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DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

June 27, 2005

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol St NE #215
PO Box 2148
Salem OR 97308-2148

Re: LC 39

Dear Filing Center;

Enclosed for filing is an original plus 5 copies of Staff's Comments and Recommendations, and Draft Proposed Order from David B. Hatton.

Thank you for your assistance.

Sincerely,

Neoma Lane
Legal Secretary
Regulated Utility & Business Section

Enclosures
cc: Service List
NAL:nal/GENN0878

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 39

In the Matter of PACIFICORP 2004 Integrated Resource Plan.	STAFF'S COMMENTS AND RECOMMENDATIONS

Load Forecast

PacifiCorp tested retail load fluctuations stochastically in combination with other key variables for representative and top-performing portfolios. According to the Company, retail load varied in the model from 0.5% to 2.9% of the forecasted load growth rate.

Staff believes it also is useful to conduct scenario risk analysis of load forecast error to understand how portfolios might perform in the event loads deviate significantly from projections. Therefore, we asked PacifiCorp to develop a new hourly load forecast that is two standard deviations lower than its base-case assumption. Using that new forecast, we asked the Company to provide the deterministic present value revenue requirements (PVRR) of the portfolios for which the Company performed other scenario analysis. No portfolios were changed; only operational changes resulting from reduced load requirements were simulated in the hourly dispatch model. Such a scenario provides an indication of the relative performance of portfolios when loads turn out significantly lower than the Company forecasted and the system is overbuilt in hindsight.

According to PacifiCorp, a growth rate two standard deviations lower represents load growth at 0.4%, compared to the assumed 1.3% growth rate, and a total load that is 93.4% of the Company's base-case forecast. For comparison, the difference in loads is roughly equivalent to the difference between the Medium and Medium Low demand forecasts for the Northwest Power and Conservation Council's Fifth Power Plan. However, the Council's Medium Low forecast is closer to one standard deviation, than two standard deviations, from the Medium forecast.

The deterministic PVRR of all portfolios is lower under Staff's load scenario, presumably the result of increased sales and reduced fuel and other O&M costs. PacifiCorp's preferred Portfolio E performs the worst of the six portfolios evaluated under the lower load scenario, and all-gas Portfolio M moves from least-cost among the 17 portfolios tested in the Integrated Resource Plan (IRP) to third place among the six portfolios included in scenario analysis.

Portfolio Q, which expands transmission into Wyoming to allow greater access to shorter-term market transactions and includes a third coal plant, moves from the worst-performing of all 17 portfolios in the IRP to the least costly of the six portfolios tested.

Because no portfolio in the IRP isolates the effect of building only transmission facilities, we cannot tell whether the improved PVRR of Portfolio Q in the reduced load scenario is the result of more market transactions, fuel type (more coal and less natural gas), or a combination of these and other factors. *See* PacifiCorp's Response to Staff Data Request No. 1.

Regarding the effect of electricity industry restructuring on loads, Staff agrees with PacifiCorp that it should continue to plan to serve the entire forecasted load in its Oregon service territory on a long-term basis given the level of participation in direct access to date and customers' ability to return to cost of service rates each year. This issue should be revisited if direct access participation increases significantly, if the Company adopts and has sizable participation in a tariff similar to Portland General Electric's five-year opt-out program, or if customers participate in a permanent opt-out tariff as envisioned in Commission Order No. 05-133.

Planning Reserve Margin

In July 2004, the Commission acknowledged a planning margin of 12% for Portland General Electric's IRP. PGE's planning margin consists of 6% operating reserves as required by the Western Electricity Coordinating Council and an additional 6% planning reserve, all under average hydro conditions. *See* Order No. 04-375.

Staff is not convinced that the benefits of PacifiCorp's proposed 15% planning margin outweigh the costs. The 12% planning margin stress case had a PVRR about $140 million, or 1%, lower than Portfolio E, which like other portfolios includes a 15% planning margin. The average all-in stochastic cost for the 12% stress case was only 0.2% higher compared to Portfolio E, with an upper tail PVRR (average of the five worst results) just 1.2% higher. Production and fixed costs for the 12% stress case are significantly lower than for Portfolio E, although total variable costs are higher due to greater market purchases and lower sales revenues.

Staff acknowledges that based on PacifiCorp's analysis, the loss of load probability for a 12% planning margin would be about four days in 10 years. We point out, however, that the actual planning margin for the 12% stress case PacifiCorp tested would be higher most years, presumably the result of large, lumpy resource additions and planning to the single peak hour of the year: 15% in FY 2006-2008 and 2011, 14% for FY 2009 and FY 2014, and 13% for FY 2012; it would dip to 12% only in FY 2010, FY 2013 and FY 2015. *See* IRP Technical Appendix at 83.

Staff is skeptical about the unserved energy costs PacifiCorp used in its planning margin analysis. They may be out-of-date, they are not from PacifiCorp's service area, and they are very high. They come from a 1990 Electric Power Research Institute study for Pacific Gas & Electric in California, and range from $5,210/MWh for agricultural customers to $6,590/MWh for residential customers and from $15,290/MWh for large industrial customers to $44,910/MWh for small commercial customers. Further, PacifiCorp took the weighted average of these numbers, $24,000/MWh, and used that value for setting the planning margin.

The recent Statewide Pricing Pilot in California shows that residential customers are willing to curtail loads at prices far lower than these interruption costs. But even at PacifiCorp's high assumed interruption costs for customers, the "bathtub chart" curve for residential and agricultural customers bottoms out at a planning margin of about 12%. *See* IRP Technical Appendix at 221. Voluntary load reductions from customer classes with the lowest interruption costs should be taken into account in estimating the costs of reducing unserved energy.

In addition, some demand response resources, such as interruptible contracts and the Energy Exchange program, have lower fixed costs than single-cycle combustion turbines (SCCTs), which served as the basis for the Company's estimated cost of reducing unserved energy. Such programs could make a planning margin higher than 12% more attractive, but these demand-side management (DSM) resources were not included anywhere in the Company's planning margin or portfolio analyses.

Further, the planning margin was determined on the basis of meeting the single peak hour of the year. Staff asked the Company to reproduce its system and East side coincident capacity charts if instead of planning to the coincident peak hour for the Eastern control area the Company planned to the "super-peak" period — the average of the eight super-peak hours. The data show that planning reserve capacity could be reduced by some 200 MW in FY 2011 and FY 2012, for example, if the Company planned to the super-peak period instead of the single peak hour of the year. *See* PacifiCorp's Response to Staff Data Request No. 4.

We also asked what would be the resulting preferred portfolio and its PVRR if the Company planned to the average of the super-peak period instead of the single peak hour. The revised obligation amount had no impact on the timing of the capacity additions in Portfolio E. The Company therefore constructed an alternative portfolio, assuming the FY 2010 combined-cycle combustion turbine (CCCT) is replaced by SCCTs with a lower overall amount of capacity — 174 MW in FY 2010 and another 174 MW in FY 2011. The deterministic PVRR of the revised portfolio is $100 million less than the Company's preferred Portfolio E. *See* PacifiCorp's Response to Staff Data Request No. 5.

The methodology used by the Northwest Planning and Conservation Council in its Fifth Power Plan to analyze the appropriate planning margin is superior to PacifiCorp's methodology. The Council assesses the cost-risk tradeoff of various planning margins *within* its portfolio modeling. In contrast, PacifiCorp predetermined the planning margin for all portfolios in a sideboard analysis (15%), then conducted stress tests of two other levels (12% and 18%) based on the initial Reference Portfolio A, which was *not* among the top-performing portfolios.

Staff recommends that the planning margin be an analysis *variable* in the modeling of all portfolios. Therefore, Staff recommends that for the next IRP or Action

Plan brought forward for the Commission’s acknowledgment, PacifiCorp determine the appropriate planning margin by analyzing the cost-risk tradeoff of various planning margins *within* stochastic modeling of portfolios, rather than as a separate analysis as in the 2004 IRP. Ideally, Staff recommends that the Company analyze the cost-risk tradeoff of *all* portfolios at various planning margins. At a minimum, we recommend that the Company initially build all portfolios to a set planning margin, test them stochastically, and adjust top-performing portfolios to higher and lower planning margins for further stochastic evaluation. Staff also recommends that the Company evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy.

Staff further recommends that the Company evaluate alternatives for determining the expected annual peak demand — for example, planning to the average of the eight-hour super-peak period, instead of the single peak hour of the year.

Demand-Side Management

As context for our comments, we highlight Docket No. UM 1093, where the Commission ordered that “The utilities' Integrated Resource Plans should evaluate demand response programs on par with other options for meeting energy and capacity needs.” *See* Order No. 03-408, Appendix A at 1. We also point toward the Commission’s 1989 least-cost planning order which states that least-cost planning “…requires consideration of all known resources for meeting the utility’s load, including…those which focus on conservation and load management, the ‘demand side,’” and “…rate design should be treated as a potential demand-side resource.” *See* Order No. 89-507 at 2 and 10.

Conservation (Class 2 DSM). Staff asked PacifiCorp for all information the Company relied on to determine the types of conservation programs that are cost-effective and the savings achievable through 2015. The Company provided a 2001 Tellus Institute study, *An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah*, prepared for an advisory group to the Utah Public Service Commission. PacifiCorp also reviewed the Council’s Fifth Power Plan to get an indication of potential program areas and used results from the Company’s 2003 RFP for DSM resources as an indication of practical resource availability. The Company plans to update its decrement values using updated market prices and its IRP methodology to assess cost-effective bids in future DSM RFPs. However, the Company states that “Further market potential analysis will not result in increased DSM resources.” *See* PacifiCorp’s Response to Staff Data Request No. 9.

Staff recommends that for the next IRP or Action Plan brought forward for the Commission’s acknowledgment, PacifiCorp conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in its Utah service area over the IRP study period and assess how the Company’s base and planned programs compare with the cost-effective amounts determined in the study.

PacifiCorp's sideboard decrement analysis of conservation may not appropriately credit conservation for reducing risk because risk analysis is performed *before* the decrement analysis. The Council's Fifth Power Plan showed risk reduction as a significant benefit of conservation resources.

Staff recommends that for the next IRP or Action Plan, PacifiCorp develop supply curves for various types of Class 2 DSM resources and evaluate whether modeling them as portfolio options that compete with supply-side options — including an analysis of the risk reduction benefits — is preferable to the current decrement approach.

Further, we recommend that the Company acquire all conservation found to be cost-effective up to the levels required to serve load growth, whether through RFPs or in-house programs, and not apply an artificial cap of 200 MWa for those additional programs. We therefore propose the following modification to Action Item 2: Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth.

Dispatchable Load Control (Class 1 DSM). We applaud PacifiCorp's Class 1 DSM analysis in the 2004 IRP as a good first step toward treating demand response resources on par with supply-side resources. The Company found that Class 1 resources are highly cost-effective, reducing PVRR of Portfolio E by $139 million for a present-value cost of only $4.6 million. *See* IRP at 167.

We believe, however, that the cost-effectiveness of the identified resources suggests there likely are more Class 1 DSM resources available that would be attractive at costs *above* this level. We note that the Company's evaluation of Class 1 resources was conducted as a sideboard analysis, and only on the Company's preferred portfolio, rather than *within* modeling of portfolios.

Staff recommends that for the next IRP or Action Plan, the Company use RFP and in-house analyses to develop supply curves for a wide variety of Class 1 resources spanning a range of costs. Staff further recommends PacifiCorp not place firm constraints on the amount of Class 1 DSM resources modeled and test them only in the preferred portfolio, but instead test various amounts and types in portfolio modeling as resources that compete with generating resources.

Price Responsive Load Reduction (Class 3 DSM). The Company performed no modeling of Class 3 DSM programs in the IRP and included no peak reductions from such programs in its analysis. The Company states: "The load reductions observed through implementation of these programs at PacifiCorp are neither predictable, consistent or persistent," and "These types of programs are not included in this IRP as a long-term reliable resource…." *See* IRP at 31 and 82.

Yet long-term pricing programs at other utilities show persistent load reductions during peak periods and help avoid the need for new power plants. For example, Georgia

Power has the highest level of participation in a two-part real-time pricing program and is the most extensively analyzed such program in the U.S. As of 2002, the program had 1,500 participants and provided a peak load reduction of 1,000 MW. *See* Oregon Public Utility Commission Staff, *Demand Response Programs for Oregon Utilities*, presented at the Commission's June 3, 2003, public meeting.

Staff sent a letter to PacifiCorp on August 3, 2004, advising the Company of our view on including Class 3 programs in IRP modeling. We stated, "Including the result of such programs in the load forecast as the reductions occur is insufficient. Only portfolio modeling can accurately advise the company of the cost-effectiveness of such programs for critical peak and other hours of the year, relative to other resource options." PacifiCorp responded in a letter on August 25, 2004: "[T]he Company's demand buy-back programs cannot be modeled as a firm long-term resource because the programs are designed more as a short-term tactic to manage significant price increases…. Customer curtailment only occurs if the prices are very high and the customer has flexibility in the production of their product." We similarly criticized the Company's approach to Class 3 DSM resources in written comments on the draft IRP.

Staff believes the Company's evaluation of Class 3 DSM programs falls short of mandates in Commission Order No. 89-507 and No. 03-408. Moreover, we point out the Commission's direction in its order on PacifiCorp's 2003 IRP: "[T]he Commission will require for the next IRP or Action Plan Pacific brings forward for acknowledgment, that it assess Class 1, Class 3 and Class 4 DSM resources in Oregon and include in the portfolios those DSM resources that are least cost." *See* Order No. 03-508 at 20.

Potential new interruptible contracts and demand buybacks such as the Energy Exchange should have been modeled as demand-side resources that compete with supply-side resources in the 2004 IRP. Based on extensive experience with the Energy Exchange in 2000 and 2001, the Company could determine a portion of this resource that can be treated as firm. For example, if customer participation varied from 30% to 60% of identified curtailable load at a market price of $150/MWh, the Company could treat 30% of the identified curtailable load as firm at $150/MWh. Spread over a sufficient number of participants, the Company could reasonably estimate the probability of participation levels at somewhat lower prices, as well.

We recognize that such analysis may need to be performed in stochastic modeling. That's because the Company's deterministic modeling assumes base-case market prices rather than price excursions.

Regarding *existing* interruptible contracts, we strongly disagree with the Company's planning assumption that they would not be renegotiated upon expiration, or that there would be no other such contracts to take their place. The apparent result is that no interruptible contract capability is assumed in the IRP after the 127 MWa of Nucor and Monsanto contracts in Utah expire in December 2006. *See* IRP Technical Appendix at 41. Renegotiation of these contracts would significantly reduce the need for additional new generating resources.

In addition, we cite comments on the IRP by the Utah Association of Energy Users: "[T]he IRP does not include any of the US Magnesium interruptible load as a resource, even though US Magnesium's 85 MW load is subject to curtailment during the hottest peak hours of the summer and US Magnesium is required by contract and Commission order to assume the risk of both pricing and availability of market resources during peak summer hours." *See* Comments of the Utah Association of Energy Users at 20-21, Utah PSC Docket No. 05-2035-01.

Staff recommends that for its next IRP or Action Plan, PacifiCorp determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options. Staff also recommends that existing interruptible contracts be assumed to continue unless the Company for good reason believes they will not be renegotiable or other resources would provide better value.

Non-Hydro Renewable Resources

The Company reported at the May 18, 2005, public input meeting that more than 1,800 MW of projects remain on the short list from its renewable resources RFP, including more than 200 MW of projects with a 2006 on-line date. We recognize that these bids may not all prove viable. At the same time, they are not necessarily representative of renewable resources that may become available in later years in the planning period as prospecting for wind sites and technology improve over time.

We are concerned about the lack of analysis that would have shown the risk characteristics of a portfolio with more than 1,400 MW of renewable resources. Wind resources, with no fuel costs, are not subject to fuel price volatility. In that respect they are similar but superior to coal resources, which historically have had limited price volatility. However, coal plants may in the future encounter greater price volatility related to coal markets, fuel transportation and pollutant regulation.

In response to concerns about the slow progress in acquiring renewable resources and an on-again, off-again federal production tax credit, Staff recommends that PacifiCorp execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of power purchase agreements upon its extension. Portland General Electric is in the process of developing such an agreement with the Energy Trust.

Staff further recommends that in its next IRP or Action Plan, PacifiCorp analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's ability to integrate wind resources.

Potential Carbon Dioxide Regulatory Costs

Staff recommends that PacifiCorp continue to use its own base-case assumptions regarding the future regulatory costs of carbon dioxide (CO_2) emissions. The sensitivity analyses required under Order No. 93-695 provide the Commission with an indication of how portfolios may perform under potential regulation scenarios. We do not at this time support Northwest Energy Coalition's recommendation that PacifiCorp acquire CO_2 offsets today, such as those available from the Climate Trust. It is a risky strategy to acquire CO_2 offsets from sectors unrelated to the electricity industry until it becomes clearer how CO_2 emissions would be regulated by the state or federal government.

Coal Plant

We are not convinced that a second large thermal resource, whether natural gas or coal, is needed by summer of 2011 on the East side of the Company's system.

We point toward our comments on planning margin and DSM, which affect the assumed need for this resource. For example, the IRP is based on the planning margin never dipping below 15% in a single hour of any year. For its preferred Portfolio E, the planning margin is expected to be 15% only during FY 2006-2008 and 2015; the Company expects the actual planning margin to reach 16% in FY 2010 and 2012-2013, 18% in 2014, and climb as high as 19% in 2009 and 2011. *See* IRP Technical Appendix at 82. Another example is the Company's planning assumption that the 261 MW of existing interruptible contracts do not continue upon expiration.

Further, we asked PacifiCorp to test three delay scenarios for the coal plant. *See* Staff Data Request No. 3. Specifically, we asked the Company to set the planning margin in the model to zero, then calculate the PVRR results for the Company's preferred Portfolio E, as well as the level of unserved energy and the resulting planning margin. We also asked for the numeric values for the average and worst case stochastic analyses because the IRP showed results only in bar charts. *See* Staff Data Request No. 14 and 15. For comparison, we asked for the minimum, maximum and expected unserved energy for each year from FY 2006-2015 for PacifiCorp's preferred Portfolio E, as presented in the IRP. *See* Staff Data Request No. 10.

Unserved energy values represent the sum of monthly amounts for the year. *Expected* unserved energy is the average for all 100 model runs; minimum and maximum values are from the two runs with the lowest and highest total unserved energy for the entire FY 2006-2015 study period.

Staff concludes the following based on PacifiCorp's responses:

- *Deterministic PVRR* – Delaying the coal plant one year reduces PVRR by \$169.3 million (1.3%), delaying it two years reduces PVRR by \$188.2 million (1.4%), and delaying it three years reduces PVRR by \$207.0 million (1.6%).

- *Stochastic average PVRR* (stochastic average variable cost plus deterministic fixed cost) - Delaying the coal plant, whether by one year, two years or three years, reduces expected PVRR by about $850 million (6.3% to 6.4%).

- *Upper tail PVRR (average of the five highest PVRR results)* - Delaying the coal plant one year reduces worst-case PVRR by about $748 million, delaying it by two years reduces worst-case PVRR by about $671 million, and delaying it by three years reduces worst-case PVRR by about $644 million. These values represent about a 4% reduction in worst-case PVRR compared to PacifiCorp's preferred Portfolio E as filed.

- *Planning margin* – When the coal plant was delayed by *one year* in the model, the planning margin stayed at or above 15% for the next 10 years except in FY 2012, when the planning margin dipped to 12%. Delaying the coal plant by *two years* also reduced the planning margin below 15% in FY 2013, to 10%. Delaying the coal plant by *three years* reduced the planning margin a third year, in 2013, to 12%.

