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

(Docket No. 05-2035-01)

INTRODUCTION

This document provides a summary of the substantive comments submitted by the parties, along with PacifiCorp's responses.

PacifiCorp's 2004 IRP was filed with the Utah Commission on January 20, 2005. The Utah Commission then issued an invitation to Docket No. 05-2035-01 on February 10, 2005 for interested parties to comment "on the appropriateness of the IRP 2004 report and to make recommendations on whether the Commission should acknowledge the plan." Five parties submitted comments by the April 22 extended deadline:

- Mountain West Consulting, LLC (Mountain West)
- Utah Division of Public Utilities (DPU)
- Utah Association of Energy Users (UAE)
- Western Resource Advocates and Utah Clean Energy (WRA-UCE)
- Utah Committee of Consumer Services (CCS)

PacifiCorp appreciates the comments received by the five Utah parties, and welcomes the opportunity to respond to them prior to a Commission acknowledgement decision. We emphasize that the IRP process is dynamic, and that PacifiCorp strives to develop an IRP that is robust with respect to accounting for alternative futures and changing circumstances. PacifiCorp also devotes a significant effort to address stakeholder concerns and accommodate multiple stakeholder viewpoints and analysis requests. Ultimately, we believe that effective engagement by all the parties is crucial to the success of the IRP process.

A number of the parties raised key issues that support their contention that PacifiCorp's Preferred Portfolio does not represent the optimal portfolio from a risk-weighted cost perspective. These issues include the following:

- Failure to update the portfolio analysis using PacifiCorp's latest available natural gas price forecast (December 2004), and to give adequate attention to the risks of natural gas reliance.

- Capital cost values that are systematically higher than other sources, particularly for pulverized coal and IGCC, giving gas resources a relative advantage.

- An unrealistically high CO_2 regulatory cost risk, which favors gas over coal.

- PacifiCorp's decision to exclude available non-firm transmission as a resource, which is claimed to bias economic results in favor of gas over coal.

- Inaccurate or obsolete characterization of the commercial viability and costs of Integrated Gasification Combined Cycle (IGCC) technology, which the parties advocate for PacifiCorp's next coal plant.

Since these issues relate to the IRP's adequacy for acknowledgement, PacifiCorp addresses them first. Two parties, CCS and UAE, also proposed alternative portfolios claimed to be superior to PacifiCorp's Preferred Portfolio. These alternative portfolios focus on deferring or eliminating the first East-side gas resource in FY 2010. PacifiCorp addresses these alternative portfolios next.

The remainder of the document provides responses to comments organized by each of the relevant Utah IRP Standards and Guidelines. Note that Guidelines 5 through 8 are not listed because substantive issues were either not raised by the parties, or else they were covered in other parts of the comment documents.

USE OF THE DECEMBER 2004 GAS PRICE FORECAST FOR PORTFOLIO ANALYSIS

Most of the parties view PacifiCorp's decision to not update the entire IRP analysis using the December 2004 gas price forecast as a major modeling flaw. Several of the parties contend that this flaw essentially invalidates the IRP by biasing the simulation results in favor of gas-fired resources over other alternatives. CCS, UAE, and Mountain West stated that PacifiCorp's June 2004 base case natural gas price forecast is too low in light of recent gas market developments or other forecast sources, and criticize PacifiCorp for not redoing the portfolio analysis using the December 2004 forecast. UAE stated that the relationship between gas and contract prices, especially at high prices, was not well explored; it advocates additional sensitivity/stress case analysis. CCS notes that the gas price forecast used for the high gas price scenario was not sufficiently extreme. DPU is unclear on why two gas price forecasts—IRP Base and PIRA—are needed to express the gas price increases for the high gas price scenario.

Response:

Some criticisms to the IRP results are based on not using one of the higher, more recent forecasts of natural gas prices.[1] These criticisms are not valid nor are they reason to withhold acknowledgement of the IRP for several reasons. First, the IRP did, in fact, use a range of natural gas forecasts and stochastic analysis to verify the validity of the Preferred Portfolio under higher natural gas futures. Moreover, the IRP analysis concluded that the decision on the first supply resource is actually independent of which natural gas forecast is used. Finally, the course of action recommended by those parties is impractical, if not impossible, and not compatible with a reasonable IRP process. For these reasons, as explained in greater detail below, the IRP results are valid and consistent with the recent trend of natural gas prices.

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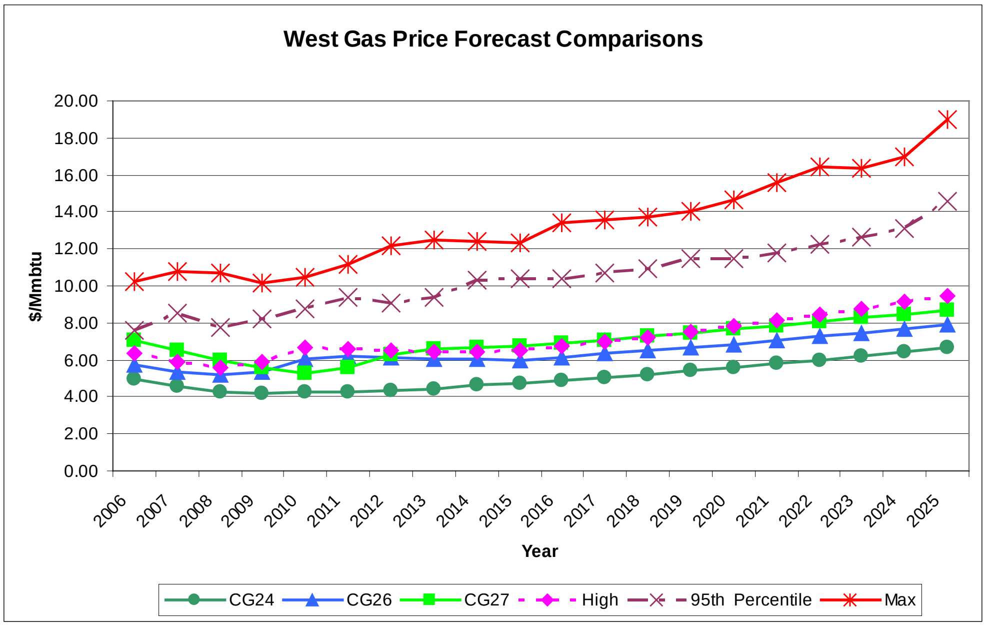
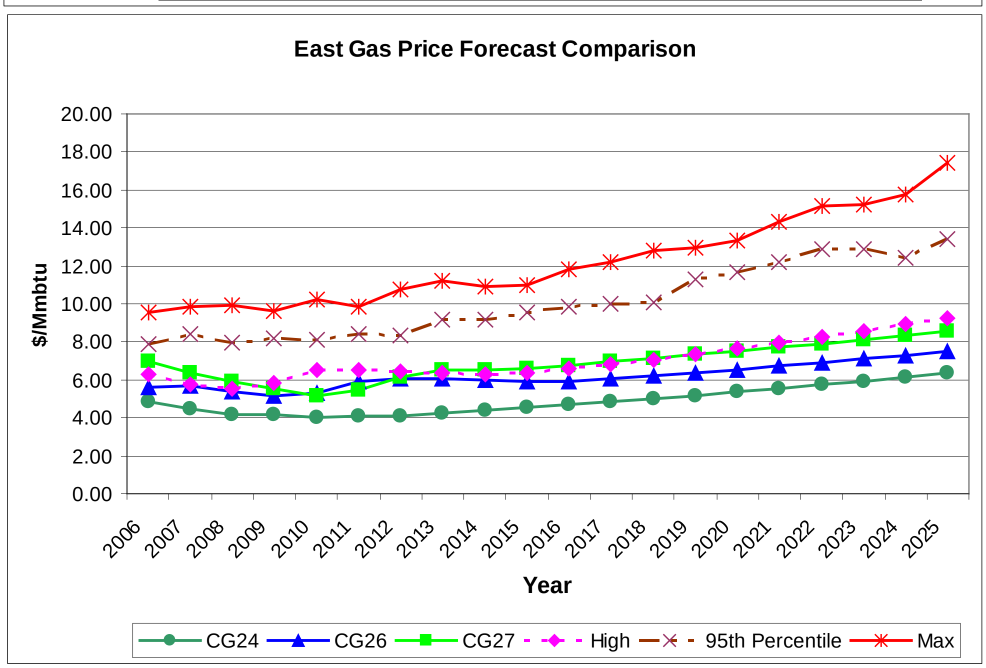
[1] For the 2004 IRP the natural gas price forecast is defined within PacifiCorp as CG24. This forecast was completed on June 30, 2004. Subsequent forecasts of natural gas prices have trended higher than the CG24 forecast over the IRP planning horizon.

