ORDER NO. 08-232

ENTERED 04/24/08

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

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In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER	)	ORDER
	)	
2007 Integrated Resource Plan.	)	

DISPOSITION: MODIFIED PLAN ACKNOWLEDGED WITH EXCEPTIONS AND REQUIREMENTS FOR THE NEXT PLANNING CYCLE

PacifiCorp, dba Pacific Power (Pacific Power or Company), seeks acknowledgment of its 2007 Integrated Resource Plan (IRP). This IRP filing is in accordance with the Public Utility Commission of Oregon's (Commission's) Order No. 07-002, as corrected by Order No. 07-047, [1] which requires all regulated energy utilities operating in Oregon to engage in integrated resource planning.

We acknowledge the plan, as modified, with four exceptions. Although the filing satisfies our procedural requirements for the IRP process, we identify specific portions of the IRP that either do not satisfy identified substantive planning requirements or do not seem reasonable in light of current circumstances. We also identify several requirements for Pacific Power's next planning cycle.

INTRODUCTION

Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Utilities must involve the Commission and the public in their 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 risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies. *See* Order No. 07-002.

[1] The Commission originally adopted least-cost planning in Order No. 89-507 (docket UM 180). The Commission updated the utility planning process in docket UM 1056.

The Commission "acknowledges" resource plans that satisfy the procedural and substantive requirements, and that seem reasonable at the time acknowledgment is given.

Pacific Power's 2007 IRP

On May 30, 2007, Pacific Power filed its IRP. In the filing, the Company projects its energy and capacity needs will grow faster than historical averages. Specifically, Pacific Power estimates that it will become energy deficit on an average annual basis system-wide by 2009. The Company projects it will become capacity deficit in 2010, based on the single peak hour of the year and a 12 percent reserve margin.

Pacific Power used two modeling tools to develop and test resource portfolios designed to meet its resource needs. The capacity expansion model (CEM) performs a "deterministic," least-cost optimization of resource options over the 20-year study period assuming a set of fixed assumptions and constraints. The CEM minimizes operating costs of existing resources and optimizes resource additions in order to meet projected loads and a planning margin. Each resulting portfolio includes the types of resource additions and when and where (east or west control area) they would be added, including the estimated cost of transmission needed to get the power to Pacific Power's system. The Company used Planning and Risk (PaR), a production cost model that accounts for chronological commitments and dispatch constraints, to conduct 100 model runs for each probabilistic (stochastic) analysis. Pacific Power quantified the variability of five stochastic risks:[2] loads, natural gas prices, wholesale power prices, hydroelectric availability and thermal unit availability.

The Company first used the CEM to screen supply- and demand-side resources using 16 "alternative future" scenarios.[3] The Company used these studies to identify resource patterns attributable to changes in assumptions and to identify resources that frequently appear under a range of futures. The alternative futures address potential carbon dioxide (CO_2) regulatory costs, natural gas and wholesale electricity prices, load growth, potential scope of renewable portfolio standards, availability of federal renewable production tax credits, and achievable market potential for peak reduction programs.

The Company also tested 16 "sensitivity analysis" scenarios (SAS) to determine optimal portfolios resulting from changes to variables or other factors such as a 12 percent and an 18 percent planning reserve margin, impact of a regional transmission project, low and high commodity and capital costs, and inclusion of integrated gasification combined-cycle coal (IGCC) plants.

[2] Stochastic risks are quantifiable as a known fluctuation around an expected value.
[3] Called "CAF," for CEM alternative future. All CAF studies were based on a 15 percent reserve margin.

Pacific Power next used the CEM to develop "risk analysis" portfolios for stochastic simulation. The Company provided the CEM with fixed resource investment schedules for wind, demand side management (DSM) and distributed resources based on the results of the alternative future scenarios. The model optimized the selection of other resource options based on various resource strategies such as eliminating or deferring coal plants, gas plants or short-term market purchases. The Company then simulated the resulting portfolios using the PaR model.

The Company simulated each risk analysis portfolio under five CO_2 adder levels: \$0/ton, \$8/ton, \$15/ton, \$38/ton and \$61/ton (2008 dollars).[4]

The Company used stochastic mean cost (average present value of revenue requirements (PVRR)) as the key cost metric. The Company also reported on several risk exposure measures, as well as capital costs, customer rate impact, supply reliability statistics and emissions externality costs.