- *Unserved energy* - When the coal plant is delayed by *one year*, from summer 2011 to summer 2012, the expected amount of unserved energy in FY 2012 is 81,343 MWh. (Unserved energy over all model runs for that year ranged from zero to 259,069 MWh.) When the coal plant is delayed two years, expected unserved energy is 80,257 MWh in FY 2012 and 112,293 MWh in FY 2013. When the coal plant is delayed three years, expected unserved energy is 81,343 MWh in FY 2012, 108,638 MWh in FY 2013, and 49,341 MWh in FY 2014.

For perspective, PacifiCorp's preferred Portfolio E *as filed* shows 75,135 MWh of expected unserved energy in FY 2007, with a range of 18,084 MWh to 188,113 MWh over all model runs.

We further compare these figures to results from PacifiCorp's Energy Exchange (Class 3 DSM) program for Oregon industrial customers from December 2000 to August 2001, where energy use reductions totaled more than 38,000 MWh. We also cite PacifiCorp's agreements with three large Oregon customers for buybacks lasting longer than one week during the period March 2001 through September 2001. Customers reduced loads under the contracts by 61,385 MWh. Combined, these buyback reductions totaled about 99,000 MWh. *See* Oregon Public Utility Commission Staff, *Demand Response Programs for Oregon Utilities*, presented at the Commission's June 3, 2003, public meeting. The avoided costs for deferring the coal plant may enable sizable buyback payments to Utah customers that could achieve results similar to Oregon's experience.

In addition, PacifiCorp's 20/20 Customer Challenge Program for residential and commercial customers reduced energy use by an estimated 97,650 MWh in Utah alone in the summer of 2001. The Company offered a 10 percent discount on monthly bills for customers using at least 10 percent less electricity compared to the same period during the prior year, and a 20 percent discount if they reduced electricity use by at least 20 percent. The program required no enrollment or special meters. *See* Staff Exhibit 1, Quantec, *Customer Energy Challenge Report*, prepared for PacifiCorp, 2002.

Regarding the fuel type of the proposed summer 2011 East-side resource, all-gas Portfolio M is the least costly of all portfolios tested under PacifiCorp's base-case assumptions, with a PVRR about $29 million (0.22%) less than the Company's preferred Portfolio E. *See* IRP Technical Appendix, Table E.1.

Staff compares the all-in stochastic performance of the two portfolios as follows:

- The average stochastic cost (stochastic variable costs plus deterministic fixed costs) of Portfolio M is only 2.5%, or about $331 million, higher than PacifiCorp's preferred Portfolio M.
- The "upper tail" cost, the average of the five highest PVRR results, is about 7% higher for Portfolio M than PacifiCorp's preferred portfolio.

Staff cautions relying on the upper tail values in the IRP because they are based on only five results out of a total of 100 model runs. For comparison, the Northwest Power and Conservation Council's Fifth Power Plan uses a risk measure that is the average of the worst 10% results — some 75 results out of 750 iterations.

We are concerned about the long lead time associated with coal plants, which increases planning risks related to load forecasts, technologies, electricity and natural gas prices, and other factors. The Company's updated coal plant timeline shows it will take six years to permit and construct the next coal plant, regardless of whether the plant uses pulverized coal or IGCC technology. The Company notes that the RFP process now required by recently passed Utah Senate Bill 26 could add another 16 months to 18 months. *See* PacifiCorp's response to Data Request No. 1.7 of the Utah Committee of Consumer Services.

We note that Portfolio E performed poorly in our requested scenario analysis, where loads turn out two standard deviations lower than forecasted. We also note that PacifiCorp did not examine whether a portfolio with renewable resources in excess of 1,400 MW would have a lower expected PVRR than Portfolio E. Renewable resources also typically are in far smaller increments and often have a shorter lead time.

Moreover, Staff finds Parties' arguments that are founded on scientific and economic analyses of what CO_2 adder would likely be needed to avoid catastrophic climate change more persuasive than PacifiCorp's reliance on what CO_2 adder might be politically feasible in the near term. Staff finds that it is reasonable to conclude based on the evidence in this docket that the risk to ratepayers of a CO_2 adder higher than PacifiCorp assumed in its base case ($8.38/ton CO_2 in 2010$) is greater than the risk benefits of Portfolio E — primarily due to natural gas price volatility — estimated in the Company's stochastic analyses. All-gas Portfolio M was the least-cost portfolio for all

CO_2 allowance cases except a zero adder — including the Company's base-case CO_2 allowance.

Further, PacifiCorp's analysis relies on a 40-year amortization period for coal plants, which may not be tenable without the unplanned retirement of an existing coal plant or the addition of carbon sequestration.

We are interested in learning more about IGCC technology. It offers potentially more stable fuel prices than natural gas, with the ability to add more cost-effective sequestration at a later date if carbon adders warrant and the facility is located where economic sequestration opportunities are available. However, IGCC technology is just beginning to reach commercialization, and carbon sequestration is in its infancy. We recommend that both be more thoroughly investigated in the next IRP.

Staff recommends that the Commission:

- Not acknowledge Action Item 8, acquisition of a 600 MW high capacity factor resource on the East side of the system by CY 2011
- Explicitly not acknowledge a new coal unit by CY 2011
- Direct PacifiCorp to assess in the next IRP or Action Plan brought forward for the Commission's acknowledgment IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties including market prices and CO_2 regulation

Staff recommends that the Company continue environmental permitting and preparing detailed plans, including an economic review and justification for building or contracting for an additional thermal unit on the East side, and refining the level and type of resources needed and the procurement date.

Distributed Generation

The nationwide study on prospects for combined heat and power (CHP) resources in which PacifiCorp participated pursuant to its 2003 IRP was limited to projects no larger than 10 MW. Most economic CHP plants are larger than this. The study concluded that 2% of customers surveyed are strong prospects and 11% are soft prospects over the next five years. PacifiCorp translates that to 100 MW in its Utah market and notes that the figure is comparable to two previous Utah studies that project 100 MW to 150 MW of realistic market potential. The Company used the study to assess the market for CHP resources at 45 MW in Oregon over five years. This number is very low, likely due to the 10 MW limit on project size. A single project could easily overtake the 45 MW figure.

In contrast, a recent study prepared for U.S. Department of Energy estimated the additional economic potential in Oregon at 384 MW by 2025, without taking into account existing state incentives or any reduction in technology costs. In a scenario with incentives, reduced costs and other favorable conditions, the study estimated that 1,831 MW in additional systems could be installed in Oregon in the next 20 years. *See* OPUC

Staff, *Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations*, presented at the Commission's February 25, 2005, public meeting.

We note that sideboard stress tests for the IRP on both CHP and dispatchable customer standby generation resources reduced the PVRR of PacifiCorp's preferred Portfolio E. However, CHP resources are included within the Company's portfolio modeling only when it is confident a power purchase agreement for a particular project will transpire, unlike other types of resources.

At its May 2005 public input meeting, PacifiCorp reported that for its RFP for a CY 2009 East-side resource, distributed generation 3 MW or larger will be eligible to participate. In its June 17, 2005, response to questions at the meeting, the Company stated it intends to propose that the resources be under PacifiCorp's control, such as would be the case with dispatchable standby generation.

Staff recommends that for the next IRP or Action Plan brought forward for the Commission's consideration, PacifiCorp evaluate within portfolio modeling the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. Further, we recommend that PacifiCorp evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.

Transmission

PacifiCorp's 2003 IRP analyzed a transmission-only portfolio that provided a comparison with other portfolios that included new generating resources along with associated transmission. We are concerned that it is impossible to tell from the 2004 IRP whether some combination of additional transmission to enable additional short-term market transactions, along with new generating resources and their associated transmission, would have been a better choice than PacifiCorp's preferred portfolio.

Staff recommends that for the next IRP or Action Plan, PacifiCorp analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

Summary of Staff's Recommendations

Staff recommends that the Commission acknowledge PacifiCorp's 2004 IRP with one exception and 11 modifications to the Action Plan. The exception is Action Item 8: Procure a 600 MW high capacity factor resource in or delivered to Utah by the summer of 2011. Staff recommends that the construction of a second large thermal resource in or delivered to Utah by the summer of 2011 not be acknowledged, including acquisition of a new coal unit.

Staff recommends the following modifications to the Action Plan:

Revised Implementation Action

1. Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth. (Action Item 2)

Additional Implementation Actions

2. Execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of power purchase agreements upon extension of the federal production tax credit.

3. For the next IRP or Action Plan, analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's ability to integrate wind resources.

4. For the next IRP or Action Plan, conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in PacifiCorp's service area over the IRP study period and assess how the company's base and planned programs compare with the cost-effective amounts determined in the study.

5. For the next IRP or Action Plan, develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.

6. For the next IRP or Action Plan, assume existing interruptible contracts continue unless they are not renegotiable or other resources would provide better value.

7. For the next IRP or Action Plan, determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options.

8. For the next IRP or Action Plan, assess IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties including market prices and CO2 regulation.

9. For the next IRP or Action Plan, analyze planning margin cost-risk tradeoffs within stochastic modeling of portfolios. If feasible, analyze the cost-risk tradeoff of all

portfolios at various planning margins. If not feasible, build all portfolios to a set planning margin, test them stochastically, and adjust top-performing portfolios to higher and lower planning margins for further stochastic evaluation. Evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Evaluate alternatives for determining the expected annual peak demand for determining the planning margin — for example, planning to the average of the eight-hour super-peak period.

10. For the next IRP or Action Plan, analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

11. For the next IRP or Action Plan, evaluate within portfolio modeling the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. Evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.

Agreed-Upon Modifications

It is Staff's understanding that PacifiCorp agrees to modify its Action Plan pursuant to Staff recommendations #1, 2, 3, 5, 6, 8 and 10, above. The Company does not at this time agree to modify its Action Plan pursuant to Staff recommendations #4, 7, 9 and 11. We recommend the Commission require these as conditions for acknowledgment.

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 39

In the Matter of	)	
	)	DRAFT PROPOSED ORDER
PACIFICORP	)	
	)	
2004 Integrated Resource Plan.		

DISPOSITION: PLAN ACKNOWLEDGED WITH EXCEPTION, AGREED-UPON MODIFICATIONS AND CONDITIONS

INTRODUCTION

On January 20, 2005, PacifiCorp, dba Pacific Power & Light Company (PacifiCorp or the Company) filed its Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 89-507, which requires all regulated energy utilities operating in Oregon to engage in least-cost resource planning.

Requirements for Least-Cost Planning

The Commission requires regulated energy utilities to prepare least-cost plans every two years. Utilities must involve both the Commission and the public in their least-cost planning process, and prior to resource decision-making. Substantively, the Commission requires that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider uncertainty; (3) make the primary goal of the process a resource plan that is least cost to the utility and its ratepayers and consistent with the long-run public interest; and (4) create a plan that is consistent with the energy policy of the state of Oregon stated at ORS 469.010. *See* Order No. 89-507.

Order No. 89-507 also specifies that the Commission will “acknowledge” least-cost plans that satisfy the procedural and substantive requirements, and that seem reasonable at the time acknowledgment is given.

PacifiCorp satisfied Oregon's procedural requirements relating to its planning process. In the analysis below, the Commission identifies specific portions of PacifiCorp's filed IRP that did not satisfy all of Oregon's substantive least-cost planning requirements or that did not seem reasonable in light of current circumstances after review of the Company's analysis and the Parties' comments. However, PacifiCorp has agreed to modify its plan to address most of the identified concerns. The Commission concludes that PacifiCorp's IRP, with agreed-upon modifications, satisfies Oregon's least-cost planning requirements and appears reasonable in light of current circumstances with one exception and the conditions described below. Accordingly, the plan with agreed-upon modifications is acknowledged with one exception and on four conditions.

PacifiCorp

PacifiCorp serves some 1.6 million customers in six Western states: Oregon, Utah, Wyoming, Washington, Idaho and California. For the fiscal year (FY) ending March 31, 2004, the Company sold 48,679 gigawatt-hours (GWh) of electricity to retail consumers in its service territory and 13,407 GWh of electricity to wholesale customers.

PacifiCorp owns or has interests in 71 generating plants with net plant capability totaling 7,987 megawatts (MW). For the FY ending March 31, 2004, 68.4% of the Company's energy requirements were supplied by 11 coal plants, 5.4% from 54 hydroelectric plants, 0.2% from one wind plant, and 4.1% from four natural gas plants and one geothermal plant. Short-term and long-term contracts and spot market purchases supplied the remaining 22% of the Company's energy needs.

PacifiCorp developed its long-term load/resource balance during the period March 2004 through May 2004. The Company's load forecast *implicitly* includes the continuing effects of historical Class 2 demand-side management (DSM). For the period 1993 through FY 2004, the amount was 198 average megawatts (MWa). In addition, the Company assumes for its base-case that conservation will reduce loads at the generation level by 250 MWa during the period FY 2005-2014, with a peak effect of 323 MW. This amount is *explicitly* included in the Company's load forecast. It is composed of the Energy Trust's contribution for Oregon, totaling 86 MWa, and a 147 MWa expansion of PacifiCorp's existing conservation programs to other states by 2014.

PacifiCorp expects loads to grow by 2.7% per year on average in the eastern portion of its service territory (Utah, Idaho and Wyoming), and 1.1% in the western portion (Oregon, Washington and California) through FY 2015. The Company forecasts *peak* load to grow on average 3.8% per year in the East and 1.5% per year in the West. Among the six states in its service area, the Company estimates *average annual growth* over the next 10 years at 1.0 % in Oregon and 3.5% in Utah, with summer coincident system peak loads growing in these states at 1.3% and 4.6%, respectively.

According to PacifiCorp's estimates, the system becomes capacity-deficit beginning FY 2009, with the gap growing to about 2,800 MW by FY 2015. The majority of additions are needed in the eastern portion of the system. The gap in PacifiCorp West is a result of a financial and energy problem; the gap in PacifiCorp East is a transmission and capacity problem.

The western side of PacifiCorp's system is capacity-sufficient until FY 2011. The capacity deficit grows to about 1,000 MW in FY 2015. However, the West is energy-deficit in the off-peak period until the expiration of the BPA peaking contract in FY 2012, when the region becomes short during both on- and off-peak hours.

The eastern side of PacifiCorp's system is capacity-deficit during peak hours in the summer beginning in FY 2009. The deficit grows to about 1,800 MW by FY 2015. The off-peak hours are energy-surplus for 10 years without any resource additions.

PacifiCorp's Preferred Resource Strategy

Based on the analysis described below, PacifiCorp selected Portfolio E with DSM as its preferred course of action. Portfolio E with DSM calls for the following resources from FY 2005 to 2015:

- 2,629 MW of thermal generation capacity, consisting of two coal plants and two natural gas plants in the East, and one natural gas plant in the West
- 177 MW of Class 1 DSM (direct load control) resources split between the West and East sides

All portfolios evaluated, including the preferred portfolio, include "Planned Resources" that PacifiCorp has firmly decided to acquire:

- Up to 450 MWa of Class 2 DSM (conservation) resources
- 1,400 MW of renewable resources
- Up to 1,200 MW of shaped capacity resources on a rolling annual basis
- 100 MW of known Qualifying Facilities on the East side

Implementation Actions for PacifiCorp's Preferred Portfolio

The Company requests acknowledgment for the following Action Plan for its preferred portfolio. The Action Plan includes activities for any decision the Company intends to make in the next two to four years. The resource types evaluated in the IRP are considered to be proxy resources representing the fuel type and operating characteristics that best fit the deficit position. PacifiCorp will determine the actual type of resource to acquire during the procurement process. Size is rounded to the nearest 50 MW.

1. Continue to aggressively pursue cost-effective renewable resources through current and future RFP(s)
    - Size: 1,400 MW
    - Resource evaluated in IRP: Wind
    - Timing: FY 2006-2015
    - Location: System

2. Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and up to an additional 200 MWa if cost-effective programs can be found through the RFP process.
   - Size: 450 MWa
   - Resource evaluated in IRP: 100 MW decrements of Class 2 DSM (conservation) at various load shapes
   - Timing: FY 2006-2015
   - Location: System

3. Include Combined Heat and Power (CHP) as eligible resources in supply-side RFPs.
   - Size: n/a
   - Resource evaluated in IRP: Two 45-MW units using National Renewable Energy Laboratory (NREL) cost estimates
   - Timing: FY 2010 (summer of 2009) and FY 2012 (summer of 2011)
   - Location: System

4. Include a provision for Standby Generators in supply-side RFPs. Investigate, with Air Quality Officials, the viability of this resource option.
   - Size: n/a
   - Resource evaluated in IRP: 75 MW in Utah
   - Timing: FY 2010 (summer of 2009) and FY 2012 (summer of 2011)
   - Location: Utah

5. Procure cost-effective summer load control program in Utah by the summer of 2008.
   - Size: 50 MW
   - Resource evaluated in IRP: Irrigation load control
   - Timing: FY 2009 (summer of 2008)
   - Location: Utah

6. Procure cost-effective summer load control program in Oregon, Washington, and/or California by the summer of 2008.
   - Size: 50 MW
   - Resource evaluated in IRP: Irrigation load control
   - Timing: FY 2009 (summer of 2008)
   - Location: Oregon/Washington/California

7. Procure a flexible resource in or delivered to Utah by the summer of 2009.
   - Size: 550 MW
   - Resource evaluated in IRP: Flexible, natural-gas fired combined-cycle combustion turbine
   - Timing: FY 2010 (summer of 2009)
   - Location: Utah

8. Procure a high capacity factor resource in or delivered to Utah by the summer of 2011.
   - Size: 600 MW
   - Resource evaluated in IRP: Pulverized coal plant
   - Timing: FY 2012 (summer of 2011)
   - Location: Utah

9. Continue to work with other regional entities to develop Grid West. Continue to actively participate in regional transmission initiatives (e.g., RMATS, NTAC).
   - Size: n/a
   - Resource evaluated in IRP: Transmission from Wyoming to Utah
   - Timing: FY 2013 and beyond
   - Location: System

10. Incorporate Capacity Expansion Model into portfolio and scenario analysis.
    - Size: n/a
    - Resource evaluated in IRP: n/a
    - Timing: 2006 IRP
    - Location: n/a

PacifiCorp intends to issue an RFP in 2005 for a natural gas-fired plant to be completed by summer 2009 and an RFP in 2006-07 for a coal plant to be in service by summer 2011. Both plants are for the East side of the system. PacifiCorp also plans to issue RFPs to meet 2006 conservation needs outside of Oregon and to acquire load control resources system-wide from 2006 through 2008.

DISCUSSION

Procedural Requirements

Energy utilities must file least-cost plans every two years and involve the Commission and the public in its planning process. *See* Order No. 89-507 at 3. The Commission finds PacifiCorp satisfied these procedural requirements.

PacifiCorp filed this plan approximately two years after filing its previous Integrated Resource Plan. The Company's filing was timely under Order No. 89-507.

The public involvement process included eight public input meetings beginning December 11, 2003, and four technical workshops. PacifiCorp distributed a draft of its plan for comment by participants in November 2004 before submitting its final plan to the Commission on January 20, 2005.

The Commission held a Special Public Meeting regarding PacifiCorp's plan on April 25, 2005. On or before May 23, 2003, the Citizens' Utility Board (CUB), the Oregon Department of Energy (ODOE), Renewable Northwest Project (RNP), Northwest Energy Coalition (NWEC), and the Hydropower Reform Coalition/WaterWatch of Oregon submitted written comments to the Commission and Parties regarding the IRP. PacifiCorp filed a reply to Parties' comments on June 6, 2005. Staff circulated to Parties its comments, recommendations and a draft proposed order on June 27, 2005. The Commission held a second Special Public Meeting on August 1, 2005.

