ORDER NO. 03-508

ENTERED AUG 25 2003

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 31

In the Matter of PACIFICORP Resource and Market Planning Program (RAMPP-7).)	ORDER

DISPOSITION: LEAST-COST PLAN WITH AGREED-UPON MODIFICATIONS ACKNOWLEDGED IN PART

INTRODUCTION

On January 24, 2003, PacifiCorp, dba Pacific Power & Light Company (Pacific 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 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.

Pacific satisfied Oregon's procedural requirements relating to its planning process. In the analysis below, the Commission identifies specific portions of Pacific'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 Pacific's May 2003 load forecast and other circumstances. However, Pacific has agreed to modify portions of its Action Plan to address most of the identified concerns. The Commission concludes that Pacific's IRP, with agreed-upon modifications, satisfies Oregon's least-cost planning requirements and appears reasonable in light of current circumstances with specific exceptions described below. Accordingly, the plan with agreed-upon modifications is acknowledged in part.

PacifiCorp

Pacific serves approximately 1.5 million customers in six Western states: Oregon, Utah, Wyoming, Washington, Idaho and California. In 2002, the Company sold 47,527 gigawatt-hours (GWh) of electricity to retail consumers in its service territory and 24,438 GWh of electricity to wholesale customers in the Western interconnection.

Pacific owns or has interests in generating plants with an aggregate capacity totaling 7,920 MW. Under average water conditions, about 6 percent of the Company's energy requirements for 2003 would be supplied by its 53 hydroelectric plants, including 14 large facilities; 66 percent from 18 thermal plants it owns or has interest in; and the remaining 28 percent from long-term purchase contracts, exchange and other purchase arrangements. The thermal plants include 12 coal-fired plants, four natural gas-fired plants, one geothermal plant and a plant that burns black liquor at a paper mill. Pacific also owns one wind plant and has a 20-year agreement for the output from another.

The 2001 load forecast Pacific used to prepare its IRP projected that its loads will grow by 2.2 percent in the eastern portion of its service territory (Utah, Idaho and Wyoming), and 2.0 percent in the western portion (Oregon, Washington and California), per year, on average, over the next 20 years. It estimates that actual growth could vary between 1.4 percent and 3.4 percent. The Company estimates annual growth at 1.6 percent in Oregon. Pacific assumes, for its load forecast, that the Energy Trust of Oregon will acquire conservation at historic levels.

Pacific anticipates that expiring supply contracts and derating and retirement of hydroelectric and thermal plants will increase the projected gap between loads and existing resources. To close the gap, Pacific proposes the addition of 4,000 MW of new energy and capacity resources through 2013.

Pacific's preferred resource strategy. Based on its analysis described below, Pacific selected "Diversified Portfolio I" as its preferred course of action. Diversified Portfolio I calls for the following resources during the period 2004 to 2014:

- 450 MWa of DSM resources and 90 MW of direct load control to reduce overall and peak demand requirements
- 2,100 MW of base load thermal resources
- 1,400 MW of renewable resources
- 1,200 MW of natural gas units to meet peak demand

- Transmission upgrades and additions to make the best use of the network; provide better access to market and support new generating resources
- 700 MW of shaped products and power purchase agreements to meet immediate energy needs and to optimize the utility's portfolio

Implementation Actions for Diversified Portfolio I. The Company proposes 28 implementation actions to carry out its Action Plan for Diversified Portfolio I (Attachment A to this Order):

- 11 actions for supply-side resources
- 10 actions for demand-side resources that reduce overall system demand and peak requirements
- Four actions related to transmission additions to support the portfolio resources
- Three actions to resolve strategy or policy decisions

Supply-side action items consist of acquiring thermal and renewable resources on the East and West sides of the Company's system. The Company proposes four sequential RFPs to acquire supply-side resources, the first of which this Commission approved on June 3, 2003, for the East side.

For base load resources, the Company proposes to add a coal plant and two natural gas-fired plants in the East, one natural gas-fired plant in the West, and wind facilities throughout its system beginning in FY2006.[1] The Company also proposes a flat off-peak contract in the West to meet near-term energy needs and contracts for thermal base load facilities throughout its system starting FY2006. To meet peak energy needs, the Company proposes contracted resources beginning in FY2004 in the East and building peakers throughout its system starting FY2006.

The demand-side management (DSM) Action Items include four classes of resources: Class 1 DSM resources are actively controlled by the utility and are fully dispatchable. Examples include direct load control of electric water heating and air conditioning systems. Class 2 DSM resources provide energy or capacity savings through technology changes in equipment and buildings. Examples are conservation programs that provide incentives for efficient lighting or motors. Class 3 DSM resources achieve energy or capacity savings during times of tight supplies through financial incentives, with hour-by-hour load reductions measured for each customer. Examples include Pacific's Energy Exchange program and real-time pricing. Class 4 DSM resources include both conservation education programs and pricing structures, such as inclining block and time-of-use rates, that lead to behavioral changes in energy use.

The DSM action items in Pacific's IRP are directed toward the East side of the system. Under Oregon's electric industry restructuring law, the utility no longer acquires

[1] Pacific's fiscal year, ending March 31. For example, FY2006 is April 1, 2005 to March 31, 2006.

Class 2 resources in the state. The Action Plan also specifies no Class 1, Class 3 or Class 4 DSM programs for Oregon. Although the IRP did not evaluate or include in the Action Plan Class 1 resources for Oregon, the Company's current RFP for 100 aMW or more of cost-effective DSM resources allows bidders to propose them. The Company also may issue additional RFPs for DSM resources.

DISCUSSION

In Order No. 89-507, the Commission identified several procedural and substantive elements of least-cost planning. We address these requirements below.

Procedural Requirements

As noted above, energy utilities must file least-cost plans every two years and involve the Commission and the public in its planning process.[2] The Commission finds Pacific satisfied these procedural requirements. Pacific filed this plan approximately 18 months after filing its previous least-cost plan and allowed significant amount of public involvement in the plan's preparation.

Pacific started its public input meetings related to the development of this plan on December 13, 2001. The public input process included nine full-day meetings and multiple half- or full-day meetings on various technical subjects. Twenty-four parties participated in the review process. Pacific distributed a draft of its report for comment before submitting its final plan to the Commission.

The Commission held a Special Public Meeting on Pacific's plan on April 17, 2003. On May 5, 2003, the Citizens' Utility Board (CUB), the Industrial Customers of Northwest Utilities (ICNU), Oregon Office of Energy (OOE) and Renewable Northwest Project (RNP) submitted written comments to the Commission and parties. Pacific filed a reply to the parties' comments on May 19, 2003. The Commission held a second Special Public Meeting on June 3, 2003. Staff circulated to parties its comments, recommendations and a draft order on July 3, 2003. Pacific, OOE, RNP and the Northwest Energy Coalition submitted comments by July 14, 2003, in response to Staff's filing. Staff issued its public meeting memo and revised proposed order on July 18, 2003. The Commission held a final Special Public Meeting on July 22, 2003, to consider acknowledgment of Pacific's IRP, and allowed an opportunity to provide additional written comment on Implementation Actions 3 and 4.

Substantive Requirements

Evaluating resources on a consistent and comparable basis. Pacific'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

[2] *See* Order No. 89-507 at 3.

and shaping of hydroelectric resources, considers purchases and sales at four market trading hubs (mid-Columbia, California-Oregon Border, Palo Verde and Four Corners), and takes into account transmission paths and constraints to provide a detailed examination of the economic and operational performance of resource alternatives.

The Company modeled on a system-wide basis, with the following key assumptions:

1. To allow modeling of different sites, technologies and transmission costs, all new resources are specific Company-owned assets. The Action Plan, however, shows that the Company will decide on a case-by-case basis whether to invest in a new resource itself or contract with a third party to obtain power at least-cost.

2. Long-term contracts are not renewed, and needs not met by new firm resources are met through short-term market purchases.

3. Resources are served by firm transmission.

4. Portfolios are built to match load growth, plus a 15 percent planning margin.

Pacific developed more than 40 portfolio options that could meet its projected resource requirements, spanning a wide range of possible resource strategies. Each portfolio specified the types of resource additions and when they would be added and assumed a 15 percent planning margin. All portfolios included base DSM investments, sizable wind resource additions, short-term purchases to meet energy and capacity needs in FY2004-06, new peakers to meet Pacific's proposed 15 percent reserve margin and transmission upgrades. The Company estimated for each portfolio the cost of transmission upgrades needed to get the power from the new generating resources to Pacific's system.

A simulation of each portfolio calculated the operating costs of the new system (portfolio additions plus existing resources) under a common and representative set of assumptions about the future. The assumptions cover available power contracts, DSM resources, air emission rates and compliance costs, fuel costs, power plant heat rates, hourly operating margin, plant operating life, hydroelectric plant relicensing, inflation rates, caps on market access, planning reserve margin, production tax credit for renewable resources, spot market purchases, characteristics of resource options, demand growth assumptions, load forecasts, transmission losses, forced outage rates for thermal plants, plant operation and maintenance costs, market price forecast and transmission system flows. Pacific 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 performance measures, including PVRR and capital costs, pollutant emissions (tons and percent of cap), market sales and purchases (average megawatts and percent of load), existing and new unit capacity factors, and system transfers between East and West (megawatt-hours).

Pacific used the same interest rate to discount all resource costs over the entire study horizon to a base year.

Uncertainty. Pacific used a new methodology to evaluate how alternate resource options perform given future risks and uncertainties. The Company sorted future risks and uncertainties into three categories: Stochastic, Scenario and Paradigm risk.

