State of Utah

DEPARTMENT OF COMMERCE
Committee of Consumer Services

To: Utah Public Service Commission

From: The Committee of Consumer Services
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Date: August 31, 2007

Subject: Docket No 07-2035-01: In the Matter of the Acknowledgment of PacifiCorp Integrated Resource Plan 2007

1. Introduction and Summary

The Committee of Consumer Services (Committee) appreciates this opportunity to review and comment on PacifiCorp's (PacifiCorp or the Company) 2007 Integrated Resource Plan (IRP or resource plan) filing. The Committee approached its analysis by examining the plan and approach from the perspective of the ratepayer classes that it represents. Specifically, does this process and this specific plan result in a resource acquisition plan that will provide low cost, reliable service to the residential, small commercial and irrigator customer classes by considering the appropriate costs, benefits and risks associated with various resource choices?

Based on its analysis, the Committee recommends that the Utah Public Service Commission (Commission) ***not*** acknowledge PacifiCorp's 2007 IRP. The Committee makes this recommendation because the IRP does not adhere to the Commission-approved Standards and Guidelines and is based upon several modeling flaws that prevent the Committee from having confidence that the resultant action plan reflects a least cost and least risk plan for resource acquisition.

The Committee further recommends that the Commission consider process improvements that will more closely tie PacifiCorp's planning process to its actual resource acquisition choices and that will better utilize the participation of stakeholders.

The Committee recognizes that this is a time of great uncertainty in the electric industry. It is concerned that our comments do not get misinterpreted as explicit support for resources not selected in this plan. Rather, it is the Committee's contention that the current uncertainty underscores the need for robust planning processes. It is critical for the Company to clearly outline the tradeoffs associated with resource choices. It is only after sound and well supported evidence is presented that regulators, stakeholders, and policymakers can be expected to provide more specific opinions on which tradeoffs are preferred. The Committee does not find adequate information in this plan to provide such opinions at this time.

The Committee organizes its comments in the following manner. First, the Committee will address certain shortcomings relative to the adherence of this plan to the Commission approved Standards and Guidelines. Next, the Committee will elaborate further on some of the more significant issues, grouped into the following categories:

- Modeling Issues
- Optimality of Preferred Plan
- Resource Adequacy
- Overall Process

Finally, the Committee will provide specific recommendations for Commission action.

2. Adherence to the Standards and Guidelines

The Commission has established a set of Standards and Guidelines for Integrated Resource Planning for PacifiCorp, Utah Jurisdiction.[1] These Standards and Guidelines provide clear Commission direction for the Company to utilize in preparing its resource plan filing, and more fundamentally, to help guide its long-term planning process. The Committee notes several specific cases in which the Company's IRP does not adhere to the Standards and Guidelines as ordered by the Commission.

This section is intended to highlight some of the most notable problems, not to serve as a comprehensive analysis of the Company's compliance with each guideline. However, these examples alone are sufficient grounds for the Commission to withhold its acknowledgement of the resource plan currently before them.

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

The Company simply did not consider demand-side resources on a comparable basis with the supply-side resources contained in this resource plan. The Company expects to improve this process in its next round of modeling when it is able to incorporate the

[1] Public Service Commission of Utah, *Report and Order on Standards and Guidelines,* In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Docket No. 90-2035-01, June 18, 1992.

results of its recent DSM potentials study. However, it is critical to be pursuing all cost effective DSM as soon as possible to help mitigate the serious need for future additional resources. The Committee discusses this issue further in its section on modeling issues.

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

The IRP Standards and Guidelines require that the Company's Strategic Business Plan be consistent with its Integrated Resource Plan "to ensure that ratepayers receive the benefits from IRP."[2]

It appears that the Company determined the primary components of the resource plan outside of the planning process, and then constructed the final analysis to achieve that end. While there may be good reason to make certain resource selections, the reasons should be justified on their merits, and the effect of the decision should be made transparent. It appears to the Committee that the approach taken by the Company obfuscated rather than clarified important cost/risk tradeoffs. The Committee believes that it was the Commission's intent not solely to ensure a link between the business plan and IRP, but to signal that the business plan should be developed from the IRP, not the reverse.

Standard and Guideline 1: Definition: Integrated resource planning is a utility planning process which evaluates all known resource 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 set of resources the Company selected as its Preferred Portfolio is not optimal "given the expected combination of costs, risk and uncertainty," and its choice is not consistent with PacifiCorp's analysis. Its selection appears to represent the Company's attempt to respond to the disparate concerns of its stakeholder groups across its many jurisdictions while maintaining planning on a system basis.

The Committee does not fault the Company for its attempt to create a set of resources that all stakeholders will support. However it appears to us that the Company was somewhat disingenuous in its development and analysis of the final five portfolios that obscured rather than clarified important cost/risk tradeoffs. The Committee provides additional detail explaining why it does not agree that the preferred portfolio represents

[2] *Report and Order on Standards and Guidelines*, p. 17.

an optimal selection of resources in its section specifically addressing optimality as well as in the section addressing modeling issues.

