptable trade-off with respect to cost and risk. (The CCS cites portfolio comparisons showing that replacing front office transactions with a CCCT generally lowers stochastic risk.)

[13] The Public Utility Commission of Oregon mandates in their IRP guidelines that PacifiCorp's IRP "must be consistent with the long-run public interest as expressed in Oregon and federal energy policies" (See *Investigation Into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 (January 8, 2007), p. 7.) The Washington Public Utilities and Transportation Commission requires PacifiCorp to account for "public policies regarding resource preference adopted by Washington state or the federal government" in its portfolio analysis. (See Washington State, "Integrated Resource Planning Rules" (WAC 480-100-238, January 9, 2006.)

Response

PacifiCorp has adjusted its approach to short-term market purchase selection and risk in this IRP as compared to the 2004 IRP. Rather than fixing 1,200 MW of front office transactions in the portfolio, the Company allowed them to be selected on a comparable basis with other resources. In addition they were assigned market price risk in the stochastic analyses. That is why it plans for significantly less than an annual target amount of 1,200 MW of front office transactions as it did in the 2004 IRP. On the other hand, there is no basis to expect that short-term market purchases will not be available after 2012. For example, there are factors that could counteract tighter capacity margins in the WECC region. PacifiCorp's regional transmission expansion plan could contribute significantly to supply adequacy across PacifiCorp's system. Similarly, the regulatory cost of greenhouse gas emission control and renewable generation requirements could dampen electricity demand growth from what is currently projected.

Regarding the modeled cost and risk characteristics of front office transactions versus other resource types such as combined cycle units, PacifiCorp used this information, along with non-modeling considerations (planning flexibility, resource diversity, capital budget impacts, etc.) to ascribe to front office transactions the role of bridging resource.

PacifiCorp's models used inappropriate inputs and logic for the treatment of CO_2 costs, renewable portfolio standards, and coal commodity prices

The WRA believes that the CO_2 cost adder values used in PacifiCorp's portfolio analysis are "inappropriate", and cite several reasons:

- The CO_2 cost adder values for the alternative future scenario analysis are all too low
- The high CO_2 adder value is applied to only 6 of 16 alternative future scenarios
- PacifiCorp assumed delayed implementation of the high CO_2 adder value ($61/ton) used in the stochastic simulations
- PacifiCorp applied an unrealistically low discount rate

The WRA criticized PacifiCorp's use of a 6 percent system-wide renewable portfolio standard (RPS) requirement as a medium case, stating that the Company should have accounted for a possible Utah RPS requirement. It also stated that the Company failed to capture realistic coal price volatility in its alternative future scenarios.

Response

In crafting the alternative future scenarios, PacifiCorp relied heavily on feedback from IRP meeting participants. After presenting an initial alternative future scenario structure to meeting participants, PacifiCorp then proposed an alternate version based on IRP participant feedback. This alternate scenario structure allowed more straightforward comparisons among the different variable values, and was symmetrical with respect to high and low values across the scenarios. For example, six CAF scenarios used the high CO_2 cost adder assumption and six scenarios used the low CO_2 cost adder assumptions. A number of scenarios where variable values were logically inconsistent were modified appropriately based on participant suggestions. The CO_2 adders selected were also open to deliberation, and a consensus was reached on using the $38 per ton value as the high case (refer to page 121 of the 2007 IRP report).

Given the high degree of collaboration involved in determining an appropriate set of CAF scenarios to study, it is puzzling as to why the WRA did not recommend different CO_2 cost adder values for the set of alternative future scenarios if there was so much dissatisfaction.

Concerning the application of an unrealistically low discount rate, PacifiCorp applied its after-tax weighted average cost of capital (WACC) of 7.1 to discount all cost streams. The use of the WACC is mandated by the Public Utility Commission of Oregon in their IRP guidelines, and there has been no expression of concern raised by other Utah parties on the appropriate discount rate. Use of an alternate discount rate has ramifications beyond calculating CO_2 costs; it impacts financial modeling elsewhere in the IRP, as well as raises consistency issues with respect to the reporting of costs for business planning, accounting, and regulatory purposes. While deserving of discussion for the next IRP process, the Commission should not consider it as justification for finding that the IRP is not in compliance with the guidelines.

In regard to the 6 percent RPS generation requirement, this is a case where the Company is expected to have anticipated future policy developments well before they have occurred. PacifiCorp developed the medium RPS requirement in early 2006 based on current RPS rules in California and the expectation that RPS rules would be implemented in Washington and Oregon. The Company notes that the appropriate treatment of a Utah or federal RPS was not raised by any of the IRP meeting participants prior to the filing of the IRP, including the WRA's comments on the draft IRP document provided on May 11, 2007.

Finally, in response to the WRA's criticism on the handling of coal price volatility, PacifiCorp notes that for its existing coal-fired generation, coal is either delivered under long-term contracts or is supplied directly from a captive mine, and therefore would not be subjected to the same volatility as spot market coal purchases. As stated on page 122 of the IRP, coal price volatility for new resources is based on the U.S Energy Information Administration's low and high delivered coal price sensitivity forecast cases reported in the 2006 Annual Energy Outlook.[14]

PacifiCorp failed to account for "an array of critical new public policy objectives entered into just prior to, and soon following, the submittal of the IRP filing."