Stochastic risk is quantifiable as a known fluctuation around an expected value. Pacific quantified the variability of five stochastic risks: (1) retail loads, (2) natural gas prices, (3) electricity prices, (4) hydroelectric generation, and (5) thermal unit availability. Pacific then used Monte Carlo simulation to model the performance of the final portfolios. Monte Carlo simulation allowed Pacific to address the asymmetric nature of these risks as well as the interactions between these risks. Diversified Portfolio I outperformed the other final portfolios on most measures of stochastic risk. Those measures include the 95^{th} percentile PVRR (95 of the 100 simulated portfolio runs were less than this PVRR level), mean-of-tail (worst-case) PVRR, 95^{th}-5^{th} percentile (90 of the 100 simulated portfolio runs had a PVRR within this range), and coefficient of variation (standard deviation of the 100 simulations divided by their mean). Diversified Portfolio II outperformed Pacific's preferred plan in another risk measure, the 5^{th} percentile (best-case) PVRR, and this portfolio followed closely the performance of Pacific's preferred plan for most of the other risk measures.

Scenario risks represent abrupt changes in risk factors. It is not possible to represent these abrupt changes (or shocks) using a known statistical process. Pacific evaluated each portfolio's sensitivity to these abrupt shocks by manually adjusting the assumed values of key risk factors. For example, the Company tested the effect of a 10-percent planning margin as compared to a 15-percent margin. The company also varied the timing and order of new power plants, modified West-side loads for Oregon customers that may choose alternative suppliers, changed cost assumptions for wind, changed CO_2 allowance costs, changed hydroelectric relicensing costs, changed the value of green tags, varied the ability to purchase energy on the spot market, and varied the production tax credits for renewable energy resources.

The Company tested these stresses against its preferred plan, which assumes a planning reserve margin of 15 percent, limits spot market purchases to 5 percent, assigns zero capacity to wind resources, assumes no industrial loads leave its system as a result of direct access in Oregon, bases natural gas prices on a blend of near-term and long-term forecasts, uses Pacific forecasts for coal prices, uses the Company's forecasts for demand growth, and makes other assumptions regarding possible futures.

Paradigm risks represent radical changes associated with novelty and innovation. Pacific addressed the potential impact of paradigm risks in a qualitative, rather than quantitative, manner. Pacific discussed the possible impacts of major changes in market structure or regulatory requirements, such as changes in transmission operation and control resulting from formation of a regional transmission organization or implementation of the Federal Energy Regulatory Commission's (FERC's) Standard Market Design, establishment of a Renewable Portfolio Standard, and the effect of the Multi-State Process (MSP) on regulation and cost recovery.

Primary goal must be least-cost/consistent with public interest. As discussed above, Pacific developed 40 portfolios consisting of a wide-ranging variety of resources. The portfolios were designed to meet the Company's forecasted loads and a reserve margin. Pacific'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, Pacific identified risk factors, such as volatility of fuel and spot market prices, current and potential federal regulations, environmental costs and benefits, and weather. The Company assessed cost variability of the resource scenarios and impacts on rates. The Company also evaluated trade-offs among the portfolios, such as PVRR versus risk. Further, Pacific examined the full, long-run costs of its resource choices, including possible shifts in societal values, such as enactment of standards for carbon dioxide emissions. Ultimately, Pacific selected what it thought was the best resource portfolio, considering PVRR and other analyses, as the basis for preparing the Action Plan.

Consistency with Oregon's energy policy. Oregon's overall energy policy is stated in ORS 469.010(2). The policy states, in part, "It is the goal of Oregon to promote the efficient use of energy resources and to develop permanently sustainable energy resources." The plan promotes the efficient use of energy resources through the DSM Action Plan items. The IRP and Action Plan include a strong commitment to the development of permanently sustainable wind resources.

Party Comments

As noted above, in the months preceding this order, ICNU, OOE, RNP, CUB and Pacific filed written comments regarding Pacific's least-cost plan. Further, the parties had opportunity for oral presentations to the Commission at three Special Public Meetings. Following is the Commission's discussion of issues raised by the parties, as well as the Commission's disposition.

Load Forecast. ICNU states that Pacific did not adequately document the process it used for load forecasting. Further, ICNU questions whether the Company considered in its load forecasting and rate impacts analysis all the possible costs the Company faces, including air emissions and hydro relicensing costs that may total $2 billion to $4.4 billion (NPV) over the study period. ICNU notes that higher rates resulting from such costs may cause loads to decline. ICNU recommends that Pacific include a section on load forecasting in the main body of any IRP and that Pacific establish the underlying assumptions.

OOE points out that Oregon's residential load appears high in the 2001 forecast the Company used to prepare the IRP. OOE states that Pacific forecasts an annual growth rate of 2.9 percent from 2001 to 2004 and 1.9 percent from 2001 to 2024, while annual growth in the 1990s was only 1.5 percent. With electric space-heating loads decreasing and the state's flagging economy, OOE suggests that growth in Pacific's residential sales in Oregon over the next decade likely will be lower than in the 1990s.

OOE also raises a concern about a possible anomaly in Pacific's peak forecast. OOE points out that the forecast shows a decrease in the ratio of peak to average loads in the East and an increase in the West, yet the West side of Pacific's system is winter peaking and electric space heating is declining. OOE recognizes that faster-growing commercial loads would increase the ratio in the West, but would appear to have similar effects on both sides of the system. Despite these concerns, OOE recommends that requests for proposals go forward for resources planned to be on line by 2007 because "resource needs this decade are almost certainly greater than that level."

Pacific responds to ICNU's concerns about the adequacy of the load forecast by stating the Company will provide more detail in the next IRP and planning process. Regarding ICNU's inquiry into air emissions and hydro relicensing costs and the price elasticity effects, Pacific responds that the 2001 load forecast used in the IRP did not include these estimated future costs. Instead, Pacific based the forecast on historical price trends. Pacific states that future large capital expenses will be evaluated and included in future load forecasts if appropriate. Pacific points out that its modeling did consider the relationship between price and load. In response to OOE's concerns about forecasts of residential load and peak load growth, Pacific cites the amount of time that has elapsed since it made its initial estimates and states it intends to make any necessary adjustments in the Action Plan update due in October 2003.

Staff compared Pacific's recently released 2003 load forecast to the 2001 forecast that Pacific used to prepare the IRP. Staff states that the new forecast estimates that Oregon peak loads in 2006 will be 312 MW lower than assumed for purposes of preparing the IRP. Staff also notes that the new forecast shows Utah's requirements will be an estimated 493 MW higher in 2006 than projected in the forecast used in the plan. Staff comments that the new load forecast indicates that new peaking resources likely will not be needed on the West side of Pacific's system by FY2006, and that the East side of the system may need more peaking resources than assumed in the IRP.

Staff adds that energy requirements on the East side of Pacific's system are estimated to be 147 aMW greater in 2008 than projected in the 2001 forecast the Company used for the IRP, and 184 aMW greater in 2009. In contrast, Staff notes that West-side energy requirements are now estimated to be 2,014 GWh, or 230 MWa, lower in 2007 than in the forecast used to prepare the IRP. Staff states that it understands

Pacific is updating its load/resource balance estimates and that its Action Plan update in October 2003 will show that a new base-load plant is not needed in the West by FY2007.

Commission disposition: The Commission recognizes that the issues ICNU and OOE raise regarding Pacific's load forecast may have affected the results underlying the Company's proposed two-year implementation actions. The Commission also notes that the May 2003 load forecast indicates that fewer resources will be needed on the West side of Pacific's system and more resources may be needed on the East side than assumed in the IRP. Accordingly, the Commission recognizes that Pacific must acquire in the near future sizable resources to serve growing East-side loads. On the West side of Pacific's system, however, the May 2003 load forecast, together with insufficient analysis as identified below regarding the appropriate planning reserve margin, market exposure level, capacity credit for wind resources, and combined heat and power and demand-side management resources, throw into doubt the timing, level and type of resources needed.

Supply Criteria. ICNU is concerned that Pacific's use of conservative assumptions — a 15-percent reserve margin and a 5-percent limit on short-term market purchases — causes a higher than necessary level of proposed resource additions and the selection of wind resources. ICNU states that if the reserve margins were lower and market purchases higher, the Company would not need the level of new resources it identifies in the IRP. ICNU is concerned about the high price to consumers of the level of risk Pacific seeks to avoid. Further, ICNU points out that these assumptions were based on the FERC's proposed Standard Market Design, which has met considerable opposition. ICNU states that Pacific should propose and independently justify an appropriate reserve margin and market exposure level. ICNU points out Pacific's analysis that shows the cost of building to a 15 percent reserve margin is not offset by the same level of risk reduction.

OOE states that FERC has abandoned a prescriptive standard for capacity reserve margin for its proposed Standard Market Design and that Pacific's analysis does not support a 15 percent reserve margin. OOE cites the sensitivity analysis Pacific performed that indicates that a 10 percent margin is preferable.[3] OOE points out Pacific's statement that a 10 percent planning margin increases spot purchases from 1,000 MWh per year to 7,000 MWh per year, compared to the 15 percent margin assumed in the plan. OOE states that even at an unlikely price of $1,000 per MWh, this higher level of spot purchases would add only $6 million in costs for the year. OOE therefore concludes that the lower expected costs of adopting a 10 percent planning reserve margin overwhelms the cost of the additional market purchases that would be required. OOE further states that using a 10 percent margin instead of a 15 percent margin lowers the PVRR of the deterministic case, the 95th percentile case, and the mean-of-the-tail results, all of which indicates that a 10 percent margin has lower risk. OOE notes that the "apparent error of

[3] "A lower margin (from 15% to 10%) is shown to consistently reduce the 20 year PVRR by between $100 million and $325 million, or 0.8%and 2.5%." IRP at 139.

setting too high a reserve margin" is compounded by not assigning any capacity value to wind resources.

OOE states that Pacific provides no analysis to support the IRP's statement, at page 61, that firm resources be "added to limit expected spot purchases to 5-percent or less of each year's hours." OOE requests that Pacific conduct sensitivity analyses around this value.

Pacific responds to parties' concerns about the 15 percent planning reserve margin by stating that FERC's April 2003 white paper on Standard Market Design specifically said it would not require a minimum level of resource adequacy, and by pointing out that Action Item 24 proposes additional study on the planning margin.