Standard and Guideline 4b: PacifiCorp's future integrated resource plans will include: an evaluation of all present and future resources including future market opportunities (both demand-side and supply-side, on a consistent and comparable basis.

In addition to the problems associated with comparable treatment of DSM (or lack thereof as discussed earlier), this IRP also fails to adhere to the guideline of treating supply-side resources consistently and comparably. 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. Given this pre-screening step, it's questionable whether the Company (or any party for that matter) can say with any confidence that the IRP process produced candidate portfolios that were truly evaluated on a least cost, least risk basis.

Standard and Guideline 4d: PacifiCorp's future integrated resource plans will include: a 20-year planning horizon.

PacifiCorp's current IRP does not include a true 20-year planning horizon, as it appears to only optimize for the first ten to twelve years and uses growth stations for the later years. This practice is certainly contrary to the intent of the guidelines and also inconsistent with industry best practices. The Committee further discusses this issue in its section addressing modeling issues.

Standard and Guideline 4f: PacifiCorp's future integrated resource plans will include: 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 Committee believes that risk analysis, albeit an important component of resource planning, does not fully satisfy this guideline. 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. Many recent events clearly indicate that a more responsive process is necessary to respond to changes in the marketplace[3]. It should not be considered adequate or acceptable for the Company to make regulatory filings indicating emergency needs or requesting approval of resources that haven't been demonstrated as optimal from an integrated planning perspective. This is precisely

[3] Some examples include: the apparent delay and/or cancellation of IPP 3, the Company's benchmark resource in its current IRP; and the load lightener DSM program that did not perform as expected and was cancelled.

what will occur unless the Commission requires more robust response to this guideline and more information on contingency plans in future resource plan filings.

Another important function that following this guideline could serve would be to develop a transition portfolio to meet the Company's load obligations over the next 10 years or so that could serve as a "bridge" to future resources still under development.

Standard and Guideline 4k: PacifiCorp's future integrated resource plans will include: a range … of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options.

PacifiCorp appropriately examined a range of values in its scenario analysis of CO2 adders. However, this IRP does not include a range of any other external costs. To appropriately examine the impacts of emissions, use of water, and other "intangible" external costs, PacifiCorp should be held to this Guideline and be required to include a range of estimated costs. Otherwise, the Commission and other stakeholders and policymakers would have no basis to understand how explicit consideration of these costs might affect selection of resource options, as intended in the guideline.

3. Modeling Issues

The Committee appreciates the modeling improvements PacifiCorp undertook in this IRP that respond directly to the Committee's past recommendations including: use of the CEM for scenario modeling, and inclusion of IGCC, wind, and short-term market purchases in the risk modeling. However, additional work remains in order to achieve an underlying modeling process that would provide an accurate and comprehensive view of the tradeoffs associated with various resource choices. Specifically, PacifiCorp must make improvements in how it comparably treats certain resources within the modeling process and must provide an actual 20 year planning horizon in order for regulators and policy makers to be presented with results that can lead to meaningful policy discussions and decisions. Further, the Commission should consider providing more specific direction to the company on its inclusion and use of externality values in order to provide a more robust picture of all costs involved with certain resource choices.

3.1 Comparable Evaluation of Resources

3.1.1 Treatment of DSM

The Standards and Guidelines require that the integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis. The Company attempts to meet this standard by including Class 1 and 3 DSM with supply-side resources for selection in the CEM, however, the proxy supply curves which identify the price/quantity relationship of strategies and options were pre-selected by PacifiCorp and therefore do not provide an opportunity for the CEM to select from the full range of DSM resources available. This appears to be a limiting factor in identifying all cost effective DSM that could be achieved.

Class 2 DSM programs were evaluated using a decrement analysis. The Company states that it intends to model Class 2 DSM programs as options in the CEM during the next IRP cycle. Inclusion of Class 2 DSM programs in the CEM will allow these resources to be evaluated on a more comparable basis with supply-side resources, a step that is missing in this IRP.

When performing the risk analysis Class 1 DSM resources were considered. The Company seems to have less confidence in Class 3 DSM and states there is a need for further research on the reliability of Class 3 DSM resources for addressing peak load and to improve the modeling for these programs. The DSM potential study is expected to provide needed information in these areas. Because Class 3 resources were not included in the risk analysis the Company had no way of ascertaining the full benefit that could be provided from all DSM resources and could not evaluate supply-side and demand-side resources on a comparable basis as required. The full risk mitigation value of DSM may have been overlooked and the resulting portfolio may understate the amount of DSM that the Company should acquire.

The east side of the system is projected to continue growing with Utah's peak growth surpassing energy growth. The Committee is concerned that the Company has not identified, evaluated or selected all cost effective DSM that is achievable. It is unconvinced that this IRP contains sufficient amounts of DSM to address the east side growth in a low cost, low risk manner. If the full value of DSM is not captured in analysis it can result in the Company building more generation and/or transmission to meet growth rather than pursuing valuable DSM programs.