Substantive Requirements

Evaluating resources on a consistent and comparable basis. PacifiCorp's modeling simulated the integration of new resource alternatives with its existing generation and transmission assets. The model uses hourly data for loads, market prices and shaping of hydroelectric resources, considers purchases and sales at four market trading hubs, and takes into account transmission paths and constraints to provide a detailed examination of the economic and operational performance of resource alternatives.

Base-Case Assumptions. The Company modeled on a system-wide basis with the following assumptions for a 20-year study period — April 1, 2005, to March 31, 2025:

- Where possible, new resources are modeled as specific assets.
- Inflation rates not established by external sources are based on the following annual rates:
  - CY 2004-2010 – 2.02%
  - CY 2011-2020 – 2.94%
  - CY 2021-2030 – 3.48%
- Long-term purchases and sales contracts are not renewed, including the following:
  - The West Valley lease expires May 31, 2008.
  - The 400 MW power purchase agreement with TransAlta Energy Marketing expires in FY 2008.
  - The 575 MW BPA peaking contract expires in FY 2012.
  - 127 MWa of interruptible contracts in Utah expire in December 2006.
- Resources are served by firm transmission. There are no changes in transmission rights except those resulting from contractual obligations and transfer capability made available through modeled transmission additions.
- Portfolios are built to match load growth plus a 15% planning margin.
- Loads grow on average 2.1% per year. The East side grows at 2.7% per year on average and the West side at 1.1% through 2015.

- Wind resources contribute to the reserve margin at 20% of their nameplate rating, based on a study performed for the IRP.

- No loads leave PacifiCorp's system over the study period as a result of direct access in Oregon.

- Natural gas prices are based on blending PacifiCorp's near-term forecasts as of June 30, 2004, with a long-term forecast dated May 11, 2004, derived from external sources, primarily PIRA Energy Group. The Company developed two hourly forecasts for natural gas prices: one for the East side (Opal market hub) and one for the West side (an average of prices at Sumas, Stanfield and Opal).

- Delivered coal costs for Wyoming and Utah are based on PacifiCorp's estimates.

- Hourly wholesale electricity prices as of June 30, 2004, for the Mid-Columbia, California-Oregon Border, Four Corners and Palo Verde market hubs are based on near-term forward prices from the market and long-term fundamental price scenarios simulated in the Company's MIDAS model.

- The federal production tax credit will continue at $18/MWh for the first 10 years of operation for wind and closed-loop biomass projects.

- New wind and biomass plants provide a green tag value of $5/MWh for the first five years of production.

- A perfect cap-and-trade regime exists such that there will be a purchaser for all pollutant emissions at the following prices:
  - Sulfur dioxide - $877/ton in 2010
  - Nitrogen oxides - $2,105/ton in 2010
  - Mercury - $40,934/lb in 2010
  - Carbon dioxide (CO_2) - $8/ton (2008$) – In recognition of the timing uncertainty of CO_2 regulation, costs are phased in at $4.19/ton in CY 2010 (representing a 50% probability of an $8.38/ton allowance cost in 2010$), increase to $8.80/ton by CY 2012, and grow at inflation thereafter.

- "Existing Resources" are those currently in operation or for which procurement contracts have been signed as of May 1, 2004, such as the Currant Creek and Lake Side natural gas plants.

- All portfolios include the following resources:
  - 450 MWa of conservation including the Energy Trust's contribution
  - 1,400 MW of renewable resources
  - 100 MW of known Qualifying Facilities on the East side with non-firm pricing contracts (no capacity contribution is assumed)

- Up to 1,200 MW of market purchases on a rolling annual basis. Seasonal transactions are available from one to three years (or more) in advance based on historical operational data and PacifiCorp's forward market view. Transactions include 500 MW of annual 7x24 products on the West side, and on the East side 500 MW of heavy-load hour (HLH) products at Four Corners and 200 MW of HLH products at Mona, both in the third quarter.

Portfolios Tested. Each portfolio specifies the types of resource additions and when and where they would be added, including the estimated cost of transmission upgrades needed to get the power from the new generating resources to PacifiCorp's system. The Company used a "Reference Portfolio" (Portfolio A) to develop eight new portfolios and analyze the effects of resource type, timing and location:

- Portfolio A
  - Dry-cooling natural gas-fired combined-cycle combustion turbine (CCCT) in the East - FY 2009
  - Pulverized coal plant in Utah - FY 2011
  - Dry-cooling natural gas-fired CCCT in the West - FY 2013
  - Single-cycle combustion turbine (SCCT) in the West - FY 2013
  - Wet-cooling natural gas-fired CCCT in the East - FY 2014
  - Integrated Gasification Combined-Cycle (IGCC) coal plant in Wyoming - FY 2015
- Portfolio B – Replace FY 2011 pulverized coal plant with CCCT
- Portfolio C – Replace FY 2009 CCCT with SCCTs
- Portfolio D – Defer Utah pulverized coal from FY 2011 to FY 2014 and move up natural gas CCCT from FY 2014 to FY 2011
- Portfolio E – Replace FY 2015 IGCC with Wyoming pulverized coal plant
- Portfolio F – Substitute FY 2011 Utah pulverized coal plant with a Wyoming plant
- Portfolio G – Build two FY 2013 SCCTs on the East side instead of the West side
- Portfolio H – Replace FY 2014 CCCT with compressed air energy storage
- Portfolio I – Replace FY 2014 CCCT with hydro pumped storage

PacifiCorp then developed a second round of portfolios to reduce present value revenue requirements (PVRR), provide a representative set of portfolios for risk analysis, and test portfolios recommended by PacifiCorp staff and public participants in the IRP process:

- Portfolio J – Portfolio B, with Wyoming pulverized coal replacing IGCC
- Portfolio K - Portfolio C, with Wyoming pulverized coal replacing IGCC
- Portfolio L - Portfolio D, with Wyoming pulverized coal replacing IGCC
- Portfolio M – All natural-gas CCCTs
- Portfolio N - All natural-gas SCCTs and CCCTs
- Portfolio O – Substitute an IGCC plant for the Utah FY 2011 pulverized coal plant

- Portfolio P - Constructed by the Capacity Expansion Model; substitutes a natural-gas SCCT in FY 2014 and a natural-gas CCCT in FY 2015 for the FY 2015 Wyoming pulverized coal plant
- Portfolio Q – Development of two PacifiCorp-owned 345 kV transmission lines to transport power to northern Utah, along with an additional pulverized coal plant in Wyoming

Altogether, PacifiCorp tested 17 portfolio options for meeting its projected resource requirements, plus the stress cases described below. A simulation of each portfolio calculated the operating costs of the new system (portfolio additions plus existing resources) under a common set of assumptions about the future, described above. PacifiCorp then combined operating costs with the capital costs of new resources to determine the present value revenue requirements (PVRR) of each portfolio, which is the sum of year-by-year revenue requirements after accounting for the time-value of money.

Next, the Company screened each portfolio against other performance measures, including capital costs, pollutant emissions, market sales and purchases, unit capacity factors, and system transfers between East and West.

Demand-Side Management Resources. The Company divides DSM into four categories:

- Class 1 - Dispatchable load control of end uses such as air conditioning, water heating, space heating, lighting and irrigation during peak hours
- Class 2 – Conservation, providing long-term energy reductions
- Class 3 – Price-responsive load reduction as a result of short-term price signals, including time-varying pricing, interruptible contracts and the Energy Exchange demand buy-back program
- Class 4 – Energy and capacity reductions achieved through behavioral responses to programs such as Power Forward in Utah, achieving up to 70 MW of load reduction through public appeals to cut back usage during peak hours on critical load days

For Class 1 DSM resources, the Company’s base case includes 125 MW of load control by 2006 — maintaining the Idaho irrigation program at current levels (35 MW) and increasing air conditioning control to 90 MW.

New this planning process, PacifiCorp modeled potential direct load-control programs as resources that could compete with supply-side options. The Company did not determine the types and amounts of new load control resources in its full portfolio modeling. Rather, the Company used its new Capacity Expansion Model to select among eight proxy programs. The amounts evaluated were limited to 100 MW each. The Company then added to its preferred Portfolio E the selected load-control resources and analyzed the benefits of resource deferral. Three resources were deferred as a result of adding direct load control resources, reducing the PVRR of Portfolio E by $134 million:

- The Utah gas-fired CCCT was deferred from FY 2009 to FY 2010.
- The Utah pulverized coal plant was deferred from FY 2011 to FY 2012.
- The West-side gas-fired SCCTs were deferred from FY 2014 to beyond the period covered by the Action Plan.

Based on this modeling, the Company plans to add a total of 40 MW of load control beyond the base case assumptions on the East side and 40 MW on the West side by FY 2009. The preferred portfolio includes an additional 40 MW of load reduction each on the East and West sides of the system by FY 2014. The total amount of Class 1 programs assumed in the IRP is 302 MW over 10 years — 125 MW in the base case, plus 177 MW of new resources if found to be cost-effective.

Next, the Company performed a "decrement analysis" on its preferred Portfolio E with Class 1 DSM resources to further improve the PVRR. The decrement analysis estimated the reduced system operating costs from a range of Class 2 DSM (conservation) programs. The Company ran the IRP model with and without eight 100 MW conservation decrements to the load forecast on the East and West sides shaped to the following loads: residential cooling, commercial cooling, commercial lighting, and total control area. The decrements began in FY 2009.

Based on the decrement analysis, the Company plans to acquire an additional 200 MWa of conservation resources outside Oregon if found to be cost-effective through RFPs. To make that determination, the Company plans to re-run its decrement analysis with updated gas and electricity price forecasts.

PacifiCorp did not model Class 3 DSM programs in the IRP. At its May 2005 public input meeting, however, the Company stated that it will allow load curtailment (i.e., interruptible loads) of 25 MW or larger to bid into its RFP for 2009 resources.

Uncertainty. PacifiCorp performed risk analysis on the seven portfolios with the lowest PVRR under the Company's base-case assumptions. In least-cost order, they are portfolios M, P, K, E, L, N and J. The Company also performed risk analysis on Portfolio Q, the costliest portfolio, because it represented a transmission expansion scenario (with a third coal plant), as well as the 12% and 18% planning margin stress cases.

PacifiCorp sorts future risks and uncertainties into three categories: paradigm, stochastic and scenario risk.

Paradigm risks represent radical changes. PacifiCorp addressed the potential impact of paradigm risks in a qualitative, rather than quantitative, manner. The Company discussed the possible impacts of major changes in market structure or regulatory requirements, such as customers choosing alternative suppliers in states allowing direct access and changes in transmission operation and control resulting from formation of a regional transmission organization. Other examples of paradigm risks include changes in state or federal mandates, such as establishment of a renewable portfolio standard and innovative emissions regulation.

The Company also discusses how it would handle a significant change in loads or resources (IRP at 190):

> Material shifts in either loads or resources could affect the timing and size of major resource additions. Examples of significant changes that could occur include a large loss of load under retail competition (OR SB1149), the dramatic reduction in load from a large end-use customer or customers or a terrorist event that could impact the economy. Another example includes a substantial increase in the power that is sold to PacifiCorp from Qualifying Facilities which could result in a decrease in the need for a new resource and could change the timing and/or mix of the planned resources.
>
> Possible paths PacifiCorp could take if a major shift in either the loads or resources would occur include:
>
> - Delay or accelerate resource procurement(s)
> - Reassess the amount and timing of the need

Stochastic risk is quantifiable as a known fluctuation around an expected value. PacifiCorp quantified the variability of five risks: (1) retail load, (2) natural gas prices, (3) electricity prices, (4) hydroelectric generation and (5) thermal unit outages. PacifiCorp then used Monte Carlo simulation to model the performance of top-performing and representative portfolios in 100 model runs. The simulation allows PacifiCorp to address the asymmetric nature of these risks as well as the interactions among them.

Portfolio E outperformed the other portfolios on most measures of stochastic risk:

- Portfolio E had the lowest average stochastic cost (stochastic variable costs plus the deterministic fixed cost) based on the 100 model runs.
- Portfolio E had the second lowest standard deviation and variance, following Portfolio Q, based on the 100 model runs.
- Portfolio E had the second lowest average risk based on the difference between the average stochastic cost and the deterministic cost, following Portfolio Q.
- Portfolio E was among the four with the best “upper tail” results, based on the average of the five worst model runs. Portfolios E, Q, K and L have statistically equal upper tail average costs.
- Portfolio E was among the five portfolios (along with portfolios K, L, Q and the 12% planning margin case) with the least risk relative to cost, based on two types of cost-risk tradeoff: (1) deterministic PVRR (costs under the Company’s base-case assumptions) vs. the average upper-tail (worst case) results and (2) average stochastic cost vs. the standard deviation of stochastic costs.

PacifiCorp also performed a “spark spread” stochastic analysis that allowed only natural gas and electricity prices to move randomly along with thermal plant outages; loads and hydro generation remained constant. The purpose of this analysis is to measure the impact of volatility due primarily to price fluctuations. Portfolios E, K and Q performed better under this test than all-gas portfolios M and N.

Due to natural gas price volatility, portfolios with fuel diversity in capacity additions such as Portfolio E exhibited less risk than all-gas portfolios M and N. Portfolio Q, with significant new transmission providing greater market access along with three new coal plants, also performed well in the stochastic analyses.

Scenario risks represent abrupt changes in risk factors. PacifiCorp performed a high natural gas price analysis and various CO_2 allowance cost analyses on all-gas portfolios M and N, which had the lowest deterministic costs, as well as portfolios E, K, L and Q, which performed well in the stochastic analyses.

The “high gas” scenario tested the portfolios’ sensitivity to a large fundamental increase in natural gas prices. The Company used as the basis an updated PIRA Energy Group forecast, which the Company planned to use in its December 31, 2004, official price forecast for CY 2005 to 2015. This update is on average $2.27/MMBtu higher at Henry Hub than PacifiCorp’s base-case forecast. The Company increased this updated forecast by 10% to create a higher sensitivity case. In addition, a real escalation adjustment reflects the possibility of gas demand outpacing gains in production in the long term. The Company developed a “high gas” power price forecast in the MIDAS model for the scenario analysis.

Under the high gas case, the PVRR of all portfolios increased between 6% and 13% and market transactions were exercised more fully. All-gas Portfolio M was the most significantly affected, moving from least-cost to sixth place. Portfolios E, K and Q, with the least amount of natural gas generation, performed best.

At its May 2005 public input meeting, PacifiCorp stated that its current natural gas price forecast for the 20-year planning period is about 40% higher, and its Mid-Columbia electricity price forecast is about 17% higher, than the base-case forecasts used in the IRP.

In compliance with Commission Order No. 93-695, PacifiCorp performed scenario analysis on the following CO_2 regulatory cost adders (2010$):

- $0
- $14.90 ($10 in 1990$)
- $37.25 ($25 in 1990$)
- $59.60 ($40 in 1990$)

As in its base case, PacifiCorp assumed for each analysis that the adder begins in 2010 with a 50% likelihood of occurrence, with the allowance fully implemented in 2012 and growing at inflation thereafter. The Company also assumed a maximum allowable amount of emissions system-wide fixed at 2000 levels and a perfect cap-and-trade system.

Three variables are modified in response to changing CO_2 allowance costs: electric market clearing prices, natural gas prices and allowance costs for other pollutants. The analysis provides deterministic, rather than stochastic, results.

PacifiCorp concludes that there is little impact to PVRR or differentiation in portfolio performance at its base-case assumption of an $8.38/ton (2010$) allowance cost. Significant differences occur, however, at the low- and high-end allowance cases.

Portfolio Q, with major transmission additions and a third coal plant, had the lowest PVRR in a scenario with no carbon regulation. All natural-gas Portfolio M was the least-cost portfolio for all other cases, including the Company's base-case allowance. Portfolio M generates substantial emissions credits by reducing existing coal operations and running new and existing gas plants more. At the same time, this portfolio is most significantly affected by the high fuel prices resulting from high CO_2 adders in the $37.25/ton and $59.60/ton cases.

At a regulatory cost of $33/ton CO_2 (1990$), PacifiCorp estimates that an IGCC plant with CO_2 capture and sequestration is cost-effective, compared to a supercritical pulverized coal plant without it.

Primary goal must be least-cost/consistent with long-run public interest. PacifiCorp tested 17 portfolios plus six stress cases consisting of a variety of resources. The portfolios were designed to meet the Company's forecasted loads and a 15% planning reserve margin.

Planning reserve margin is a way to balance the tradeoff between resource adequacy and cost. It represents the difference between a control area's expected annual peak capability (including long-term firm wholesale purchases) and its expected annual peak demand (retail sales plus long-term firm wholesale sales), expressed as a percentage of the expected annual peak demand.

PacifiCorp conducted a separate planning margin study for the 2004 IRP. First, the Company built loads and resources for a sample year (FY 2009) to several levels of planning margin for the system peak hour. Then, the Company stressed variables such as unit forced outage, hydro availability and weather-caused load variations in 100 runs using the MARKETSYM hourly model.

A loss of load hour is where demand exceeds supply, but provides no indication of magnitude or duration of the outage. Unserved energy is the amount of obligation not served over a period of time. "Expected" unserved energy is the *average* unserved energy over 100 model runs when systems are stressed stochastically.

To estimate the cost of unserved energy, the Company used a weighted average of interruption costs by customer class, based on 1990 estimates from the Electric Power Research Institute (EPRI) for Pacific Gas & Electric (PG&E). PacifiCorp used the capital cost of a natural gas-fired SCCT, at $72/kW/year, to estimate the cost of reducing unserved energy for each planning margin level. The model also could call on other supplies in the Western Electricity Coordinating Council (WECC) region, up to firm transmission rights.

PacifiCorp compared the lower costs of expected unserved energy with the costs of the additional resources needed to achieve each planning margin tested. The Company concluded that a 15% planning margin, which represents a loss of load probability of two days (48 hours) in 10 years, strikes a balance between reliability and cost. The Company deemed this level as minimizing total costs, including the capital costs of new resources plus the cost of unserved energy. Setting the margin above 15% did not provide a significant increase in system reliability, but would cost significantly more.

Least-Cost Portfolio. PacifiCorp's examination of what is "least-cost" is based in part on its calculation of PVRR of each portfolio using a discounted cash-flow model. In addition to assessing and comparing the capital and operating costs of each portfolio, PacifiCorp identified risk factors such as volatility of fuel and spot market prices, current and potential federal regulations, and load fluctuations. The Company assessed cost variability of the resource scenarios and impacts on rates.

In addition, the Company evaluated trade-offs among the portfolios, such as PVRR versus risk. Further, PacifiCorp evaluated scenarios that indicate the potential long-run costs of its resource choices, including possible shifts in societal values such as enactment of regulations for CO_2 emissions. Ultimately, PacifiCorp selected what it thought was the best resource portfolio, considering PVRR and other analyses, as the basis for preparing the Action Plan.

Portfolio M, the all natural-gas portfolio, was the least-cost portfolio under PacifiCorp’s base-case assumptions. The PVRR for Portfolio M is $29 million, or about 0.2%, lower than Portfolio E. Other portfolios performing well in this “deterministic” analysis were Portfolios P, K, L, N and J and the 12% planning margin case.

Based largely on the stochastic risk analysis described above, PacifiCorp chose Portfolio E, with a combination of natural gas and coal plants, as its “least cost, risk informed” portfolio. Portfolio K, with SCCTs instead of a CCCT added in FY 2009, had a nearly identical cost and risk profile compared to Portfolio E.