Implementation Actions for Pacific Power's Preferred Resource Strategy

Based on the analysis described above, Pacific Power selected Portfolio risk analysis (RA) 14 as its preferred course of action to meet its projected resource needs. The Company RA 14, "primarily on the basis of relative cost-effectiveness, customer rate impact, and cost/risk balance across the CO_2 adder levels."[5]

As filed, the RA 14 portfolio includes the following resource additions from 2007 to 2016:[6]

- 2,000 megawatts (MW) of renewable resources by 2013, including 400 MW expected to be on-line by year-end 2007
- 900 MW of base load/intermediate load resources on the east side beginning 2012, modeled as pulverized coal plants
- 1,500 MW of combined-cycle combustion turbine (CCCT) natural gas plants beginning 2011
- 450 average megawatts of "base" and "planned" conservation
- 100 MW of additional direct load control beginning 2010
- 100 MW of combined heat and power facilities through contracts under the Public Utility Regulatory Policies Act (PURPA)
- Short-term market purchases primarily on the west side, varying annually from 336 MW to 660 MW
- Transmission additions beginning 2010 to support integration of resources with loads

[4] *See* additional discussion under Guideline 8.
[5] IRP at 6.
[6] Resource sizes are approximate.

The Company filed the following Action Plan to implement its preferred portfolio. The Action Plan includes activities for decisions the Company intends to make in the next two to four years. Pacific Power states that resources evaluated are proxies representing the fuel type and operating characteristics deemed to best fit the deficit position; actual resource types to be acquired will be determined in the procurement process. Resource sizes are rounded to the nearest 50 MW.

1. Acquire 2,000 MW of renewable resources by 2013, including the 1,400 MW outlined in the Company's Renewable Energy Action Plan
   - Size: 2,000 MW
   - Resource evaluated: Wind
   - Timing: 2007-2013
   - Location: System

2. Use decrement values to assess cost-effectiveness of new program proposals. Acquire the base conservation (Pacific Power and the Energy Trust of Oregon (ETO) combined) of 250 MWa and up to an additional 200 MWa if cost-effective initiatives can be identified. Incorporate conservation potential study findings in the 2007 IRP update and 2008 IRP planning processes
   - Size: 450 MWa
   - Resource evaluated in IRP: 100 MW decrements at various load shapes
   - Timing: 2007-2014
   - Location: System

3. Acquire 100 MW of new Class 1 DSM[7] programs
   - Size: 100 MW
   - Resource evaluated in IRP: Irrigation load control in the east and west; control of summer loads in the east
   - Timing: 2007 to 2014
   - Location: 50 MW in the east, 50 MW in the west

4. Leverage Class 3 and 4 DSM resources to improve system reliability during peak load hours; incorporate DSM potential study findings in the 2007 IRP update and 2008 IRP planning processes
   - Size: n/a
   - Resource evaluated in IRP: Demand buyback and pricing programs, customer education
   - Timing: TBD
   - Location: System

[7] Demand side management.

5. Pursue at least 75 MW of combined heat and power (CHP) for the west side and 25 MW for the east side, including purchases pursuant to PURPA regulations and RFPs; incorporate CHP potential study findings in the 2007 IRP update and 2008 IRP planning processes
    - Size: 100 MW
    - Resource evaluated in IRP: 25 MW steam-topping cycle CHP; 5 MW gas combustion turbine CHP
    - Timing: 2007 to 2014
    - Location: System

6. Incorporate potential study findings for dispatchable standby generators in the 2007 IRP update and 2008 IRP planning processes
    - Size: TBD
    - Resource evaluated in IRP: 60 MW of diesel engine capacity on the west side
    - Timing: 2007 to 2014
    - Location: System

7. Procure a base load/intermediate load resource
    - Size: 550 MW
    - Resource evaluated in IRP: CCCT (Wet “F” 2X1) with duct firing
    - Timing: 2012
    - Location: East

8. Procure a base load/intermediate load resource
    - Size: 350 MW
    - Resource evaluated in IRP: 340 MW supercritical pulverized coal plant in Utah
    - Timing: 2012
    - Location: East

9. Procure a base load/intermediate load resource
    - Size: 550 MW
    - Resource evaluated in IRP: 527 MW supercritical pulverized coal plant in Wyoming
    - Timing: 2014
    - Location: East

10. Investigate a base load/intermediate load resource
    - Size: 350 MW
    - Resource evaluated in IRP: CCCT (Wet “G” 1X1) with duct firing
    - Timing: 2016
    - Location: East

11. Procure a base load/intermediate load resource
    - Size: 600 MW
    - Resource evaluated in IRP: CCCT (Wet "F" 2X1) with duct firing
    - Timing: 2011
    - Location: West