PacifiCorp updates its long-range forecasts of natural gas and electricity prices at least quarterly, because expectations for future prices change as a function of current market factors as well as expected future conditions. The Company also recognizes that long-range forecasts are imprecise and it is therefore prudent to test plans against a range of future conditions. For this reason, the IRP contained scenario and stochastic analyses.

The charts below compare Calendar Year gas prices for the reference and high gas scenario cases with the Company's gas price forecast as of the end of December 2004 (CG26) and PacifiCorp's latest March 2005 forecast (CG27).





Note: CY 2025 prices for the Max and 95 percentile trends include only the first three month of the year.

As illustrated, the high gas case scenario is higher than the December updated forecast, and higher than the most recent update. While some parties have argued that the high gas case isn't sufficiently above the updated forecast to be called extreme, those arguments ignore the much higher gas cases that were considered as part of the stochastic analysis.

The purpose of the high gas price scenario was to evaluate the consistency of results in the event of a high gas price future. Figure 8.39 on page 161 of the 2004 IRP illustrates that Portfolio E has the lowest PVRR among the portfolios considered assuming the high gas scenario. As such, even if the most recent gas price forecast, CG27, is considered as the base scenario, the results are consistent with the results of the filed 2004 IRP and no further analysis seems appropriate at this time.

In practice PacifiCorp evaluates stochastic variations in the gas price forecast among other variables. The reason PacifiCorp analyzes these stochastic changes in the gas price forecast is to evaluate the consistency of results between the stochastic analysis and other analysis in the IRP. That is, one purpose of stochastic analysis is to evaluate portfolios in the event of high gas price futures. The stochastic analysis produces 100 different possible futures (iterations) of gas prices recognizing that there could be large variability in the forecast of natural gas prices. Details of the methodology of the stochastic analysis are contained in Chapter 4 and Appendix G of the 2004 IRP.

The attached graphs also illustrate the maximum value of the 100 iterations for the gas prices and the 95th percentile value of the gas prices according to the stochastic analysis. As indicated by the graphs, both the maximum gas price forecast and the 95th percentile gas price greatly exceed the values of the high scenario gas price forecast and the CG27 price forecast. It should be noted that the 95th percentile is 48% (20 year average) higher than CG27, and therefore is clearly within the suggested high gas price scenario of 20% higher than CG27.

Table 8.21 on page 151 of the 2004 IRP document summarizes the results of the stochastic analysis illustrating the rankings of various measures. The measures on this table most relevant to the maximum gas price forecast and the 95th percentile gas price forecast are measures 3, 4, and 6 through 10 since each of these measures deal with the dispersion of the 100 iterations (forecasts) of natural gas prices. For each of these measures Portfolio E is clearly a leading portfolio and robust with regard to future gas price assumptions. Since Portfolio E with dispatchable DSM is the Preferred Portfolio, the results of the high gas price forecasts from the stochastic analysis are consistent with the final results and conclusion of the 2004 IRP. This result confirms that Portfolio E with dispatchable DSM is preferred when high and even extreme gas prices are considered.

Since the IRP's scenario and stochastic analyses covered high and extreme gas price cases without a change in the final result, as described above, then the IRP's use of a lower base forecast for initial screening purposes is not invalidated by higher subsequent gas price forecasts. Clearly, any long term resource plan cannot rely solely on a point forecast of natural gas prices. The long term resource plan is determined by several pieces of analysis and information: a deterministic point forecast, stochastic analysis, scenario analysis, and non-quantitative factors as discussed in Chapter 8 of the 2004 IRP. Therefore, a CG24 baseline forecast with both scenario and stochastic analysis encompassing a CG27 future is a usable and valid natural gas forecast for IRP purposes. This conclusion is even stronger if the stochastic and scenario analysis did not change the overall results. Therefore, the analysis based on CG24 cannot be characterized as incorrect or flawed, and the results of the 2004 IRP using CG24 are valid.

Some parties have suggested that PacifiCorp should redo its IRP in light of higher natural gas price forecasts. As described above, PacifiCorp's use of scenario and stochastic analysis obviates such action. Moreover, as a practical matter, an IRP could never be completed if analyses were required to be redone upon any change in assumptions. Since careful and thoughtful analyses take time, assumptions and forecasts can and do change during the course of such analyses. The practical challenge for IRP is to conduct analyses in such a fashion that they are robust and not stale before they are completed, and remain valid and relevant for planning purposes, despite changes to base assumptions. PacifiCorp did indeed recognize the evolving changes in natural gas markets in the latter stages of its IRP preparation. The increases in price forecasts and the issues surrounding them were addressed in an issue paper prepared in November, discussed at a public input meeting and incorporated in the final report in Chapter 1 and Appendix A. In addition, a revised high gas scenario reflecting these changes was analyzed to confirm that the Preferred Portfolio remained valid. PacifiCorp's recognition of changing forecasts and use of scenario and stochastic analyses, as described above and in Chapter 8 of the IRP, meets the standard of a practical and meaningful plan and process.

CAPITAL COST BIAS IN FAVOR OF GAS PLANTS

CCS stated that capital costs are "systematically higher than other sources, but most pronounced for pulverized coal and IGCC", giving gas resources a relative advantage.

Response:

For the IRP draft submitted in early November 2004, CCS provided a similar comment, stating that PacifiCorp's capital costs appear too high which skews the portfolio cost results in favor of gas-fired technologies. PacifiCorp responded in Chapter 9 (page 178) that the technology cost information was based on the latest information at the time and recent company experience, and when expressed on a comparable basis, the costs are consistent with other cost analysis study results applicable to PacifiCorp's region. PacifiCorp stands by this assertion, and reemphasizes the importance of avoiding comparing cost estimates based on differing assumptions.

The PacifiCorp estimates for new plant costs, specifically the fourth potential sub-critical pulverized coal unit at Hunter and the Combined Cycle combustion turbine projects, are based on actual engineering studies conducted specifically for these projects. These costs reflect current available material and labor markets and also include all costs required to complete these specific projects. The Hunter 4 estimate was based on work from 2001 and was refreshed with a new study in 2004 which updated issues such as steel and major equipment costs. Comparing power plant prices with other sources must be done with great care to verify that costs are quoted on a similar basis and include all costs. PacifiCorp is confident that the power plant cost estimates presented in the 2004 IRP reflect reasonable estimates for the cost of both coal plants and natural gas based combustion turbines as these facilities would be built in the PacifiCorp service territory. PacifiCorp is clear that there is no bias whatsoever in these cost estimates.

PacifiCorp compiled the following table by conducting a check with published quotations for new coal plants in the US, contemporary with a Hunter 4. When considering the full cost of a new coal plant, the IRP estimates are consistent with these reported costs. Costs for IGCC are being studied in additional detail but initial indications are that IGCC capital costs will be 10-15% more than a comparable sub-critical or super-critical pulverized coal plant.

New Pulverized Coal Plants

Plant	PacifiCorp (Hunter 4)	Wisconsin Energy (Oak Creek)	Wisconsin Power Services (No Site)	Peabody (Thoroughbred)	Xcel Energy (Comanche 3)
Plant Cost in $/kW	$1,687	$1,748	$1,600	$1,667	$1,800
Size in MW	575	1,230	500	1,500	750
Estimated Cost	$970 Million	$2.15 Billion	$800 Million	$2.50 Billion	$1.35 Billion
Reference	2004 IRP	"Coal plant prompts anger, support," Milwaukee Journal Sentinel, 9/30/04.	"Utilities want a new power plant, and they may want it run on coal," Wisconsin State Journal, 5/25/04	"Coal Gets New Respect," ENR, 11/18/02	"Colorado approves first new coal-fired power plant in 23 years," Associated Press, 12/17/04

We also note that the capital cost difference between coal and gas plants actually continues to widen due to increasing costs of steel products and the higher levels of carbon steel and alloy materials in coal plants relative to gas plants.