The WRA states that PacifiCorp's IRP is flawed because it is founded upon an "inaccurate planning environment" that does not address important new policy developments such as the Western Climate Initiative and Utah Renewable Energy Initiative. Although the WRA states that this "[i]n large part...was no fault of the company's"[15], they claim this flaw represents grounds for Commission non-acknowledgement.

<u>Response</u>

The WRA's comments demonstrate a lack of understanding that the IRP represents a snapshot view of the planning environment at the time the IRP is being prepared, and that acknowledgement needs be based on what was known at that time. Taking the WRA's reasoning

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[14] U.S. Energy Information Administration, *Annual Energy Outlook 2006 with Projections to 2030,* DOE/EIA-0383(2006), December 2005.
[15] WRA Comments, p. 3.

to its logical conclusion, PacifiCorp should never expect to obtain an acknowledged IRP because the IRP process will always lag behind new policy developments.

The 12 percent planning reserve margin advocated by PacifiCorp is not sufficiently supported by analysis or resource adequacy considerations

The DPU and CCS object to a preferred portfolio with a 12 percent planning reserve margin. Reasons cited include: (1) PacifiCorp's stochastic risk simulations show that higher reserve margins decrease risk with an acceptable increase in cost, (2) PacifiCorp has not demonstrated that market liquidity will be sufficient beyond 2012 to support the level of front office transactions included in the preferred portfolio, and (3) the 12 percent planning reserve margin, in conjunction with other Company assumptions and resource strategies, could have a deleterious impact on resource adequacy.

Response

The selection of a planning reserve margin level has been one of the most contentious issues throughout the last two PacifiCorp IRP cycles. Public stakeholders have vociferously argued for a 12 percent margin (or even lower) as well as a 15 percent margin, citing the same portfolio reliability, cost, and risk information to support their own positions on the matter. The Public Utility Commission of Oregon singled out the 15 percent planning reserve margin used in the 2004 IRP as a non-acknowledged element of the plan.[16]

With this backdrop, PacifiCorp believes the proper context to consider the planning reserve margin is the one stated by the UAE in their comments: "The planning margin should be used as a tool to help evaluate timing for investment in new resources and not a measure of actual system reserves."[17] Additionally, the Company considers the reliance on a fixed planning reserve margin level for the duration of the action plan time horizon to be ill advised at the present time given the volatile regulatory environment and the resource adequacy impacts of PacifiCorp's regional transmission expansion plan.

PacifiCorp believes that the 12 percent margin is a reasonable starting point for a preferred portfolio given the trend towards more regulatory-driven resource acquisition constraints and uncertainty over their ultimate costs to ratepayers. In making this determination, the Company considered its system simulation results, as well as its mandate to provide least-cost electricity service in the face of rapidly increasing resource costs. At the same time, the Company anticipates adjusting the planning margin within a range of 12 to 15 percent as either an outcome of continued IRP portfolio analysis with updated modeling assumptions, or to comply with new regional resource adequacy standards.

[16] Public Utility Commission of Oregon, "In the Matter of PacifiCorp 2004 Integrated Resource Plan," (Order No. 06-029, Docket No. LC 39, January 23, 2006), p. 22.
[17] UAE Comments, p. 8.

2. The Company will submit its Integrated Resource Plan biennially.

The DPU notes that there is no record of the Commission responding to PacifiCorp's IRP deadline extension request (from January 17, 2007 to March 31, 2007). The DPU also recommends that the Commission have PacifiCorp make adjustments to the Company's action plan to correct for deficiencies with respect to the Standards and Guidelines, and then proceed directly to develop the 2008 IRP without remedying this IRP.

Response

PacifiCorp confirms that the Commission did not take action on its motion for a deadline extension request; the Company interpreted this as consent for the extended deadline, and the Company notes that the Commission accepted the filing on the revised filing date and opened the associated docket without issue.

4.a. PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.

The parties levied the following criticisms of PacifiCorp's load growth forecast:

- PacifiCorp has underestimated load growth in Utah
- PacifiCorp has underestimated future peak demand in Utah

The detailed criticisms, and PacifiCorp's responses, are provided below.

PacifiCorp has underestimated load growth in Utah

Some Utah parties expressed concern with the lower load growth in Utah in the March 2007 load forecast. They expressed concern over the changes in Utah's forecasted capacity and energy requirements between the May 2006 forecast and the March 2007 forecast. The DPU and the CCS did not believe that the Company provided enough economic or demographic evidence to support these changes to its peak demand and energy forecasts. They were also concerned about the use of estimated future load growth that is significantly lower than historical growth. The CCS notes that the Company's forecast appears to be at odds with other publicly available forecasts regarding the Utah economy and cites the Utah Governor's Office of Planning and Budget's July 2007 economic and demographic forecast.