In its response to parties' concerns about the 5-percent limit on market exposure, Pacific states that parties generally agreed to this limit as a starting point for developing the portfolios. The Company points out that increasing the market limit would not decrease the *level* of resources that it requires, only *where* it gets those resources — spot market vs. contracts or assets. Pacific points out that its assumptions for market exposure and planning reserve are intertwined, and that the Company's study on the planning margin will provide useful information about resource adequacy assumptions.

Staff points out Pacific's analysis demonstrating that resource additions to the portfolios through 2013 are reduced by 500 to 550 megawatts when the planning reserve margin is reduced from 15 percent to 10 percent. Staff states that Pacific's analysis also shows that the lower-planning margin consistently reduces the 20-year PVRR of Diversified Portfolio I, the Company's preferred plan, by $325 million, or 2.5 percent. A major factor in this reduction is a reduction in present-value levelized fixed costs.

Regarding the Company's assumption about market access, Staff understands that Pacific's market access is constrained by transmission and liquidity. However, Staff notes that the Company's assumption of a 15 percent planning reserve margin is a significant component of its assumption for market exposure. Therefore, Staff believes the Company should refine its assumptions regarding market exposure as it conducts further analysis on the appropriate planning reserve margin.

Commission disposition: The Commission agrees with the parties that Pacific did not justify a 15 percent planning reserve margin or a 5 percent limit on market exposure. Analysis in the IRP and Pacific's 2003 load forecast show that resource acquisitions are more critical in the short-run on the East side of Pacific's system. Therefore, decisions regarding West-side resources and East-side resources that would be on line after FY2007 can be postponed until Pacific completes its study on the reserve margin and conducts tests on various levels of market exposure. The Commission expects that Pacific will further explore during the next IRP cycle the supply criteria issues raised by the parties.

Base case. ICNU comments that Pacific did not prepare a "base case" that "identifies the utility's most reasonable estimation of future conditions, based on what is known today." Such a base case, ICNU states, would allow the Company to test stresses and alternate scenarios to determine the impact of a range of potential outcomes. ICNU maintains that lack of a base case is a flaw in Pacific's approach and leads to inappropriate assumptions for resource planning and risk mitigation measures.

Pacific responds that it is unclear how ICNU's request for a base case view of the future is different from the methodology the Company used in the IRP. Pacific cites its work with the public to define a reasonable view of future factors, including green tag rules and values, emissions costs, transmission, resource alternatives, risk parameters and others; its stress testing for those factors; and its risk analysis.

Commission disposition: The Commission understands that ICNU is looking for a "base case" that models price risk for electricity and natural gas as a scenario risk, as has been done in prior IRPs. This modeling resulted in a base price forecast as well as low- and high-price forecasts. In the present IRP, Pacific models price risk as a stochastic risk and includes a base price forecast (found in Appendix C in the IRP). However, instead of modeling low- and high-price forecasts, Pacific's new risk methodology uses 100 scenarios of randomly drawn prices. The Commission believes this is a significant improvement because such "Monte Carlo" simulations help identify the probability of possible futures and provide a rigorous means of addressing the potential convergence of high natural gas prices, high market prices for electricity and poor hydro conditions.

The Commission notes that a comprehensive list of "base case" assumptions can be found in IRP Appendix C. The performance of the final portfolios under "base case" assumptions is summarized in scorecard format in IRP Appendix E. "Stress test" scorecards are also presented in Appendix E.

The Commission understands the fundamental differences between stochastic, scenario, and paradigm risks and that these differences call for a hybrid approach to risk analysis. The Commission also understands that the results of this analysis cannot be reduced to a single number. Even if today's expected paths for future retail load, gas prices, electricity prices, hydroelectric generation, and thermal outages are all accurate, it is still reasonable to expect variation around these expected paths. It is not reasonable to assume that these variations will cancel each other out. It is important to address the dependencies of these risk factors. Pacific's new hybrid approach to risk analysis is a reasonable analysis of uncertainty. Pacific's choice to use its hybrid approach, rather than the modeling recommended by ICNU, is not a flaw in Pacific's analysis.

Coal Plant. OOE recommends that the Commission not acknowledge acquisition of a coal-fired plant in this planning cycle. OOE disagrees with the plan's conclusion, at page 149, that "[r]esults appear to favor adding a new coal unit[.]" OOE points out that there is only a 0.21 percent difference in the PVRR between Diversified Portfolio I and

II, and that variation 2 on Diversified Portfolio I adds only 0.03 percent to the PVRR. The key difference between the portfolios is delaying the Hunter 4 coal plant from 2008 to 2012 and moving a natural gas plant forward. Such a delay, OOE states, will provide the Company with better information on climate change, limits on mercury and other air emissions, and technologies for wind and integrated-gasification combined-cycle (IGCC) technology for coal. OOE also states that there are negligible benefits of procuring the Hunter 4 plant in 2008 (under Diversified Portfolio I) vs. 2012 (under Diversified Portfolio II), yet the reduction in risks could be large.

Further, OOE asserts that Pacific mischaracterized the risk of compliance costs for CO_2 emissions because the Company did not include the effects on wholesale prices. OOE cites the Northwest Energy Coalition's memorandum of February 18, 2003, which notes that the CO_2 stress test does not take into account the impact on wholesale prices of changing the CO_2 tax rate. OOE explains that a CO_2 tax would increase operating costs for all utilities with fossil-fuel generation, and therefore their demand for power from the wholesale market would increase, raising wholesale prices. That, in turn, would increase the cost of the portfolios with coal resources (Diversified Portfolios I, II and III) relative to the all-natural gas portfolio and the portfolio with additional renewable resources (Renew II). OOE states that shifting to Renew II could yield significant cost savings if it becomes clear that a CO_2 tax makes that portfolio lower cost, but it will be impossible to do so if Pacific makes an early commitment to a coal plant.

OOE also points toward IRP results showing that delaying the Hunter 4 coal plant one year, from 2008 to 2009 (Diversified Portfolio I - variation 1), *raises* the PVRR by $12 million. That would be the scenario in the event the Company proposes the coal plant as the next best alternative for the RFP for the second East-side, base-load plant proposed this planning cycle. However, OOE states, the IRP shows that delaying the coal plant three years, until 2012 (Diversified Portfolio I - variation 2), *lowers* the PVRR by $8 million. OOE states that delaying a coal plant should either raise or lower the PVRR, but not both, indicating that differences in the PVRR from the timing of a coal plant are "spurious." OOE concludes that the differences in PVRR should be given no weight when compared to the substantial reduction in risk from delaying a commitment to a coal plant.

OOE further asserts that permitting activities for Hunter 4 are premature. OOE states that air quality permits typically require construction of a plant to begin within 18 months, and that it should not take six to eight years to build Hunter 4. OOE concludes that for the plant to be on-line in 2012, permitting need not begin until 2005, and thus the Commission should wait until the next planning cycle to consider acknowledgment of permitting activities. Finally, OOE states that ORS 757.355 appears to prohibit the Commission from including the permitting costs in rates unless and until the plant is operating, and that decisions on whether to include permitting, design and construction costs in rates should all be made at the same time. Because Pacific cannot recover permitting costs until the plant is built and in rates, OOE asserts, the Company would have an incentive to build the plant after it has incurred those costs, unless it can sell the site and related permits.

RNP recommends that the Commission "not acknowledge any plans by the Company for a coal plant expansion or acquisition as part of the 2003 IRP." RNP is concerned that through RFP 2003-A, the Company is moving forward with plans to acquire a coal plant before further review and justification. RNP points out that Pacific is the largest coal-power producer in the Western energy market and that it would be risky for the Company to add another coal plant in light of potential future regulatory constraints on CO_2 emissions.

CUB requests that if the Commission acknowledges the IRP, it not give the go-ahead for a new coal plant. CUB comments that another coal plant in Pacific's system is neither least cost nor in the public interest for Oregon customers over the long run. CUB believes that Pacific's preference for a coal plant is based on economic development for Utah and a rate-basing opportunity for the Company. CUB advises that the Commission consider whether building a coal plant, with its high fixed costs, is the appropriate response to Oregon's modest load growth. CUB states that Pacific already has an "enormous" amount of CO_2 risk, and that another coal plant would negate the environmental advances made through the green pricing options Pacific offers its customers. Further, CUB points out Pacific's statement, at page ten in the IRP, that the differences in PVRR between the five diversified portfolios "could arguably be described as statistically insignificant." CUB states that Diversified Portfolio I has the highest fixed costs of these portfolios, the difference in PVRR between committing to the Hunter 4 coal plant in 2008 and delaying it until 2012 is "virtually nonexistent," and that such a delay may allow the use of cleaner coal technology.

In response to parties' concerns, Pacific states that a coal plant is part of what it believes to be the least-cost portfolio and that the Company is developing this option in more detail, but no final decisions to proceed with the plant have yet been made. Pacific recognizes the opportunity and benefits of IGCC that OOE and CUB raise, but contests the level of reductions in CO_2 emissions CUB says such technology can achieve.

Staff recommends that the Commission not acknowledge the construction or purchase of a new coal plant by FY2008 or FY2009. Staff states that the Company should delay potential acquisition of a new coal plant on the East side until FY2012 and move up to FY2008 procurement of an East-side natural gas plant. Staff points out that this is the acquisition schedule under Diversified Portfolio II, and that the PVRR for this portfolio is comparable to the PVRR of Pacific's preferred plan. Staff cites Pacific's statements that the plans have "nearly identical risk profiles" measured by the 95th percentile and that they are "statistically indistinguishable."[4] Staff points out that Pacific's preferred plan performs better in the mean-of-tail (worst-case) PVRR and coefficient of variance analyses. Staff notes, however, that Diversified Portfolio II

[4] IRP at 105, 110.

outperforms Pacific's preferred plan in the 5th percentile (best-case) PVRR analysis and follows it closely in most other risk measures.