UNREALISTICALLY HIGH CO_2 REGULATORY COST RISK ASSUMPTIONS

DPU, UAE and CCS claim that the IRP's assumptions supported an unrealistically high CO_2 regulatory cost risk, which favors gas over coal; they generally advocate removal or deferral of a carbon tax policy as a base case assumption. (WRA-UCE had an opposing view; it supports PacifiCorp's modeling framework, but expressed concern that the modeling assumptions might support an unrealistically *low* CO_2 regulatory cost risk.)

Response:

PacifiCorp contends, along with other IRP intervenors, that there is a significant risk surrounding potential CO_2 regulations that warrants continued consideration in planning, and that PacifiCorp's modeling approach adequately considers uncertainty in both the timing and magnitude of CO_2 control costs.

PacifiCorp agrees with the sentiment expressed by UAE, that "it is extremely difficult to predict the likelihood or level of potential carbon taxes." That is why the IRP includes a probability-weighted implementation assumption[2] and a range of CO_2 allowance cost scenarios to address cost uncertainty. Since PacifiCorp believes that some form of climate change policy will likely be in effect by 2010, it was deemed prudent to include a carbon tax adder in the portfolio cost evaluation. The carbon base case assumption is based on influence of several recent legislative proposals (McCain-Lieberman and Carper proposals), as well as other market indicators such as the cost of CO_2 offsets obtained by The Climate Trust and existing markets for greenhouse gas emissions in the United Kingdom and Denmark. This carbon adder also acts as a proxy of a wide range of possible US policy options—such as cap and trade programs—not necessarily a carbon tax. In summary, it is PacifiCorp's contention that there is a significant risk surrounding future CO_2 regulations that warrants consideration in current planning.

NON-FIRM TRANSMISSION AS A PORTFOLIO RESOURCE

CCS and UAE question PacifiCorp's modeling assumption to exclude available non-firm transmission as a resource, stating that this biases economic results in favor of gas over coal (CCS), and over-construction (UAE).

Response:

PacifiCorp recognizes the interest in using non-firm transmission, and has noted in the IRP that it is a conservative assumption. However, modeling non-firm transmission is impractical, because non-firm transmission doesn't provide the long-term availability required for long-term planning purposes. Resources that cannot be relied upon create serious risks for a load serving utility such as PacifiCorp, when evaluating long-term resource alternatives. Sensitivities around non-firm transmission, and the appropriate manner to plan for resources that are not guaranteed, should be discussed with public input participants for consideration in the next IRP as part of scenario analysis.

CHARACTERIZATION OF INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) TECHNOLOGY

All parties endorsed more examination of IGCC procurement potential, while two (DPU and WRA-UCE) commend PacifiCorp's commitment to studying IGCC for the 2004 IRP. Nevertheless, some parties took issue with PacifiCorp's assessment of IGCC's near-term commercialization potential and cost assumptions. WRA-UCE and Mountain West claimed that IGCC technology assumptions result in overstated costs. WRA-UCE also recommended that PacifiCorp examine deployment opportunities including alternative fuels (bituminous coals and a blend of PRB coal/petcoke), membrane technology, coproduction, and alternative turbine

[2] To reflect some uncertainty concerning the timing of this policy PacifiCorp assumed a 50% probability that the policy will occur in 2010, and 75% probability that the policy will occur in 2011, and certainty that the policy will be in effect by 2012.

manufacturers. To ensure that IGCC is evaluated on a comparable basis with other resources, Mountain West advocated a Commission-supervised study.

Response:

PacifiCorp acknowledges that the outlook for IGCC is evolving rapidly as commercialization efforts gain momentum and electric utility experience with the technology progresses. In light of the changing and emerging IGCC picture, PacifiCorp continues to investigate the application of IGCC technology in the PacifiCorp system (Preliminary results from PacifiCorp's recent site-specific study are summarized below.) Although the IGCC cost estimates relative to conventional coal may be higher than some published reports, PacifiCorp believes the conservative approach used for the 2004 IRP approximates the probable risk of an IGCC application in the PacifiCorp service area due to such factors as site elevation, new technology, local labor costs, and probable coal resources. PacifiCorp points out that the IRP's IGCC cost estimates are based on numerous studies conducted over the last few years by various organizations including EPRI and the US Department of Energy. The estimates also incorporated the operating experience of the Polk and Wabash River IGCC plants.

Since the publication of the 2004 IRP, PacifiCorp contracted with Parsons E&C to conduct a site specific study to understand the cost impacts of installing an IGCC utilizing Utah coal and operating at elevation. The results from this study will be incorporated into the next resource planning process. Initial indications from this continuing work are supporting some of the parties' comments on the 2004 IRP. For example, the output from an IGCC at elevation, according to initial indications from this new study, does not degrade as much as anticipated resulting in less capital cost differences between IGCC and Pulverized Coal (PC). However, IGCC still has a higher capital cost than more conventional coal boiler based power plants. O&M costs also continue to be significantly higher with IGCC than for PC plants.

Regarding IGCC availability, the 2004 IRP characterizes IGCC with a lower availability than more conventional systems. This lower availability was based on the actual operating experience of the Polk and Wabash River IGCC plants, which do not have spare gasifier capacity. The issue of adding spare gasifiers requires more detailed study. Even though natural gas can be used as a backup fuel, the desirability of having a system capable of running 90% of the time on coal will probably justify the added capital cost of the spare gasifier. Some gasification systems that do not utilize refractory in the gasifier design can also achieve high availabilities without a spare gasifier, but such systems typically also have higher initial capital costs.

The availability issue, along with consideration of alternative fuels, membrane based air separation systems, and other innovative cost reduction techniques, will be revisited as part of future resource planning evaluations once the next generation of IGCC plants are designed and begin operation. Many of these techniques must wait for demonstration on a utility-scale basis before they can be fully assessed.

ALTERNATIVE PORTFOLIO PROPOSALS

CCS and UAE proposed alternative portfolios that rely on non-gas resources and other strategies to defer or replace the East-side FY 2010 CCCT proxy resource. Both CCS and UAE feel that PacifiCorp's Preferred Portfolio is biased towards gas-fired, utility-owned resources, and is therefore not optimal as indicated in the Utah Commission's IRP process definition. ("The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.") CCS and UAE feel that this alleged bias represents grounds for not acknowledging the IRP.

Response:

The CCS and UAE alternative portfolios to the Preferred Portfolio were both proposed for the first time after the IRP was filed with the Commission. In both cases, the alternative portfolios delay or replace the first resource identified in the Preferred Portfolio by making changes to critical base-level assumptions, such as planning margin and the amount of Front Office Transactions. Making major changes to such base assumptions is not warranted given that PacifiCorp carefully considered the suitability of these assumptions for planning purposes early on in the 2004 IRP cycle. Assuming the availability of customer-based resources and Front Office Transactions beyond what PacifiCorp finds reasonable for base planning purposes is only appropriate for portfolio stress testing, which PacifiCorp did perform for the planning margin, CHP resources, and standby generators. Finally, the parties' suggested changes were not raised throughout the year-long public input process but rather afterwards. In the Company's view, one purpose of the public planning process is to allow all parties to raise changes such as those suggested by the CCS and UAE in a meaningful way that allows discussion by all parties and provides the Company with time to consider the merits of the suggestions in the final plan. We are disappointed that the process didn't work that way this time.

While the Company believes that the IRP process has been rigorous, exhaustive and unbiased, the fact remains that the CY 2009 resource will be selected through an all-fuel RFP process which will be subject to Commission and independent evaluator supervision. In addition, the RFP process for the procurement of the CY 2009 resource has an inherent flexibility due to the long time period that such formal processes demand. In the event there is a change in the load or resource picture (i.e., a new large QF or resource opportunity becomes available, or if there is a change in the load projection) then the RFP process will allow for a review of that change prior to the time that a resource commitment is made. Parties should also be reassured that PacifiCorp will evaluate all alternatives prior to making a decision, since the competitive bidding process adopted in the Energy Resource Procurement Act, U.C.A. §54-17-101 et seq., (the "Procurement Act") calls for a Commission prudence review prior to a resource commitment.

UTAH STANDARDS & GUIDELINES COMPLIANCE

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.