Response

PacifiCorp implemented load forecast ranges for deterministic scenario analysis as well as for stochastic short-term and long-term volatility modeling. Details concerning these forecasts appear in the 2007 IRP and were also discussed at IRP public meetings.

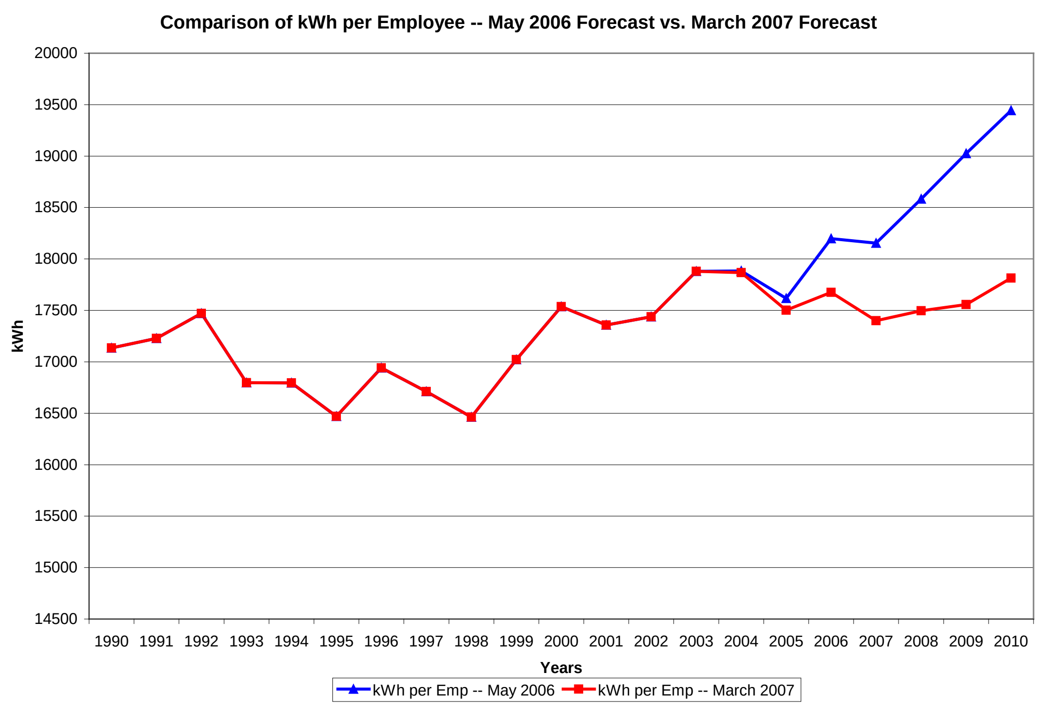
The deterministic scenario analysis evaluated alternative future scenarios, which included cases to test the impact of variations in load growth. In developing these deterministic scenarios, PacifiCorp relied heavily on feedback from public stakeholders. PacifiCorp developed low, medium, and high values for different variables, including load forecasts. In addition, PacifiCorp provided a range of load forecasts using stochastic analysis. This range covers nearly all possible load growth trajectories including those in Utah. If the load forecast picture were to change dramatically, the IRP and RFP processes could be adjusted as required.

As stated in the 2007 IRP (page 62):

> "The primary changes to the original May 2006 load forecast result from recent trends and conditions on the east side of PacifiCorp's service territory. Growth in Utah was slowing from what was previously planned; therefore, its growth rates were reduced. This was mainly associated with the growth in the commercial class and a slowing of the service activity in the state."

In the IRP public meeting on April 18, 2007, the Company presented the significant causes of the change in the overall growth rate and magnitude of forecast of changes between May 2006 and March 2007. This document indicated that the bulk of the change in Utah was due to a lower commercial growth rate. In the normal course of business, the forecast is updated with additional information and judgments that occur.

Several economic and demographic variables are needed to produce the PacifiCorp forecast, e.g., real personal income, population, and employment by sectors. A detailed analysis of each would be unwieldy for a response of this nature. However, the use of primary economic variables compared to energy forecasts is enlightening. For example, non-agricultural employment compared to the total retail sales forecasts of May 2006 and March 2007 indicates that the reduction of the forecast in Utah was warranted. The Global Insight forecast used to produce the May 2006 forecast was produced in the fall of 2005 and the Global Insight forecast used to produce the March 2007 forecast was produced during the fall of 2006. A graph of the ratio of Utah total retail sales to employment is presented below.



The ratio of sales to employment for the May 2006 forecast indicates that the ratio is too high after 2006. In practice, PacifiCorp recognized that the change in usage due to changes in economic growth was too high in the May 2006 forecast and made adjustments to the March 2007 forecast.

PacifiCorp has underestimated future peak demand in Utah

The CCS notes the Company does not adequately justify forecasting Utah's peak growth below its historical growth and states that the Company provides little economic or demographic evidence to support these changes to its peak demand and energy forecasts.