Action Item 2, Class 2 DSM, in the Action Plan indicates that the Company will..."Acquire the base DSM (PacifiCorp and ETO combined) of 250MWa and ***up to*** (emphasis added) an additional 200MWa if cost-effective initiatives can be identified."[4] The Committee believes that there should be no limitation on the amount of cost-effective DSM that the Company acquires.

The Committee appreciates that the Company continues to work on improving its modeling efforts to develop a more accurate picture of the amount of cost-effective DSM

[4] On page 138 the Company states that the amount, the value or the potential acquisition of cost-effective energy efficiency will not be arbitrarily limited by the methods currently being used in this process.

that can be achieved. In this IRP the Company states its intent to utilize the system-wide DSM study that was completed in June 2007 in the 2007 IRP update and/or the 2008 integrated resource planning processes. The Committee is hopeful that the Study will allow for more accurate, detailed modeling and analysis of DSM programs. However, the Study has not yet been vetted through a public comment process. This is an important step that the Company should take prior to incorporating the results in its next IRP process.

3.1.2 Pre-screening of Technologies

The IRP Standards and Guidelines require "an evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis."[5] It appears to the Committee that the Company's application of its two stage approach has resulted in the exclusion from risk modeling of particular technologies that may be most beneficial in a high risk environment. These technologies have therefore not been evaluated on a consistent and comparable basis.

The Committee recommends that high cost but risk mitigating technologies such as solar and storage technologies be evaluated in the risk modeling phase. In order to accurately assess their risk mitigating benefits, it would recommend that several portfolios be developed in which the only difference was the inclusion of a specific technology.

One technology for which this prescreening practice is particularly troubling is geothermal resources. According to Table 5.3 of the IRP, a generic eastside geothermal resource is priced at approximately $38/mWh, with the inclusion of a $20/mWh tax credit that is expected to be renewed. The Committee is particularly concerned that such a resource isn't examined in the Company's risk analysis and is left to wonder why the Company doesn't more actively pursue a resource that appears to have such favorable cost characteristics.

3.1.3 Removal of SCCTs from evaluation

PacifiCorp removed SCCTs from the final five portfolios. Because no portfolios differ only by the type of gas resource that is added, no stochastic analysis is available to determine whether this strategy is beneficial.

PacifiCorp justified its decision by stating that "the PaR stochastic simulation captures extrinsic (or optionality) value of a resource, while the CEM does not. [Therefore] a CCCT is expected to have a lower PVRR impact than a non-base load gas resource with all else held constant." While PacifiCorp's justification may have some intuitive appeal, the Committee believes the Company should have undertaken the analysis to support this conclusion.

[5] *Report and Order on Standards and Guidelines*, p, 42.

Further, the Company repeatedly indicates that it is seeing relatively faster peak load growth in the summer months versus winter months due to the increase in residential and commercial air conditioning load on its system (refer to IRP pages 64-65). The Company expects this trend to continue resulting in system peak demand growing faster than overall (average) demand. This trend would appear to support an explicit examination of the value of peaking resources to the PacifiCorp system. An additional factor that may lend support to peaking resources is the fact the Company plans to add 1600 MWs of intermittent wind resources to its system in the 2007-2013 period.

Without more comprehensive analysis the Committee cannot support the decision to exclude SCCTs from the resource plan.

3.1.4 Selection of Wind

The addition of 600 MW of extra wind in several of the portfolios that were subjected to stochastic risk analysis demonstrated the potential for wind energy to mitigate market and gas price risk by allowing the use of these resources to be avoided when the wind is blowing. What remains unclear is whether PacifiCorp has identified the optimal quantity of wind for its system from a risk mitigation perspective.

The Committee reviewed three sets of portfolios which differed only by the amount of wind included and how they were then optimized.[6] We observe that on average:

- Expected cost increases by $44 million; risk exposure declines by $921 million;
- An additional PVRR dollar spent on wind reduces risk by $20.78. The lowest pay-off occurs with a $0/ton carbon value adder and the highest with a $38/ton carbon value adder.

This initial analysis suggests that wind provides benefits to the system and warrants additional analysis to determine what level of additional wind resources maximizes these benefits.

We believe an analysis of the optimal quantity of wind from a risk mitigating perspective sing the PaR model would be useful. The Committee suggests that PacifiCorp create several base-case portfolios representing a different mix of resources. Incremental amounts of wind could then be added successively until no further reductions in risk exposure occurred. This would test the optimal amount of wind for a resource mix type. By using more than one base case resource mix, PacifiCorp could test how well wind mitigates the risk of alternative resource mixes.

[6] Three sets of portfolios allow evaluation of the effect of adding an additional 600 MW of high capacity wind: RA1 with RA3; RA2 with RA7; and RA5A with RA5B from PacifiCorp's Supplemental Response to DPU 1st Set Data Request 1.52 and 1.53. We used the average mean and risk exposure measure across the three portfolio sets and five C02 adder cases in creating the ratio.

3.1.5 Wind as proxy for all renewable

The treatment of wind as a proxy for all renewable resources is another problematic aspect of the modeling included in this IRP. 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. This analysis could be appropriately undertaken within the context of the integrated modeling of an IRP, provided that the different types of resources are not prescreened as discussed above.