12. Procure base load/intermediate load resources beginning summer of 2010; use the base load RFP as appropriate to fill the need in the east
    - Size: 350 MW to 650 MW
    - Resource evaluated in IRP: Front office transactions (West – flat annual products; East – 3rd quarter heavy-load hour products)
    - Timing: 2010 to 2014
    - Location: East/west

13. Pursue the addition of transmission facilities or wheeling contracts as identified in the IRP to cost-effectively meet retail load requirements, integrate wind and provide system reliability; work with other transmission providers to facilitate joint projects where appropriate
    - Size: Various
    - Resources evaluated in IRP:
      Path C Upgrade
      Utah – Desert Southwest
      Mona – Utah North
      Craig Hayden – Utah North
      Miners – Utah North
      Jim Bridger – Utah North
      Walla Walla – Yakima
      Walla Walla – West Main
    - Timing: 2010 and beyond
    - Location: System

14. Continue to have dialogue with stakeholders on Global Climate Change issues
    - Size: n/a
    - Resource evaluated in IRP: n/a
    - Timing: Ongoing
    - Location: System

15. Evaluate technologies that can reduce the carbon dioxide emissions of the Company's resource portfolio in a cost-effective manner, including but not limited to, clean coal, sequestration, and nuclear power
    - Size: n/a
    - Resource evaluated in IRP: n/a
    - Timing: Ongoing

- Location: System

16. Continue to investigate implications of integrating at least 2,000 MW of wind into Pacific Power's system
    - Size: n/a
    - Resource evaluated in IRP: n/a
    - Timing: 2007-2008
    - Location: System

17. Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions
    - Size: n/a
    - Resource evaluated in IRP: n/a
    - Timing: 2007-2008
    - Location: System

18. Work with states to gain acknowledgment or acceptance of the 2007 integrated resource plan and action plan; to the extent state policies result in different acknowledged plans, work with states to achieve state policy goals in a manner that results in full cost recovery of prudently incurred costs
    - Size: n/a
    - Resource evaluated in IRP: n/a
    - Timing: 2007
    - Location: System

Pacific Power issued a Request for Proposals (RFP) in fulfillment of Action Items 7, 8 and 9. *See* docket UM 1208. The Company indicated the RFP also could be used to fill east side needs in lieu of short-term market transactions identified in Action Item 12. Pacific Power also may issue RFPs related to conservation, demand response and dispatchable standby generation identified in Action Items 2, 3 and 6. The Company plans to issue an RFP at a later date for renewable resources, as well as an RFP for "incremental" thermal resource needs beginning 2012-2017.

Parties' Recommendations

Parties mainly criticize Pacific Power's IRP analysis related to costs and risks of coal plants and greenhouse gas emissions. All parties recommend the Commission not acknowledge any Action Items that could lead to coal plant acquisitions. The Company's reply argues in part that the coal plants in the Action Plan are simply "proxy" resources. However, Staff and parties point out Pacific Power's use of coal plants as benchmark resources[8] in its current RFP.[9]

[8] The Commission defines a benchmark resource as "a site-specific, self-build option for which there is a commitment to proceed if it is the resource selected through the RFP. This definition does not preclude a

Parties also argue that none of the scenarios Pacific Power analyzed would meet state goals for reducing greenhouse gas emissions as established in Oregon House Bill (HB) 3543 (2007 Session). Further, the Company's analysis shows that only the "Emissions Performance Standard" portfolio would reduce its greenhouse gas emissions.

Northwest Energy Coalition (NWEC) recommends the Commission not acknowledge the IRP, asserting significant flaws in the Company's modeling. In the alternative, NWEC recommends the Commission indicate it would accept the Emissions Performance Standard portfolio with a more robust DSM program. Under high CO_2 adders, this portfolio performs better than the preferred portfolio based on stochastic mean PVRR, the Company's primary cost metric. On average across all adders studied, the stochastic mean PVRR for the Emissions Performance Standard portfolio is in the middle of the pack for the final risk analysis portfolios. The 95^{th} Percentile values are comparable to values for the preferred portfolio.

In lieu of new coal resources, the Oregon Department of Energy (ODOE) recommends the Commission indicate that Pacific Power should acquire more than the 2,000 MW of renewable resources in the Action Plan or show why such an action would not be least cost, adjusted for risk. ODOE also recommends Pacific Power increase its acquisition of energy efficiency and peak reduction programs.