A number of the parties took issue with PacifiCorp's selection of the Preferred Portfolio as representing the optimal resource set. DPU stated that the IRP met the "spirit of this Standard" and that the Preferred Portfolio "is a reasonable selection", but questioned whether the Preferred Portfolio was optimal given incomplete automated resource addition logic functionality. As discussed above, CCS and UAE disagreed that the Preferred Portfolio was optimal on the grounds that other resources are in their opinion superior to the FY 2010 CCCT resource.

Response:

PacifiCorp believes it has developed a plan that evaluates resource alternatives on a consistent and comparable basis to identify the least-cost, risk-informed plan to meet future customer needs under a range of scenarios. The IRP will be used to determine the type and timing of new resource decisions from a planning perspective, and the RFP process will ultimately determine the next resource that will be procured to best serve the customers need. As was stated earlier, the RFP will be flexible enough to adapt to changes in PacifiCorp's load and resource balance and to take advantage of any market opportunities.

PacifiCorp addressed the use of Resource Addition Logic in the 2004 IRP in Appendix L-Response to Comments (page 165). PacifiCorp has been working with Global Energy Decisions (GED) for the past year to develop the Capacity Expansion Model (CEM) which incorporates the Resource Addition Logic requested by parties in the 2003 IRP. The Company incorporated use of this model to the best of its ability in the 2004 IRP, and received the final version of the product for use in future planning efforts in April 2005.

That being said, PacifiCorp believes that good things were achieved with the model in this IRP cycle. Most notably, it was used to generate a candidate portfolio that ran a close second in the PVRR rankings of the deterministic simulations. This portfolio informed the modeling process significantly because it included the size and timing of several resources similar to those in the Preferred Portfolio (see Chapter 7). This served to validate the manual build process as well as to provide some validation for the CEM itself. In addition, the model proved very helpful with adding Class 1 DSM programs to the preferred supply-side portfolio, and testing the assumption of 1,400 MW of planned wind resources.

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

Two parties, DPU and UAE, addressed this Standard. DPU stated that PacifiCorp's IRP met the Standard, while UAE advocated annual IRP filings due to the magnitude of resource needs and potential ratepayer impacts.

Response:

PacifiCorp indicated in the 2004 IRP that it intended to file an update to the Action Plan no less frequently than annually. This update will be similar to the 2003 IRP that was filed for information purposes with the Commission in October 2003, and at a minimum will include material changes to assumptions, an updated load and resource balance, and a progress report and changes or updates to the Action Plan. In addition to the update filing, PacifiCorp will be hosting quarterly update meetings with participants to keep them informed on progress toward meeting Action Plan items.

3. IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.

Two parties, DPU and UAE, addressed this Standard. DPU affirmed that PacifiCorp "organized a robust, open, accessible process that included input from numerous state agencies and stakeholder groups." (CCS also commended PacifiCorp's "responsive IRP process"). UAE stated that the quality of public input was limited by the inability of outside parties to access and verify the data and analysis tools/models used in the IRP process. UAE also questioned the accuracy of IRP models in light of the GRID evaluation for the QF docket.

Response:

An open and active public dialogue like that encouraged in public input meetings provides the best means of verifying inputs, assumptions and results. PacifiCorp intends to continue this process in the future and encourages the parties to participate.

Decisions regarding access to the IRP model must weigh the benefits of increased transparency against confidentiality risks, timing constraints and costs. Cost may include such things as licensing fees, installation, training and upkeep of the model.

PacifiCorp is currently in the process of reviewing and comparing the inputs to both the Grid and IRP models. A large amount of the differences identified before were due to differences in fixed costs that are included in the GRID model and not the IRP model because the IRP is used only to evaluate differences in resource portfolios. This includes such items as firm wheeling expense and the fixed portion of long-term purchase and sales contracts. Additionally, some input data varies due to the timing of the studies. This would include forecasts for loads, fuel and market prices as well as up to date contract information. The Company intends to provide the results of its review of these two models to parties as part of the QF docket.

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

DPU stated that PacifiCorp met this requirement. CCS asserted that PacifiCorp did not provide a range of demand forecasts as required; the stochastic analysis only accounted for cost effects of varying load along with other critical variables.

Response:

As noted by CCS, PacifiCorp provided a range of forecasts using stochastic analysis; 100 different and separate futures of load growth were simulated. From these 100 iterations, the 95th percentile of system peak demand was approximately 1,400 MWs higher in FY2015 and the 5th percentile of system peak demand was approximately 1,100 MWs lower. This range covers nearly all possible load growth trajectories. CCS's indicates that PacifiCorp did not individually analyze the impact of each load growth forecast on a simulated build decision. PacifiCorp contends that this suggestion is impractical because each additional deterministic load scenario would cause additional sets of candidate portfolio analyses with potentially different build patterns. PacifiCorp believes it would be imprudent to plan on any future other than the expected future given the lead time necessary to acquire certain resources, and stochastic analysis provides ample assessment of load forecast uncertainty while retaining the reasonableness of planning for one expected outcome. PacifiCorp also emphasizes that the IRP and RFP processes can adjust as required if the load forecast picture changes dramatically.

Finally, PacifiCorp points out that its approach is consistent with the Utah Standards and Guidelines, which requires the Company to provide a range of load forecasts for the purposes of assessing load forecast uncertainty.

4a(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.

CCS pointed out a discrepancy between Utah peak forecasts and actual historical data, indicating significant over-forecasting of non-coincident peak growth and under-forecasting of coincident peak growth. CCS also seeks clarification of why sales for resale are included in historical jurisdictional load data reported in Appendix I.

Response:

The historical data for coincident and non-coincident peak demand are not weather-adjusted. The forecast of coincident and non-coincident peak demand assume normal weather conditions. Thus, the historical peak demands and the forecasted peak demands are not presented on a comparable basis. Any statement concerning under- or over-forecasting the coincident and non-coincident peak demands must consider the historical information on a weather-normalized basis in order to be consistent with the forecasts.

The comparison of non-coincident and coincident peak demands is further complicated by the fact that PacifiCorp was winter peaking through CY 1998 and summer peaking thereafter. However, Utah was summer peaking throughout the time period reflected in the tables of

Appendix I. This means that the coincident peak for Utah occurred during the winter through 1998 and during the summer after 1998. Since factors causing a winter peak are different than the factors causing a summer peak, any comparison of Utah's coincident peak during this time period is suspect and inconsistent.

Regarding the treatment of Sales for Resale in Appendix I, sales for which PacifiCorp has generation are included because they are part of PacifiCorp's obligation. For example, PacifiCorp is obligated to supply Clark County PUD certain generation for a period of time and has certain resources (contracts, for example) dedicated to supply this load.

4a(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.

Two parties (Mountain West and UAE) disagreed with PacifiCorp's conclusion that customers are not responsive to price changes for Summer A/C demand. Mountain West stated that there does not appear to have been a careful exploration of price elasticity applying to customer pricing and DSM programs. UAE recommended that PacifiCorp be instructed to more directly address price elasticity, to forecast effects of projected rate design on consumption by rate classes, and to propose meaningful rate design changes to address Utah's "exponential" peak load growth. DPU stated that demand may be more responsive to price increases in the long run than indicated in the IRP, citing inadequate capture of the new 3-tier residential rate and Cool Keeper price signals. DPU recommended continued examination of the load forecasting methodology as more data under the new block rate become available.

Response:

On June 25 2004, an IRP Load Forecasting Technical session presented to interested parties the results of an elasticity study. The findings of this study concluded that residential electricity usage was price inelastic and that price changes appear to be limited in their efficiency and effectiveness for controlling air conditioning use in the long run. PacifiCorp performed this study using econometric analysis and by comparing billing information for various months. PacifiCorp will continue to evaluate the price elasticity question as more data becomes available through the three-tiered rate structure, and will consider suggestions from interested parties on the evaluation of price elasticity.

PacifiCorp has implemented a number of meaningful rate design initiatives in Utah that provide appropriate pricing signals to customers to help address Utah's peak load growth. Some of these initiatives were just implemented in 2005 and their effects are not yet known. These initiatives are summarized below.

<u>Rate Design Task Force</u>
In 2004, the Utah Rate Design Taskforce reviewed alternative time and/or season-differentiated rate designs for Schedules 6 and 9. The Taskforce included the Company, the DPU, the CCS,

Federal Executive Agencies, Kroger Co., Utah Association of Energy Users, and Utah Industrial Energy Consumers. The Taskforce Report included a number of recommendations that were implemented on March 1, 2005 as part of the Company's general rate case.