3.2 Appropriate Planning Horizon

The Standards and Guidelines direct that PacifiCorp use a 20-year planning horizon. [7] As discussed below, it appears to the Committee that the Company has produced a ten-year plan because of its method of addressing end effects in its capacity expansion modeling. This is not in conformity with the Standards and Guidelines and should be corrected in future IRPs and any analysis utilizing the IRP modeling.

The Committee is pleased that for the first time in conducting an IRP, PacifiCorp used software containing automatic resource optimization logic, the Capacity Expansion Model ("CEM") for its scenario analysis. The CEM performs automatic economic screening of generation supply-side and demand-side resources and determines the optimal resource expansion plan for a specified planning scenario.

However, the Committee believes that certain aspects of PacifiCorp's CEM modeling were flawed and should be corrected in subsequent analyses. One significant problem relates to the time period over which PacifiCorp conducts the optimization analysis. The CEM can be setup to perform an optimization for time periods spanning from one to thirty years, and possibly longer, although typically utilities conduct resource optimization studies for periods between twenty and thirty years. PacifiCorp, on the other hand, initially conducted its optimization studies for ten years, but after encountering counter-intuitive results, expanded its optimization analysis to twelve years, treating the remaining years as "end effects".[8] End-effects treatment in resource planning attempts to capture the benefits of operating long-lived generating resources over the lifetime of those assets, which typically extends beyond the end of the resource planning period. To consider "end-effects", PacifiCorp extended the study period for another eight years and during that time, PacifiCorp added combined cycle "growth stations". In other words, during the last eight years of the study period, whenever the

[7] *Report and Order on Standards and Guidelines*, pp. 42-43.

[8] In response to DPU Data Request 1.1 and 1.20, PacifiCorp explained that results it obtained based on a 10 year optimization analysis were anomalous, yet those anomalies disappeared once it extended the optimization analysis from ten year to twelve years.

installed capacity fell below its twelve percent reserve margin target, PacifiCorp added sufficient combined cycle capacity to meet the reserve margin target.

The Committee has two objections to PacifiCorp's approach to its planning horizon and treatment of end effects. First, twelve years is very short for an optimization period, especially considering the length of time that it takes to plan, design, construct and begin to operate generation resources. Some of the Committee staff, as well as a consultant working for the Committee have considerable experience conducting IRP studies, and have never encountered resource optimization analyses conducted for as few as twelve years. Most utilities perform optimal expansion plan analyses for twenty years and some analyses even extend out as far as thirty years. Based on our experience and investigation, utilities within the Southern Company System, Xcel Energy in Colorado and Minnesota, utilities in Kentucky including Louisville Gas and Electric, Duke Power and Hawaiian Electric have all conducted recent IRP studies with optimization analyses for periods of twenty years or more.

Second, while the most important period for planning decisions is the first ten years of the study horizon, benefits derived from resources added during that time period will be greatly influenced by the next set of resources that will be added later in time. Recall that after the initial twelve-year optimization period, PacifiCorp adds only combined cycle unit growth stations for the remaining eight years of the study period. Adding only one type of generating unit during this eight-year period is highly unusual and could lead to incorrect resource selection decisions being made for the first twelve years of the study period. Essentially, PacifiCorp optimizes its resource selection during the first twelve years, and then continues to evaluate those resources for the remaining eight years with a sub-optimal set of combined cycle units.

In contrast, it is standard practice in the utility industry to attempt to optimize resources for all time periods, subject to risk considerations. Consider the actual sequence of events that utilities employ in resource planning, which is to first conduct an optimal resource planning study, then acquire or build the optimal resources, and then once again conduct an optimal resource planning study for the next planning period. While conditions don't always turn out exactly as predicted, this planning approach should lead to the most optimal set of resources being added over the long-term. PacifiCorp's approach is flawed because it optimizes its resource selection during the first twelve years, and then continues to evaluate those resources for the remaining eight years using a set of resources that it most likely would never build. If PacifiCorp did commit to build the resources it selected using its optimal resource planning approach during the first twelve years, it would also have to build only combined cycle units during the next eight years, in order to obtain a least cost system over the entire twenty year period. PacifiCorp would not do this in actual practice, and therefore it should not conduct its resource planning studies using this approach either.

PacifiCorp may have experienced excessive run-time problems when it conducted CEM optimization runs for twenty-year periods. If so, then it should be noted that better methods exist for PacifiCorp to reduce run-times in conducting its resource planning studies. Typically, optimization analysis runtime increases substantially based on the number of resource options being evaluated. As a means to reduce runtime, after the first twelve years of the study period, PacifiCorp could reduce the number of resource options available for evaluation. This approach would allow PacifiCorp to save a considerable amount of run time, and still conduct a reasonable optimization analysis for the entire twenty-year period. For example, after the first twelve-year period PacifiCorp could reduce the options to just a proxy coal, combined cycle, combustion turbine and renewable energy resource. Reducing the set of available options in this manner would still result in a reasonably optimal expansion plan over the entire twenty-year period.