<u>Response</u>

The large change in the peak demand sited is mainly centered in the year 2009. For both forecasts, i.e., the May 2006 and the March 2007 forecast, the long-term nine-year average annual growth rates are similar, with the May 2006 forecast having a 3.0% coincident peak growth and the March 2007 having a 2.9% coincident peak growth. As is common in both of PacifiCorp's forecasts, the long-term growth rates are not constant for each year of the forecast horizon. The first two to three years of the forecasts exhibit deviations from the long-term trend due to business cycle factors. In preparation for the May 2006 forecast, the difficulties of the housing market were not yet apparent and for the first few years of the forecast horizon, robust economic growth was assumed, causing relatively strong growth for sales and demand in Utah. For the March 2007 forecast, the weakness in the housing market was becoming apparent and slower growth was assumed in the forecast for the next two to three years. This slower growth causes the deviation in 2009 between the March 2007 forecast and the May 2006 forecast. This weakness in the housing market and other factors causes a decline in the long-term growth rate of 0.1% in the peak demand.

4.a.i The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.

The DPU requested that future IRPs include a fuller explanation of forward price curves. As they stated in their comments, "…the price curves for both electricity and natural gas show marked declines in price over the next few years before they go up. The basis for these price curves, particularly the near-term decline in price, was not evaluated in detail. These price curves likely had a major effect on what the model will choose for resources – i.e. low market prices will tend to favor the selection of Front Office Transactions (since electricity costs are declining) and more natural gas plants (since natural gas costs are also declining)."

Response

As explained in the May 2006 Public Input Meeting, the electricity and natural gas price forecasts consist of the following elements:

- First 72 months: market observations compiled by PacifiCorp Front Office
- Blending: transition from market quotes to MIDAS forecast (1 year)
- Fundamentals: MIDAS price forecast (balance of 20 year period)
- Extrapolation: growth at inflation (beyond 20 years)

The first 72 months are derived from market price observations and therefore any near-term declines (or increases, for that matter) are purely a function of market activity and not a result of model simulations or assumptions made by the Company. These market observations come from numerous sources and for many years in the future, and are compiled by the PacifiCorp Front Office. The market prices are subject to many levels of validation and analysis. PacifiCorp Risk Management independently obtains market quotes on a daily basis from multiple independent third party sources such as Amerex, FutureSource, ICAP, ICE, Prebon, Tradition, and Tullett, and compares these broker quotes to market price information prepared by the front office. Deviations beyond an allowable threshold are discussed, substantiated or updated. In addition, since the market price curve—particularly the first six years—has a direct impact on the calculation of market gains and losses that may appear on the audited financial statements of the company, external auditors subject the quarter-end market price forecast to audit.

4.a.ii Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.

In its comments, the DPU concludes that load growth analysis is inadequate in the IRP and there is little discussion on the effects of the various factors on consumption. In addition, the UAE expresses doubt that the IRP has adequately tested for or assumed customer responsiveness to aggressive cost allocation/rate design changes or DSM programs.

Response

Since the 2004 IRP, PacifiCorp has performed three separate studies on the effects of the price of electricity on electricity usage in Utah. Each study evaluates increasing block rates of the residential customer class and attempts to measure the impact of the increasing price of electricity during the summer on usage of electricity, especially during times of peak demand in Utah.

These three studies, described in detail in Appendix A of the 2007 IRP and also discussed at the January 2006 Public Input Meeting, can be classified as

- Total residential class analysis through econometric methods
- Analysis, using econometric methods, of customers who called about their electric bills, and

- Sub-group analysis of the residential class using cluster analysis and econometric analysis.

In all three of these studies, it was determined that electricity is price inelastic. While these may not represent studies of extreme price changes, they are based on samples of real customers within the PacifiCorp territory.

In addition, as discussed in 4.a. above, deterministic scenario analysis evaluated alternative future scenarios, which included cases to test the impact of variations in load growth. In developing these deterministic scenarios, PacifiCorp relied heavily on feedback from public stakeholders. PacifiCorp developed low, medium, and high values for different variables, including load forecasts. In addition, PacifiCorp provided a range of load forecasts using stochastic analysis. This range covers nearly all possible load growth trajectories, in addition to natural gas and electricity price scenarios.

4.b An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.

For this guideline, a number of parties faulted PacifiCorp for using wind as a proxy for all renewables and not optimizing the amount of wind.

Use of Wind as a Renewable Resource Proxy

Parties commented on modeling adequacy for various resource types, including wind projects. The DPU, the WRA and the CCS noted that wind resources were used as a proxy for all renewable resources. As the CCS states, “Renewable resources are not a set that can be represented by a single technology or fuel type. Rather, these are diverse resources with greatly differing characteristics. Certain characteristics might be better or less well suited to meet the system needs.” The WRA stated, “Just as a coal plant could not be used as a surrogate for all conventional resources (*e.g.*, SCCTs, CCCTs, pulverized coal, IGCC and nuclear), neither can wind be used as a surrogate for the many types of renewable resources available to PacifiCorp.”