PacifiCorp chose Portfolio E over Portfolio K because of the Company’s operating experience with CCCTs, potential to share common plant facilities and spare parts with other CCCTs in Utah, better heat rate and lower emission rates. On balance, PacifiCorp found the advantages of SCCT technologies, including greater dispatch, build flexibility and lower capital cost, did not outweigh the advantages of a CCCT for the FY 2009 East-side resource.

Reducing PVRR of the Preferred Portfolio. After selecting Portfolio E, the Company performed load control analysis and conservation decrement analysis to evaluate the cost-effectiveness of potential new DSM programs, as described above. The Company also performed *stress tests* on Portfolio E to assess the following potential improvements:

- *Planning margins that are lower and higher* than the 15% level used in developing the portfolios (12% and 18%).

- *Replacement of market purchases* with CCCT plants in FY 2009 and FY 2013. This stress case demonstrated that the shaped market transactions included in the Action Plan are significantly more cost-effective than building or buying long-term assets.

- *Procurement of an IGCC resource in FY 2011*, instead of a pulverized coal plant. This stress case was based on more recent information on technology and cost, compared to the IGCC portfolios initially studied. Capital costs and fixed O&M costs are higher, but availability increased from 75% to 90%. While the PVRR of the early IGCC portfolio is slightly lower than Portfolio O, which is based on older information, it is still $222 million higher than Portfolio E. For perspective, however, the early IGCC portfolio translates into an average annual rate increase of about 2.7% for FY 2006 to 2016, which PacifiCorp considers not significantly different than the customer impact results for other portfolios.

- *Procurement of 90 MW of combined heat and power (CHP) resources* on the West side in FY 2013. With the assumption that these resources are firm, this stress case eliminated the need for a 97 MW SCCT in the West and lowered the PVRR by $37 million.

- *Procurement of 75 MW of customer-owned dispatchable standby generation*. For this stress case, PacifiCorp assumed it could acquire control of 25% of the approximately 300 MW of existing standby generators in its Utah service area by FY 2009. These are typically backup diesel generators at large commercial and industrial facilities. This stress case delayed by one year each a natural gas plant and a coal plant. The stress case also assumed PacifiCorp could acquire 40 MW of standby generation in the West, avoiding one 97 MW SCCT. Compared to Portfolio E, the PVRR for this portfolio is $60 million lower, with a reduction in capital costs of almost $130 million. PacifiCorp expresses concern, however, about air quality restrictions in Salt Lake City.

The Company did not make any changes to Portfolio E based on these stress tests. However, the Action Plan includes CHP and standby generation as eligible resources for supply-side RFPs.

<u>Consistency with Oregon's energy policy</u>. Oregon's overall energy policy is stated in ORS 469.010. The policy states, in part, "[i]t is the goal of Oregon to promote the efficient use of energy resources and to develop permanently sustainable energy resources." The IRP promotes the efficient use of energy resources through DSM Action Plan items. The Action Plan also includes acquisition of 1,400 MW of renewable resources.

Parties' Comments

As discussed above, in the months preceding this order, ODOE, CUB, RNP, NWEC, Hydropower Reform Coalition/WaterWatch of Oregon, Staff and PacifiCorp filed written comments regarding the Company's IRP. Further, the Parties had opportunity for oral presentations to the Commission at two Special Public Meetings, on April 25 and August 1, 2005. Following is the Commission's discussion of issues raised by the Parties, concluding with their overall recommendations, as well as the Commission's disposition.

<u>Load forecast</u>. Staff notes that for representative and top-performing portfolios, PacifiCorp tested retail load fluctuations stochastically in combination with other key variables. According to the Company, retail load varied in the model from 0.5% to 2.9% of the forecasted load growth rate.

Staff believes scenario risk analysis of load forecast error is useful in understanding the potential performance of portfolios in the event loads deviate significantly from projections. Therefore, Staff asked PacifiCorp to develop a new hourly load forecast that is two standard deviations lower than the Company's base-case assumption. Using that new forecast, Staff asked the Company to provide the deterministic PVRR of the portfolios for which the Company performed other scenario analysis. No portfolios were changed; only operational changes resulting from reduced load requirements were simulated in the hourly dispatch model. This scenario provides an indication of the relative performance of portfolios when loads turn out lower than the Company forecasted and, therefore, the system is overbuilt in hindsight.

According to PacifiCorp, a growth rate two standard deviations lower represents load growth at 0.4%, compared to the assumed 1.3% growth rate, and a total load that is 93.4% of the Company's base-case forecast. For comparison, the difference in loads between the base case and Staff's lower load scenario is roughly equivalent to the difference between the Medium and Medium Low demand forecasts for the Northwest Power and Conservation Council's Fifth Power Plan. However, the Council's Medium Low forecast is closer to one standard deviation, than two standard deviations, from the Medium forecast.

Staff notes that the deterministic PVRR of all portfolios is lower under its load scenario, presumably the result of increased sales and reduced fuel and other O&M costs. Staff points out that PacifiCorp's preferred Portfolio E performs the worst of the six portfolios evaluated under the lower load scenario, and all-gas Portfolio M moves from least-cost among the 17 portfolios tested in the IRP to third place among the six portfolios PacifiCorp included in scenario analysis.

Portfolio Q, which expands transmission into Wyoming to allow greater access to shorter-term market transactions and includes a third coal plant, moves from the worst-performing of all 17 portfolios in the IRP to the least costly of the six portfolios tested. Because no portfolio in the IRP isolates the effect of building only transmission facilities, Staff states that it cannot tell whether the improved PVRR of Portfolio Q in the reduced load scenario is the result of more market transactions, fuel type (more coal and less natural gas), or a combination of these and other factors. *See* PacifiCorp's Response to Staff Data Request No. 1.

Regarding the effect of restructuring on loads, Staff agrees with PacifiCorp that it should continue at this time to plan to serve the entire forecasted load in its Oregon service territory on a long-term basis given the level of participation in direct access to date and customers' ability to return to cost of service rates each year. Staff believes this issue should be revisited if direct access participation increases significantly, if the Company adopts and has sizable participation in a tariff similar to Portland General Electric's five-year opt-out program, or if customers participate in a permanent opt-out tariff as envisioned in Commission Order No. 05-133.

Commission disposition: The Commission expects to see worst-case risk analysis in IRPs, including the risk that retail loads could vary significantly above or below forecasts. In addition to stochastic worst-case analysis that takes into account a number of variables, including retail load fluctuations, the Commission is interested in scenario risk analysis indicates how portfolios may perform if loads deviate significantly from projections.

Planning reserve margin. CUB suggests that a planning margin lower than 15% would be justified if it could help defer a coal plant, as described under "Coal plant," below.

PacifiCorp asserts that changing the planning margin for the purpose of avoiding investment in one type of technology or fuel type is inappropriate. Moreover, the Company states it decides technology and fuel type in the procurement process.

In support of its selected planning margin, the Company lists the factors it considered, including its obligation to provide reliable low-cost power, WECC reserve requirements, a stochastic system dispatch analysis of planning margin impacts on reliability, a cost-risk tradeoff analysis for various planning margin levels, deterministic cost analysis of 12% and 18% planning margin cases, the economic implications of physical short exposure to markets, industry standard reliability thresholds, and planning margin assumptions made by other Western utilities. The Company opines that until there is clarity regarding possible resource adequacy standards under development by regional organizations, there is no compelling reason for it to change its methodology for determining the optimal planning margin.

Staff is not convinced that the benefits of the Company's proposed 15% planning margin outweigh the costs. Staff notes that the 12% planning margin stress case portfolio had a PVRR about $140 million, or 1%, lower than Portfolio E which like other portfolios assumes a 15% planning margin. The all-in stochastic cost for the 12% stress case was only 0.2% higher compared to Portfolio E, with an upper tail PVRR (average of five worst results) just 1.2% higher. Staff further notes that production and fixed costs for the 12% stress case are significantly lower than for Portfolio E, although total variable costs are higher due to greater market purchases and lower sales revenues.

Staff acknowledges that based on PacifiCorp's analysis, the loss of load probability for a 12% planning margin would be about four days in 10 years. However, Staff points out that the actual planning margins for the 12% stress case would be higher most years, presumably the result of large, lumpy resource additions and planning to the single peak hour of the year: 15% in FY 2006-2008 and 2011, 14% for FY 2009 and FY 2014, and 13% for FY 2012; it would dip to 12% only in FY 2010, FY 2013 and FY 2015. *See* IRP Technical Appendix at 83.

Staff is skeptical of the unserved energy costs PacifiCorp used in its planning margin analysis. Staff expresses concern that they may be out-of-date, they are not from PacifiCorp's service area, and they are very high. They come from a 1990 EPRI study for PG&E in California, and range from $5,210/MWh for agricultural customers to $6,590/MWh for residential customers and from $15,290/MWh for large industrial customers to $44,910/MWh for small commercial customers. PacifiCorp took the weighted average of these numbers, $24,000/MWh, and used that value for setting the planning margin.

Staff notes that the recent Statewide Pricing Pilot in California shows that residential customers are willing to curtail loads at prices far lower than the interruption costs PacifiCorp used in the IRP study. Similarly, ODOE notes "…there are many customers willing to voluntarily reduce their use at prices well below 100 times normal retail prices. PacifiCorp did not consider a serious 'buy back' program to assure reliability in a resource short situation." *See* ODOE Opening Comments at 17.

Staff points out that even at these high assumed interruption costs for customers, the "bathtub chart" curve for residential and agricultural customers bottoms out at a planning margin of about 12%. *See* IRP Technical Appendix at 221. Staff indicates that voluntary load reductions from customer classes with the lowest interruption costs should be taken into account in estimating the costs of reducing unserved energy.

Further, Staff states that some demand response resources, such as interruptible contracts and the Energy Exchange program, have lower fixed costs than SCCTs, which served as the basis for the Company's estimated cost of reducing unserved energy. Such programs could make a planning margin higher than 12% more attractive, but these DSM resources were not included anywhere in the planning margin or portfolio analyses.

Staff points out that in July 2004 the Commission acknowledged for Portland General Electric's IRP a planning margin of 12%, consisting of 6% operating reserves as required by WECC and an additional 6% planning reserve, all under average hydro conditions. *See* Order No. 04-375.

Staff notes that the planning margin was determined on the basis of meeting the single peak hour of the year. Staff asked the Company to reproduce its system and East side coincident capacity charts if instead of planning to the coincident peak hour for the Eastern control area the Company planned to the "super-peak" period — the average of the eight super-peak hours. Staff points toward data showing planning reserve capacity could be reduced by some 200 MW in FY 2011 and FY 2012, for example, if the Company planned to the super-peak period instead of the single peak hour of the year. *See* PacifiCorp's Response to Staff Data Request No. 4.

Staff asked the Company what would be the resulting preferred portfolio and its PVRR if the Company planned to the average of the super-peak period instead of the single peak hour. The revised obligation amount had no impact on the timing of the capacity additions in Portfolio E. The Company therefore constructed an alternative portfolio, assuming the FY 2010 CCCT is replaced by SCCTs with a lower overall amount of capacity — 174 MW in FY 2010 and another 174 MW in FY 2011. The deterministic PVRR of the revised portfolio is $100 million less than Portfolio E. *See* PacifiCorp's Response to Staff Data Request No. 5.

Staff advises that the planning margin be an analysis *variable* in the modeling of all portfolios. Staff asserts that the methodology used by the Northwest Planning and Conservation Council in its Fifth Power Plan to analyze the appropriate planning margin is superior to PacifiCorp's methodology. The Council assesses the cost-risk tradeoff of various planning margins *within* its portfolio modeling. In contrast, PacifiCorp predetermined the planning margin for all portfolios in a sideboard analysis (15%), then conducted stress tests of two other levels (12% and 18%) based on the initial Reference Portfolio A, which was not among the top-performing portfolios.

Staff recommends that for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp determine the appropriate planning margin by analyzing the cost-risk tradeoff of various planning margins *within* stochastic modeling of portfolios, rather than as a separate analysis as in the 2004 IRP. Ideally, Staff recommends that the Company analyze the cost-risk tradeoff of *all* portfolios at various planning margins. At a minimum, Staff recommends that the Company initially build all portfolios to a set planning margin, test them stochastically, and adjust top-performing portfolios to higher and lower planning margins for further stochastic evaluation. Staff also recommends that the Company evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy.

Staff further recommends that the Company evaluate alternatives for determining the expected annual peak demand — for example, planning to the average of the eight-hour super-peak period, instead of the single peak hour of the year.

Commission disposition: PacifiCorp's IRP analysis does not satisfy that its proposed 15% planning margin is appropriate. The 12% planning margin stress-case portfolio is less costly on a deterministic basis, and its expected stochastic cost and upper tail cost are similar to Portfolio E which includes a 15% planning margin. The assumed costs to customers of unserved energy, and the cost for reducing it, are disputable. Moreover, the Company did not fully analyze the cost-risk tradeoff of various planning margins within stochastic modeling of portfolios. A planning reserve margin of 15% is not acknowledged.

For its next IRP or Action Plan, PacifiCorp should determine the appropriate planning margin by analyzing the cost-risk tradeoff within stochastic modeling of portfolios. In particular, the Company should assess the cost-risk tradeoff of each portfolio at various planning margins, or explain why it cannot do so. In that case, the Company should at a minimum build all portfolios to a set planning margin, test them stochastically, and adjust top-performing portfolios to higher and lower planning margins for further stochastic evaluation. The Company also should evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Further, the Company should evaluate alternatives for determining the expected annual peak demand — for example, planning to the average of the eight-hour super-peak period, instead of the single peak hour of the year.

Demand-side management. CUB asserts that the primary driver behind the "presented urgency to make a coal investment decision … is growth in load in Utah.… The IRP has not satisfied us that all possible measures have been, or will be, taken to aggressively address the real problem by reducing the Company's East-Side peak load." *See* CUB Opening Comments at 13.

CUB maintains that PacifiCorp has known for a decade that Utah's load growth, including its peak loads, are cost drivers. While the average annual growth of Oregon's contribution to PacifiCorp's system coincident peak has been negative over the past 13 years, Utah's contribution has grown an average of 6.2% each year, CUB states. *See* IRP Technical Appendix, Table I.4. CUB notes PacifiCorp's forecast that over the next 10 years, Oregon's contribution to system coincident peak load will increase by an average of 1.3% per year, while Utah's contribution will grow by 4.6% per year. *See* IRP Technical Appendix, Table I.5.

On an energy basis, CUB points out that Utah's load growth has outstripped Oregon's by nearly 10 times over the last 13 years, and PacifiCorp expects Utah's load growth rate to outpace Oregon's by a factor of three from 2006 to 2015. *See* IRP Technical Appendix, Table I.3.

CUB states, "During the Energy Crisis, PacifiCorp felt the sting of having less resource available to serve load, in part because of the remarkably aggressive rate of Utah load growth. We wonder if this rush to add base-load coal is both a too-late reaction to serving Utah's inexorable load growth, and an overreaction to it through massive base-load additions." *See CUB Opening Comments at 14.*

CUB acknowledges that the Company's IRP begins to address the East side peaking problem, but notes that of the nine activities PacifiCorp identifies that are reducing peak loads on the East side today, load reductions for four of them are not included in the IRP analysis and reductions from 261 MW of interruptible contracts are not included after expiration of current contracts. *See* PacifiCorp's Response to CUB Data Request No. 4. CUB opines that the Company should assume for planning purposes that reductions from interruptible contracts continue, and take actions to ensure they do.

CUB wonders if PacifiCorp is sufficiently aggressive in its pursuit of load reductions for air conditioning, irrigation and industrial loads. CUB maintains, "If the Company does not rely on its DSM programs in its IRP, then the IRP will include enough resources such that the Company won't need those DSM programs." *See* CUB Opening Comments at 15.

PacifiCorp states that it is aggressively pursuing DSM, noting a 60% increase in Class 2 DSM from 2002 to its goal for FY 2006, including Energy Trust programs. Further, Class 1 DSM resources have grown from zero in 2002 to over 90 MW in summer 2005 in the East. PacifiCorp plans to increase this level to more than 150 MW by 2008, and the Action Plan envisions a larger build-out over the planning period. Including its 261 MW of customer curtailment agreements in the East, PacifiCorp states that the net peak effect of existing and planned DSM over the next 10 years is 866 MW.

Conservation (Class 2 DSM). NWEC generally supports PacifiCorp's evaluation of DSM resources. However, NWEC criticizes the Company's analysis of cost-effective conservation opportunities. The Company first identifies a preferred portfolio and then runs a decrement analysis on that portfolio to identify how much conservation is cost-effective. NWEC maintains that the approach means that the risk reduction benefits of conservation are not analyzed, because all risk analysis is performed *before* the decrement analysis. Therefore, NWEC states, this approach underestimates the potential value of conservation as a tool for mitigating fuel price and environmental regulatory risks to ratepayers.

NWEC points out that the low-cost DSM investments PacifiCorp identified in the decrement analysis delay the need for East and West supply-side resources and reduce costs to customers.

PacifiCorp responds that it followed the general guidelines for decrement analysis as described by a 1995 report by the Tellus Institute. PacifiCorp states that the methodology captures the value of reduced fuel use and pollutant emissions for a large block of potential DSM, although small blocks may not capture these values because they may not register a change in PVRR.

Staff asked PacifiCorp for all information the Company relied on to determine the types of conservation programs that are cost-effective and the savings achievable through 2015. The Company provided a 2001 Tellus Institute study, *An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah*, prepared for an advisory group to the Utah Public Service Commission. The Company also reviewed the Council's Fifth Power Plan to get an indication of potential program areas. Further, the Company's 2003 RFP for DSM resources provided an indication of practical resource availability. The Company plans to update its decrement values using updated market prices and its IRP methodology to assess cost-effective bids in future DSM RFPs. Staff points out, however, that "Further market potential analysis will not result in increased DSM resources." *See* PacifiCorp's Response to Staff Data Request No. 9.

Regarding NWEC's concern that PacifiCorp's sideboard decrement analysis of conservation does not appropriately credit conservation for reducing risk, Staff points out that analysis in the Council's Fifth Power Plan showed risk reduction as a significant benefit of conservation resources.

Staff recommends that the Company acquire all conservation found to be cost-effective up to the levels required to serve load growth, whether through RFPs or in-house programs, and not apply what it views as an artificial cap of 200 MWa for those additional programs. Staff therefore proposes the following modification to Action Item 2: Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth.

Staff also recommends that for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in its Utah service area over the IRP study period and assess how the Company's base and planned programs compare with the cost-effective amounts determined in the study.

Further, Staff recommends that for the next IRP or Action Plan, PacifiCorp develop supply curves for various types of Class 2 DSM resources and evaluate whether modeling them as portfolio options that compete with supply-side options — including an analysis of the risk reduction benefits — is preferable to the current decrement approach.

Dispatchable Load Control (Class 1 DSM). As context for its comments, Staff highlights Docket No. UM 1093, where the Commission ordered that "The utilities' Integrated Resource Plans should evaluate demand response programs on par with other options for meeting energy and capacity needs." *See* Order No. 03-408, Appendix A at 1.

Staff commends PacifiCorp's Class 1 DSM analysis in the 2004 IRP as a good first step toward treating demand response resources on par with supply-side resources.

Staff notes that the Company found that Class 1 resources are highly cost-effective, reducing PVRR of Portfolio E by $139 million for a present-value cost of only $4.6 million. *See* IRP at 167. Staff believes that the cost-effectiveness of the identified resources suggests that there likely are more Class 1 DSM resources available that would be attractive at costs above this level. Staff notes that the Company's evaluation of Class 1 resources was conducted as a sideboard analysis, and only on the Company's preferred portfolio, rather than *within* portfolio modeling.