The Committee recommends that the Commission require PacifiCorp, in all future analysis utilizing CEM modeling, to conduct its optimization analysis for the entire twenty-year study period[9]. It is critical that the Commission require the Company to implement this change quickly, as the unreasonably short time horizon could distort the Company's analysis of the responses to its RFP, underway in Docket No. 05-035-47.

4. Optimality of Plan

4.1 Overview of Plan Development

The PacifiCorp IRP Team produced a large body of analysis. The analysis was conducted in three stages. The first stage used a capacity expansion model to consider the type, timing and location of resources under possible alternative futures. This information was then used to develop alternative sets of resources for risk modeling which was conducted in two stages. The risk modeling included the effects of five carbon adder values ranging from $0/ton to $61/ton, and variability in loads, outages, hydro production, and market and gas prices. From this analysis the Company developed estimates of the expected cost associated with alternative sets of resources and the magnitude of the potential for the portfolio cost to exceed expectations. The possibility that costs could exceed expectations is referred to as risk exposure.

[9] In the alternative, the Commission could allow the Company the opportunity to conduct an analysis to evaluate its optimization modeling approach and compare its results to results obtained based on an optimization performed for the entire twenty year study period. Should the results it reports to the Commission be similar, then PacifiCorp could be permitted to continue to conduct its optimization as it has been doing. However, if the results based on the Company's method are less optimal, then the Company should be required to conduct optimization studies over the entire twenty-year study period for all future IRP studies.

PacifiCorp conducted the analysis of risk in two phases. Portfolios RA1-RA12 were developed in the first phase. The Company's 10-Year Business Plan which it shared with regulators early in 2007 was based on the preliminary results from this phase. RA5 is most like the original Business Plan.[10]

PacifiCorp indicates that the feedback it received in conjunction with its assessment of state policy directions prompted it to investigate alternatives to the Business Plan. PacifiCorp then developed five additional portfolios, RA13-RA17 and selected RA14. [11]

Two key elements to consider in evaluating the optimality of a portfolio are its expected cost and risk exposure. Ideally, the portfolio with the lowest expected cost would also have the lowest expected risk. However, often there are tradeoffs. Lower risk portfolios can be associated with a higher expected cost and vice versa, so tradeoffs may exist between cost and risk. Understanding the magnitude of these tradeoffs is essential to sound decision making.

CCS Exhibit One provides a consistently scaled, visual picture of the cost/risk tradeoffs of the seventeen portfolios that PacifiCorp developed for risk analysis under the average carbon adder value case.[12] Risk exposure is portrayed on the vertical axis. It reflects by how much actual cost could exceed expected cost.[13] Expected cost is portrayed on the horizontal axis.[14] The scaling was chosen so that distance on the vertical axis and distance on the horizontal axis reflect roughly equivalent dollar amounts.

The exhibit makes clear that the variation in expected cost is quite small across the seventeen portfolios as compared to the variation in risk exposure. In the average carbon value adder case, the portfolio with the highest expected cost is 4.6% greater

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[10] The primary difference between RA5 and the other low risk portfolios is the early addition of coal-fired resources.

[11] The final five portfolios differ significantly from the previous twelve in the following ways:

- All include short-term market purchases beyond 2011.
- All but one is built to a 12% planning reserve margin.
- IGCC was removed as an option;
- Simple Cycle Combustion Turbine (SCCT) units were removed as an option;
- All but one include an additional 600 MW of wind; however the new wind schedules have a lower capacity factor than the wind that was included in the previous modeling;

Four of the five portfolios limited SCPC units to two, reduced their size, and sited them in 2012 and 2014. A fifth portfolio, added an additional two units late in the period.

[12] For each defined portfolio, RA1-RA17, PacifiCorp conducted a total of 500 modeling runs. In each modeling run, power prices, natural gas prices, hydro availability, outages, and loads varied randomly within defined parameters that reflect five years of historical variability. One-hundred modeling runs were conducted for five carbon adder values: \$0/ton, \$8/ton, \$15/ton, \$38/ton and \$61/ton. The risk modeling assumed a cap and trade carbon tax policy.

[13] Risk Exposure is equal to the mean of the Present Value Revenue Requirement (PVRR) of the five most costly portfolio runs minus the mean of the PVRR over the 100 runs that were conducted for each carbon adder value.

[14] The cost measure used for this analysis is the mean of the PVRR over the 100 runs that were conducted for each carbon adder value. Statistically, it is the expected value.

than the portfolio with the lowest expected cost. However, the risk exposure of the riskiest portfolio is 46.4% greater than the risk exposure of the least risky. This analysis would seem to indicate that the risk exposure would play a primary role in selecting the preferred portfolio.

CCS Exhibit Two provides a reference for understanding the differences in risk exposure among the portfolios. It sorts the portfolios from the most risky to the least to correspond to the vertical axis in Exhibit One.

4.2 Cost Risk Tradeoff does not support the selection of the preferred portfolio

The set of resources the Company selected as its Preferred Portfolio, RA14, is not supported by the results of PacifiCorp's risk modeling[15]. RA14 has the lowest expected cost of the seventeen portfolios modeled. However, it is one of the riskiest plans evaluated -- only two are riskier.