<u>Response</u>

PacifiCorp’s decision to continue to use wind as a proxy for all renewables in the 2007 IRP stems from three considerations. First, this resource is widely available throughout PacifiCorp’s service territory, and is expected to represent the vast majority of renewable resources anticipated to be added to the company’s portfolio. Wind is also a mature, cost-effective, and clean technology—attributes that make it a good standard for representing the risk-reduction benefits of renewables.

Second, the use of wind as the proxy renewable resource is consistent with the modeling approach used in the 2004 IRP and is the approach that has been previously acknowledged. The use of wind as a proxy resource was discussed at the January 13, 2006 renewables technical workshop, and participants did not voice opposition to the resource proxy approach at that time.

Third, from a practical modeling standpoint, at the time that PacifiCorp was integrating the CEM into its modeling methodology, and resource options were being formulated for alternative future scenario analysis, the Company was concerned about the implications of approaching the software vendor's recommended upper-limit on the number of resources that can be handled. This technical concern, coupled with the reasons given above, supported the continued use of wind as a proxy for renewable resources in the company's IRP modeling.

It should be noted that this modeling assumption does not limit the Company's action plan to solely acquiring wind resources. The action plan references cost-effective renewable resources, and there is no limitation on technology type. PacifiCorp will also investigate for future IRP modeling the addition of more renewable technologies as resource options in the CEM.

The Amount of Wind Was Not Optimized

The CCS questioned whether the 600 MW of extra wind represented an optimal quantity of wind for PacifiCorp's system from a risk mitigation perspective, and the DPU suggested that this quantity was arbitrarily determined and added to the group 2 portfolios on an ad hoc basis. The CCS suggests that it would be useful to perform an analysis of the optimal quantity of wind from a risk mitigation perspective using the PaR model.

Response

The Company's view is that the 600 MW of nameplate renewable capacity represents a reasonable amount of incremental resources to acquire in the short- to medium-term when balancing renewable portfolio standard requirements against factors that limit the pace at which renewables can be procured (tightening market conditions for generators, competition for wind generation sites, increasing costs, etc.) While there was some subjectivity in developing this capacity amount, it should not be considered an arbitrarily determined estimate. Given that the incremental 600 MW of renewable capacity was evaluated as part of the group 1 portfolio analysis, it clearly was not "suddenly inserted" in the group 2 portfolio as characterized in the DPU's comments.[18]

PacifiCorp agrees with the CCS that additional wind resource analysis is warranted, and has identified this in action items in the IRP Action Plan. (Refer to Action Items 16 and 17 on page 227 of the IRP.) One of PacifiCorp's modeling priorities regarding wind and other renewable resources will be to determine how to represent state and federal RPS requirements as accurately as possible given model design constraints, and subsequently determine the resource strategy that meets the best cost/risk standard given these regulatory resource requirements.

4.b.i An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.

For this guideline, a number of parties faulted PacifiCorp for failing to quantify an optimal amount of energy efficiency resources (Class 1, 2 and 3 DSM programs).

[18] DPU Comments, p. 44.

Treatment of Class 2 DSM Programs

Regarding the treatment of Class 2 DSM programs, CCS noted that by evaluating Class 2 DSM programs using a decrement analysis, these programs were not evaluated on a comparable basis with supply-side resources. In addition, the WRA commented that PacifiCorp's DSM analysis lacked adequate consideration of Class 2 DSM, and understated the potential, and optimality, for all customer classes.

Response

PacifiCorp has repeatedly stated in public meetings and the IRP report that the Class 2 DSM decrement analysis and planned DSM targets (250 MWa for currently budgeted programs plus an additional 200 MWa of new cost-effective programs) represent an interim resource planning strategy to guide the Company until the results of the multi-state DSM potentials study could be incorporated into the IRP modeling process. This interim evaluation strategy was necessary because of the lack of adequate Class 2 DSM cost/supply data for modeling purposes. PacifiCorp determined that a thorough review of available program information, combined with the Company's DSM implementation experience, was preferable to resource optimization modeling with unsound and makeshift cost/supply data. The Class 2 DSM targets represent the best planning estimates that could be developed by the Company during the preparation of the 2007 IRP, and are not intended as a substitute for the comprehensive potentials study recently completed by the Company.

Concerning the capture of Class 2 DSM's risk reduction benefits, the use of stochastic simulations does capture the stochastic risk reduction resulting from fewer spot market purchases, reduced use of natural gas, and re-optimized operation of current and IRP resources due to the addition of the Class 2 DSM resource in the preferred portfolio. The benefit of resource deferral associated with Class 2 DSM is reflected in the results of the capacity expansion model, since more resources would have been added had the Class 2 DSM not been included in the retail load forecast. Risk reduction attributable to an $8/ton CO_2 adder is also accounted for in all of the Company's models.

Treatment of Class 1 and 3 DSM Programs

The CCS expressed concerns that the proxy supply curves for Class 1 and 3 DSM, which identify the price/quantity relationship of strategies and options, were pre-selected by PacifiCorp and were not optimized by the CEM model. Further, WRA notes concerns that the IRP also fails to treat DSM as a true resource that can be scaled up or down depending on resource needs and alternatives and that the resource plan shows the energy savings from DSM programs declining over time.