Staff comments that the delay in acquiring a coal plant would allow Pacific to better assess the risks of adding more coal generation to its system and take advantage of advances in generation technology. Staff notes that Pacific's recently approved RFP (2003-A) calls for a base load plant on the East side in FY2008 and thus is consistent with Staff's recommendation to move forward acquisition of a natural gas plant and delay procurement of a coal plant.

Staff understands from Utah's division of air quality that it is not too early to begin environmental permitting activities for a coal plant to be on-line in FY2012, or a year or two earlier. The division notes that starting the permitting process early helps prevent "train wrecks" in the process later. Consistent with its recommendation that the Commission not acknowledge a coal plant for operation in FY2008 or FY2009, Staff recommends that the Commission acknowledge environmental-permitting activity for Hunter 4 for operation after FY2009.

Pacific agrees with Staff's recommendation to substitute a natural gas-fired plant in FY2008 for the coal plant originally planned, but disagrees with delaying its acquisition until FY2012. The Company believes such specificity will limit its ability to pursue coal earlier if it finds it is a least-cost resource, or it will prohibit its use as the next best alternative in the RFP process. Accordingly, Pacific also requests acknowledgment of environmental permitting for Hunter 4 for implementation and operation at an unspecified future date.

Commission disposition: The Commission finds Pacific has not shown the addition of a coal plant by FY2008 or FY2009 is reasonable, in light of current circumstances. There is potential for significant reduction in risk if addition of a coal plant is delayed. Delaying any acquisition by a few years will allow the Company to better assess compliance costs for air pollutant and CO_2 emissions and consider technological advances for coal and other generating resources. Further, the difference in PVRR is nil between Diversified Portfolio II and Diversified Portfolio I – variation 1, both of which add a new coal plant in FY2012, and Diversified Portfolio I, which adds it in FY2008. The Company's PVRR risk analysis does not indicate that Diversified Portfolio I is clearly superior to Diversified Portfolio II.

In addition, the Commission concludes that environmental permitting activities for Hunter 4 are appropriate to ensure it remains an option for operation after FY2009, consistent with its finding that Pacific has not shown that acquisition of a coal plant in FY2008 or FY2009 is reasonable.

Renewable Resources. ICNU comments that more analysis of the cost-of-wind resources is needed and that meeting a Renewable Portfolio Standard (RPS) should not be used to justify wind additions until such a requirement is in place. ICNU does not oppose Pacific's acquisition of wind resources, but wants to ensure they are cost-competitive with other resources, their actual costs can be tracked, and their above-market costs are established for compliance with public purpose requirements set forth in ORS 757.612(3)(b)(B).

OOE suggests that Pacific indicate in the wind RFPs that more wind may be acquired if transmission and integration issues can be resolved and that the Company consider acquiring options for the full capability of some large prime sites. OOE comments that assignment of zero capacity for wind resources is unreasonable and may lead to acquiring too much capacity from other resources. OOE points to studies in other systems indicating effective capacity values for wind resources of 15 percent to 25 percent of turbine nameplate ratings. OOE states that a loss-of-load-probability study would help determine a reasonable estimate of the impact of wind variability on system operations and that such a study should be included in the Company's Action Plan.

RNP highlights Pacific's findings that renewable resources are a least cost resource. RNP recognizes that "renewable resources provide risk mitigation against volatile natural gas prices and future environmental regulation because they do not have any fuel costs and have few to no harmful environmental emissions." RNP cites the benefit of resource diversity and the potential for other renewable resources to offset low hydropower availability. RNP states that the risk of an RPS is a prudent consideration for including renewable resources, but is not a sufficient reason on its own. RNP points out that Pacific's analysis demonstrates that 1,400 MW of wind resources are cost-effective for the Company's system over the next 10 years and that those resources are included in each of the portfolios based solely on the economic merits.

RNP states that Pacific's final evaluation of wind generation is improved compared to the draft IRP. However, RNP remains concerned that wind resources are undervalued, specifically because Pacific assigns no capacity value to them because they are intermittent. RNP cites the result of the Company's stress test using a 15 percent capacity value for wind, which is a $103 million to $107 million decrease in the PVRR. RNP points out Pacific's statement that "if the built wind capacity did contribute to the planning margin at its expected capacity factor of 32-36 [percent], the amount of new capacity installed in the system through 2013 could be reduced by approximately 475 MW." RNP recommends that Pacific develop techniques to assign capacity value for intermittent resources.

RNP also is concerned about what it considers to be inaccurate modeling results for the Renewable Portfolio, which was designed to test the effect of adding more wind to the system beyond the 1,400 MW already included in each portfolio. Because Pacific did not assign any capacity value to the additional 1,146 MW of wind in the Renewable Portfolio, RNP states, Pacific includes three additional fossil-fuel plants to meet the 15 percent planning margin. As a result, the Renewable Portfolio has a higher PVRR than the other diversified portfolios and the greatest fuel expense.

RNP expresses concern about the timing of renewable resource acquisitions. RNP recommends a more aggressive wind acquisition plan than acquiring 100 MW in FY2006 and 1,000 MW during FY2007 to FY2011. RNP cites the benefits of earlier wind acquisition, including resolving uncertainties related to integration costs and capacity credit and the opportunity to obtain the most cost-effective wind sites that are close to transmission.

To dispel any skepticism about the level of wind Pacific plans to acquire, RNP points out that 580 MW of wind resources already are serving customers in the Northwest, 219 MW have been approved for construction in Oregon and Washington, and another 944 MW are in the permitting process in Oregon, Washington and Idaho. RNP notes that developers are requesting transmission on BPA's system for wind projects totaling 4,150 MW. RNP cites a recent study by the Tellus Institute that identifies about 11,000 MW of achievable wind power potential for the three states.

In response to ICNU's comments, Pacific states that it included wind resources in the portfolios based on economic merit, not potential RPS requirements. In response to parties' comments about adding wind resources earlier, Pacific states that its forthcoming RFP for renewable resources will help clarify questions of resource cost and availability. Further, during the public input process, the Company committed to earlier installations if they are deemed economic. Pacific responds to RNP's concerns about the accuracy of the Renewable Portfolio modeling by stating that the higher fuel costs are due to substantial new gas-fired generation that is included.

Pacific agrees to perform studies to determine the appropriate capacity value for wind resources, but it disagrees that its assumption of zero capacity was unreasonable given market and regulatory conditions, as well as industry practices, at the time it developed the IRP. The Company notes that information today on the topic remains unclear and that it is premature to imply that some level of credit is reasonable.

The Northwest Energy Coalition requests that the Commission require Pacific to determine the appropriate capacity credit for wind resources and include the revised credit in new analyses to justify Implementation Actions for base load, peaking, wind and shaped-product resources and for determining an appropriate planning reserve margin.

Staff states that the Company's analysis shows that the proposed wind resources are least-cost and notes that they do not pose the risks related to fuel price and emissions compliance that fossil-fuel resources do. Staff agrees with ICNU that an RPS should not be used to justify wind resources in an IRP until such a standard is in place. Staff notes that ICNU's interest in more analysis on the cost of wind resources will be addressed by Pacific's forthcoming RFP for wind resources, as well as its further evaluation of integration and firming costs and an appropriate capacity credit. Staff believes that Pacific's assignment of a zero capacity value for wind resources likely is incorrect, that it could lead to acquiring more thermal resources than are necessary to serve projected loads, and that the Company should conduct analyses to determine an appropriate value.

However, Staff does not believe that this deficiency affects any of the Implementation Actions acknowledged in the proposed order, as modified. Although Pacific already has agreed to study the capacity credit, Staff agrees with the Northwest Energy Coalition that Commission action is desirable to ensure any future IRP or Action Plan the Company brings forward for acknowledgment takes into account an appropriate capacity credit for wind resources.

Commission disposition: The Commission agrees that economic wind installations should be moved up. The Commission agrees that a zero capacity credit for wind may be incorrect and may lead to acquiring more resources than are necessary to serve projected loads. The Commission understands that Pacific is developing, with public input, a methodology for determining an appropriate capacity value for wind resources. The Commission also understands that the Company will determine the amount and type of shaped products needed to firm up the wind resources selected through the RFP process based on this methodology. The Commission recognizes that the lack of capacity credit for wind contributed to a PVRR for the Renewable Portfolio higher than that of any of the other diversified portfolios. The Commission directs Pacific to determine an appropriate capacity credit for wind resources and to incorporate it in the next IRP or Action Plan that it brings forward for acknowledgment.

Combined Heat and Power Systems. ICNU states that Pacific did not adequately analyze combined heat and power systems (CHP, or cogeneration) as a potential resource on the West side of the Company's system. ICNU notes Oregon legislation to foster the development of this resource and its advantages over other generating resources, such as reducing transmission congestion and environmental impacts.

OOE comments that the IRP does not account for the potential of CHP and other generating technologies at customer sites to reduce energy and capacity needs and that the load forecast should account for likely customer generation. OOE summarizes findings from a recent study by the Tellus Institute that estimated natural gas-fired CHP systems could total 2,345 aMW in the Northwest by 2020.

Pacific responds to ICNU's and OOE's concerns regarding the adequacy of the CHP analysis by stating that it does not forecast the implementation of CHP at customer sites, and that its load forecasts do not include such "speculative" load reductions. Pacific notes, however, that CHP resources are welcome to bid into Pacific's supply-side RFPs. Pacific states that it will use the results of its East side CHP study to help develop distributed resource plans system-wide. It also points out its participation in a microturbine demonstration project in Portland.

Staff comments that Pacific did not evaluate the potential of customer-sited CHP to meet its energy and capacity needs. Staff notes that customer generation can reduce the Company's energy needs, improve reliability of the electric system and, with the appropriate agreements in place, provide the Company with flexible capacity to meet peak loads at least cost. Staff points out that Action Item 8, "Complete an evaluation of the available, realistic CHP sites and market size within the PacifiCorp area," applies only to Utah. Staff recommends the Company conduct a timely assessment of CHP potential in Oregon.