Staff recommends that the Company use RFP and in-house analyses to develop supply curves for a wide variety of Class 1 resources spanning a range of costs. Staff further recommends that for the next IRP or Action Plan, PacifiCorp not place firm constraints on the amount of Class 1 DSM resources modeled and test them only in the preferred portfolio, but instead test various amounts and types in portfolio modeling as resources that compete with generating resources.

Price Responsive Load Reduction (Class 3 DSM). Staff criticizes the Company for performing no modeling of Class 3 DSM programs in the IRP and including no peak reductions from such programs in its analysis. Staff notes the following statements: "The load reductions observed through implementation of these programs at PacifiCorp are neither predictable, consistent or persistent," and "These types of programs are not included in this IRP as a long-term reliable resource…." *See* IRP at 31 and 82.

Staff points out that long-term pricing programs at other utilities show persistent load reductions during peak periods and help avoid the need for new power plants. Staff cites Georgia Power, whose two-part real-time pricing program has the highest level of participation and is the most extensively analyzed program in the U.S. As of 2002, the program had 1,500 participants and provided a peak load reduction of 1,000 MW. *See* Oregon Public Utility Commission Staff, *Demand Response Programs for Oregon Utilities*, presented at the Commission's June 3, 2003, public meeting.

Staff sent a letter to PacifiCorp on August 3, 2004, advising the Company of Staff's view on including Class 3 programs in IRP modeling: "Including the result of such programs in the load forecast as the reductions occur is insufficient. Only portfolio modeling can accurately advise the company of the cost-effectiveness of such programs for critical peak and other hours of the year, relative to other resource options." PacifiCorp responded in a letter on August 25, 2004: "[T]he Company's demand buy-back programs cannot be modeled as a firm long-term resource because the programs are designed more as a short-term tactic to manage significant price increases…. Customer curtailment only occurs if the prices are very high and the customer has flexibility in the production of their product." Staff similarly criticized the approach in its written comments on the draft 2004 IRP.

Staff believes the Company's evaluation of Class 3 DSM programs falls short of the mandates in Commission Order No. 89-507 that least-cost planning "…requires consideration of all known resources for meeting the utility's load, including…those which focus on conservation and load management, the 'demand side,'" and "…rate design should be treated as a potential demand-side resource." *See* Order No. 89-507 at 2 and 10. Further, Staff highlights the Commission's requirement in Docket No. UM 1093 to "…evaluate demand response programs on par with other options for meeting energy and capacity needs." *See* Order No. 03-408, Appendix A at 1.

Moreover, Staff points out the Commission's direction in its order on PacifiCorp's 2003 IRP: "[T]he Commission will require for the next IRP or Action Plan Pacific brings forward for acknowledgment, that it assess Class 1, Class 3 and Class 4 DSM resources in Oregon and include in the portfolios those DSM resources that are least cost." *See* Order No. 03-508 at 20.

Relying on prior Commission decisions, Staff states that potential new interruptible contracts and demand buybacks such as the Energy Exchange, should be modeled as resources that compete with supply-side resources. Staff asserts that based on the Company's extensive experience with the Energy Exchange in 2000 and 2001, the Company could determine a portion of this resource that can be treated as firm. For illustrative purposes, Staff explains that if customer participation varied from 30% to 60% of identified curtailable load at a market price of $150/MWh, the Company could treat 30% of the identified curtailable load as firm at $150/MWh. Spread over a sufficient number of participants, Staff asserts that the Company could reasonably estimate the probability of participation levels at somewhat lower prices, as well. Staff states that such analysis may need to be performed in stochastic modeling, because deterministic modeling assumes base-case market prices rather than price excursions.

Regarding *existing* interruptible contracts, Staff disagrees with the Company's planning assumption that they would not be renegotiated upon expiration, or that there would be no other such contracts to take their place. The apparent result is that no interruptible contract capability is assumed in the IRP after the 127 MWa of Nucor and Monsanto contracts in Utah expire in December 2006. *See* IRP Technical Appendix at 41. Staff notes that renegotiation of these contracts would significantly reduce the need for additional new generating resources.

In addition, Staff cites comments on the IRP by the Utah Association of Energy Users: "[T]he IRP does not include any of the US Magnesium interruptible load as a resource, even though US Magnesium's 85 MW load is subject to curtailment during the hottest peak hours of the summer and US Magnesium is required by contract and Commission order to assume the risk of both pricing and availability of market resources during peak summer hours." *See* Comments of the Utah Association of Energy Users at 20-21, Utah PSC Docket No. 05-2035-01.

Staff recommends that for its next IRP or Action Plan, PacifiCorp determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options. Staff further recommends that existing interruptible contracts be assumed to continue unless the Company for good reason believes they will not be renegotiable or other resources would provide better value.

Commission disposition: The Commission concurs with Staff's assessment that PacifiCorp's proposed acquisition of Class 2 DSM programs should not be capped based on the limited analysis in the IRP. The Commission agrees with Staff's proposed modification to Action Item 2: Acquisition of 250 MWa of base Class 2 DSM and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth, is acknowledged.

In addition, for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should:

- Conduct an economic analysis of achievable new Class 1 and Class 2 DSM measures in its Utah service area over the IRP study period and assess how the Company's base case and planned programs compare with the cost-effective amounts determined in the study.
- Develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.
- Determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options.
- Assume that existing interruptible contracts will continue unless the Company for good reason believes they are not renegotiable or other resources would provide better value.

Non-hydro renewable resources. CUB criticizes the Company for failing to reexamine the amount of wind resources that is now cost-effective and appropriate. CUB acknowledges PacifiCorp's concern that wind resources beyond the 1,400 MW assumption PacifiCorp carried forward from its 2003 IRP could be difficult to integrate into its system. CUB states that wind integration requires flexible resources that can ramp up and down to take full advantage of whatever wind generation is available, and that choosing to add a significant amount of inflexible base-load coal would exacerbate PacifiCorp's integration concerns. CUB states that PacifiCorp not only failed to fully examine wind's potential, but in so doing selected a portfolio that hinders the integration of wind into its system.

Finally, CUB points toward the slow progress of the Company in meeting the renewable resource target identified in its 2003 IRP. While noting the difficulties with the on-again, off-again federal production tax credit, CUB states that it does not sense PacifiCorp's commitment to wind either in its current IRP or its generation portfolio.

ODOE states that the IRP includes little analysis of wind or other renewable resource additions beyond the 1,400 MW assumed as planned resources. ODOE states that the Company's decision to cap renewable resource acquisitions at 1,400 MW is based on forecasted wholesale electric prices. *See* IRP Technical Appendix at 145-146. ODOE believes this cap is inappropriate for two reasons:

- The projects in the supply curve come from only one RFP issued in 2004. The appropriate supply curve should be developed from multiple RFPs through 2012. They likely will offer more renewable resources than the additional 1,500 MW (beyond the 1,400 MW target) the Company identified through the first RFP at or below a 20% premium over forecasted prices, including estimated costs for transmission and integration. ODOE considers such a premium "modest" given what it views as the high risks of CO_2 adders above PacifiCorp's assumed level. Further, ODOE notes that this premium likely will decline over the next 10 years because of improvements in renewable resource technologies.

- The cap ignores the potential benefits of additional renewable resources in reducing exposure to the risks of high gas prices and CO_2 regulations beyond the base-case CO_2 adder. PacifiCorp conducted no analyses of these benefits, but should do so before acquiring other supply-side resources.

ODOE states that given the short lead times for many wind projects and PacifiCorp's ability to facilitate transmission, additional renewable resources beyond the 1,400 MW included in the Action Plan are possible and desirable. ODOE states that there appears to be time to build transmission to new renewable resources in lieu of building a coal plant and its associated transmission, and asserts that these actions should be in the Company's Action Plan.

ODOE notes that the Company's Action Plan calls for renewable resources providing 7% of its energy supply in FY 2015. *See* PacifiCorp's Response to Data Request No. 2 from the April 25, 2005, workshop. In contrast, ODOE cites Puget Sound Energy's goal to meet 10% of its electric energy sales with renewable resources in 2014, as well as Idaho Power's 11% goal for 2010. ODOE also cites Renewable Portfolio Standard requirements for five states in the Western Interconnection:

- California – 20% by 2017
- Nevada – 15% by 2013
- Colorado – 10% by 2015
- New Mexico – 10% by 2011
- Arizona – 1.1% by 2007 (60% of the target must come from solar resources)

ODOE asserts that PacifiCorp's uncertainty about whether it can integrate more than 1,400 MW of wind resources into its largely thermal system is the result of relying too heavily on inflexible coal plants or being overly cautious. ODOE points out that CCCTs are superior to pulverized coal plants in their ability to follow loads and shape intermittent renewable resources such as wind. Minimum times to full load are 54%

quicker and ramp rates are 44% faster for 2x1 wet-cooled CCCTs compared to pulverized coal. *See* PacifiCorp's Responses to ODOE Data Request No. 2.1 and 2.2. ODOE cites this fact as an unanalyzed advantage of all-gas Portfolio M over Portfolio E.

RNP recommends that the Commission direct PacifiCorp to prioritize renewable resource acquisitions to meet the Company's 1,400 MW target — specifically, to dedicate resources to ensure continued progress in meeting this target. RNP states that the Company received more than 6,000 MW worth of bids in response to its renewable resources RFP, but thus far has acquired only one 64.5 MW project. That's in comparison to the 1,059 MW of natural gas resources procured through other RFPs, the group notes.

RNP opines that PacifiCorp has expeditiously acquired its planned fossil-fuel resources, but not its planned renewable resources. The group comments that "[a]n IRP action plan is a 'package deal' — it is not appropriate for the Company to only acquire the fossil resources in its action plan without also meeting its renewables target." Further, the group expects PacifiCorp "to participate in regional activities affecting the development of renewable resources, and to creatively confront, analyze, and solve the problems that arise in acquiring renewable resources." *See* RNP Comments at 2.

RNP points out successful acquisition of renewable resources by other utilities in the region, including Puget Sound Energy's purchase of the 150 MW Hopkins Ridge project under construction in Washington and a letter of intent to purchase the 230 MW Wild Horse wind project in that state. RNP also cites Northwestern Energy's contract for the 135-150 MW Judith Gap wind project in Montana and PGE's contract for a 75 MW expansion at the Klondike wind farm in Oregon.

RNP commends PacifiCorp for its wind capacity study for the IRP, which determined that wind resources contribute 20% of their nameplate capacity to the planning margin. RNP notes that this is a significant improvement from the 2003 IRP, which assumed that wind resources did not make any such contribution. RNP recommends that the Company should continue to study wind's capacity credit as it gains experience with wind acquisition in the coming years.

RNP states that it originally supported PacifiCorp's decision to maintain a 1,400 MW target for renewable resources during the 2004 planning cycle, unadjusted from its 2003 IRP target. RNP's position was in recognition of the Company wanting to learn more about integration and transmission issues so it could effectively model and plan for higher levels of renewable resources. RNP states that it now believes that the 2004 IRP analysis is deficient for not modeling portfolios with additional wind resources. The group points toward the bids the Company received for renewable resources. Of the 6,000 MW of bids received, 1,400 MW were at or below the forward price projections, and an additional 900 MW were 10% above the forward price curve. *See* Technical Appendix J.

RNP notes that the 1,400 MW would represent 7% of the Company's portfolio on an energy basis by 2015. Considering the price stability and risk reduction benefits of renewable resources for an existing resource base heavily dependent on fossil fuels, RNP maintains that at a minimum an additional 900 MW of wind resources should have been modeled in the IRP. RNP opines that had more progress been made in acquiring renewable resources, we would not be faced with the urgency of moving forward on new coal resources.

NWEC also praises PacifiCorp's study on wind capacity credit. NWEC points toward results showing that wind contributes about the same capacity on an energy basis as a CCCT. For example, 20 MW of load can be served reliably with either 33 MW of a CCCT at 93% capacity factor or 100 MW of wind resources with a 33% capacity factor.

NWEC expresses concern, however, that the Company has not made much progress toward its 2003 IRP goal of 1,400 MW of renewable resources. NWEC states, "The IRP is a *portfolio* whose value was considered, and acknowledged, as a package. In our opinion, moving forward only with the fossil fuel portion of the plan is not in accordance with that acknowledgment." *See* NWEC Comments at 1.

NWEC expressed greater concern that the 2004 IRP did not seriously investigate the relative costs and risks of acquiring more wind resources than the 2003 IRP goal. In the earlier IRP, PacifiCorp analyzed a portfolio that included another 1,143 MW of wind plus 100 MW of geothermal resources. NWEC criticized PacifiCorp's rejection of that portfolio as too costly on the grounds that the resources were assigned no value for capacity or reducing fuel price risk, the green tag value was underestimated, and the Company did not consider how the additional renewable resources would reduce emissions from purchased power. According to NWEC, the current IRP's treatment of this issue is worse — it's missing.

NWEC cites the "extremely flat" supply curve for renewable resources based on the Company's RFP responses shown in Appendix J. NWEC states that the flat curve indicates that the amount of renewable resources that is deemed cost-effective is highly dependent on assumptions about future electricity and gas prices, carbon costs, wind integration costs and other factors. NWEC recommends that such assumptions be modeled stochastically and under stress tests for higher natural gas costs and CO_2 adders. More important, NWEC states, is analyzing the risk metrics of a heavier renewable resources portfolio.

NWEC points out another problem it sees with the IRP analysis: PacifiCorp has not taken into account the value of preserving its options. For example, the Company states that it may have difficulty integrating more than 1,400 MW of wind into its system, but then proposes to add more coal plants rather than natural gas plants, which NWEC believes will constrain its integration capability further. NWEC states that the Commission should weigh seriously how the Company's proposal to build coal plants will limit future options to add more wind resources if conditions warrant it. Coal-heavy portfolios should be penalized in the analysis because of this effect, NWEC states.

NWEC concludes that given the analysis in the 2004 IRP, it is "impossible" for the Commission to evaluate whether the higher expected cost for a portfolio with another 1,000 MW or so of renewable resources is worth its risk reduction benefits related to fuel price stability and emissions reductions, and that would lead to an uninformed decision regarding the Company's proposed Action Plan.

PacifiCorp notes that while Parties generally support PacifiCorp's efforts to improve the modeling of wind resources, most alleged deficiencies in their treatment in portfolio analysis. In response, PacifiCorp first points to a draft report from Lawrence Berkeley National Laboratory that shows the Company's 1,400 MW of renewable resources modeled in every portfolio is much higher than amounts modeled by all other utilities in the region. The Company states that the amount in its planned portfolio by 2014 is roughly equivalent on an energy basis to the final portfolio amounts of Puget Sound Energy, Idaho Power, Portland General Electric and Avista *combined*.

PacifiCorp responds to concerns that its modeling did not capture the impact of coal resources on wind integration. The Company states that its model includes minimum-up, minimum-down and ramp rate data by generating unit. PacifiCorp further notes that while resources with dynamic regulating reserve capability are necessary to accommodate wind resources, not all resources must have that capability. The Company expects to have sufficient regulating reserve resources to accommodate the 1,400 MW of projected wind additions regardless of the quantity and fuel type of base-load resources added to the system.

PacifiCorp acknowledges that the supply curve based on its renewable resources RFP does not indicate that 1,400 MW is a hard upper limit on cost-effectiveness. However, the Company maintains that this amount should remain the planning target until it obtains additional experience with substantial amounts of wind in its system and improves methods for estimating integration costs. The Company is investigating a potential modeling improvement for the next IRP that would estimate wind output stochastically, thus improving estimation of imbalance costs. PacifiCorp states that the Action Plan allows flexibility to substantially increase the level of wind resources procured over the 10-year planning period if the economics of wind projects makes it favorable to do so.

PacifiCorp states the following hurdles to its efforts to acquire renewable resources:

- Short and undependable extensions of the federal production tax credit
- Rising wind turbine prices due to higher steel prices and a weak dollar in relation to foreign currencies
- Lack of available turbines

PacifiCorp continues to negotiate with bidders and remains optimistic about the prospects for meeting its 2006 targets assuming the tax credit is extended by the end of 2005.

Staff highlights the Company's report at the May 2005 public input meeting that more than 1,800 MW of projects remain on the short list, including more than 200 MW of projects with a 2006 on-line date. Staff points out that the bids may not all prove viable, nor are they necessarily representative of renewable resources that may become available in later years as prospecting for wind sites and technology improve over time.

Staff is concerned about the lack of analysis that would have shown the risk characteristics of a portfolio with more than 1,400 MW of renewable resources. Staff points out that wind resources, with no fuel costs, are not subject to fuel price volatility. In that respect Staff states they are similar but superior to coal resources, which historically have had limited price volatility but may in the future encounter greater volatility related to coal markets, fuel transportation and pollutant regulation.

In response to concerns about the slow progress in acquiring renewable resources and an on-again, off-again federal production tax credit, Staff recommends that PacifiCorp execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of power purchase agreements upon its extension. Staff notes that Portland General Electric is in the process of developing such an agreement with the Energy Trust.

Staff further recommends that in its next IRP or Action Plan, PacifiCorp analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's ability to integrate wind resources.

Commission disposition: We note that the Company has reached agreement to acquire only one renewable resource project, and that it did not meet its 2005 target of 100 MW. Further, we acknowledged PacifiCorp's 2003 IRP with the agreed-upon modification to the Action Plan that the Company would acquire renewable resources sooner than the yearly targets if economic to do so. Given the level of bids the Company shows in the IRP as potentially economic, we would expect the Company might have exceeded, rather than fallen short of, its early target.

The Commission agrees with RNP that the Company should devote sufficient resources to reach its renewable resources targets. The Commission declines, however, to direct how PacifiCorp should allocate resources, as RNP recommends.

PacifiCorp has cited the delay in renewing the federal production tax credit, and its short extension, as one of the problems affecting its acquisition of renewable resources. We therefore agree with Staff that the Company should execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable the

Company to complete power purchase agreements quickly upon extension of the federal production tax credit.

In addition, for the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's ability to integrate wind resources.

Potential CO_2 regulatory costs. CUB maintains that PacifiCorp's assumed cost for meeting future CO_2 regulations is too low. CUB states that "…it cannot seriously be considered a realistic internalization of the potential regulatory response to carbon." *See* CUB Opening Comments at 8.

RNP opines that PacifiCorp's assumed \$8/ton CO_2 adder (2008\$) is on the lower end of the reasonable range of costs and cites base-case adders used by others:

- Idaho Power - \$12.30/ton beginning in 2008
- California Public Utilities Commission (CPUC) – An escalating cost of \$5/ton in the near term, \$12.50/ton by 2008 and \$17.50/ton by 2013

RNP recommends that PacifiCorp continue to evaluate the appropriate CO_2 value for its base case and revise the value in its next IRP.

NWEC similarly points out other utilities and jurisdictions that have assumed higher CO_2 costs in the future. In addition to Idaho Power's and CPUC's values, NWEC cites Xcel Energy's agreement as part of a comprehensive settlement in its 2003 least-cost plan in Colorado to use a proxy cost value of \$9 per ton of CO_2 beginning in 2010 and escalating thereafter at 2.5%.

NWEC states that scientific consensus is moving toward the position that global climate change is more likely to cause much more serious impacts, and in a shorter period of time, than previously thought. NWEC points toward the strategy adopted by the Governor's Advisory Committee on Global Warming in December 2004, which calls for large reductions in CO_2 emissions, in recognition of the danger. NWEC opines that the CO_2 adder used in PacifiCorp's analysis seriously undervalues the risks. For example, NWEC states that even a 1% chance that the Greenland ice cap melts, or the Gulf Stream is disrupted, will have an expected value of damage much higher than represented by PacifiCorp's cost adder. NWEC asserts that it isn't simply a matter of whether or even how much shareholders will pay in future CO_2 mitigation costs in some future rate case. NWEC asserts that avoiding catastrophic impacts must be the first concern of the Commission.