- Schedule 9. Redesigned Schedule 9 implements time of use demand and energy pricing by season for all large commercial and industrial customers served at transmission voltage.
- Schedule 8. Previous Schedule 6 customers over 1 MW were moved to new Schedule 8. The new schedule contains time of use demand and energy pricing by season.

Other Time of Use Rates

- Residential Time of Use Experiment. This experimental rate was introduced in Docket No. 03-2035-02. After the results of its second season (Summer 2005) are available, the Company will prepare a program evaluation to assess the program's effects.
- Schedules 6A and 6B. These time of use rates continue to be available for general service customers under 1 MW.
- Schedule 23B. This time of use rate continues to be available for customers under 30 kW.

Seasonal Residential Rates

Seasonal rates, first introduced in Docket No. 03-2035-02, charge higher rates in the periods from May through September than during other times of year. These include a three-block, inverted, standard residential rate where all usage over 1000 kWh/month is charged at over 9 cents per kWh. Commercial standard tariff customers also see higher prices in the May-September months.

The Company believes that these accomplishments, some of which occurred only during the past few months, are a good step toward dealing with growth in Utah's peak. We will continue to assess and review the effects of these new rates, and will work with parties to provide new pricing options as we have done in the past. Finally, we point out that the philosophy has been to introduce price signals, not price shocks, which explains why there has been no obvious change in behavior.

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*.*

Except for DPU, which stated that PacifiCorp met this Standard, the parties called attention to various resources for which the Company's evaluation approach apparently failed the "consistent and comparable basis" test. The range of resources cited includes Qualifying Facilities (QFs) and other customer-based resources, Front Office Transactions, PacifiCorp/regional transmission investments, and resources categorized by PacifiCorp as "Planned". To address this range of topics, the comments and responses are grouped by resource category.

Response:

Qualifying Facilities and Other Customer-Based Resources

UAE asserts that QFs and other customer-based resources were not evaluated on a fair and consistent basis because they were excluded from the portfolio development process, and only assessed after the Preferred Portfolio was determined.

Response:

Concerning QFs, PacifiCorp assumed 100 MW of potential QF resources would be delivered to northern Utah. This proxy represented long term QFs that PacifiCorp was in negotiation with but for which a contract had not been signed. These customer-based alternatives were factored into the portfolio development process as a resource to meet future load in the L&R balance. Including additional QF capacity in candidate portfolios beyond the 100 MW was not consistent with PacifiCorp's identified QF opportunities at the time the IRP was filed and would have been speculative. Existing QFs, such as Desert Power, were also included as resources in the analysis. The intention to have QFs that are larger than 100 MW bid into the RFP process means that customers can benefit from QFs if they provide best value.

Specifically with respect to CHP resources, as stated in the 2004 IRP, page 86, customer opportunity and customer economics drive the development of CHP projects. That being said, the Primen nationally syndicated market study that the Company participated in gave PacifiCorp the information needed to estimate the market potential for cogeneration in its service territory over the next 5 years. This data is based on customers stating intention and interest. Forecasting beyond this timeframe would be mere speculation. PacifiCorp strives to conduct IRP modeling as close to real-world practice as possible. Since the Company can not drive CHP development, we do support it and help customers assess their potential as they develop a business interest. Therefore, we modeled CHP as a scenario based on the identified potential through the Primen study's assessment of customer responses. This assessment is summarized in Appendix L of the IRP 2004 (page 162).

Note that the Northwest Power and Conservation Council (NWPCC) in its Fifth plan stated that

> "because of its generally small-scale, diversity, and unpredictable schedule, the Council did not evaluate cogeneration in the portfolio analysis".

<u>Front Office Transactions</u>

Both CCS and Mountain West are uncomfortable with the level of Front Office Transactions assumed because of the lack of adequate risk analysis performed relative to other resource alternatives (cited by CCS) and rising energy prices (cited by Mountain West). Mountain West claimed that the practice of assuming that "Planned" resources—of which Front Office Transactions is the main component—are committed for purposes of portfolio development fails the consistency and comparability test. Moreover, backing out some of the FOT's from the planned resource category is warranted, which results in an earlier resource deficiency. Finally, Mountain West questioned why PacifiCorp did not use comparably sized resources in the "Replace FOT" stress case, such as a mix of CCCTs and smaller IC Aero SCCTs.

Response:

Sufficient risk analysis was conducted on the Front Office Transaction proxy resource, and 1,200 MW is reasonable based on PacifiCorp's experience with shaped products and its forward-view perspective on transaction volume at the time the IRP was filed. We emphasize that the FOT amount is characterized as a reasonable upper bound on transaction activity (see Appendix C, page 57), and that they are modeled as a dispatchable resource to capture their flexibility value.

In deciding on the level of FOTs and the appropriate risk analysis to support it, PacifiCorp attempted to reach a middle ground; it considered intervenor requests for less conservative treatment of short-term market opportunities, while being cognizant of other intervenors' risk-averse stance on market activity. For example, looking at historical transaction data for the Mona Point of Delivery, 200 MW is well below the amounts actually delivered. In the case of Four Corners, not only is the 500 MW firmly supported by historical transaction levels, but additional generation continues to be built in this area, further supporting our ability to procure Four Corners to the stated levels. Concerning appropriate risk analysis, PacifiCorp included an extreme scenario where no FOTs are available (FOT stress case portfolio, documented in Chapter 7, page 109), in addition to a stochastic analysis that captured variability in market conditions. PacifiCorp would appreciate receiving specific FOT risk analysis recommendations from those intervenors who are still dissatisfied with PacifiCorp's approach.

PacifiCorp disagrees with Mountain West's view that the Planned Resources are not committed as far as long term resource planning is concerned. Such committed resources are qualitatively different than the proxy resources being evaluated, and should therefore be treated differently in a planning and modeling context. For example, in the case of Front Office Transactions, PacifiCorp will negotiate for an amount of Front Office Transactions irrespective of the acquisition paths associated with the proxy resources. Therefore, it makes sense to include a reasonable and historically defensible FOT quantity in the load and resource balance to explicitly recognize the flexibility and diversity benefits of this resource.

Mountain West questioned PacifiCorp's choice of replacement resources not comparably sized to the 1,200 MW of Front Office Transactions. PacifiCorp points out an error in Tables 7.21 and 8.33. These portfolio resource tables should have shown that 174 MW of East-side IC Aero SCCTs were added in FY 2010, and another 87 MW IC Aero unit added in FY 2015. PacifiCorp also excluded the 100 MW of QF capacity assumed for northern Utah, so the total capacity amount removed was actually 1,300 MW.

<u>PacifiCorp/Regional Transmission Investments</u>
CCS stated that PacifiCorp has not adequately followed the earlier Commission directive to "evaluate transmission alternatives on a consistent and comparable basis with generation alternatives..." In particular, it suggests that sizing the Bridger line to not accommodate wheeling opportunities is not optimal. CCS also wants to see greater coordination between other Company transmission planning venues and the IRP. Regarding Grid West, CCS claims that no "real analysis" on Grid West/RTOs has been performed per the Commission directive, and that PacifiCorp's assertions on RTO benefits are misplaced.

Response:

PacifiCorp included transmission alternatives in every portfolio that was developed in the 2004 IRP. Transmission to integrate potential resource, and large scale transmission investments to gain access to potentially lower cost resource options were evaluated in portfolios to determine the Preferred Portfolio. An action item was included in the Action Plan related to continuing to pursue transmission opportunities in regional transmission efforts. PacifiCorp's IRP group works closely with other parts of the Company who are involved in regional transmission planning efforts to evaluate transmission opportunities for inclusion in the IRP.

CCS commented that the Company should have sized the Bridger line to accommodate wheeling opportunities. From a load serving utility perspective, requesting larger transmission than is needed to serve native load is speculative behavior that doesn't fit within the goals and objectives the Company has established for system balancing. Since transmission can only be re-marketed at the cost for which it was purchased (embedded cost + rate of return), there is no upside to acquiring more transmission than is needed to serve load.