Commission disposition: The Commission agrees with the parties that Pacific did not fully assess CHP opportunities on the West side of its system. The Commission notes, however, that the Company will consider CHP proposals in its supply-side RFPs. CHP has the potential to reduce energy and capacity needs and provide Pacific with flexible capacity to meet loads at least cost. CHP has potential benefits over other supply-side alternatives, such as reducing transmission congestion and environmental impacts. The Company should assess potential CHP sites and market size throughout its service territory as a first step toward improved treatment of these resources in future IRPs.

Demand-side Management. CUB comments that the Multi-State Process is expected to continue the allocation of costs for demand-side management (DSM) *situs* to each state and the costs of generation system-wide. CUB points out that DSM is a least-cost resource in the IRP, that Oregon has been a leader in DSM activities in Pacific's service area, and that other states have benefited from DSM that Oregon customers paid for. CUB requests that the Commission make it clear in its order that it is willing to disallow generation costs that are not least cost, but were incurred due to a failure to achieve regulatory approval for DSM in other states.

OOE points out that the Action Plan includes no Class 1 DSM (fully dispatchable; load reduction) programs for Oregon and does not appear to include Class 3 (nondispatchable; buydown) programs such as real-time or critical-peak pricing anywhere in Pacific's service territory. OOE believes the Action Plan should include such programs and that load forecasts should be adjusted to account for the likely reductions in loads that result.

Pacific responds to CUB's comments regarding the potential failure to implement DSM in other states by noting that the Company is actively encouraging DSM in all states in which it operates and referring to its plans to issue an RFP for DSM resources. Pacific responds to OOE's comments by referring to its Energy Exchange and residential time-of-use programs in Oregon. Pacific notes it has filed an interruptible tariff in Utah and is considering the same for other states. Pacific states that it will consider bids for Class 1 resources in Oregon in its RFP process.

In its comments on the draft proposed order, Pacific agrees to evaluate all DSM resources it considers "long term." The Company does not believe that Class 3 and Class 4 resources are "firm enough to be considered long term resources that can prospectively displace planned supply side resources with a predictable cost and value." However, the Company plans to use Class 3 and Class 4 resources to encourage cost-effective peak load reduction and behavioral change that reduce the need for future resources. Pacific states that it cannot predict the impact of these DSM resources, but their impact will be reflected in changes to the historical load shape over time.

Staff comments that Pacific incorrectly assumed in the IRP that Oregon's electric industry restructuring law excludes the Company from running Class 1 DSM programs in the state. Staff points out that the Commission has authority to approve several types of DSM programs. Staff notes Portland General Electric's (PGE's) recent pilot program for direct load control of residential water and space heating (Class 1), the energy buyback programs the electric utilities put in place during the energy crisis of 2000-01 (Class 3), Pacific's and PGE's time-of-use programs for small customers (Class 4), and inclining block rates for PacifiCorp residential customers (Class 4).

Staff points out that the Company did not model DSM resources for Oregon, and thus did not compare their cost against peaking units for the West side. Staff points out that Pacific has not considered or analyzed even on- and off-peak pricing for large customers on cost-of-service. Staff states that Pacific did not adequately address the potential of Class 3 or Class 4 programs to shave peak loads anywhere in its service area. Staff notes that there is ample evidence in Oregon and elsewhere that customers reduce loads in response to price signals and that these load reductions can be predicted as accurately as other factors affecting the load forecast. Staff states that modeling of all eligible classes of DSM resources in Oregon, tailored to West-side peaking needs, may show that they are a least-cost resource that can reduce or defer the need for peaking units and reduce power costs. Although Pacific did not analyze DSM resources for Oregon in its IRP, Staff states that the Company is accepting bids for Class 1 resources in Oregon through its current DSM RFP and that it may learn more about the costs of these resources through the process.

Staff understands that Item 10 in the Action Plan, "Conduct an Economic and Market Potential study of the PacifiCorp service territory to determine the magnitude of the DSM opportunities available to PacifiCorp," does not include Class 3 DSM programs. Staff states that it is unclear whether Oregon will be included in the study. Staff recommends that the Commission's acknowledgment of the IRP be subject to Pacific covering in the study all classes of DSM resources in Oregon that the Company is permitted to acquire.

In addition, Staff recommends that for the next IRP or Action Plan, the Commission require Pacific to assess all eligible DSM resources in Oregon and include in the portfolios those DSM resources that are least cost. Further, Staff believes that the Company should include in its load forecast the likely impacts of its DSM programs.

Staff further recommends that the Commission require, as a condition of acknowledgment of the IRP, that Pacific implement by May 1, 2004, new voluntary DSM pilots or programs for small and large customers in Oregon if the Company's demand response assessment due year-end indicates they have value because they are cost-effective today or build capability for the future.

Commission disposition: The Commission agrees with OOE and Staff that the IRP did not assess DSM programs in Oregon and Class 3 and Class 4 DSM programs system-wide to determine whether they can defer or reduce capacity needs and reduce power costs. The Commission agrees with Staff that Pacific's proposed DSM study should include all classes of DSM resources and assess opportunities in Oregon. In addition, the 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. The Commission also directs Pacific to include in its load forecast the likely impacts from implementation of DSM programs. The Commission further agrees that the Company should put in place new DSM pilots or programs for small and large customers in Oregon, based on the results of its demand response assessment due year-end.

The Commission finds a rate case is the appropriate forum to address CUB's request to disallow generation costs incurred due to a failure to achieve regulatory approval for DSM in other states, rather than this case. Staff has indicated that it will ask Pacific to report to the Commission on DSM filings in other states.

West-side Peaker Units. Staff recommends that the Commission not acknowledge procurement of reserve peaker units for the West side for operation in FY2006 (230 MW). Staff states that Pacific's 2003 load forecast demonstrates that West-side capacity requirements will be far lower than those estimated in the 2001 load forecast used to prepare the IRP. Specifically, the updated forecast for monthly peak demand in Oregon indicates that capacity requirements will be about 300 MW less in 2006 than assumed in the IRP.

Staff comments that even using the 2001 forecast, Pacific's IRP does not provide justification for the reserve peaker units the Company proposes to operate in the West beginning in FY2006. Staff asserts that Pacific has not sufficiently analyzed the appropriate planning reserve margin, market exposure level and capacity credit for wind resources and that accordingly, the conclusion that peakers are needed is premature. Staff further comments that Pacific did not adequately evaluate demand-side management or combined heat and power alternatives in Oregon that could defer or reduce the need for peaking units. Staff states that Pacific should explore whether such alternatives may be least cost for any capacity deficit the Company now projects for the West side.

Commission disposition: The Commission finds Pacific's May 2003 load forecast, finalized after the Company filed the IRP, does not justify the addition of peakers in the West beginning in FY2006. In addition, modifications to Pacific's planning reserve margin, market exposure level, and capacity credit for wind resources may obviate the need for peakers by FY2006. Further, Pacific must analyze whether implementation of demand-side management or combined heat and power alternatives can defer or reduce the need for peakers before the Commission can conclude addition of peakers in the West is reasonable for any future IRP or Action Plan that the Company brings forward for Commission acknowledgment.

West-side Base Load Unit. Staff recommends that the Commission not acknowledge procurement of a base-load unit in the West of the system for operation in FY2007 (Implementation Action 1). Staff points toward the Company's new load forecast, which indicates that West-side loads will be far lower than those estimated in the 2001 forecast used in the IRP, and notes that Pacific need not make decisions regarding a new base-load unit until the next planning cycle. Staff understands that the Company is updating its load/resource balance estimates and that its October Action Plan update likely will show that a new base-load unit is not needed on the West side by FY2007. Staff also notes that the Company's refinement of assumptions for planning reserve margin, market exposure and wind capacity credit may affect the timing and size of a new base-load unit needed to serve slower-growing West-side loads.

Staff believes it is reasonable, however, for the Company to conduct analyses to determine the level and timing of resources that will be needed in the future. Staff also believes the Commission should acknowledge Pacific's proposed economic review for a combined-cycle combustion turbine on the West side of Pacific's system at a later date.

Commission disposition: The Commission agrees that the level and timing of resources needed in the West of the system are unclear, especially in light of the 2003 load forecast. Accordingly, the Commission concludes that activities necessary to determine the level of resources needed, refine the procurement date, and conduct economic analyses to justify whether to build or buy a base-load unit are warranted. However, the Commission concludes that procurement of a West-side base-load unit may not be needed in this planning cycle. If Pacific's modeling of resource needs based on updated load/resource and supply criteria assumptions show that the Company needs a base-load unit in the West before FY2007, it may seek acknowledgment of this resource action before the next planning cycle.

Additional East-side Base Load Unit. To serve rapidly growing East-side loads, Staff recognizes the need for another base-load unit (Implementation Action 4), in addition to the plant the Company plans to procure through RFP 2003-A (Implementation Action 2). However, Staff believes the Company must refine its load/resource balance estimates based on its updated load forecast, as well as refine its supply criteria assumptions, before the Commission should acknowledge the size or timing of such a plant. Further, as noted earlier, Staff recommends that the Commission not acknowledge acquisition of a new coal plant by FY2009.

Commission disposition: The Commission concludes that Pacific's IRP and its updated load forecast justify the acquisition of an additional base-load unit to serve growing East-side loads. However, Pacific's assumptions for supply criteria are not sufficiently refined, and a new load/resource balance based on the updated load forecast is not yet available, to allow the Commission to reach any conclusions regarding the appropriate size of the unit or when it should be acquired. The Commission's acknowledgment of this Implementation Action excludes a new coal plant, as explained *supra*.

Shaped Products. Staff comments that the 2003 load forecast indicates that contracts for shaped products to fill off-peak needs in the West of the system for FY2004-06 will not be needed. In addition, Staff recommends that the Commission acknowledge contracting for thermal shaped products to achieve the planning margin Pacific establishes after further analysis and with public input, but not the 15 percent margin assumed in the IRP.