NWEC points out that site cleanup costs traditionally have been included in both IRP analysis and rates. NWEC maintains that it has always been considered prudent for utilities to pay-as-they-go for mitigation and site cleanup, as well as to collect revenues in advance for estimated site restoration costs. NWEC explains that such rate treatment avoids pushing out to future generations the costs for actions taken today, as well as inefficient price signals to consumers of the true costs of their energy use.

NWEC asserts that CO_2 emissions should be considered part of site cleanup, and that an after-the-fact cleanup strategy may be too costly and come too late to avoid serious climate impacts. Therefore, NWEC recommends that PacifiCorp acquire CO_2 offsets now — from the Climate Trust, for example. NWEC states that a Montana developer recently contracted with the Climate Trust to acquire CO_2 offsets for less than \$2.50/ton. NWEC asserts that it would be "imprudent" for the Company not to seek such offsets at this time, given that their cost in the future will likely be higher than \$8/ton.

ODOE maintains that "PacifiCorp's base case CO_2 cost adder of \$8.38 per ton of CO_2 (2010\$) does not begin to capture the stringency of likely future constraints." *See* ODOE Initial Comments at 1. ODOE cites mounting scientific evidence of climate change, studies indicating that high CO_2 adders are needed to stabilize CO_2 emissions to a level that would avoid catastrophic climate change, and regulatory momentum to address these concerns, discussed under "Coal plant," below.

ODOE cites two other problems with PacifiCorp's analysis of the potential impact of CO_2 regulatory costs. First, none of the Company's scenario analyses considered a firm constraint on CO_2 emissions without an opportunity to trade for or buy offsets. ODOE states this could occur if a cap is imposed on short notice and transportation and other CO_2-emitting sectors are similarly regulated, or if allowance trading is not permitted. In such cases, PacifiCorp would be forced to cap its total CO_2 emissions.

ODOE calculates that in a scenario where CO_2 emissions allowances are not available or trading is not permitted, the *value* of new coal plants is \$12.36/MWh, compared to a *cost* of \$36.50/MWh. ODOE further concludes based on its calculations that if such a scenario occurs shortly after PacifiCorp completes construction of the 958 MW of coal plants in its preferred Portfolio E, the net present value of these plants would be *negative* \$2 billion. If only the 2011 coal plant is considered in the analysis, the cost under this scenario could be \$1.4 billion, according to ODOE. The calculations take into account the improved efficiency of the new coal plants, the retirement of existing coal plants that would be required to offset emissions from the new plants, reduced operational costs for the old coal plants, and the cost of low- or zero-CO_2 replacement resources. *See* spreadsheet attached to ODOE Initial Comments.

Second, ODOE criticizes PacifiCorp's assumption that a large supply of low-cost CO_2 offsets would be available if trading of emissions allowances is permitted. ODOE notes that the Company does not indicate which sectors could supply them. ODOE points out that in addition to electricity generation, transportation and stationary fossil fuel are the other major sources of CO_2 emissions. ODOE asserts that neither sector shows promise of low-cost offsets as illustrated today by fairly flat petroleum consumption in Europe and Japan despite very high gasoline taxes. Further, ODOE maintains that biological sequestration – planting trees, for example – is unlikely to provide dependable CO_2 offsets given the temperature and precipitation changes expected to occur with global warming.

PacifiCorp responds to concerns about its \$8.38/ton base-case CO_2 adder (2010\$) being too low by explaining that it was developed after studying a number of policy and market analyses in the U.S. and overseas. The Company also cited recent developments that provide support, including a proposal by the National Commission on Energy Policy, a bipartisan group of energy leaders, for a national cap on CO_2 emissions that would reduce intensity by 2.4% to 2.8% and cap costs at \$7/ton CO_2 with escalation at 5% annually. PacifiCorp adds that Sen. Bingaman proposed inclusion of these provisions in the current energy bill, but the Company does not believe the proposal will pass this year.

The Company also cites analysis of the most recent cap-and-trade bill submitted by Senators McCain and Lieberman. The U.S. Energy Information Administration's analysis of the bill shows CO_2 allowance costs beginning at some \$15/ton in 2010, rising to \$45/ton in 2034. PacifiCorp does not believe this bill will pass in its current form.

PacifiCorp asserts that the uncertain timing of state and federal regulations, and available information on potential regulatory scenarios, provide further support for its CO_2 cost assumptions. The Company states that it incorporated a CO_2 adder in its base-case assumptions because it believes that is a prudent and necessary step for protecting customers from future risks of carbon constraints.

PacifiCorp addresses Parties' concerns that it did not adequately consider policy developments in Oregon related to climate change by stating that as a multi-state utility it objects to a statewide load-based cap due to the complexity and cost of the methodology that would be needed, and because it expects that the costs of an aggressive cap on emissions by a single state would be high. Further, the Company opines that there have been no specific policy recommendations on CO_2 regulation in the state that are amenable to base case or scenario analysis.

PacifiCorp states that it would be complex to segregate emissions reductions from a wide variety of activities throughout the Company and assign emissions and reductions across all states. The Company maintains that for the purpose of cost recovery, it would be challenging to isolate factors that increase and decrease CO_2 emissions, such as altering plant usage and making additional market purchases. Further, the Company states that it might invest in efforts to reduce *total* CO_2 emissions to meet a cap imposed by a single state, such as additional renewable resources. It foresees conflicts between states if implementation costs are borne solely by Oregon, but benefits accrue to all states — higher gas prices leading to larger benefits from additional renewable resources, for example.

PacifiCorp believes the best information today points to regulatory regimes that institute national or regional caps and encourage trading of emissions allowances for economic efficiency. The Company cites national cap-and-trade policies including the

1990 amendments to the Clean Air Act which instituted a cap-and-trade program for sulfur dioxide; the Clear Air Interstate Rule, which created a regional cap-and-trade program in the East; and EPA's recent rulemaking creating a mercury cap-and-trade system.

PacifiCorp acknowledges that it is useful to consider a regulatory scenario that would not allow any emissions trading in order to understand the costs to reduce CO_2 internally. However, the Company does not believe it is reasonable to assume no trading as a base-case assumption.

PacifiCorp reports that it continues to monitor the market price of off-system CO_2 offsets and that the Climate Trust continues to find offsets in the range of $2/ton to $5/ton CO_2. The Company acknowledges the limitations of extrapolating from this information offset prices under unknown future regulatory regimes.

Staff recommends that PacifiCorp continue to use its own base-case assumptions regarding the future regulatory costs of CO_2 emissions. The sensitivity analyses required under Order No. 93-695 provide the Commission with an indication of how portfolios may perform under potential regulation scenarios. Staff does not at this time support NWEC's recommendation that PacifiCorp acquire CO_2 offsets today, such as those available from the Climate Trust. Staff believes it is a risky strategy to acquire CO_2 offsets from sectors unrelated to the electricity industry until it becomes clearer how CO_2 emissions would be regulated by the state or federal government.

Commission disposition: We agree with Staff that PacifiCorp should continue to use its own assumptions about future regulatory costs of CO_2 emissions in base-case analyses. The sensitivity analyses required by Order No. 93-695 indicate how portfolios may perform under potential CO_2 regulation scenarios. We also concur with Staff that it is premature to acquire CO_2 offsets, other than those which may be conveyed through Tradable Renewable Certificates associated with renewable resource acquisitions.

Coal plant. None of the Parties, including Staff, recommends that the Commission acknowledge acquisition of a coal-fired resource in the summer of 2011.

CUB states that PacifiCorp's IRP fails to adequately address the costs and risks associated with greenhouse gas emissions and climate change. CUB asks the Commission to consider carbon-intensive resources such as coal in light of the long-run public interest standard established in Order No. 89-507.

CUB asserts that the IRP suffers primarily from the following six flaws which lead the Company toward acquisition of coal resources:

- The Company's plan to add two more coal plants to its already coal-intensive system flies in the face of mounting scientific evidence demonstrating the occurrence and effects of climate change, as well as the response by Oregon, the U.S. and the international community.

- The difference between the expected PVRR of PacifiCorp's preferred portfolio and a portfolio that replaces the two coal plants with natural gas plants is negligible. Further, CUB states that PacifiCorp did not make a compelling case that the risk of gas price volatility is greater than the risk of CO_2 regulation or the cost of climate change.

- PacifiCorp is pulled toward coal plants because they serve as economic development for several states on the East side of the Company's system, and because the Company is comfortable with and knowledgeable about coal resources, skewing the IRP analysis qualitatively toward coal resources.

- The IRP's failure to reexamine the quantity of wind resources that the Company identified as economic in the 2003 IRP to determine if that amount remains adequate or appropriate may have skewed its modeling toward base-load coal plants, rather than more flexible gas-fired plants.

- The IRP has not satisfied that all possible measures have been or will be taken to aggressively address the problem of reducing Utah's load, especially its peak load.

- Given the likelihood of future regulation of CO_2 emissions, adding a more efficient coal plant may simply result in the retirement of a less-efficient coal plant, leaving ratepayers with yet another costly resource acquisition to close the load-resource gap and significantly increasing the cost of PacifiCorp's preferred portfolio.

CUB points out that a coal-heavy utility like PacifiCorp may be targeted for governmental and societal responses to atmospheric carbon loading and that under such a situation adding a coal plant would be costly to shareholders and customers. CUB calls failing to plan for such a possibility "imprudent in the extreme." *See* CUB Opening Comments at 3.

CUB cites evidence from the 2001 report of the Intergovernmental Panel on Climate Change, such as average global surface temperature projected to increase by 1.4°C to 5.8°C in the next 100 years and CO_2 emissions from fossil fuel-burning virtually certain to be the dominant influence on atmospheric CO_2 in the 21st century. CUB also cites what it calls a modest proposal, published in the August 13, 2004, edition of *Science*, to hold annual CO_2 emissions for the next 50 years at their current level of 7 billion tons. CUB notes that the proposal would stabilize CO_2 emissions at an estimated 500 parts per million (ppm), compared to the pre-industrial level of 280 ppm and current levels of 375 ppm. CUB reports that the authors offer a number of technology options related to electricity generation to achieve their goal, including substituting natural gas resources for coal, carbon capture and storage, and wind resources.

CUB also cites the recommendations of the Governor's Advisory Group on Global Warming:

- By 2010, arrest the growth of greenhouse gas emissions and begin to reduce them,
- By 2020, achieve a 10% reduction below 1990 greenhouse gas emission levels, and
- By 2050, achieve a climate stabilization emission level of at least 75% below 1990 levels.

CUB points out that these kinds of greenhouse gas reductions would require serious reductions in the energy sector. CUB states that the electricity industry represents 40% of CO_2 emissions in the U.S., that these emissions account for 25% of global CO_2 emissions, and therefore the electricity industry in the U.S. accounts for 10% of global CO_2 emissions.

Referring to ODOE's comments in this docket, CUB states that it is difficult to consider a 20% increase in PacifiCorp's CO_2 emissions through 2018 an acceptable level of risk for customers or see how the Company's strategy could meet the CO_2 reductions called for by the Governor's Advisory Group.

CUB notes the recommendation by the Advisory Group to examine the feasibility of and design a load-based greenhouse gas allowance standard, as well as PacifiCorp's assertion in the IRP that states enacting CO_2 regulations would bear the cost of regulation. CUB concludes that Oregon ratepayers should not be committed to additional coal resources until potential CO_2 regulations and accompanying costs are known.

CUB maintains that climate change is an essential consideration in any least-cost planning process. CUB cites the Commission's stated intent in Order No. 89-507 that the utilities' resource plans consider the ramifications of resource decisions on the long-run public interest. CUB points out that the order recognized that not all costs are quantifiable. CUB asserts that it is part of the Commission's intent to examine the costs of climate change not only on PacifiCorp's shareholders and ratepayers but on society as a whole, especially given the Company's contribution to CO_2 emissions with its current resource mix.

CUB maintains that computer modeling today cannot begin to adequately address the costs and risks of climate change, and that the small difference in expected PVRR between PacifiCorp's preferred portfolio and the all-gas portfolio is meaningless. CUB presumes that for PacifiCorp, the unknown risk of future gas price volatility is more meaningful than the non-quantifiable risk of both climate change and the future regulatory response to CO_2 emissions.

CUB maintains that PacifiCorp did not make a compelling case that gas price risk is greater than the risk that CO_2 regulatory costs will be far higher than the Company assumes. CUB compares PacifiCorp's preferred portfolio with the all-gas portfolio, using various assumptions about plant lives, both high and base-case natural gas prices, and various CO_2 costs. Under the high-gas case with a CO_2 adder of $14.90/ton, all-gas Portfolio M is only 2% to 4% more expensive than the preferred portfolio, depending on the assumed life of the plants. *See* PacifiCorp's responses to ODOE's Data Request No. 1.2. CUB calls the cost difference between these portfolios "mere background noise, especially given the mounting threat of climate change." *See* CUB Opening Comments at 9.

CUB opines that the Company should not consider adding a coal plant until it has fully utilized DSM and wind resources, and it should use the most efficient, cleanest coal resource commercially available designed for adding carbon capture and sequestration at a later date.

CUB expresses concern about the risks inherent with new technology such as IGCC, including the risk of stranded assets. CUB states that both IGCC and carbon sequestration technologies are not yet mature and therefore pose a cost risk. CUB cautions against rushing to invest in a coal resource in the near-term. Instead, CUB recommends aggressively managing Utah's growing load and waiting to first see if coal is necessary and, if so, for the technology to mature.

CUB cites Staff's requested scenario analysis of delaying by three years acquisition of the first coal plant in Portfolio E, noting that the PVRR decreases and the resulting planning margin drops below 12% in only one year. *See* PacifiCorp's response to OPUC Staff's Data Request No. 3. CUB states that a 12% planning margin represents 5.6 days of outages over 10 years based on data in IRP Technical Appendix at 221. CUB concludes, "Weighing the risks of climate change and carbon cost, against such a small magnitude of expected outage, makes PacifiCorp's choice to invest in more coal extremely difficult to justify." *See* CUB Opening Comments at 11.

CUB states that with CO_2 regulation on the horizon and given PacifiCorp's already carbon-intensive resource mix, the addition of a more efficient coal plant could result in the retirement of one of its existing coal plants. CUB concludes that a new coal plant might net only a small resource addition, requiring yet another costly resource acquisition to replace the retired plant.

CUB concedes that a new coal plant would not necessarily mean the retirement of an existing coal plant, but states "the possibly is moving, none too slowly, into the reasonable range of foreseeable futures…. [I]t is an outcome that would be enormously costly for ratepayers and shareholders alike. A non-coal resource investment is a far more logical way to avoid the potential problem, by avoiding coal's significant addition to PacifiCorp's overall exposure to carbon-risk." *See* CUB Opening Comments at 17.

CUB opines that given estimated PVRR savings from deferring the coal plant, a lead time of seven or eight years, an aggressive peak-load shaving program in the East, and the option to site a single-cycle natural gas combustion turbine close to peak load, there's nothing to lose by waiting a few years before committing to a large investment in a coal plant. CUB recommends using the time to manage load, find a supply-side resource other than coal if load management does not suffice, and wait for further maturation of IGCC technology.

ODOE recognizes that if significant constraints are not placed on PacifiCorp's CO_2 emissions, new coal plants might be part of a least-cost and least-risk method of meeting load growth. However, ODOE asserts that PacifiCorp's base-case CO_2 adder is not representative of the cost of likely emissions constraints.

ODOE concludes that PacifiCorp's analysis in support of new coal plants rests on the assertion that they will reduce risk. ODOE maintains, "This alleged risk reduction benefit is an artifact of analyzing gas price risk inside a *stochastic* model, but only analyzing the risks of higher CO_2 adders as required by Order No. 93-695 in a separate scenario analysis." *See* ODOE Initial Comments at 1.

ODOE states that all-gas Portfolio M's average cost over the 100 stochastic model runs is greater than Portfolio E's by $366 million because gas price risk is bounded by zero but almost unbounded at the high end. ODOE recognizes that Portfolio E's PVRR also has less variance. ODOE further notes that the PVRR for Portfolio E is $104 million less than Portfolio M under a zero CO_2 adder. However, ODOE points out that this cost advantage is smaller than Portfolio M's $132 million advantage under a $14.90/ton CO_2 adder ($10/ton in 1990$). Further, Portfolio M has a PVRR advantage over Portfolio E by a factor of 3.6 to 6 under the two higher CO_2 adders tested.

Looking at the "high gas" scenario analysis, ODOE acknowledges that the PVRR for all-gas Portfolio M exceeds Portfolio E's by $564 million under PacifiCorp's base-case CO_2 adder of $8.38/ton. However, ODOE points out that the PVRR for Portfolio M is $374 million lower at a CO_2 adder of $37.25/ton, and $623 million lower at $59.60/ton. ODOE views this as an indication of similar risk levels for the two portfolios.

ODOE concludes that the reduced gas-price risk from building new coal plants in PacifiCorp's preferred Portfolio E is roughly comparable to its increased cost risk of likely CO_2 adders. ODOE asserts that had PacifiCorp conducted a complete stochastic analysis on the full range of CO_2 adders and natural gas prices, the PVRR variance of the two portfolios would have been similar. Further, ODOE maintains that if a portfolio with higher amounts of renewable resources had been studied in the IRP, it would likely be the portfolio with the least overall risk.

ODOE explains that the CO_2 reduction goals of the Governor's Advisory Group on Global Warming are based on stabilizing CO_2 concentration in the atmosphere this century at such a level. ODOE indicates that a reduction in worldwide emissions of more than 50% would be needed to halt net CO_2 additions to the atmosphere and stabilize CO_2 concentrations, and that would require coal plants to be replaced by zero- or low-CO_2 emission resources. ODOE estimates that substituting existing coal plants with wind plants or new IGCC plants, including CO_2 sequestration, yields a cost per ton of CO_2 removed of about $32/ton to $45/ton. Calculations were based on a cost of $50/MWh to

$60/MWh for IGCC plants with sequestration or wind resources, and operating costs for existing coal plants of $15/MWh to $17.50/MWh (2004$).

ODOE cites the Climate Stewardship Act of 2003 proposed by Senators McCain and Lieberman that would cap U.S. greenhouse gas emissions at 2000 levels from 2010 to 2015, then ratchet the cap down to 1990 levels beginning in 2016. ODOE notes the bill received 44 votes in 2004. ODOE cites a 2003 report by scientists at the Massachusetts Institute of Technology that estimates the bill would result in a CO_2 allowance cost of about $20 to $40 in 2010, rising to about $30 to $65 by 2020 (1997$). *See* ODOE Initial Comments at 7.

ODOE states that the U.S. formally ratified the United Nations Framework Convention on Climate Change, with an objective to stabilize greenhouse gas concentrations in the atmosphere at a level that would "prevent dangerous anthropogenic interference with the climate system." *See* ODOE Initial Comments at 7, quoting from the Convention. ODOE cites recent study results in *Science*, published by the American Association for the Advancement of Science, indicating that a worldwide cost adder of $41/ton CO_2 (2004$) is needed before 2050 to reduce this danger below a 1% probability. ODOE points out that this adder level is based on the assumption that a 2.85°C change in climate would cause dangerous results. If instead the threshold is 1.92°C, the study indicates a CO_2 tax of $109/ton CO_2 (2004$) before 2050 would be needed to reduce the likelihood of dangerous interference with the climate to a 15% probability. ODOE cautions that even a 1% probability is greater than society normally tolerates for catastrophic outcomes.