CCS correctly commented that there had been no analysis of GridWest in the IRP. The IRP contains a qualitative discussion of GridWest, but does not attempt to model a GridWest environment since the structure and function of GridWest is still being defined and is not solely within the control of the Company. GridWest became a member organization on December 15, 2004 and currently has technical workgroups working on high-level cost-benefit analysis that should be available mid-summer 2005. The IRP group will monitor GridWest progress and begin including scenarios regarding the proposed environment as the scope becomes more defined.

4b(i). [PacifiCorp's future integrated resource plans will include:] An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.

Two parties, WRA-UCE and Mountain West, contend that the decision to assess DSM after modeling the supply-side resource portfolios resulted in a failure to evaluate DSM on a consistent and comparable basis. Mountain West commented on specific Class 1 DSM modeling deficiencies, including use of outdated price forecasts (which undermines DSM market penetration estimates). They also claimed that the Class 1 proxy resources of 355 MW was arbitrary in their opinion, but on the other hand, stated that they are skeptical that the Cool Keeper program can reach 90 MW.

While WRA-UCE generally supported PacifiCorp's DSM modeling approach, it asserted that performing risk analysis prior to running DSM decrement analysis may not have fully captured DSM's fuel/environmental regulation risk mitigation value.

Response:

The RFP informed the design of the proxy load control resources. Because of the small size, limited market potential, and number of Class 1 DSM options, the IRP team chose to evaluate Class 1 DSM resources to lower the PVRR of the preferred supply side portfolio. The Class 1

DSM additions provided the added benefit of delaying the need for supply-side resources. These programs have successfully achieved this deferral in three cases. Load control programs do not have the “capacity factor” to compete with most supply side resources as their availability is generally limited to 100 hours. Supply side resources can benefit the system through sales when the plant is “in the money”, whereas a Class 1 program merely maintains a reserve margin or temporarily defers peak loading on the system.

Regarding Mountain West’s comments on DSM modeling deficiencies, PacifiCorp’s response on the validity of its gas price forecast is provided in the first section of this document. For the Class 1 DSM proxy resource size (355 MW), the Load Control options were limited to the types and sizes of load control bids that were received in the DSM RFP 2003, and were therefore not based on an arbitrary amount as Mountain West claims. On the Cool Keeper program, the Company believes that the assumptions regarding its potential are reasonable. PacifiCorp has outsourced the Cool Keeper program to Comverge on a pay-for-performance basis. PacifiCorp only pays for proven load reducing capability of the system. Comverge, through their 10 year contract with PacifiCorp, targeted a 30% market penetration level at the current customer incentive level. Comverge’s statements are based on their extensive experience in this industry, and having more load control points than any other company in the nation.

For Class 2 DSM, PacifiCorp followed the general guidelines for decrement analysis as described by the Tellus Institute in their report, “Costing Energy Resource Options: An Avoided Cost Handbook for Electric Utilities” completed in September, 1995. Sections II.2.A and II.2B. discuss the ideal decrement analysis and why there are practical limitations to conducting this analysis on a program opportunity by program opportunity basis. The methodology used does capture the value of fuel and pollutant reduction values for a large block of potential DSM. Small blocks of DSM may not capture these values as they may be too small to register a change in PVRR. The Company plans to update the decrement analysis in the June-August timeframe in order to use these new values for valuation of the 2005 DSM RFP bids.

4b(ii). [PacifiCorp's future integrated resource plans will include:] An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.

Parties commented on modeling adequacy for various resource types, including wind projects, existing contracts and other available market resources, Combined Heat and Power (CHP) projects, and Internal Combustion engines.

WRA-UCE and CCS called for inclusion of additional wind resources in the portfolio analysis beyond the 1,400 MW cited in the 2004 IRP action plan. WRA-UCE and Mountain West believe that PacifiCorp's 20% capacity contribution for wind fails to reflect the full system capacity value. WRA-UCE and Mountain West also have concerns about the handling and estimation of system integration costs.

CCS and UAE cited alternative market resources that should have been evaluated and discussed in the IRP. These include the TransAlta, West Valley, and BPA Peaking contract renewals (CCS), as well as the Payson gas plant and planned IPP expansion (UAE).

WRA-UCE discussed deficiencies in PacifiCorp's treatment of CHP, and recommended improved CHP modeling for future IRPs (i.e. model capacity contributions as decrements to load or statistically as part of a LOLP analysis).

Mountain West characterized several of PacifiCorp's IC engine cost and performance assumptions in Chapter 6 as inaccurate; these include the NO_X rate in reference to an SCCT, the machine number, heat rate, and startup cost compared to an air-cooled CCCT.

Response:

Wind Resources

The IRP assessed the wind resources that are technically and economically feasible. To do so, PacifiCorp modeled the planned IRP wind resources using historical wind data available at the time and justified the 1,400 MW procurement projections against the amount of cost effective responses received for the 2003 Renewables RFP. As more cost and performance data by location becomes available and PacifiCorp operators and planners gain more experience with wind resources, this information will be included in the next IRP. Methodologies for calculating the costs and benefits of wind generation will continue to be revisited and improved.

PacifiCorp performed an effective load carrying capability (ELCC) study using two years of historical hourly wind generation to define the performance of a proxy wind resource. The study focused on the impact of the wind resource addition on system reliability during the most critical operating period for the company and resulted in assigning a 20% ELCC for wind resources towards meeting the planning margin.

Although other studies were conducted using reliability measures over a year of operations, PacifiCorp focused on the contribution of the resource towards meeting the planning margin constraint. Since the peak system obligation hour occurs during the summer for the system, defining the ELCC for the summer months more closely aligns with PacifiCorp's planning methodologies.

Wind integration costs were calculated using the wind data and integration methodologies available at the time. However, PacifiCorp plans to update and refine the wind integration study performed for the 2003 IRP

Alternative Market Resources

Resource evaluations with respect to specific projects or contracts fall under the purview of PacifiCorp's RFP process rather than the IRP process. As mentioned in the Supply Side Procurement Program section in Chapter 9 (see pages 184-6), resource evaluations will consist of comparisons with identified alternatives, such as "existing resource options that PacifiCorp may contractually hold or negotiate."

CHP modeling

PacifiCorp welcomes specific suggested improvements in modeling CHP for future IRP's. General comments that modeling needs to be improved do not give the Company enough information to evaluate the merits of a suggestion. An issue that needs to be considered in any proposed modeling suggestion is that these units are sited based on customer economics and opportunity. QFs come in at avoided costs. A plant that otherwise qualifies as a QF can also bid in to a supply side RFP and get the capacity pricing received if the bid wins.

IC engines

The performance and the cost assumptions for the IC engine came from a vendor quote which PacifiCorp considers to be reliable.

4b(iii). The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.

UAE stated that PacifiCorp's assessment of customer participation opportunities "failed miserably". UAE asserted that the Company's project forecasts for QFs are "low and inadequately supported", and it recommended that at least the full 275 MW of QF capacity available under the QF stipulation should be assumed.

UAE also cited alleged deficiencies in the characterization of interruptible contracts as resource opportunities (Monsanto, Nucor, and US Magnesium).

CCS recommended that PacifiCorp study extending plant lives and model plant life extension as a resource option.

Response:

At the time the IRP was being developed, PacifiCorp identified 190 MW of QF activity under negotiation in Utah and included that amount as either existing or planned resources in the IRP. PacifiCorp recognizes that there may be more QF development, and it will take that into account in the RFP process and in future IRPs.

Concerning interruptible load contracts, PacifiCorp's treatment is to model them, at a minimum, through their expiration dates. However, PacifiCorp is open to discussing alternative treatment of interruptible contracts for future IRPs.

Regarding plant life extension as a resource, PacifiCorp agrees that plant life expectancy becomes particularly important in the out years of the 20-year planning cycle. The expected retirement dates of a number of major thermal plants scheduled past calendar year 2020 cause significant changes in the trends observed in the Company's load and resource balance. However, such plant life extensions are well outside of the Action Plan time horizon, and therefore were not targeted for analysis in this IRP.

4c. [The resource assessments should include:] An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions.

Two parties addressed this Standard in their comments. DPU stated that PacifiCorp met this Standard. UAE declined to comment on whether or not PacifiCorp met the Standard; instead, it simply emphasized Commission and independent evaluator roles in the procurement process outlined in Utah SB 26.

Response:

PacifiCorp will be working with the Commission to implement the requirements outlined in Utah SB 26.