Commission disposition: The Commission finds that the 2003 load forecast indicates that contracts for shaped products will not be needed to fill off-peak needs in the western part of the system in FY2004-06. The Commission agrees with Staff that contracts for shaped products should be based on the new planning margin Pacific establishes, not the planning margin originally outlined in FERC's Standard Market Design proposal.

Transmission System Analysis. Staff supports Pacific's proposal to detail and commission selected transmission power system analysis studies to support implementation of Pacific's IRP. However, Staff recommends that the Commission acknowledge Pacific's proposed studies only to the extent they are commissioned to support implementation of Pacific's IRP as modified in this order, rather than implementation of Diversified Portfolio I. Pacific concurs with Staff's recommendation.

Commission disposition. The Commission agrees that detailing and commissioning of selected transmission power system studies to support the implementation of the IRP Action Plan, as modified in this order, is reasonable and should be acknowledged.

Risk Analysis. ICNU notes the shift in IRP focus from demand-side management in the past to risk and uncertainty today and cites the need to guard against building a future based primarily on a reaction to the energy crisis of 2000-01. ICNU cites the dual risk and opportunity of direct access — the risk of load loss and the opportunity for Pacific to seek customers to "opt out of new resource reliance," thus lessening the need for new resources and reducing risk. ICNU recognizes that modeling and analysis only go so far, and that in the end, utility management makes the critical decisions.

CUB points out that Pacific's preferred option has the highest fixed cost among the diversified portfolios and the lowest variable cost. CUB cites Pacific's statement that the PVRR between these portfolios "could arguably be described as statistically insignificant." CUB states that Pacific's justification for choosing Diversified Portfolio I must be that it is less risky than the others, presumably because it relies on a coal resource and avoids an over-reliance on natural gas, with its volatile prices. CUB questions whether Pacific adequately addressed all the potential risks of the portfolio options and whether the Company drew the right conclusions. CUB questions whether the preferred option was selected in the interest of shareholders (highest rate base) or customers.

CUB also considers Pacific's assessment of environmental factors inadequate. CUB states that the Company did not describe recent statistical trends for atmospheric carbon loading and global climate change, nor did it sufficiently model rising compliance costs as CO_2 loading escalates. CUB asks whether a more comprehensive analysis of CO_2 risk would have affected Pacific's choice of Diversified Portfolio I, which calls for a coal plant in 2008 and therefore may preclude the use of clean coal technologies that are under development. CUB also questions whether acquiring such a high level of resources actually would reduce net variable power costs through reduced market exposure, given Pacific's experience between 1995 and 2001 when the Company's contracts for wholesale sales tied up its rate-based resources.

In response to ICNU's concerns regarding the risk analysis process, the Company notes that different parties have different opinions on the appropriate tradeoff between cost and risk and that the studies supporting the IRP are not based on the energy crisis. Regarding CUB's comments about selection of Diversified Portfolio I, the Company states that it prefers resources that minimize costs and risks to customers and ensure the risks borne by the Company are commensurate with the normal risks of a utility. Pacific states that its RFP process for resources will clearly demonstrate that the resource options the Company selects are in the best interest of customers and shareholders at the time the decision is made. In response to CUB's comments about the risk of CO_2 compliance costs, Pacific cites its stress testing of a variety of CO_2 tax levels.

Staff comments that Pacific identified all major risks associated with resource planning and that the risk analysis in the current IRP is a significant improvement over earlier plans. In particular, the plan addresses more accurately the relationship of natural gas prices, electricity market prices and hydro conditions. Staff points toward Pacific's discussion of risk allocation (shareholder vs. customer), and notes that the Company has not proposed any change to the traditional allocation of risk/reward between shareholders and customers.

Staff points out that the Company did not test a variety of spot market purchase levels to determine the appropriate risk mitigation strategy, and it chose a 15 percent planning reserve margin instead of a 10 percent margin even though the potential cost of the more conservative strategy appears to outweigh the benefits.

Commission disposition: For the reasons stated by Staff, the Commission concludes that Pacific has conducted a comprehensive risk analysis. As noted earlier, the Commission understands that the Company is developing a methodology to determine an appropriate planning reserve margin and will be looking at assumptions about spot market purchases as part of that analysis.

Multi-State Issues. CUB questions how the Company could implement the Action Plan without resolution of the multi-state allocation issue. In response to the new load forecast that Pacific issued in May 2003, CUB notes that Utah's load growth is 2.3 times Oregon's. CUB points out that Utah's industrial loads are driving the need for new base load resources, and growth in the state's residential and commercial loads is driving the need to add summer peaking units. CUB states that Oregon must consider whether building a base load resource, specifically a coal plant, is the appropriate response to Oregon's modest load growth.

Further, CUB states that Oregon's least-cost planning policy refers to what is least cost for Oregon ratepayers, not the system as a whole, and they are not necessarily the same. CUB's review of the allocation factors suggests that Oregon may benefit from a resource plan with lower capital costs and higher variable costs.

Pacific responds that the IRP and MSP are closely linked. The IRP identifies new resources that are needed, and the MSP will provide clarity on how they will be paid for. Pacific notes that the MSP outcome may affect implementation of the Action Plan. Pacific states that it must acquire significant levels of resources in order to maintain reliable electric service, and therefore it is critically important that regulators acknowledge the IRP as well as ensure a "useful and durable" MSP outcome.

Commission disposition: The Commission recognizes the importance of promptly resolving MSP issues and the possibility that these issues will hamper needed investments. At this time, however, the Commission reviews least-cost plans for multi-state utilities like Pacific to determine whether the Company is proposing a reasonable plan for meeting the needs of all of its customers, without regard to who pays for new resources. Acknowledgment of a plan does not signify anything about the appropriate Oregon share of the costs of new investments, even if those investments are prudent. The reasonable share of costs for Oregon will be addressed in the MSP and in general rate cases.

Procurement Process. While ICNU supports a competitive bidding process, it is concerned that Pacific or its affiliate PPM Energy will be allowed to participate. ICNU is particularly concerned about participation of any Pacific affiliate in the Company's RFPs for wind resources.

CUB states that it is critically important for least-cost purposes that regulators ensure Pacific's procurement process does not favor the Company (self-bid options) when choosing which resources to acquire or who will build them. CUB requests that in addition to requiring an unbiased observer throughout the bid process, the Commission require a utility to disclose up-front the baseline information it used to calculate the costs of its self-build option, including estimated costs for construction, natural gas forecasts, transmission costs, and forced outage and economic dispatch rates. CUB asks the Commission to disallow in rates "speculative 'development' costs" that the utility may incur for its self-build option, which would undercut independent producers who also incur such costs.

Pacific agrees with CUB that any competitive bidding process must be administered in an unbiased fashion. The Company states that its proposed procurement process is consistent with the Commission's order on competitive bidding and adds a blinded evaluation process and the use of an independent third-party consultant. Regarding ICNU's concerns about affiliates participating in bidding, Pacific responds that they will not be allowed to bid in the first RFP and that Oregon's affiliate interest requirements would ensure affiliates do not receive preferential treatment if they are allowed to participate in any future RFP.

Commission disposition: The Commission recognizes the importance of an unbiased procurement process in acquiring resources at lowest cost. Issues raised by the parties were considered as part of the public review process for approval of the Company's RFP 2003-A and likely will be raised in forthcoming RFPs for additional resources.

Overall Recommendations. OOE recommends that the Commission acknowledge that Pacific needs to acquire resources that the Company plans to have on line by 2007 and that requests for proposals for those resources go forward because "resource needs this decade are almost certainly greater than that level." However, OOE states that Pacific has not demonstrated that the specific megawatt targets for energy and capacity in the Action Plan are appropriate, particularly beyond 2007.

ICNU does not make a recommendation about acknowledgment of the IRP. ICNU expresses reservations regarding load forecasting, modeling, planning assumptions, risk mitigation measures, and deficiencies in analysis of wind and CHP resources. ICNU recommends that if the Commission acknowledges the IRP, it be explicit regarding the breadth and effect of that acknowledgment. ICNU notes that the Commission's policy on least-cost planning requires utility management to retain full responsibility for making and accepting the consequences of its decisions. ICNU points out that consistency or inconsistency of Company actions with an acknowledged IRP does not guarantee any specific rate treatment, and that such actions remain subject to review in a rate case proceeding when it seeks cost recovery.

CUB does not make a recommendation on whether the Commission should acknowledge the IRP. CUB states that Pacific has improved its modeling and how it accounts for environmental risk and the benefit of renewable resources, but that some of the assumptions and most of the conclusions indicate that the utility wants to substantially increase its rate base with new generation, particularly coal-fired generation. CUB questions whether Pacific's preferred option is consistent with the long-run public interest of Oregon ratepayers. CUB asserts that Diversified Portfolio I could result in the largest rate base of any of the considered options and therefore it is in the best interest of Pacific's shareholders.

RNP supports acknowledgment of the IRP with the exception of expansion or acquisition of a coal plant.