Response

PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, and transmission. Chapters 5 and 6 document how PacifiCorp developed and assessed these technologies. In brief, the company used a combination of PacifiCorp generation staff expertise, Electric Power Research Institute Technical Assessment Guide (TAG®) data, and capacity expansion optimization modeling to assess these technologies. Generation resource types were initially assessed by PacifiCorp's generation experts, and a list that captures the salient technology types and configurations was assembled (Chapter 5, Tables 5.1 and 5.2). Decisions on what generation resources to include in the Capacity Expansion Module was based on generation staff recommendations regarding commercial availability and the need to limit resource options to a manageable number based on model constraints and run-time considerations. (The company notes that the need to place restrictions on the number of resource options is a common IRP problem for utilities that use such optimization models for long-term planning.)

Based on the modeling lessons learned for this IRP and the expansion of resource options arising from the June 2007 DSM potentials study, PacifiCorp intends to explore new methods to accommodate a broader range of technologies while meeting the requirement to assess technologies on a "consistent and comparable basis."

4.b.ii An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.

A number of parties expressed concern with the types of projects included for evaluation by the CEM and PaR models.

These concerns include the CCS's comments that

> "The treatment of wind as a proxy for all renewable resources is another problematic aspect of the modeling included in this IRP" and
>
> "The pre-screening of certain resources (solar, geothermal, gas CT units) by the Company and excluding them from risk analysis may be inconsistent with the Commission's IRP guidelines or at least industry "best practice" resource planning standards."

In addition, WRA stated,

> "PacifiCorp states that it screened out technology risk… Technology risk (*i.e.*, the risk that a new technology will prove uneconomic) should *not* be used as a screen to eliminate resources just as market price risk, gas cost risk and carbon risk are not used to screen out resources. This applies to IGCC, concentrating solar power, compressed air storage, and any other resources which PacifiCorp rejected because they are not yet commercially mature."

<u>Response</u>

A key point that has been overlooked is that IRP has not identified specific resources to procure, or even determined a preference between asset ownership versus contracted resources. These decisions will be made subsequently on a case-by-case basis with an evaluation of competing resource options including updated available information on technological, environmental and other external factors such as electric and natural gas price projections. These options will be fully developed using competitive bidding with a request for proposal (RFP) process, or other procurement methods as appropriate. Resources such as solar projects, IGCC and other resource types still developing technical and economic feasibility, can be evaluated or selected through an RFP process.

Conversely, by including those named resource types in the preferred portfolio, PacifiCorp has not committed to building specific resources. This misconception stems from confusion regarding the role of a "proxy resource" in portfolio evaluation, and the role of the preferred portfolio itself. As mentioned in Chapter 2 of the IRP report, the purpose of a proxy resource is to represent the indicative characteristics of an asset-type resource that *might* be procured.[19] When included in the preferred portfolio, the proxy resource informs action plan development and selection of benchmark resources for competitive procurements. It does <u>not</u> imply that PacifiCorp has decided to procure this specific resource or even this specific technology.

4.d A 20-year planning horizon.

The CCS claims that PacifiCorp failed to conduct 20-year optimizations with the CEM as required in the Commission's Standards and Guidelines. It also faulted the Company for evaluating only a single proxy resource—combined cycle combustion turbine (CCCT) "growth stations"—in the out-years of the study period.

<u>Response</u>

The CCS claim that PacifiCorp did not conduct 20-year optimizations with the CEM is incorrect; the CEM *was* allowed to optimize resources for a 20-year period as required by the Commission's Standards and Guidelines. However, PacifiCorp restricted the model's resource choices to only CCCT growth stations beyond the 12-year investment time period. This was done for the following reasons:

- Use of a proxy resource was viewed as a practical compromise solution given issues with the number of resource options that can be used in the model, as well as the uncertainty over resource technologies and costs that far into the future. A combined cycle growth station is a reasonable choice for a proxy resource given the prospect for CO_2 regulation and its flexibility to serve both intermediate and base load requirements.

- It is consistent with the proxy resource approach used in previous IRPs; for example, PacifiCorp used market purchases as the growth station concept for production cost simulation modeling conducted for the 2004 IRP. This proxy resource approach was not raised as a substantive issue by parties in the 2004 IRP, or in the public meetings devoted to modeling methodologies for the 2007 IRP.

The Company agrees with the CCS that the modeling approach and resource options used for the entire 20-year study period require revisiting. This evaluation will be largely driven by the recent passage of state environmental and resource compliance laws with specific year-by-year requirements beyond the 10-year investment focus of the IRP.

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[19] PacifiCorp, *2007 Integrated Resource Plan*, page 14.

4.e An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.