4d. [The resource assessments should include:] A 20-year planning horizon.

DPU and UAE addressed this Standard; DPU stated that PacifiCorp had fulfilled this requirement, while UAE claimed that limiting the Action Plan to a ten-year period, and not a 20-year period, is short-sighted.

Response:

As indicated in Appendix C, the study period of the 2004 IRP covers a 20-year period beginning April 1, 2005 and ending March 31, 2025. Market simulations cover the entire study period. In accordance with Utah IRP Standard and Guideline 4e, PacifiCorp develops portfolios of various resource options to determine the Preferred Portfolio from which the four-year Action Plan is developed.

4e. [The resource assessments should include:] 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.

DPU mentioned that Chapter 9 adequately outlined resource decisions and implementation, thereby meeting this Standard. Other parties focused on the progress of the 2003 Renewables RFP, level of PacifiCorp's aggressiveness in pursuing DSM opportunities to postpone the RFP process for the proposed FY 2010 CCCT resource, and CHP incentives.

DPU, Mountain West Consulting, and WRA-UCE commented on the lack of progress in procuring resources under the 2003 Renewables RFP. UAE stated that the RFP process was too long, and advocated amending the Action Plan to include an RFP contract completion schedule.

Most parties stressed that PacifiCorp should be more aggressive in pursuing DSM opportunities. UAE stated that reliance on just RFPs to identify and acquire DSM programs is short-sighted.

UAE advocated postponing the RFP process for the proposed FY 2010 CCCT by at least a year to allow sufficient time for PacifiCorp to investigate resource options that can eliminate or postpone a large baseload gas plant.

WRA-UCE stated that the Action Plan should include a discussion of CHP financial and regulatory incentives.

Response:

Renewable RFP Progress

PacifiCorp received a strong response to the RFP, with more than 50 proposals totaling over 6,000 MW of capability. About 2,000 MW fell to the shortlist. On May 3, 2005 the Company announced a power purchase agreement in which it will purchase the output of a 64.5-megawatt wind-powered electric generating project to be built about 10 miles southeast of Idaho Falls, Idaho. The project was originally to be larger, but was limited due to wind turbine availability.

Uncertainty related to the Production Tax Credit (PTC), increasing wind turbine due to increases in steel prices, the falling dollar, and scarcity of the wind turbines have resulted in a slower procurement process. Looking forward in 2006, more than 200 MW remain on the short list that the Company are actively negotiating. Successful negotiations will depend on timely passage of the PTC extension, and the economics of the proposed projects.

Pursuit of DSM Opportunities

The Company is aggressively pursuing DSM. There has been a 60% increase in Class 2 acquisition from 2002 (15.4 MWa) to the current FY2006 goal (24.8 MWa, includes ETO). The 2005 DSM RFP will include even more Class 2 DSM. In addition, Class 1 resources have grown from nothing in 2002 to over 90 MW in the summer of 2005. PacifiCorp has plans to increase this level to over 150 MW of Class 1 by 2008. The IRP action plan includes even a larger build out of Class 1.

PacifiCorp does not outsource all programs or completely turn-key every program. For example, Energy FinAnswer and FinAnswer Express, two programs for commercial and industrial customers that are responsible for most of the Class 2 DSM acquisition, are not outsourced. Specific engineering studies and design work is outsourced. Project management and incentive management is conducted by company personnel. Outsourcing is used when it provides benefits to customers and the approach for each type of DSM program and opportunity is structured to maximize cost effectiveness and measurable results.

Postponement of CY 2009 Resource RFP

PacifiCorp believes that the IRP has identified the timing and need for new resources and that it would be imprudent to delay the issuance of the RFP given the lead time associated with the procurement process and the time requirements of the regulatory process stemming from the Procurement Act.

CHP Financial and Regulatory Incentives in the Action Plan
In the Action Plan, PacifiCorp included an action item for CHP, stating that CHP and other distributed resources would be included as an eligible resource in the anticipated CY 2009 and CY 2011 procurements. PacifiCorp notes that most CHP projects can qualify as QF's. As such, QF's are paid avoided costs (their incentive). Paying anything in addition to avoided costs for QFs would not be least cost and would violate ratepayer indifference standards.

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.

DPU states that the Path Analysis Standard is met by virtue of the Chapter 9 discussion. In contrast, UAE claims that the IRP failed to incorporate adequate planning flexibility, and does not define a decision mechanism for selecting among or modifying paths.

Response:

PacifiCorp developed an Action Plan path analysis for the various resource decisions in the IRP. The path analysis can be found in Chapter 9 on pages 201-202. PacifiCorp will continue to work in a collaborative effort with public input meeting participants to further refine this area in future IRPs. PacifiCorp anticipates using the Capacity Expansion Model to develop path analysis in future IRPs. Unless the rules set by the regulatory bodies influencing resource choice decisions change, PacifiCorp would anticipate that the 'decision mechanism' would adhere to the least cost / lowest risk dictum given the conditions prevalent at the 'specific point in time' that such decision would be made.

4g. [PacifiCorp's future integrated resource plans will include:] 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.

DPU believes that the risk assessment presented in Chapter 4 fulfills this requirement. Both DPU and UAE would like PacifiCorp to provide a more thorough discussion of this Standard for the next IRP.

Response:

The methodology used for Customer Impact analysis during the 2003 IRP was discussed at some length, and it was decided a similar methodology be used for the 2004 IRP.

As previously discussed, we are currently unable to estimate the impact of the IRP on different classes of customers since these impacts are usually determined as part of a cost of service study, a rigorous and intense analysis which is usually filed in a rate case proceeding. Since the IRP would not be able to determine the impact to customers outside this mechanism, the IRP assumes that all customer classes are impacted equally by the different expansion plans. We also add that rate design is a rate case issue and that rate design decisions can influence costs to customer classes independent of IRP planning.

4h. [PacifiCorp's future integrated resource plans will include:] An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.

For this Standard, parties addressed such topics as fuel price and carbon tax risk (both addressed above), price risk associated with Front Office Transactions, and the extent of risk analysis provided for all portfolios modeled.

DPU felt that the risk discussion in Chapter 4 met the requirement for this Standard, but at the same time expressed concern over price risk associated with new gas-fired resources identified in the Preferred Portfolio. DPU also stated that if fuel volatility risk is being passed entirely to the ratepayer via the Utah PCAM, PacifiCorp should reassess how risk is accounted for since the IRP resource decisionmaking presumes risk sharing.

CCS expressed concern over the extent of risk analysis conducted for Front Office Transactions. It recommended that the Commission direct PacifiCorp to disclose the volume of transactions subject to indexing and that this volume, including the 1,200 MW of front office transactions, be subjected to stochastic risk analysis.

Both CCS and UAE believe that all portfolios investigated should have been included in the stochastic risk analysis. CCS claimed that excluding portfolios with alternative resources such as IGCC, compressed air energy storage, and hydro storage, precluded comprehensive analysis of advantages and disadvantages of particular technologies.

UAE felt that PacifiCorp did not adequately discuss the ratepayer/shareholder risk issues surrounding the utility self-build bias that the Procurement Act addresses.

Response:

Natural gas price risk was considered in two different modeling methodologies. The first method was stochastic analysis, where 100 different futures of natural gas prices were modeled, and the second method was a high gas scenario. The stochastic analysis was performed on 10 different potential portfolios while the high gas scenario was considered on 5 different potential portfolios. PacifiCorp contends that considering this many portfolios under several different possible futures more than adequately addresses the natural gas price risk.

Concerning CO_2 regulatory risk, the section entitled "Unrealistically High CO_2 Regulatory Cost Risk Assumptions" speaks to PacifiCorp's stance on the treatment of CO_2 cost assumptions for resource planning. The Company asserted that its modeling approach adequately considers uncertainty in both the timing and magnitude of CO_2 control costs.

Regarding power cost recovery mechanisms (PCAMs), they are meant to share power cost changes (both up and down) between customers and shareholders beyond a certain threshold. As described in Chapter 4 of the IRP document, shareholder vs customer risk is discussed at some length but is not considered as a quantifiable risk within the IRP methodology. Therefore, the fact that a PCAM existed or did not exist during the IRP process had no material effect on the portfolio risk analysis.