PacifiCorp conducted the analysis of risk in two phases. Portfolios RA1-RA12 were developed in the first phase. The Company's 10-Year Business Plan which it shared with regulators early in 2007 was based on the preliminary results from this phase. RA5 is most like the original Business Plan.[16]

PacifiCorp indicates that the feedback it received in conjunction with its assessment of state policy directions prompted it to investigate alternatives to the Business Plan. PacifiCorp then developed five additional portfolios, RA13-RA17 and selected RA14. [17]

The Committee contends that RA14 is not the optimal set of resources given the expected combination of costs, risk and uncertainty. RA 14 includes short-term market purchases after 2011 and builds to a 12% planning reserve margin. The inclusion of

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[15] RA14 adds over 1500 MW of CCCTs and 867 MW of SCPC units between 2011 and 2016. It adds a CCCT on the west side in 2011. On the east side, CCCTs are added in 2012 and 2016. On the east side, 340 MW of a SCPC unit is added in 2012 and 527 MW in 2014. The portfolio includes 1600 MW of wind, 100 MW of CHP, and 104 MW of Class 1 DSM. It includes 512 average MWs of short-term purchases over the 2012 to 2016 time frame and builds to a 12% planning margin

[16] The primary difference between RA5 and the other low risk portfolios is the early addition of coal-fired resources.

[17] The final five portfolios differ significantly from the previous twelve in the following ways:

- All include short-term market purchases beyond 2011.
- All but one is built to a 12% planning reserve margin.
- IGCC was removed as an option;
- Simple Cycle Combustion Turbine (SCCT) units were removed as an option;
- All but one include an additional 600 MW of wind; however the new wind schedules have a lower capacity factor than the wind that was included in the previous modeling;

Four of the five portfolios limited SCPC units to two, reduced their size, and sited them in 2012 and 2014. A fifth portfolio, added an additional two units late in the period.

these components is contrary to the conclusions easily drawn from a more explicit examination of those issues.

4.2.1 Reliance on Short Term Market Power

PacifiCorp developed several portfolios that allow a direct comparison of the strategy of relying on the market to be compared with the strategy of firming short-term transactions with CCCTs.[18] In the four cases the Committee considered, firming market transactions with a CCCT reduces risk. In 3 of the 4 cases, expected cost was reduced as well. Only one case resulted in a cost-risk tradeoff. On average, firming market purchases lowers expected cost by $122 million and reduces risk exposure by $862 million.

While PacifiCorp indicates that it believes the market is liquid enough to support its continued use of short-term market purchase, citing that it has received offers for a third-quarter product of over 5000 MW for delivery between 2007 and 20012, [19] the Committee remains unconvinced that those same MW would be available beyond 2012.

One counter-example to PacifiCorp's evaluation of market availability is the Draft WECC 2007 Power Supply Assessment. This indicates that without additional plants added beyond those currently under construction or in the regulatory process in the near future, large segments of the west will be deficient in 2012. It also indicates that if resources that are currently in the regulatory process are not approved or are delayed, deficits could appear as early as 2009.

4.2.2 Planning Reserve Margin

PacifiCorp also developed several portfolios that allow a direct comparison of the effect of the selection of the reserve margin on expected cost and risk exposure.[20] The results of using a 15% planning reserve margin over a 12% margin are similar to the results of firming market transactions. In all five cases the Committee considered, increasing the size of the reserve margin reduces risk. In three of the five cases, increasing the reserve margin reduces expected cost. In two of the cases, a small increase in expected cost leads to a fairly significant reduction in risk. On average, increasing the reserve margin reduces expected cost by over $60 million and reduces risk exposure by $1.3 billion.

[18] The Committee compared RA15 with RA14; RA17 with RA15, RA17 with RA14 and RA1 with RA2 and averaged across the five C02 adder cases.
[19] IRP 2007, p. 205.
[20] The Committee compared RA8 with RA1; RA12 with RA11; RA4 with RA2; RA9 with RA10; and RA14 with RA16 and averaged across the five C02 cases.

4.3 Cost risk tradeoff evaluation does not fully assess potential gas and market risk

It appears to the Committee that the cost/risk tradeoff analysis, while informative, may not fully capture the risk of natural gas and market price volatility. The primary reason is that stochastic analysis uses historical volatility to predict future volatility and would therefore miss a fundamental shift in these markets that could be brought about by Climate Change policy.

CCS Exhibit Three[21] demonstrates how carbon policy could affect the cost-risk tradeoffs of alternative resource selections. It demonstrates that the ranking of cost/risk tradeoff pairs change little as the carbon value adder rises. This is because market and gas price risk dominate cost-risk tradeoffs, even with a high carbon adder value.

A secondary reason why PacifiCorp's modeling may not fully capture the risk of natural gas and market price volatility is that the modeled cost of Energy Not Served (ENS) may be too low. PacifiCorp priced ENS at $400/MWh—the current FERC cap on the CAISO market. This cap is expected to increase to $1000/MWh as part of the CAISO Market Redesign and Technology Upgrade. When this occurs, the Committee believes that emergency power may be priced far in excess of $400/hr.