Staff supports acknowledgment of the IRP with the following modifications to the Action Plan:

Revised Implementation Actions

1. Procurement of a base load unit in the West of the system by FY2007 is not acknowledged. Acknowledgment of a base load unit in the West extends only to preparing detailed plans, including an economic review and justification for building or buying a base load CCCT, and refining the level of resources needed and the procurement date. (Implementation Action 1)

2. Procurement of a base load unit in the East of the system is acknowledged, but does not extend to building or buying a new coal unit by FY2008. (Implementation Action 2)

3. Environmental-permitting activity for Hunter 4 is acknowledged to ensure this base load option is available for implementation and operation after FY2009. (Implementation Action 3)

4. The need for an additional base load unit, other than a new coal plant, on the East side of the system is acknowledged, but not a specific resource size or procurement date. (Implementation Action 4)

5. Evaluation of combined heat and power sites and market size *throughout* PacifiCorp's service territory is acknowledged. (Implementation Action 8)

6. A study of economic and market potential to determine the magnitude of demand-side management opportunities *throughout* Pacific's service territory, including for Oregon Class 1, Class 3 and Class 4 resources, is acknowledged. (Implementation Action 10)

7. Procurement of reserve peaker units for the system for operation in FY2006 is acknowledged only for the East side. (Implementation Action 15)

8. Acquisition of wind generation on the West and East sides of Pacific's system is acknowledged, but the resources should be acquired sooner if economic to do so. (Implementation Actions 18 and 19)

9. Contracting for asset-based shaped products to fill the off-peak needs in the West of the system for FY2004-06 is not acknowledged. (Implementation Action 21)

10. Contracting for thermal shaped products to achieve the appropriate planning margin established through Implementation Action 24 is acknowledged. (Implementation Action 21)

11. Determination of the planning margin PacifiCorp will adopt if different from the 15 percent planning margin in the Company's filed plan is acknowledged, but without reference to FERC's proposed Standard Market Design rule. (Implementation Action 24)

12. Commissioning of selected transmission power system analysis studies to support the Action Plan, as modified in this order, is acknowledged. (Implementation Action 25)

Additional Implementation Actions

13. For the next IRP or Action Plan brought forward for the Commission's acknowledgment, Pacific shall assess Class 1, Class 3 and Class 4 demand-side management resources in Oregon and include in the portfolios those resources that are least cost. Further, the Company shall include in the load forecast it uses for the next IRP or Action Plan the likely impacts of implementing DSM programs.

14. If the Company's demand response assessment due year-end indicates new voluntary demand response pilots or programs for small and large customers in Oregon are cost-effective now or build capability for the future, Pacific shall bring them forward by March 31, 2004, for the Commission's consideration with a proposed effective date of May 1, 2004.

15. Pacific shall determine an appropriate capacity credit for wind resources and incorporate it in the next IRP or Action Plan requiring Commission action.

Pacific submitted a letter on July 17, 2003, agreeing to all of Staff's modifications except Action Items 3 and 4. Pacific wants the flexibility to use the Hunter 4 coal plant as the next best alternative for the RFP it plans to issue next year for the FY2009 plant. Pacific contends that, by adopting Staff's modifications to Action Items 3 and 4, the Commission would preclude consideration of a coal plant as a possible resource choice for the FY2009 East-side base load need, which may result in the company having to acquire potentially higher-cost resources to serve that need. Pacific adds that the RFP process, not the IRP process, is the proper forum for making specific resource choices, as the RFP process will identify the specific least cost resources available to serve that need.[5]

[5] In comments filed on July 25, 2003, Pacific noted the concerns of Staff and other parties that the RFP process would not provide a full opportunity to discuss and debate the environmental assumptions used in the evaluation of the plant. To address those concerns, Pacific agreed to file a Resource Rate Plan for the plant under ORS 757.212 if it decides to use a coal plant as its next best alternative for the upcoming RFP. This proposal may have merit; however, we agree with CUB, RNP, NW Energy Coalition, OOE and Staff that Pacific's proposal simply arrives too late. The Resource Rate Plan provisions of ORS 757.212, which allow the Commission to make a binding commitment to the future ratemaking treatment of a resource, have not been used before and the timing and procedures for approving a rate plan are uncertain.

After consideration, the Commission adopts Staff's modifications to Action Items 3 and 4. While Pacific is correct that the RFP process will determine the lowest-cost resource, that determination is based on an evaluation of relevant factors at the time the RFP is issued. The RFP process does not address the issue of timing—that is, when is the best time to acquire a particular type of resource. In contrast, the IRP process can examine how staging particular resource acquisitions over a period of time may reduce costs as well as risks. As Staff notes, Pacific's 2003 IRP shows that delaying the acquisition of Hunter 4 from FY2009 to FY2012 reduces revenue requirements by $8 million.

In summary, the Commission concludes that Pacific has not shown in this planning cycle that a coal plant is the least-cost alternative for the FY2009 plant. In making this decision, however, we note that Pacific may file amendments to its IRP within the two-year planning cycle. Therefore, if PacifiCorp desires to amend the IRP to include the Hunter 4 plant as the next best alternative, the Company may bring forward for acknowledgment changes to the IRP showing that a coal plant is the least cost option for FY2009.

CONCLUSION

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

Pacific's RAMPP-7 report and Action Plan, including modifications agreed to by Pacific in its July 17, 2003, letter, reasonably adhere to the principles of least-cost planning set forth in Order No. 89-507, and should be acknowledged with the following exceptions:

> Implementation Action 3 is acknowledged in part. Environmental-permitting activity for Hunter 4 is acknowledged, but only to ensure this base load option is available for implementation and operation after FY2009.
>
> Implementation Action 4 is acknowledged in part. The need for an additional base load unit on the East side of the system is acknowledged, but not a specific resource size or procurement date. Acquisition of a new coal plant by FY2009 also is not acknowledged.

The Commission would acknowledge Implementation Actions 3 and 4 without exception if modified as follows:

> Implementation Action 3: Continue environmental-permitting activity for Hunter 4 to ensure this base load option is available for implementation and operation after FY2009.
>
> Implementation Action 4: Procure a base load unit in the East of the system, other than a coal plant, with the size and procurement date based on updated load

forecasts, an updated load/resource balance and further analysis of supply criteria assumptions.

Attachment B shows the Action Plan Implementation Actions with agreed-upon modifications and Commission exceptions.

Effect of the Plan on Future Ratemaking Actions

Order No. 89-507, at pages 6 and 11, sets forth the Commission's role in reviewing and acknowledging a utility's least-cost plan:

> 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.

This order does not constitute a determination on the ratemaking treatment of any resource acquisition or other expenditures undertaken pursuant to Pacific's RAMPP-7 report. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the least-cost planning process to complement the ratemaking process. In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged least-cost plans. Utilities will be expected to explain actions they take which are inconsistent with acknowledged least-cost plans or which the Commission has not acknowledged. Utilities will also be expected to pursue unanticipated least-cost opportunities beneficial to ratepayers which arise after Commission acknowledgment or explain why they did not pursue such opportunities. Furthermore, acknowledgment of a least-cost plan does not have any implication for how much of the cost of new resources Oregon customers should pay, even if the resources are consistent with the company's plans and determined to be prudent.

ORDER

IT IS ORDERED that:

The seventh Resource and Market Planning Program report (RAMPP-7) and accompanying Action Plan filed by PacifiCorp on January 24, 2003, including modifications agreed to by PacifiCorp pursuant to Staff recommendations #1, #2, and #5 through #15, reasonably adhere to the principles of least-cost planning set forth in Order No. 89-507, and are acknowledged in accordance with the terms of this order, with the following exceptions:

(a) Implementation Action 3 is acknowledged in part. Environmental-permitting activity for Hunter 4 is acknowledged, but only to ensure this base load option is available for implementation and operation after FY2009.

(b) Implementation Action 4 is acknowledged in part. The need for an additional base load unit on the East side of the system is acknowledged, but not a specific resource size or procurement date. Acquisition of a new coal plant by FY2009 also is not acknowledged.

Made, entered, and effective AUG 25 2003.

Roy Hemmingway
Chairman

Lee Beyer
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.

Attachment A.

Table 9.2 Action Plan Implementation Actions for Diversified Portfolio I

ADDITION TYPE	IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
Base Load - 2007*	1. Procure a base load unit in the West of the system for operation in 2007. Prepare detailed plans including an economic review and justification for building a base load CCCT in the West of the system for 2007. The review will address: • The merits, risks and benefits of negotiating alternative PPA agreements following the expiration of existing contracts in the West • The potential and options for negotiating additional capacity associated with the existing BPA contract (Sites under consideration in the review will include opportunities at Albany, Klamath Falls and others in the West of the system)	July 2003
Base Load - 2008	2. Procure a base load unit in the East of the system for operation in 2008. Prepare detailed plans including a review and justification for building or buying the base load coal unit in the East of the system for 2008. The review will include, but will not be limited to: • An economic review for selecting coal as the fuel • Alternative fuel options including natural gas • Emissions Impacts on the surrounding area • Other existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties (Sites under consideration in the review will include opportunities at Hunter, Terminal, Mona, West Valley, Gadsby and others in the East of the system)	October 2003
Base Load - 2008	3. Continue environmental permitting activity for Hunter 4 to ensure this base load plant option is available for implementation and operation by 2008 in line with DPI requirement (see Action Item 2).	July 2003
Base Load - 2009	4. Procure a base load unit in the East of the system for operation in 2009. Prepare detailed plans including a review and justification for re-powering of the existing Gadsby plant (units 1, 2 and 3) in 2009. The review will include, but will not be limited to:	July 2004

*Dates correspond to Pacific's fiscal year, ending March 31.