As discussed above, Front Office Transactions add diversity and flexibility to the portfolios. The risk analysis for this flexibility was captured by the stochastic portfolio analyses performed on the dispatchable Front Office Transactions. Given a stochastic distribution of market conditions, Front Office Transactions were dispatched within a portfolio and the resulting PVRRs were included in a risk analysis (see Chapter 8).

Concerning the inclusion of all portfolios in the stochastic analysis, as stated in the IRP document, PacifiCorp chose risk analysis portfolios on the basis of PVRR performance and the composition of resources that would be of most interest in capturing differences in risk profiles. Including all portfolios in the risk analysis would significantly increase the modeling effort and complicate the relative evaluation process without contributing insight on risk impacts that influence resource decisions, particularly during the Action Plan time horizon.

Finally, in reference to the claimed self-build bias mentioned by UAE, for analytic purposes the IRP assumes new resources are developed and owned by PacifiCorp. However, no decision has been made to invest in any specific resources. PacifiCorp has regularly stressed the need to review and compare a utility build option against a power purchase agreement (PPA) or other asset purchase or contract structure for economic benefits, risk reduction and long term optionality. The review of additional resources will be done via the RFP process which will follow the rules adopted by the Commission pursuant to the Procurement Act.

4i. [PacifiCorp's future integrated resource plans will include:] Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.

DPU states that the path analysis in Chapter 9 adequately fulfills this requirement. In contrast, UAE asserts that the Action Plan fails to incorporate sufficient flexibility.

Response:

The IRP emphasizes the need to remain flexible. The Action Plan path analysis in Chapter 9 describes some of the ways the Company proposes to adapt to changing circumstances. As stated in a previous response, the RFP process will also include the flexibility to modify the procurement timeline in order to adjust to changes in the load and resource balance.

4j. [PacifiCorp's future integrated resource plans will include:] An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.

DPU is satisfied with PacifiCorp's handling of this Standard in Appendix N. However, UAE claimed that the IRP fails to demonstrate that the incremental value of a 15% planning margin, as opposed to lower alternative planning margins, is worth the additional cost. It recommends that PacifiCorp adopt a 12% planning margin. UAE also stated that the IRP fails to adequately recognize risk mitigation benefits of more flexible resources, such as the smaller IC Aero SCCTs.

Response:

PacifiCorp included a 15% planning margin (discussed in some detail in Appendix N) in its loads and resources balance, because it was a level deemed adequate to ensure its obligation to serve load. PacifiCorp acknowledges that there is a tradeoff between cost and reliability within system planning. Greater system reliability comes with increased resource need. However, maintaining a level of resources which 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 lies somewhere in between both extremes. PacifiCorp considered the reliability cost-risk tradeoff when determining the planning margin criteria of 15%, and this level of planning margin is consistent with what is being used by neighboring utilitie**s** and what is being proposed in recent resource adequacy initiatives.

In response to risk mitigation benefits of IC Aeros and other flexible resources, we note that PacifiCorp evaluated Portfolio K, defined on page 105 in chapter 7 of the 2004 IRP document. Portfolio K is similar to Portfolio E which formed the basis for the Preferred Portfolio. The difference between Portfolios K and E is Portfolio K has 6 IC Aero SCCTs installed totaling 522 MWs, and Portfolio E has one CCCT installed with 525 MWs. Both of these installations are assumed to occur in FY 2009 for these two portfolios. The deterministic and stochastic PVRRs for Portfolios K and E are very similar even though it is more expensive on a per kW basis to operate an IC Aero than to operate a CCCT. It was determined that a major reason for Portfolio K performing nearly as well as Portfolio E both stochastically and deterministically is due to the flexible nature of the IC Aeros, e.g., quick ramp rates and short minimum up/down times. The stochastic analysis showed that Portfolio E performed only slightly better than Portfolio K on a cost and risk basis. Ultimately Portfolio E was chosen over Portfolio K for four reasons: 1) Past operating experience with CCCTs, 2) Share facilities and parts with existing CCCT units, 3) CCCT has a lower heat rate then an IC Aero, 4) CCCT has a lower per-MWh emission rates than an IC Aero.

4k. [PacifiCorp's future integrated resource plans will include:] 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.

DPU stated that the risk discussion in Chapter 9 adequately fulfilled this requirement. Other parties noted some apparent deficiencies. Mountain West and UAE cited inadequate consideration of externalities such as Utah economic impacts, and technology impacts on human health, the environment and resources such as water. CCS requested more background on cap and trade programs in practice, including trading liquidity. WRA-UCE would like to see CO_2 cost escalation assumptions reflected in sensitivity analysis in future IRPs.

Response:

An issue associated with quantifying the externalities cited by the parties is how to estimate such impacts when the location of proxy resources modeled for the IRP are unknown or imprecisely known. As mentioned in the IRP and public meetings, PacifiCorp does not presume a given resource type, ownership preference, or location for resources identified in the Action Plan. The discussion on PacifiCorp's IRP Resource Procurement Strategy (Chapter 9, pages 182-3) makes the statement that such resource 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..."

Regarding background on cap and trade programs, PacifiCorp participates in the national sulfur dioxide allowance trading program established in the 1990 amendments of the Federal Clean Air Act. Under the program, regulated, emitting entities such as PacifiCorp must meet annual emissions limits that were initially based on historic emissions levels, with gradual cuts imposed nationally over time. Emitting entities covered by the program may sell allowances to willing buyers if they are emitting below their annual limits, and purchase allowances from willing sellers if they are emitting above their annual limits.

The question of whether there will be willing buyers and willing sellers will depend upon the detailed design of a cap-and-trade program. The history of the sulfur dioxide trading program shows that liquid markets in allowances can form to reward entities that emit below their cap. For example, the sulfur dioxide trading program experienced a recent increase in the clearing price for allowances due to lower caps coming into effect compared to annual limits earlier in the program's existence and an associated increase in demand for allowances.

Because the program is national in scope, PacifiCorp can engage in transactions with other entities throughout the US. Any revenues generated by sales of excess allowances flow back to credit our customers.

PacifiCorp currently examines a number of multi-year values for carbon dioxide when evaluating resource portfolios. We believe this range provides an adequate picture of what a broad range of CO_2 regulatory regimes could mean to the Company and our customers. There are specific federal legislative proposals to limit CO_2 emissions. PacifiCorp will examine if and how such proposals can be applied to portfolio analysis in the next IRP.

4l. [PacifiCorp's future integrated resource plans will include:] A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.

DPU stated that the risk discussion in Chapter 9 adequately meets this requirement. UAE and Mountain West stressed that PacifiCorp needs to give rate design more attention to address Utah load growth. Both Mountain West and UAE advocated requiring demand meters on all new installations.

Response:

Please see the discussion on rate design in response to 4a(ii). The discussion in 4a(ii) includes a review of new rate designs recently put in place in Utah to address peak load growth.

If demand meters were required for all new customers as advocated by Mountain West and UAE, we estimate that, over time, residential and small commercial metering costs for new customers would increase by two to three times. Based on the metering type employed, meter reading labor expenses could increase substantially over time.

Costs for large commercial and industrial customers would not be affected because the Company currently installs demand meters for all industrial and large commercial customers.

We believe that current practice, where only larger customers (over 15 kW) are demand metered, targets significant customer loads and minimizes costs for all customers.

CONCLUSION

PacifiCorp contends that the IRP meets all substantive requirements of the Utah Standards and Guidelines. Parties voiced concerns and criticisms over PacifiCorp's handling of gas price forecasts, risk analysis, technology costs, alternative resources, and baseline planning assumptions (CO_2 regulatory costs, the level of Front Office Transactions, planning margin, etc.). In responding to these concerns and criticisms, the Company emphasizes that differences in opinion over its planning assumptions, and how it conducted certain aspects of its modeling and analysis process, do not provide sufficient justification for denying acknowledgement of the IRP as some of the parties claim.

PacifiCorp again thanks the parties for their constructive comments, and reiterates its intention to continue to build a stronger IRP process for all parties. We point out that the IRP is meant to be a high-level planning road map that looks at a range of risk-driven scenarios, and thereby establishes the foundation for the detailed resource perspective provided by PacifiCorp's procurement process. Within this context, PacifiCorp maintains that the 2004 IRP successfully meets the intent of the Utah Standards and Guidelines by virtue of putting forth a practical and robust plan supported by a responsive IRP process.