5. Resource Adequacy

The Committee believes that several of the Company's assumptions and modeling decisions, considered together, produces results that could significantly underestimate total resource needs. The Committee does not advocate "overbuilding" the system, but also recognizes that reliable service is a goal that must be balanced with optimizing for least cost and least risk. The factors that lead to the Committee's concern include: the use of normalized temperatures to develop a peak load forecast, a potential understatement of Utah peak demand growth, the use of a 12% planning reserve margin in determining the system position, the continued over-reliance on short-term transactions to meet firm load, and the counting of hydro resources for capacity purposes.

5.1 Peak Forecast

The Committee's understanding is that the Company's system peak forecasts are derived using the following steps:

[21] Exhibit Three consists of five pages representing the cost-risk tradeoff at successively higher carbon-value adders plus a summary page of portfolio rankings. The modeling assumes a cap-and-trade policy.

a. Individual customer class sales forecasts are aggregated at the state level and subsequently increased for line losses.
b. A regression model is used to distribute individual state loads over time (variables such as time of day, day of week, week of the year, and 30-year humidity and temperature data are some of the independent variables).
c. The individual state loads are aggregated by month and time of day and the forecasted growth in hourly load is compared against historical growth rates in that hour for reasonableness.
d. The hourly loads are then summed across the forecast period to develop the monthly peak loads.
e. The monthly coincident peaks reflect the maximum system load in the peak hour of a particular month.

Taken at face value, this appears to be a reasonable method for determining monthly coincident peak demand (and by extraction the monthly non-coincident peak demand for individual states). However, at a recent meeting with Committee staff the Company indicated that it planned according to only normal weather for the peak day. Planning to a weather normalized 94 degree day based on 30 years of history will significantly understate demand since peak will occur at temperatures that exceed 94 degrees. Company estimates that demand increases by 45-50 MW per degree increase, so demand could exceed the peak forecast by **300-450 MW.**

Five of the hottest summer (July) months on record in Utah have been recorded in the last seven years. Planning on the basis of “average” weather cannot be considered adequate to current conditions. The Company has not addressed how it intends to meet the differential from the reported peak and actual peak. Essentially, this results in an unstated and completely unquantified risk to which this planning has exposed PacifiCorp’s customers. The Committee recognizes that more traditional peak forecasts have serious challenges to overcome. Nonetheless, the Commission must require PacifiCorp to plan to a peak level that is reasonably expected to cover its actual peak, a process much more in line with industry standards.

Finally, the Committee notes that the weather normalization is based on 30 years of history and average temperatures have been rising. Therefore, this problem may be exacerbated by using a normalization method that results in average temperatures that are lower than those based on more recent data.

5.2 Utah Forecasts

Utah’s historical energy growth rate, historical summer coincident peak growth rate, historical winter coincident peak growth rate, and historical non-coincident peak growth rate exceed the current peak forecast.

Utah's Forecasted Growth Rates (2007-2016)

Coincident Peak:	2.9%
Jurisdictional (Non-CP):	3.0%
Energy Forecast	2.7%

Utah's Historic Growth Rates (1995-2005)

Coincident Peak:	7.3%[22]
Coincident Peak Summer:	5.2%
Coincident Peak Winter:	4.2%
Jurisdictional peak (Non-CP):	4.4%
Annual Average Energy:	3.0%

In contrasting its "current" March 2007 load forecast with its previous May 2006 forecast, PacifiCorp points to a recent slowing of activity in the commercial sector and a decrease in residential building permits as the basis for revising downward both its near-term (three years) and 10-year peak demand and energy forecasts. The short run forecast calls for a 254 MW decrease in peak demand and a 62 mWh reduction in energy in 2009. The ten-year forecast (2007-2016) calls for decreases in the average growth rates for peak demand and energy from 3.0% to 2.9% and 3.0% to 2.7%, respectively. However, the Company provides little economic or demographic evidence to support these changes to its peak demand and energy forecasts. In fact, the Company's forecast appears to be at odds with other publicly available forecasts regarding the Utah economy. (For example, the Utah Governor's Office of Planning and Budget's July 2007 economic and demographic forecast.)

Based on the information presented to date, the Company does not adequately justify forecasting Utah's peak growth below its historical growth. The Utah economy remains strong and Utah continues to have record summer heat.

5.3 Choice of Planning Reserve Margin

In developing its Preferred Portfolio, the Company used a 12% planning reserve margin rather than a 15% margin. This underestimates system need by **more than 300 MW** in the 2012 to 2016 time period.

[22] System peak switched from winter to summer in 1999

5.4 Inclusion of Front Office Transactions as a firm resource

The Preferred Portfolio includes **512 average MW** of planned short-term transactions over the 2012 to 2016 timeframe. The Committee believes this underestimates need by an equivalent amount.