The DPU states that PacifiCorp fails to comply with this guideline because “[t]he Action Plan is short on specifics for the next two years,” and “[a]t best, the Action [P]lan presents an outline covering the next four years, but actually the Action plan sketches an outline that represents activities over ten or more years.”[20]

Response

In the past, the Commission, the DPU, and other parties have accepted the standard structure of the IRP action plan, and have not taken exception to the way the Company handled the grouping of action items. There is an issue with the practical utility in grouping action items into two-year and four-year horizons so given the long window (up to six years) for acquiring base load resources through competitive procurements. The vast majority of action items would therefore be grouped into the “next-two-year” category.

This is an example of the DPU disregarding its own compliance evaluation history, and applying stricter standards than what has been acceptable to the DPU and the Commission in the past.

4.f A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.

The DPU did not accept PacifiCorp’s proposed approach for addressing this guideline, and therefore claimed that this guideline was not in compliance. In addition, the CCS states that “PacifiCorp has not presented any clear decision mechanism or path to modify its plans, except to the extent that it presents updates to its IRP and deviations from its IRP in its actual resource acquisition process and business planning.”

Response

In the 2007 IRP, PacifiCorp proposed the following modeling framework to assist in acquisition path analysis:

> To formulate and analyze different resource acquisition paths, the RFP modeling process includes two deterministic scenario analysis steps in which bid resources, including PacifiCorp benchmark resources, are evaluated with the Capacity Expansion Module under a range of scenario assumptions. The scenarios capture

[20] DPU Comments, p. 17.

> a combination of alternative electricity/gas prices, CO_2 cost adders, and planning reserve margins.
>
> The first scenario analysis step involves running the CEM with the full set of short-listed bid resources to assist in screening the resources. The second scenario analysis step occurs after stochastic simulation has been used to select bid resource finalists. The portfolio of bid resource finalists is subjected to another round of CEM runs using the same scenario set applied to initially screen the bid resources. In contrast to the first scenario analysis step, the bid resources are fixed, and CEM use is limited to just determining the dispatch solution and PVRR under different economic conditions. This path analysis step is intended to help assure the company that the bid resource finalists are robust with respect to cost and cost variability under alternative economic and planning assumptions.[21]

The development of a decision mechanism and alternative acquisition paths logically should occur after this modeling effort has been completed, since alternative acquisition paths are contingent on the specific resources that the Company is planning to acquire, and should not be based on the proxy resources identified in the IRP. (As mentioned in Chapter 2 of the IRP report, the purpose of a proxy resource is to represent the indicative characteristics of an asset-type resource that *might* be procured.[22] It does <u>not</u> imply that PacifiCorp has decided to procure this specific resource or even this specific technology.) Developing the acquisition contingency plan at the conclusion of the bid evaluation process thus enables the Company to use up-to-date resource, demand growth, and market price information, as well as to tie the IRP modeling analysis to actual procurement plans as opposed to older IRP data. This strategy directly addresses the CCS concern, expressed in their comments, that "the resource planning process is not very closely tied to the actual resource procurement."[23]

4.g An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.

The DPU stated that PacifiCorp partially met this standard by virtue of its portfolio modeling, incorporation of portfolio designs suggested by public stakeholders, and use of externality cost adders for CO_2 and other pollutants. However, it cited the need for the Company to "expand its analysis of externalities to include as many as can reasonably be identified."[24]

<u>Response</u>

PacifiCorp responded to the issue of externality analysis in its reply to party comments on Procedural Issue No. 5. As already stated, the Company believes that it has fully complied with this standard, as it has in past IRPs, by virtue of its externality cost modeling and the additional externality cost assessment conducted as part of the DSM potentials study. The DPU

[21] PacifiCorp, *2007 Integrated Resource Plan*, p. 234.
[22] PacifiCorp, *2007 Integrated Resource Plan*, p. 14.
[23] CCS Comments, p. 19.
[24] DPU Comments, p. 19.

recommendation to include as many externalities as can "reasonably be identified" is troubling because it goes far beyond what has been expected by the Utah Commission and other state commissions in the past. It represents a significant expansion of the scope of the IRP effort without due consideration of the impacts on an IRP process that is already overtaxed, and whether the IRP is even the proper forum for addressing them. PacifiCorp believes that it makes more sense to evaluate what externalities should and can be reasonably accommodated for a particular IRP based on a review of available information and in consultation with stakeholders during the analytical planning stage of the IRP.

4.i Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.

The DPU states that PacifiCorp failed to comply with this guideline because it used a 12 percent planning reserve margin for the preferred portfolio and increased its reliance on market purchases beginning in 2010. These two resource strategies are judged by the DPU to reduce operational planning flexibility.

Response

PacifiCorp believes that the criterion for meeting this guideline is whether PacifiCorp demonstrated that it evaluated strategies for increasing flexibility in the resource planning and procurement processes. PacifiCorp asserts that it indeed met this criterion in the following ways. First, by using the concept of a proxy resource in the IRP, the Company has not committed to a specific resource type, thereby providing flexibility to acquire alternate resources during the procurement process based on updated resource costs and load information, regulatory developments, and market conditions at the time. This flexibility is particularly important given the long interval between IRP preparation, state commission IRP acknowledgement decisions, and the end-stage of competitive procurements.