ADDITION TYPE	IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
	• Alternative existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties (Sites under consideration in the review will include opportunities at Terminal, Mona, West Valley and others in the East of the system)	
DSM	5. Design and determine the cost effectiveness of the proposed Air Conditioning Load Control program in Utah. Launch and implement the Air Conditioning Load Control program as appropriate and in line with the findings.	April, 2003
DSM	6. Design and determine the cost effectiveness of the proposed refrigerator re-cycling program. Launch and implement the refrigerator re-cycling program as appropriate and in line with the findings.	April, 2003
DSM	7. Design and determine the cost effectiveness of the proposed efficient central air conditioner program. Launch and implement the efficient central air conditioner program as appropriate and in line with the findings.	April, 2003
DSM	8. Complete an evaluation of the available, realistic CHP sites and market size within the PacifiCorp territory.	April, 2003
DSM	9. Implement and operate the specific DSM programs in the D-P40 decrement that was included DPI. This will build 150 MWa DSM between 2004 and 2014.	Commence July 2003
DSM	10. Conduct an Economic and Market Potential study of the PacifiCorp Service territory to determine the magnitude of the DSM opportunities available to PacifiCorp.	August, 2003
DSM	11. Design a "bundle" of cost effective DSM programs that build to an additional 300 MWa between 2004 and 2014 in line with the decrement options reviewed in the IRP.	July, 2003
DSM	12. Prepare, issue and implement a Request For Proposals (RFP) for 100 MWa of Class 2 DSM for implementation commencing early 2004 as part of the "bundle' of options in action item 11.	April, 2003
DSM	13. Determine revised DSM targets for the period 2004 to 2014 based on the results of action items 10, 11 and 12.	October, 2003
DSM	14. Evaluate and implement as appropriate the irrigation load control program in Idaho for 2004.	May, 2003
Peakers - 2006	15. Procure reserve peaker units for the system for operation in 2006. Develop detailed plans and proposals, including the	July 2003

ADDITION TYPE	IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
	timeline for delivery, for the reserve peakers required for system 2006: • East side – 200 MW • West side – 230 MW	
Peaking	16. Review the West Valley peaker plant performance and requirement and negotiate the West Valley Peaker plant terms and conditions in line with the existing lease contract arrangements.	July 2004
Renewables	17. Evaluate expansion options for PacifiCorp's Blundell Geothermal plant and implement expansion if appropriate and cost effective.	January 2003
Renewables	18. Prepare, issue and implement an RFP for wind generation on the West of the system in line with the proposed procurement pattern: • 100 MW – 2006 • 200 MW - 2008 • 200 MW - 2010	Issue March 2003
Renewables	19. Prepare, issue and implement an RFP for wind generation on the East of the system in line with the proposed procurement pattern: • 200 MW – 2007 • 200 MW – 2009 • 200 MW - 2011	Issue March 2003
Renewables	20. Prepare, issue and implement an RFP for renewable generation options (i.e. geothermal, solar, fuel cells) which could be implemented in addition to, or as an alternative to, the proposed wind build pattern modeled in DPI (Action Items 18 and 19).	Issue March 2003
Shaped Products	21. Determine the strategy and negotiate, as appropriate, asset based shaped product contracts to fill: • The super-peaking needs in the East of the system for 2004/05/06/07 • The off-peak needs in the West of the system for 2004/05/06 • Thermal asset based contracts in support of the capacity requirements to achieve 15% planning margin on both the East and West of the system. • Thermal asset based contracts (25 MW) to support the addition of profiled wind in the East and West of the system.	Commencing January 2003
Strategy and Policy	22. Determine the long term IRP model(s) including a review of options for using optimization logic for future IRP's	September 2003
Strategy and Policy	23. Agree any changes to Standards and Guidelines that may impact the implementation of the IRP Action Plan	December 2003

ADDITION TYPE	IMPLEMENTATION ACTIONS	TARGET DELIVERY DATE
Strategy and Policy	24. Determine the Planning Margin PacifiCorp will adopt if different from the 15% planning margin adopted in this IRP, following the outcome of the FERC's proposed SMD rule. The analysis for this will include loss of load probability studies.	December 2003
Transmission	25. Detail and commission selected transmission power system analysis studies to support the implementation of the IRP Action Plan for DPI. The studies will provide greater detail on transmission costs associated with all the portfolio additions. Particular attention is required to determine the impact of the potential wind capacity additions on the system from a system stability perspective.	July 2003
Transmission	26. Prepare detailed plans including an economic review and justification and apply for necessary transmission upgrades to support asset additions	July 2003
Transmission	27. Prepare detailed plans including an economic review and justification to implement the "Wasatch Front Triangle" transmission upgrades.	July 2003
Transmission	28. Review options for firming up the IRP non-firm transmission requirement.	July 2003

Attachment B.
Implementation Actions With Agreed-Upon Modifications and Commission Exceptions

ADDITION TYPE	IMPLEMENTATION ACTIONS
Base Load	1. Prepare detailed plans, including an economic review and justification for building a base load CCCT in the West of the system, and refine the level of resources needed and the procurement date. The review will address: • The merits, risks and benefits of negotiating alternative PPA agreements following the expiration of existing contracts in the West • The potential and options for negotiating additional capacity associated with the existing BPA contract (Sites under consideration in the review will include opportunities at Albany, Klamath Falls and others in the West of the system)
Base Load – by 2008*	2. Procure a base load unit, other than a new coal plant, in the East of the system for operation by 2008. Prepare detailed plans including a review and justification for building or buying the base load unit.
	3. Continue enviromnental permitting activity for Hunter 4 to ensure this base load plant option is available for implementation and operation after FY2009.
Base Load	4. Acknowledged: Procure a base load unit in the East of the system. Not acknowledged: Unit size, procurement date, or acquisition of a new coal plant by 2009. Prepare detailed plans including a review and justification for re-powering of the existing Gadsby plant (units 1, 2 and 3). The review will include, but will not be limited to: • Alternative existing or partially developed sites • Alternative PPA agreements with appropriate credit worthy counter-parties (Sites under consideration in the review will include opportunities at Terminal, Mona, West Valley and others in the East of the system)

*Dates correspond to Pacific's fiscal year, ending March 31.

DSM	5. Design and determine the cost effectiveness of the proposed Air Conditioning Load Control program in Utah. Launch and implement the Air Conditioning Load Control program as appropriate and in line with the findings.
DSM	6. Design and determine the cost effectiveness of the proposed refrigerator re-cycling program. Launch and implement the refrigerator re-cycling program as appropriate and in line with the findings.
DSM	7. Design and determine the cost effectiveness of the proposed efficient central air conditioner program. Launch and implement the efficient central air conditioner program as appropriate and in line with the findings.
DSM	8. Complete an evaluation of the available, realistic CHP sites and market size throughout the PacifiCorp territory.
DSM	9. Implement and operate the specific DSM programs in the D-P40 decrement that was included DPI. This will build 150 MWa DSM between 2004 and 2014.
DSM	10. Conduct an Economic and Market Potential study throughout the PacifiCorp Service territory to determine the magnitude of the DSM opportunities available to PacifiCorp, including Oregon Class 1, 3 and 4 DSM resources.
DSM	11. Design a "bundle" of cost effective DSM programs that build to an additional 300 MWa between 2004 and 2014 in line with the decrement options reviewed in the IRP.
DSM	12. Prepare, issue and implement a Request For Proposals (RFP) for 100 MWa of Class 2 DSM for implementation commencing early 2004 as part of the "bundle' of options in action item 11.
DSM	13. Determine revised DSM targets for the period 2004 to 2014 based on the results of action items 10, 11 and 12.
DSM	14. Evaluate and implement as appropriate the irrigation load control program in Idaho for 2004.
Peakers - 2006	15. Procure reserve peaker units for the system for operation in 2006. • Develop detailed plans and proposals, including the timeline for delivery, for the reserve peakers required for system 2006: • East side – 200 MW
Peaking	16. Review the West Valley peaker plant performance and requirement and negotiate the West Valley Peaker plant terms and conditions in line with the existing lease contract arrangements.
Renewables	17. Evaluate expansion options for PacifiCorp's Blundell Geothermal plant and implement expansion if appropriate and cost effective.
Renewables	18. Prepare, issue and implement an RFP for wind generation on the West of the system in line with the proposed procurement pattern: • 100 MW – 2006 • 200 MW - 2008 • 200 MW - 2010 Move up acquisition dates if economic to do so.

Renewables	19. Prepare, issue and implement an RFP for wind generation on the East of the system in line with the proposed procurement pattern: • 200 MW – 2007 • 200 MW – 2009 • 200 MW - 2011 Move up acquisition dates if economic to do so.
Renewables	20. Prepare, issue and implement an RFP for renewable generation options (i.e. geothermal, solar, fuel cells) which could be implemented in addition to, or as an alternative to, the proposed wind build pattern modeled in DPI (Action Items 18 and 19).
Shaped Products	21. Determine the strategy and negotiate, as appropriate, asset based shaped product contracts to fill: • The super-peaking needs in the East of the system for 2004/05/06/07 • Thermal asset based contracts in support of the capacity requirements to achieve the appropriate planning margin established through Implementation Action 24 on both the East and West of the system. • Thermal asset based contracts (25 MW) to support the addition of profiled wind in the East and West of the system.
Strategy and Policy	22. Determine the long term IRP model(s) including a review of options for using optimization logic for future IRP's
Strategy and Policy	23. Agree any changes to Standards and Guidelines that may impact the implementation of the IRP Action Plan
Strategy and Policy	24. Determine the Planning Margin PacifiCorp will adopt if different from the 15% planning margin adopted in this IRP. The analysis for this will include loss of load probability studies.
Transmission	25. Detail and commission selected transmission power system analysis studies to support the implementation of the IRP Action Plan as modified in this order. The studies will provide greater detail on transmission costs associated with all the portfolio additions. Particular attention is required to determine the impact of the potential wind capacity additions on the system from a system stability perspective.
Transmission	26. Prepare detailed plans including an economic review and justification and apply for necessary transmission upgrades to support asset additions
Transmission	27. Prepare detailed plans including an economic review and justification to implement the "Wasatch Front Triangle" transmission upgrades.
Transmission	28. Review options for firming up the IRP non-firm transmission requirement.
DSM	29. For the next IRP or Action Plan brought forward for the Commission's acknowledgment, assess Class 1, Class 3 and Class 4 demand-side management resources in Oregon, include in the portfolios those resources that are least cost, and include in the load forecast the likely impacts from implementation of DSM programs.
DSM	30. If the Company's demand response assessment due year-end indicates new voluntary demand response pilots or programs are cost-effective now or build capability for the future, bring them forward by March 31, 2004, for the Commission's consideration with a proposed effective date of May 1, 2004.
Renewables	31. Perform studies on the capacity value for wind resources and determine the appropriate level for use in the next IRP or Action Plan requiring Commission action.