5.5 Hydro Capacity Calculation

Sometime in the fall of 2005, the Company altered the way it calculates hydro capacity. In previous IRPs, the capacity contribution of hydro had been based on expected flows. However, beginning with the IRP 2004 Update, the Company decided to count hydro capacity by the maximum capacity that is operationally sustainable for one hour before reserves. [23] This approach is consistent with how WECC is currently requesting its balancing authorities (control areas) to report hydro capacity. However, WECC cautions that this approach significantly overestimates hydro availability, and WECC is in the process of developing a new methodology that incorporates the sustainability of water flows.

The Committee raises this issue because at the time PacifiCorp changed its counting method from the more conservative expected flows approach to one-hour sustainability, the change in assumption improved the system position significantly. The increased capacity varied year by year, fluctuating between **640 MW and 450 MW** over the 2007-2014 timeframe.

The Committee does not claim to know what the right approach for counting hydro capacity should be; we simply raise the issue as part of our overall concern that PacifiCorp may not be providing a sufficient level of firm resources to protect itself and its customers from market risk. We are aware that at times changes in assumptions are modeling improvements and at other times assumptions are made, at least in part, to achieve particular ends.[24]

6. Process

The Committee notes that the Company complies quite fully with the Commission guideline to conduct the IRP process in an open fashion with ample opportunity for participation from any and all stakeholders. Yet, the Committee is frustrated by how the

[23] It appears to the Committee that PacifiCorp is continuing to count hydro capacity calculation from the IRP 2004 Update. In a document dated August 8, 2007, PacifiCorp stated that “the one-hour sustained peak of flexible hydro generation is a reasonable way to consider the contribution of these resources to peak capacity.” PacifiCorp, *Public Review of the 2007 Integrated Resource Plan Draft Document: Follow-up Responses to Information Requests,* August 8, 2007, p. 3.

[24] In moving from IRP 2004 to the IRP 2004 Update, PacifiCorp kept the same load forecast but changed a number of resource assumptions. The effect of the changed assumptions was to delay need from 2009 to 2012, which delayed the need for a third CCCT in eastern control area. Hunter 4 was to have come on line in 2012.

process has evolved and the disproportionate influence that stakeholders have relative to the time invested in the process. It is unclear to what extent, if any, early stakeholder comments were incorporated into the resource plan. Therefore, it is also unclear to the Committee what value such processes hold. Although the Committee appreciates the opportunity to have open communications with the Company and other stakeholders on these issues, it might be more meaningful to have less activity prior to the actual resource plan filing, and more activity in its analysis and Commission review after the filing.

Further, the Committee is concerned that the resource planning process is not very closely tied to the actual resource procurement. It suggests that the Commission and other stakeholders should consider more carefully how sound planning principles can be driven forward to the tangible results of new resources that have passed the scrutiny of a least cost, least risk process.

Finally, the Committee also notes that other stakeholder processes are underway that could greatly benefit from a robust IRP process in which a wide variety of stakeholders could have confidence. For example, as policies are crafted to address climate change, the encouragement of renewable resource development and other energy initiatives, the Commission and the IRP could provide a valuable contribution to the process with a benchmark for measuring cost effectiveness. Without a robust and well accepted process for doing so, it will be difficult to measure the impacts of policy design. On the other hand, a strong process for measuring cost effectiveness might help to bridge philosophical gaps and facilitate acceptance of emerging new policies.

7. Recommendations to the Commission

Based on the analysis presented in these comments, the Committee recommends that the Commission not acknowledge this resource plan. Further, the Committee recommends that the Commission provide specific guidance for improvements to be implemented in future analyses. These include the following:

The Commission should order the Company to incorporate the following changes into its model prior to its analysis of the current request for proposals for new generating resources:

- Adopt a true 20-year horizon in the modeling process
- Use a range of externality values in assessing the impact of intangible factors, such as emissions and other environmental factors

In addition to the above outlined changes, the Commission should order the Company to incorporate the following changes into its model prior to the filing of its next IRP or IRP update:

- Reduce the prescreening of resource options, ensuring that resources that might not be top price performers, but could be good risk mitigators, are considered in the risk analysis
- Perform scenario analysis to determine and justify the most appropriate amount of future wind additions
- Model different characteristics reflecting the differences among renewable resources, rather than continuing with wind as the proxy for all renewables.
- Consistent and comparable treatment of demand-side resources
- Inclusion of SCCT or a technical justification of why it isn't necessary
- Use of a 15% planning reserve margin or a demonstration, supported by modeling runs, why a different planning reserve margin would be more appropriate
- Reduce reliance on short term market purchases, especially in later years of the planning horizon
- Support all policy choices with modeling runs demonstrating cost/risk tradeoffs
- Better capture gas price and market price risk
- Include appropriate peak forecast
- Better support Utah forecast including a reconciliation with other data sources
- Justify its methodology for determining hydro capacity
- Address the general topic of resource adequacy and reliability concerns

The Commission should assign a separate docket for the DSM potentials process to allow for public comment and a thorough and technical vetting of the information contained therein, prior to its incorporation into future Company analyses.

The Commission should also consider additional changes to the IRP process to better tie planning results to actual resource acquisition, provide for more meaningful stakeholder input, and to signal its expectation that the Company's business plan derive from the IRP, not the reverse.