Second, as discussed in PacifiCorp's response to comments on reliance on front office transactions (and acknowledged by the DPU in their comments[25]), this resource has value as an alternative to premature resource commitments, and also as a short-term contingency resource option. Foreclosing any resource option with a short lead-time reduces planning flexibility.

Finally, as described on page 203 of the IRP report, PacifiCorp has not subscribed to a fixed planning reserve margin for the duration of the action plan time horizon, but rather a range of 12 to 15 percent. PacifiCorp addressed parties' objections to the handling of the 12 percent planning reserve margin above.

PacifiCorp submits that despite the DPU's unfounded conclusion to the contrary, these steps demonstrate the Company's evaluation of strategies for increasing flexibility in the resource planning and procurement processes is in compliance with this guideline.

[25] DPU Comments, p. 20.

4.j An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.

In its comments on the 2007 IRP, the DPU states:

> The Company also could argue that its CEM and PaR analyses of different portfolio options complies with this, although not explicitly. However, PacifiCorp's own analysis shows that a 15 percent planning margin is better than 12 percent but chooses to rely on 12 percent. The Division believes this Guideline would require the Company to plan using the most economic risk/cost.[26]

Response

PacifiCorp examined the trade-off between portfolio cost and risk. This trade-off analysis is thoroughly documented in Chapter 7. A discussion on the trade-off between cost and the planning reserve margin is also provided in Chapter 7 ("Planning Reserve Margin Selection").

PacifiCorp acknowledges that there is a tradeoff between cost and reliability within system planning. However, planning solely on the basis of most economic risk/cost ignores other trade-offs that should be considered. Greater system reliability is a critical consideration and yet comes with increased resource need. Maintaining a level of resources that supplies a lower level of system reliability can also be costly due to expenses and penalties incurred during system outages; the optimum balance of cost and risk considers the tradeoff between higher and lower reliability standards. Planning solely on the basis of most economic risk/cost also ignores a key trade-off in any system-wide planning effort: the need to account for evolving state resource policies. Portfolio RA14 is viewed as the least-cost and least economically risky portfolio for reliably meeting PacifiCorp's load obligation *while also* balancing different state policies and interests. As such, it has the virtue of maximizing the benefits of having a large, integrated power system.

PacifiCorp's choice to initially adopt a 12 percent planning reserve margin, but leave itself the option of increasing the margin in response to market conditions, revised load growth projections, or new regional adequacy standards, has already been addressed earlier in these comments.

4.k A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.

The DPU stated that the Company did not provide a range of external costs for pollutants besides CO_2, and did not analyze any other externality. It also recommended that PacifiCorp expand its discussion and modeling of externalities. The CCS mentioned that a range of estimated external

[26] Ibid.

costs for the use of water and other “intangible” external costs (not enumerated in their comments) should have been included.

Response

PacifiCorp incorporated a range of other external costs by virtue of the interactive effect of CO_2 allowance prices on SO_2 and NO_X allowance prices captured in the Company’s electricity market price modeling. For each CO_2 cost adder level, PacifiCorp had corresponding SO_2 and NO_X allowance price levels as inputs to its fundamentals-based market price forecasting model, MIDAS. The treatment of externality costs in the modeling of forward electricity prices is described on page 133 of the IRP report.

PacifiCorp did not model separate scenarios involving a range of other pollutant externality costs as it did for CO_2. Lack of such scenario analysis has not been identified by the Commission as a deficiency in the past, and public IRP participants, including the DPU, have not raised this as a substantive issue prior to the filing of the IRP. The Company notes that the Public Utility Commission of Oregon (OPUC) addresses sensitivity analysis of alternative cost adders for SO_X, NO_X, and mercury in their new IRP guidelines issued in January 2007. The relevant guideline, which pertains to the handling of environmental costs, is the subject of a current OPUC proceeding.[27]

As noted in PacifiCorp’s response to comments on Procedural Issue 5, externalities were addressed separately in the Quantec LLC multi-state DSM potentials study.

CONCLUSION

PacifiCorp believes the 2007 IRP meets all substantive requirements of the Utah Standards and Guidelines, and reiterates its view that if the acknowledged 2004 IRP is used as the benchmark to determine this, then the 2007 IRP exceeds this mark because of the numerous enhancements introduced to the IRP process since the 2004 IRP was acknowledged. As such, the Company does not believe that the parties’ differences in opinion over its planning assumptions, how it conducted certain aspects of its modeling and analysis process, and expectations of even greater rigor, are valid reasons for recommending non-acknowledgment of the IRP. Nevertheless, the parties’ bring up a number of points and issues that PacifiCorp can use to help shape future IRPs. The Company is also committed to improve the next IRP—as it has for the 2007 IRP—by considering recommendations offered by participating stakeholders during the IRP planning stages, and adopting them in light of its IRP principles and system-wide obligations to customers and owners.

[27] Public Utility Commission of Oregon, “Investigation into the Treatment of CO_2 Risk in the Integrated Resource Planning (IRP) Process,” (Docket No. UM 1302, February 14, 2007).