ODOE indicates that these studies support the likelihood of adders equal to or above the $40/ton CO_2 adder (1990$) that Order No. 93-695 requires be analyzed. ODOE maintains that arguing stringent CO_2 adders or caps will never be implemented because of their impact on the economy ignores the possible political context if the climate continues to change in highly noticeable ways that threaten U.S. or European populations. Further, ODOE calculates that the highest CO_2 adder that the Commission requires be analyzed – $40/ton (1990$) – implies a doubling of wholesale electricity prices in 2023. ODOE puts that in the context of other significant price increases for fuel using data from the U.S. Energy Information Administration. Since 1995, wholesale natural gas prices have tripled and petroleum distillate prices have increased 250% in the U.S.

ODOE explains that because direct fossil fuel expenditures comprise about two-thirds of retail energy expenditures in the U.S., based on the most recent data available, doubling of wholesale petroleum and natural gas prices has a more significant impact on the U.S. economy than doubling of wholesale electric prices. ODOE estimates that a $40/ton CO_2 adder would add 58 cents to the price of a gallon of gasoline (a 40% increase) and add $3.49/MMBtu to natural gas prices (a 50% increase). ODOE does not find a high CO_2 scenario implausible on account of such fuel price increases, given recent price trends for these fuels and the resulting effect on the economy.

ODOE asserts that if PacifiCorp pursues new pulverized coal plants and future CO_2 emissions costs exceed the Company's assumed CO_2 adder of $8.38/ton, the excess costs should be recovered from PacifiCorp's shareholders. ODOE strongly disagrees with PacifiCorp's statement (IRP at 67):

> If a new generating plant were to become uneconomic to some degree as a result of government action regarding carbon emissions, that plant would not be imprudent. At this time, the potential costs of government actions regarding CO_2 emissions are highly uncertain.

ODOE replies that uncertainty is no excuse for inaction, or what it views as a CO_2 adder that is several times lower than what will be required in coming decades to avoid catastrophic climate change. ODOE maintains that PacifiCorp should analyze the cost risks associated with changes in government policy needed to avoid dangerous anthropogenic interference with the climate system, rather than focusing on what seems politically possible today.

ODOE reports that Oregon's 2000 CO_2 emissions from fossil fuels were 17% above 1990 levels. ODOE further notes the Governor's stated intent to establish a task force to examine the feasibility of and develop a design for a load-based CO_2 allowance standard for potential legislative action in 2007.

ODOE states that PacifiCorp emits about 20% of Oregon's CO_2 emissions. ODOE notes that the Company's preferred portfolio represents a 20% growth of CO_2 emissions between 2005 and 2018. *See* PacifiCorp's Response to ODOE Data Request No. 1.3. ODOE concludes that PacifiCorp's Action Plan leaves it unprepared for possible changes in Oregon laws, and that the possibilities of a state or federal Renewable Portfolio Standard or CO_2 emissions caps have significant implications for PacifiCorp.

ODOE also expresses concern that because coal plants can't ramp up and down as quickly as gas plants, acquiring more coal will make it more difficult to integrate levels of wind beyond the 1,400 MW included in the Action Plan.

ODOE states that IGCC technology may have merit, noting the IRP shows a cost premium over a pulverized coal plant of 24%. *See* IRP Technical Appendix at 67. Based on the Company's estimate that CO_2 sequestration would cost an additional $10/ton CO_2, ODOE notes that an IGCC plant with sequestration would cost an estimated $52.80/MWh (2004$). ODOE recommends further analysis of the Hunter site to refine a cost breakeven point for IGCC with sequestration vs. pulverized coal, and to set a cutoff value for acquisition of renewable resources.

RNP states that there is increasing evidence that carbon emissions will be regulated in the U.S., and that it is only a matter of when that will occur. RNP concludes that it is "imprudent" for PacifiCorp to invest in another traditional coal-fired resource, particularly because so much of its resource portfolio is comprised of fossil-fuel resources. RNP instead recommends that PacifiCorp aggressively pursue renewable resources and DSM to delay the need for new coal resources, in order to allow the Company to continue to explore IGCC technology and for its costs and risks to decline.

NWEC recommends the Company acquire its lowest cost and most environmentally responsible resources, which the organization defines as energy efficiency and renewable resources, prior to acquisition of more fossil-fuel resources, especially conventional coal resources. NWEC states that air quality, water use and climate change issues all warrant tough scrutiny prior to fossil fuel development, especially before committing ratepayers to the large risk of investing in conventional coal plants that require 40 years of operation to amortize their costs.

NWEC states that the uncertainties ratepayers face over the next few years are large and not well-accounted for in the Company's analysis. These include advances in IGCC technology that could significantly reduce its costs, the prospect that Congress will enact significant economic incentives for IGCC, a strong likelihood of CO_2 caps or other regulation much higher than PacifiCorp's assumed CO_2 adder, advances in renewable resource technologies, and the potential for liquefied natural gas imports to reduce natural gas prices. NWEC concludes that these uncertainties warrant a high value for keeping the Company's options open, rather than closing them off with large long-term investments in conventional coal technology.

NWEC does not believe that the IRP methodology gives any value to optionality, and that neglecting this value is a serious drawback to the analysis. The organization recommends one way to indicate such value: Model *all* long-term resources as if they had to be amortized over a much shorter period. Such a method would simulate the possibility that the value of a resource would have to be severely discounted in the face of new technology or rapid regulatory or price shifts. For example, a coal plant would be amortized over 15 or 20 years, instead of its presumed 40-year life.

PacifiCorp responds that it expects that risks to cost recovery for a coal plant would be minimal given regulatory mechanisms, including the Multi-State Process, and past experience that once the costs of a new generating plant are shown to be prudent, there are not serious impediments to recovery of the costs in rates in the future. In addition, the Company states that cost recovery has been fairly constant across its spectrum of plants such that fuel type would not materially affect a decision about what type of plant to build. Further, the Company does not believe that commitment to a long-term resource of any type would preclude it from responding to developments in technology, policy or markets.

PacifiCorp believes that it has sufficiently captured the option value of deferring an investment in a coal plant through its stochastic risk analysis of a variety of portfolios. PacifiCorp opines that deferring a coal plant *increases* overall portfolio risk primarily due to gas price volatility. The Company also points out that it analyzed switching the order of the second gas unit and the coal plant on the East side. The Company found no economic benefit of this deferral under a deterministic analysis.

Concerning the Parties' contention that PacifiCorp should postpone a coal plant decision and acquire alternative resources, the Company states its need to take prompt and focused steps to address the growing gap between its obligations and resources. The Company states that resource procurement must be concurrent with additional study of alternative resource options, without delay. Waiting to fully explore renewable resource, demand-side and distribution generation options would "imprudently impact" its ability to supply reliable, low cost power to its customers, according to PacifiCorp. Further, the Company asserts that using a coal-fired plant as a proxy high capacity factor resource in the IRP does not preclude consideration of other alternatives if they are appropriate for economic, risk management and system reliability reasons.

PacifiCorp disagrees with CUB that there would be little benefit if a new coal plant forced the retirement of an older, less-efficient coal plant under future CO_2 regulation. PacifiCorp's view is that replacement of older coal plants with newer coal plants could result in a net emissions reduction as well as avoiding costs required to keep the older units running.

PacifiCorp strongly disagrees that its IRP is skewed toward coal. The Company states that it determined its preferred portfolio using quantitative results from a rigorous analytical process, its resource planning experience and expert judgment. Further, the Company states that 64% of the preferred portfolio's new thermal resources are natural gas.

PacifiCorp asserts that its risk analysis was not deficient for not directly weighing CO_2 cost risk against gas price risk in stochastic or scenario analysis. First, the Company states that selection of the preferred portfolio cannot be distilled down to a simple comparison of "extreme" CO_2 regulation and gas price risks. Rather, the Company made a qualitative assessment of risk using all of the risk metrics calculated. PacifiCorp views this approach as necessary given the uncertainties in measuring resource portfolio risks and an insufficient basis to appropriately weight each risk metric in making decisions. The Company reiterates that the main conclusion of its stochastic analysis is simply that portfolios with fuel diversity in resource additions exhibited less risk than those that did not. Further, the Company explains that the purpose of its scenario analysis was to inform portfolio selection by indicating how alternative futures could affect costs.

Second, the Company contends it would be inappropriate to compare CO_2 regulation and gas price risks using the same technique given the disparate characteristics of these risks. PacifiCorp further states that it is inappropriate to conduct stochastic analysis on a full range of CO_2 risk adders because it cannot assign probabilities of occurrence with any degree of confidence. In addition, the Company cites its exclusion of all-gas Portfolio M and Portfolio Q, with three new coal plants, as evidence that the high gas price scenario was not given more weight than the high CO_2 cost scenarios. The Company points out that Portfolio Q scored well in many stochastic risk metrics, but was excluded by virtue of its poor results under testing for higher CO_2 allowance costs.

Regarding IGCC technology, PacifiCorp states that it continues to investigate it. The Company believes that the IGCC assumptions in the IRP are conservative and approximate probable risks due to such factors as site elevation, new technology, local labor costs and coal resources. PacifiCorp has recently contracted for a site-specific study to understand the cost impacts of installing an IGCC unit using Utah coal and operating at elevation.

Staff states that it is not convinced that a second large thermal resource, whether natural gas or coal, is needed by on the East side by summer 2011. Staff points toward its comments on planning margin and DSM related to the assumed need for this resource. For example, Staff notes that the IRP is based on the planning margin never dipping below 15% in a single hour of any year, without consideration of any Class 3 DSM options for reducing unserved energy. Staff states that for the Company's preferred Portfolio E, the planning margin is expected to be 15% only during FY 2006-2008 and 2015; the Company expects the actual planning margin to reach 16% in FY 2010 and 2012-2013, 18% in 2014, and climb as high as 19% in 2009 and 2011. *See* IRP Technical Appendix at 82. Another example is the Company's planning assumption that the 261 MW of existing interruptible contracts do not continue upon expiration or would not be replaced by similar contracts.

Staff asked PacifiCorp to test three delay scenarios for the coal plant. *See* Staff Data Request No. 3. In doing so, Staff asked the Company to set the planning margin in the model to zero, then calculate the deterministic and stochastic PVRR values of the Company's preferred Portfolio E, as well as the level of unserved energy and the resulting planning margin. Staff also asked PacifiCorp for the numeric values for the average and worst case stochastic analyses because the IRP showed results only in bar charts. *See* Staff Data Request No. 14 and 15. For comparison, Staff asked for the minimum, maximum and expected unserved energy for each year from FY 2006-2015 for Portfolio E as filed. *See* Staff Data Request No. 10.

Unserved energy values represent the sum of monthly amounts for the year. *Expected* unserved energy is the average for all 100 model runs; minimum and maximum values are from the two runs with the lowest and highest total unserved energy for the entire FY 2006-2015 study period.

Staff concludes the following based on PacifiCorp's responses:

- *Deterministic PVRR* – Delaying the coal plant one year reduces PVRR by $169.3 million (1.3%), delaying it by two years reduces PVRR by $188.2 million (1.4%), and delaying it by three years reduces PVRR by $207.0 million (1.6%).

- *Stochastic average PVRR* (stochastic average variable cost plus deterministic fixed cost) - Delaying the coal plant, whether by one year, two years or three years, reduces expected PVRR by about $850 million (6.3% to 6.4%).

- *Upper tail PVRR (average of the five highest PVRR results)* - Delaying the coal plant one year reduces worst-case PVRR by about $748 million, delaying it by two years reduces worst-case PVRR by about $671 million, and delaying it by three years reduces worst-case PVRR by about $644 million. These values represent about a 4% reduction in worst-case PVRR compared to PacifiCorp's preferred Portfolio E as filed.

- *Planning margin* – When the coal plant was delayed by *one year* in the model, the planning margin stayed at or above 15% for the next 10 years except in FY 2012, when the planning margin dipped to 12%. Delaying the coal plant by *two years* also reduced the planning margin below 15% in FY 2013, to 10%. Delaying the coal plant by *three years* reduced the planning margin a third year, in 2013, to 12%.

- *Unserved energy* - When the coal plant is delayed by *one year*, from summer 2011 to summer 2012, the expected amount of unserved energy in FY 2012 is 81,343 MWh. (Unserved energy over all model runs for that year ranged from zero to 259,069 MWh.) When the coal plant is delayed two years, expected unserved energy is 80,257 MWh in FY 2012 and 112,293 MWh in FY 2013. When the coal plant is delayed three years, expected unserved energy is 81,343 MWh in FY 2012, 108,638 MWh in FY 2013, and 49,341 MWh in FY 2014.

For perspective, Staff compares these unserved energy amounts to the 75,135 MWh of expected unserved energy in FY 2007 for PacifiCorp's preferred Portfolio E *as filed*, with a range of 18,084 MWh to 188,113 MWh over all model runs.

Staff further compares these figures to results from PacifiCorp's Energy Exchange (Class 3 DSM) program for Oregon industrial customers from December 2000 to August 2001, where energy use reductions totaled more than 38,000 MWh. Staff also refers to PacifiCorp's agreements with three large Oregon customers for buybacks lasting longer than one week during the period March 2001 through September 2001. Customers reduced loads under the contracts by 61,385 MWh. Combined, these buyback reductions totaled about 99,000 MWh. *See* Oregon Public Utility Commission Staff, *Demand Response Programs for Oregon Utilities*, presented at the Commission's June 3, 2003, public meeting. Staff states that the avoided costs for deferring a coal plant may enable sizable buyback payments to Utah customers that could achieve results similar to Oregon's experience.

In addition, Staff states that the 20/20 Customer Challenge Program for residential and commercial customers reduced energy use by an estimated 97,650 MWh in Utah alone in the summer of 2001. The Company offered a 10 percent discount on monthly bills for customers using at least 10 percent less electricity compared to the same period during the prior year, and a 20 percent discount if they reduced electricity use by at least 20 percent. The program required no enrollment or special meters. *See* Staff Exhibit 1, from Quantec, *Customer Energy Challenge Report*, prepared for PacifiCorp, 2002.

Regarding the fuel type of the proposed summer 2011 East-side resource, Staff points out that all-gas Portfolio M is the least costly of all portfolios tested under PacifiCorp's base-case assumptions, with a PVRR about $29 million (0.22%) less than the Company's preferred Portfolio E. *See* IRP Technical Appendix, Table E.1. Staff compares the all-in stochastic performance of the two portfolios as follows:

- The average stochastic cost (stochastic variable costs plus deterministic fixed costs) of Portfolio M is only 2.5%, or about $331 million, higher than PacifiCorp's preferred Portfolio M.
- The "upper tail" cost, the average of the five highest PVRR results, is about 7% higher for Portfolio M than PacifiCorp's preferred portfolio.

Staff cautions relying on the upper tail values in the IRP because they are based on only five results out of a total of 100 model runs. Staff notes that the Northwest Power and Conservation Council's Fifth Power Plan uses a risk measure that is the average of the worst 10% results — some 75 results out of 750 iterations.

Staff expresses concern about the long lead time associated with coal plants, which increases planning risks related to load forecasts, technologies, electricity and natural gas prices, and other factors. The Company's updated coal plant timeline shows it will take six years to permit and construct the next coal plant, regardless of whether the plant uses pulverized coal or IGCC technology. The Company notes that the RFP process now required by recently passed Utah Senate Bill 26 could add another 16 months to 18 months. *See* PacifiCorp's response to Data Request No. 1.7 of the Utah Committee of Consumer Services.

In addition, Staff notes that Portfolio E performed poorly in its requested scenario analysis, where loads turn out two standard deviations lower than forecasted. Staff also notes that PacifiCorp did not examine whether a portfolio with renewable resources in excess of 1,400 MW would have a lower expected PVRR than Portfolio E. Renewable resources typically are in far smaller increments and often have a shorter lead time.

Moreover, Staff finds Parties' arguments that are founded on scientific and economic analyses of what CO_2 adder would likely be needed to avoid catastrophic climate change more persuasive than PacifiCorp's reliance on what CO_2 adder might be politically feasible in the near term. Staff finds that it is reasonable to conclude based on the evidence in this docket that the risk to ratepayers of a CO_2 adder higher than PacifiCorp assumed in its base case ($8.38/ton CO_2 in 2010$) is greater than the risk benefits of Portfolio E — primarily due to natural gas price volatility — estimated in the Company's stochastic analyses.

Staff notes that all-gas Portfolio M was the least-cost portfolio for all CO_2 allowance cases except a zero adder — including the Company's base-case CO_2 allowance. Staff further states that PacifiCorp's analysis relies on a 40-year amortization period for coal plants, which may not be tenable without the unplanned retirement of an existing coal plant or the addition of carbon sequestration.

Staff states its interest in IGCC technology as a resource with potentially more stable fuel prices than natural gas, with the ability to add more cost-effective sequestration at a later date if carbon adders warrant and the facility is located where economic sequestration opportunities are available. Staff notes, however, that IGCC technology is just beginning to reach commercialization, and carbon sequestration is in its infancy. Staff recommends that both be more thoroughly investigated in the next IRP.

Staff recommends that the Commission:

- Not acknowledge Action Item 8, acquisition of a 600 MW high capacity factor resource on the East side of the system by CY 2011
- Explicitly not acknowledge a new coal unit by CY 2011
- Direct PacifiCorp to assess in the next IRP or Action Plan brought forward for the Commission's acknowledgment IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties including market prices and CO_2 regulation

Staff recommends that the Company continue environmental permitting and preparing detailed plans, including an economic review and justification for building or contracting for an additional thermal unit on the East side, and refining the level and type of resources needed and the procurement date.

Commission disposition: The Commission is not convinced that PacifiCorp's IRP makes the case for a second large thermal resource on the East side of the system by CY 2011. We rely particularly on comments regarding planning margin, omission of interruptible contracts, incomplete analysis of DSM opportunities and shortcomings in comparing DSM resources on par with supply-side options, failure to reexamine the potential risk reduction benefits of renewable resources above the 2003 IRP target under updated assumptions, and cost savings of the coal plant delay scenarios coupled with reasonable measures that could be taken to avoid outages, including additional short-term purchases, wind resources and DSM programs, as well as acquisition of distributed resources. Therefore, the Commission does not acknowledge construction of a 600 MW high capacity factor resource in or delivered to Utah by CY 2011.

Further, the Commission explicitly does not acknowledge acquisition of a new coal plant at this time. Portfolio M, the all natural-gas portfolio, is less costly than PacifiCorp's preferred Portfolio E under the Company's base-case assumptions. The average all-in stochastic cost for all-gas Portfolio M is 2.5% more than PacifiCorp's preferred Portfolio E, but Portfolio M performs better under all CO_2 scenarios tested except a zero adder. We find that there is considerable risk to ratepayers of CO_2 regulatory costs significantly exceeding PacifiCorp's base-case assumption of $8.38/ton (2010$), and that those risks could well exceed the estimated risk reduction benefits of

Portfolio E compared to Portfolio M attributable to gas price volatility. We also note the poor performance of Portfolio E under a scenario with significantly lower load growth than forecasted.

In addition, the Commission does not find that PacifiCorp made the case that a coal plant is in the long-run public interest in light of mounting scientific evidence about the likely effects of CO_2 emissions on climate, the potential carbon allowances that might be required to avoid catastrophic impacts, and the momentum building toward regulatory action to limit CO_2 emissions.

Hydropower resources. Joint comments by the Hydropower Reform Coalition and WaterWatch of Oregon raise issues related to dam management and licensing activities for PacifiCorp's 54 hydropower plants. In particular, these conservation groups comment that modification, enhancement, diminishment or retirement of these plants should be fully described in the IRP.

First, the groups express concerns about what they consider "pessimistic" and in some instances "inaccurate" characterization by PacifiCorp of its relicensing activities. For example, the groups assert that licensing activities take less time than the Company indicates in the plan, and that any delay may be the result of the relicensing applicant which may prefer to continue operating under the existing, less restrictive license. The groups also take issue with PacifiCorp's statement in the plan that FERC can require modifications to facilities that greatly reduce electricity production. The groups state that relicensing decreases project generation by only 1.6% on average, while capacity actually increases by an average of 4.6%.

PacifiCorp responds that while the Federal Power Act envisions a licensing process of five years, many projects take far longer. The Company cites FERC's development of a streamlined alternative to the traditional relicensing process to make the process less time-consuming and costly. The Company further cites FERC's statement that only one-third of projects undergoing traditional relicensing received a new license within five years. Finally, PacifiCorp cites examples of its own experiences with extended relicensing timelines.

Further, the groups opine that PacifiCorp's proposed reforms to the Federal Power Act will not, as the Company maintains, provide similar environmental enhancements. The groups criticize PacifiCorp's proposal which they assert would allow only the license applicant to challenge an agency's environmental conditions for relicensing, cutting out other interests.

PacifiCorp responds that the reforms the Company proposes would allow licensees to propose alternatives to agency-mandated environmental conditions so long as they provide greater operational efficiencies and the same level of environmental protection. The Company supports other stakeholders bringing forward proposals that meet these criteria.

Second, Hydropower Reform Coalition/WaterWatch of Oregon question data for projected generation losses and note what they view as inconsistencies in expected hydropower generation and capacity. They also call for PacifiCorp in future IRPs to consider the probability of dam removal when assessing the life of its hydropower assets. They further call for the Company to "weigh the relative size and age of its plants against the likely impacts of continued operation and the costs of modifying these facilities to comply with current environmental standards, and where costs outweigh the benefits, retire the facilities." *See* Hydropower Reform Coalition/WaterWatch of Oregon Comments at 6.

PacifiCorp responds that generation has declined as a result of operational constraints FERC imposes in new licenses and will continue to do so. For example, as part of relicensing for the North Umpqua project, the Company agreed to constraints that reduce generation by 8%. The Company further states that generation from owned hydro resources will decline over the next few years as several small plants are decommissioned, and the reconstruction of the Swift 2 hydro plant will not provide a corresponding increase in generation due to offsetting contract obligations. The Company provided licensing status of projects as of March 2005. Finally, the Company states that it is willing to consider dam removal if that would be the best outcome for its customers compared to relicensing alternatives.

Hydropower Reform Coalition/WaterWatch of Oregon also express concerns about pumped storage hydropower plants. Portfolio I modeled such a plant coming on-line in FY 2014. PacifiCorp did not choose this portfolio. It had the second highest deterministic PVRR of all portfolios and was not selected for risk analysis. The groups note that pumped storage plants may cause poor minimum river flows downstream, reservoir level fluctuation, and negative impacts on the river channel between the two reservoirs in arid areas such as Utah. The groups comment that if such plants are considered in the next IRP, the Company should provide information about ratepayer costs associated with environmental impacts and an analysis of construction and operation processes, such as acquiring water rights.

Finally, Hydropower Reform Coalition/WaterWatch of Oregon expressed support for PacifiCorp's "hydro endowment." The groups state that an endowment could provide a way to isolate expenditures and ensure that capital is available for facility enhancements.

PacifiCorp responds that the "hydro endowment" referred to in the IRP is not an investment-income endowment structure as the groups suggest. Rather, it a cost allocation method that "more directly assigns the costs of company-owned hydroelectric resources and, to a substantial extent, hydro-based contracts with the Mid-Columbia utilities to the former Pacific Power states." *See* IRP at 39.

Commission disposition: If pumped storage technology becomes a viable resource option in the future, the Commission expects PacifiCorp to analyze the associated environmental costs that ratepayers might incur. We also expect PacifiCorp to consider the potential cost and risk benefits for customers of dam removal when it is considering relicensing alternatives.

Distributed generation. NWEC calls for a more comprehensive treatment of CHP technology options. NWEC states that CHP can provide significant cost savings to ratepayers and reduced environmental impacts compared to conventional supply-side resources through the more efficient utilization of fuel inputs, typically natural gas, and avoidance of transmission costs.

NWEC expresses concern that the Company discounts the capacity contributions of CHP applications because their dispatch typically is not under the Company's direct control. NWEC sees this issue as comparable to those raised regarding how to model certain DSM resources and wind resources in the 2003 planning cycle. NWEC urges PacifiCorp as part of its Action Plan to perform more detailed modeling of CHP options in future IRPs.

In addition, NWEC cites a recent study for California indicating that solar photovoltaic (PV) systems can be cost-effective for areas with high summer-peaking loads, as is the case in Salt Lake City. The study estimated avoided distribution costs at 0.19¢/kWh to 2.95¢/kWh, and avoided transmission costs at 0.04¢/kWh to 0.72¢/kWh. *See* California PUC Docket R.04-03-017. NWEC recommends that PacifiCorp thoroughly investigate the use of solar to help address its Salt Lake City peaking problems.

PacifiCorp responds that it welcomes suggestions for modeling CHP for future IRPs but needs specific recommendations. PacifiCorp states that in evaluating any modeling suggestions, it would need to take into account that CHP units are sited based on customer economics and opportunity, that Qualifying Facilities would be included in the model at avoided costs, and that CHP resources can bid into supply-side RFPs.

PacifiCorp states that the large capital costs associated with solar resources "would clearly result in a relatively uneconomic outcome for portfolios with significant PV solar resources." *See* PacifiCorp's Responses to Oregon Party Comments at 19. The Company notes that the costs for solar electric systems are listed in the IRP.

Staff notes that the nationwide CHP study in which PacifiCorp participated pursuant to its 2003 IRP was limited to projects no larger than 10 MW and that most economic CHP plants are larger than this. PacifiCorp concludes from the study that 100 MW of CHP projects are possible in its Utah service area over five years, comparable to two previous Utah studies that projected market potential at 100 MW to 150 MW. The Company also used the study to assess the CHP market in its Oregon service area at 45 MW over five years. Staff asserts that this number is very low, likely due to the 10 MW limit on project size, and that a single project could easily be larger than 45 MW.

In contrast, Staff states that a recent study prepared for U.S. Department of Energy estimated the additional economic potential in Oregon at 384 MW by 2025, without taking into account existing state incentives or any reduction in technology costs. In a scenario with incentives, reduced costs and other favorable conditions, the study estimated that 1,831 MW in additional systems could be installed in Oregon in the next 20 years. *See* OPUC Staff, *Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations*, presented at the Commission's February 25, 2005, public meeting.

Staff notes that PacifiCorp's stress tests for the IRP for both CHP and dispatchable standby generation resources reduced the PVRR of PacifiCorp's preferred Portfolio E. Staff criticizes the IRP's approach to CHP resources because they are included in portfolio modeling only when the Company is confident a power purchase agreement for a particular project will transpire, unlike other types of resources.

At its May 2005 public input meeting, PacifiCorp reported that for its RFP for a CY 2009 East-side resource, distributed generation 3 MW or larger will be eligible to participate. In its June 17, 2005, response to questions at the meeting, the Company stated it intends to propose that the resources be under PacifiCorp's control, such as would be the case with customer standby generation.

Staff recommends that for the next IRP or Action Plan brought forward for the Commission's consideration, PacifiCorp evaluate within portfolio modeling the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. Staff further recommends that PacifiCorp evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.

Commission disposition: Among the ways the Commission plans to encourage utilities and customers to meet energy needs at the lowest possible cost and risk is to remove regulatory barriers to the use of distributed generation. The Commission views inadequate modeling of distributed resources in utility IRPs as one of these barriers.

For the next IRP or Action Plan brought forward for the Commission's consideration, PacifiCorp should include in its portfolio modeling high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas to evaluate the potential for reducing costs and risks of generation and transmission. Further, the Company should include in its modeling the value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.

Transmission. CUB states that transmission constraints on the East side of PacifiCorp's system are an important reason to address Utah's load growth problem. Such constraints force long lead times in resource development to account for transmission siting and construction. CUB points out a possible flaw in the IRP: The analysis did not make clear whether a new transmission asset is valuable only when associated with a particular generating resource, or whether a transmission investment could delay a commitment to a new plant by relieving constraints and opening pathways to short-term market purchases.

CUB asked the Company to address the tradeoffs between building transmission to access shorter-term purchasing opportunities and building transmission to a dedicated resource. *See* CUB Data Request No. 3. In its response, the Company states, "PacifiCorp is open to evaluating purchases from remote new or existing resources via new transmission expansions as they could prove to be more cost effective than investing in new generation with associated transmission." CUB replies, "Given this response, we are not sure if Utah's load problem is causing us to build a coal plant, as the preferred portfolio assumes, or is causing us to fix a transmission problem in the absence of a coal plant." *See* CUB Opening Comments at 16.

Staff notes that the 2003 IRP analyzed a transmission-only portfolio that provided a comparison with other portfolios that included new generating resources along with associated transmission. Staff maintains that it cannot tell from the 2004 IRP whether some combination of additional transmission to enable additional short-term market transactions, along with new generating resources and their associated transmission, would have been a better choice than PacifiCorp's preferred portfolio.

Staff recommends that for the next IRP or Action Plan, PacifiCorp analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

Commission disposition: We agree with CUB and Staff that the IRP does not sufficiently address the relative costs and risks of investing in transmission to enable more short-term market purchases, vs. meeting supply-side resource needs via long-term commitments with associated transmission costs. For the next IRP or Action Plan brought forward for the Commission's acknowledgment, PacifiCorp should analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

Overall recommendations. CUB recommends that the Commission not acknowledge a new coal plant at this time. CUB further recommends the Commission ask the Company how it would proceed on a path that included more peak-load shaving programs and no new coal-fired generation.

ODOE recommends at a minimum that the Commission not acknowledge acquisition of new coal plants pending completion of the following analyses:

- Risk analyses comparing a portfolio that has renewable resources beyond the 1,400 MW in the Action Plan with portfolios that have new coal plants

- Analysis of potential excess costs if PacifiCorp builds a coal plant without the option to sequester CO_2 and then faces an immediate or delayed requirement to reduce emissions below 2000 levels
- Analysis of the costs of alternative long-run strategies to respond to a binding and declining cap on PacifiCorp's existing CO_2 emissions through 2050
- Site-specific analyses of IGCC with sequestration at various sites
- An analysis of the transmission needed to integrate sufficient renewable and gas-fired resources to meet load growth through 2025 or, alternatively, plans including IGCC plants with a carbon sequestration option or compressed air storage for shaping wind resources, if these options have lower costs or risks

ODOE recommends a portfolio with more renewable resources, backstopped by new natural-gas plants and more demand response programs.

NWEC recommends that the Commission not acknowledge the 2004 IRP — especially the decision to acquire two conventional coal plants — without reviewing an analysis of a portfolio with far more renewable resources such as the Company tested in its 2003 IRP, without a higher assumed CO_2 adder, and without a value for optionality such as consideration of constraints that more coal plants pose for integrating additional levels of wind resources.

RNP recommends that the Commission direct PacifiCorp to prioritize renewable resource acquisitions and not acknowledge new coal-fired resources. RNP supports the comments filed in this docket by CUB, ODOE and NWEC.

Staff recommends that the Commission acknowledge PacifiCorp's 2004 IRP with one exception and 11 modifications to the Action Plan. The exception is Action Item 8: Procure a 600 MW high capacity factor resource in or delivered to Utah by the summer of 2011. Staff recommends that the construction of a second large thermal resource in or delivered to Utah by CY 2011 not be acknowledged, including acquisition of a new coal unit. Staff's recommended modifications to the Action Plan are as follows:

Revised Implementation Action

1. Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth. (Action Item 2)

Additional Implementation Actions

2. Execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of power purchase agreements upon extension of the federal production tax credit.

3. For the next IRP or Action Plan, analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk

metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's ability to integrate wind resources.

4. For the next IRP or Action Plan, conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in PacifiCorp's service area over the IRP study period and assess how the company's base and planned programs compare with the cost-effective amounts determined in the study.

5. For the next IRP or Action Plan, develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.

6. For the next IRP or Action Plan, assume existing interruptible contracts continue unless they are not renegotiable or other resources would provide better value.

7. For the next IRP or Action Plan, determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options.

8. For the next IRP or Action Plan, assess IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties including market prices and CO2 regulation.

9. For the next IRP or Action Plan, analyze planning margin cost-risk tradeoffs within stochastic modeling of portfolios. If feasible, analyze the cost-risk tradeoff of all portfolios at various planning margins. If not feasible, build all portfolios to a set planning margin, test them stochastically, and adjust top-performing portfolios to higher and lower planning margins for further stochastic evaluation. Evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Evaluate alternatives for determining the expected annual peak demand for determining the planning margin — for example, planning to the average of the eight-hour super-peak period.

10. For the next IRP or Action Plan, analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

11. For the next IRP or Action Plan, evaluate within portfolio modeling the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. Evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.

Jurisdiction

PacifiCorp is a public utility in Oregon, as defined by ORS 757.005, that provides electric service to the public.

On April 20, 1989, pursuant to its authority under ORS 756.515, the Commission issued Order No. 89-507 in Docket UM 180 adopting least-cost planning for all energy utilities in Oregon.

CONCLUSION

PacifiCorp is a public utility subject to the jurisdiction of the Commission.

PacifiCorp's 2004 Integrated Resource Plan, as modified in this order, reasonably adheres to the principles of least-cost planning set forth in Order No. 89-507, and should be acknowledged with the following exception, agreed-upon modifications, and conditions:

<u>Exception</u>:

Action Item 8, Procure a 600 MW high capacity factor resource in or delivered to Utah by the summer of 2011, is not acknowledged, including acquisition of a new coal unit.

<u>Modifications</u> agreed to by PacifiCorp pursuant to Staff recommendations #1, 2, 3, 5, 6, 8 and 10, above, are as follows:

Revised Action Item

1. Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and 200 MWa or more of additional Class 2 DSM found cost-effective through RFP or in-house programs, up to the levels required to serve load growth. (Action Item 2)

Additional Action Items

2. Execute an agreement with the Energy Trust of Oregon by October 1, 2005, to reserve funds for the above-market costs of renewable resources that benefit Oregon ratepayers and enable timely completion of power purchase

agreements upon extension of the federal production tax credit.

3. For the next IRP or Action Plan, analyze renewable resources in a manner comparable to other supply-side options, including testing cost and risk metrics for portfolios with amounts higher and lower than current targets, further refine wind's capacity contribution, and consider the effect of fuel type for thermal resource additions on the Company's ability to integrate wind resources.

4. For the next IRP or Action Plan, develop supply curves for various types of Class 1 DSM resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. Evaluate this approach for Class 2 DSM resources and recommend whether this approach is preferable to the current decrement approach.

5. For the next IRP or Action Plan, assume existing interruptible contracts continue unless they are not renegotiable or other resources would provide better value.

6. For the next IRP or Action Plan, assess IGCC technology in a location potentially suitable for CO_2 sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties including market prices and CO_2 regulation.

7. For the next IRP or Action Plan, analyze the costs and risks of portfolios that include various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

<u>Conditions</u> the Commission adopts pursuant to Staff recommendations #4, 7, 9 and 11 are as follows:

1. For the next IRP or Action Plan, conduct an economic analysis of achievable Class 1 and Class 2 DSM measures in PacifiCorp's service area over the IRP study period and assess how the company's base and planned programs compare with the cost-effective amounts determined in the study.

2. For the next IRP or Action Plan, determine the expected load reductions from Class 3 DSM programs such as new interruptible contracts and the Energy Exchange at various prices, and model these programs as portfolio options that compete with supply-side options.

3. For the next IRP or Action Plan, analyze planning margin cost-risk tradeoffs within stochastic modeling of portfolios. If feasible, analyze the cost-risk tradeoff of all portfolios at various planning margins. If not feasible, build all portfolios to a set planning margin, test them stochastically, and adjust top-

performing portfolios to higher and lower planning margins for further stochastic evaluation. Evaluate loss of load probability, expected unserved energy and worst-case unserved energy, as well as Class 3 DSM alternatives for meeting unserved energy. Evaluate alternatives for determining the expected annual peak demand for determining the planning margin — for example, planning to the average of the eight-hour super-peak period.

4. For the next IRP or Action Plan, evaluate within portfolio modeling the potential for reducing costs and risks of generation and transmission by including high-efficiency CHP resources and aggregated dispatchable customer standby generation of various sizes within load-growth areas. Evaluate the potential value of CHP resources in deferring a major distribution system investment associated with load growth, assuming physical assurance of load shedding when the generator goes off line, up to the number of hours required to defer the investment.

Effect of the Plan on Future Ratemaking Actions

Order No. 89-507 sets forth the Commission's role in reviewing and acknowledging a utility's least-cost plan as follows:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission.
>
> Plans submitted by utilities will be reviewed by the Commission for adherence to the principles enunciated in this order and any supplemental orders. If further work on a plan is needed, the Commission will return it to the utility with comments. This process should eventually lead to acknowledgment of the plan.
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan. *See* Order No. 89-507 at 6 and 11.

This order does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken pursuant to PacifiCorp's 2004 IRP. As a legal matter, the Commission must reserve judgment on all rate-making issues. Notwithstanding these legal requirements, we consider the least-cost planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged least-cost plans. Utilities will also be expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

In Order No. 05-021 (UM 1050), the Commission approved an Inter-Jurisdictional Cost Allocation method for PacifiCorp called the Revised Protocol. The Revised Protocol describes how PacifiCorp's costs are assigned or allocated among the six states the Company serves, including such activities as special contracts to retail customers, old and new qualifying facilities, company-owned and contracted hydroelectric resources, and transmission costs. The allocation of a particular expense in whole or in part is not intended to prejudge the prudence of those costs.

With the exception of certain special contracts, DSM program costs are allocated to the state in which the investment is made, and their benefits are reflected in the change in the state's load allocation. The Revised Protocol includes a hydro endowment that benefits primarily Oregon and Washington. Supply-side resources are allocated to all states based on their load allocation. Costs associated with transmission assets and firm wheeling expenses and revenues are allocated among the states in a similar manner to supply-side resources.

ORDER

IT IS ORDERED that the 2004 Integrated Resource Plan filed by PacifiCorp on January 20, 2005, is acknowledged in accordance with the terms of this order and Order No. 89-507.

Made, entered, and effective ______________________________.

______________________________	______________________________
Lee Beyer Chairman	**John Savage** Commissioner
	______________________________
	Ray Baum Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

LC 39 - Staff Exhibit 1

From: Quantec, *Customer Energy Challenge Report*, prepared for PacifiCorp, 2002.

Table 3 - Savings Statistics

	PacifiCorp Data	Quantec Model Estimates		
	Gross MWh Saved	Net MWh Savings Due to Program	Net kWh Savings Per Participant	Net MW Savings-on-Peak
Total	*326,249*	*177,200*	*139*	*66.4*
California	6,979	4,053	167	1.6
Idaho	10,954	3,862	81	1.4
Oregon	104,552	49,824	108	19.1
Utah	131,079	83,758	165	30.5
Utah Commercial	28,583	13,892	269	5.5
Washington	29,037	13,927	147	5.5
Wyoming	15,065	7,883	91	2.9
June	61,070	29,764	140	45.3
July	70,121	37,189	123	55.7
August	125,670	74,348	159	110.5
September	69,387	35,898	122	55.0
20/20% Tier	263,260	124,544	147	46.7
10/10% Tier	62,989	38,272	89	14.3
Free Savers	40,004*	14,384	21	5.4

* Overall, state and monthly participation and savings are based on PacifiCorp data. Free Saver energy savings are estimated using a sample of 60,000 customers