In addition to supporting Staff's initial comments and recommendations, Renewable Northwest Project (RNP) states that, pursuant to Guideline 1a, the Company should model other cost-effective renewable resources including geothermal, biomass and solar energy resources (both generation and direct use of solar resources); the Company should not use wind as a proxy to represent all renewable resources because specific costs and benefits are not considered. Pursuant to Guideline 2c, RNP suggests the Company provide its draft IRP to parties earlier in the process to allow time to consider proposed changes before finalizing the document.

The Citizens' Utility Board of Oregon (CUB) recommends the Commission not acknowledge actions that could lead to acquisition of new pulverized coal plants.

Revised Action Plan

Based on the parties' comments, Pacific Power agreed to modify its plan to address many, but not all, of the identified concerns. The agreed-upon modifications, which are shown in mark-up below, consist of three revised Action Items and six

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utility from designating the market as an alternative comparator during the RFP evaluation process." *See* Order No. 06-446 at 5.

[9] *See* docket UM 1208.

additional Action Items as follows:

Revised Action Items

1. Action Item 2 - ~~Use decrement values to assess cost-effectiveness of new program proposals.~~ Acquire the base Class 2 DSM (Pacific Power and ETO combined, including energy savings in Oregon beyond that funded by the ETO) of ~~250~~ 300 MWa and ~~up to an additional~~ 200 MWa or more of additional Class 2 DSM if risk-adjusted cost-effective initiatives can be identified. Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Public Utility Commission of Oregon. Will reassess Class 2 objectives upon completion of system-wide DSM potential study ~~to be completed by June 2007~~. Will incorporate potentials study findings into the 2007 update and 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. Modeling also will take into account the benefits of conservation in reducing the costs of complying with Renewable Portfolio Standards.

2. Action Item 3 (New Class 1 DSM Programs) - Targets were established through potential study work performed for the 2007 IRP. Acquire 100 MW or more of additional Class 1 resources if risk-adjusted cost-effective initiatives can be identified. A new potential study is expected to be completed by June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

3. Action Item 4 (Existing and New Class 3 Programs) - Although not currently in the base resource stack, the company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. Will incorporate potential study findings into the 2007 update and~~/or~~ the 2008 integrated resource planning processes, including developing supply curves for Class 3 resources, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

Additional Action Items

4. In the next planning cycle, include IGCC plants[10] with carbon capture and sequestration as a resource option for selection.

5. In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.

6. For the 2007 IRP update and next planning cycle, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.

7. For the next planning cycle, further develop with stakeholders use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.

8. For the next planning cycle, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.

9. Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emissions rates to short-term market transactions.

Staff's Final Recommendation

Staff recommends the Commission acknowledge, with four exceptions, Pacific Power's 2007 IRP with the nine agreed-upon modifications to the Action Plan. The exceptions are IRP Action Items 7, 8, 9 and 11, discussed below beginning on page 30. Staff explains that Pacific Power does not agree with the following recommended modifications to Action Plan items related to thermal plant acquisitions:

- In lieu of Action Items 7 and 8 - Procure flexible resources in the east (other than coal plants) by the summer of 2012. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.

[10] Integrated gasification combined-cycle coal plants.

- Action Item 9 - Procure ~~a 550 MW base load/intermediate load~~ resources in the east by the summer of 2014 other than pulverized coal plants. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.

- Action Item 11 - Procure ~~a 600 MW base load/intermediate~~ resources in the west (other than coal plants) by the summer of 2011-2012 to address contract expirations and load growth and integrate renewable resources. Refine the size and type (base load vs. peaking) after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.

Pacific Power acknowledges that its coal benchmark resources for Action Items 8 and 9 in its current RFP are no longer viable.[11] However, Pacific Power explains, coal plants were eligible to bid into the RFP. As an alternative to Staff's recommended modifications, the Company offered the following modifications to address coal plant cost and risk:[12]

- In lieu of Action Items 7 and 8: Procure resources in the east by the summer of 2012. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts. Coal resources will be required to indicate how they will indemnify the customers and shareholders for the CO_2 risk and cost greater than what the company would otherwise be exposed to with a gas resource, and must be consistent with state law and greenhouse gas emission control requirements.

- Replacing Action Item 9: Procure ~~a 550 MW base load/intermediate load~~ resources in the east by the summer of 2014. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts. Coal resources will be required to indicate how they will indemnify the customers and shareholders for the CO_2 risk and cost greater than what the company would otherwise be exposed to with a gas resource, and must be consistent with state law and greenhouse gas emission control requirements.

[11] *See* Pacific Power's November 28, 2007, informational filing in docket UM 1208.
[12] *See* Pacific Power's December 18, 2007, comments to the Commission.

- Replacing Action Item 11: Procure ~~a 600 MW base load/intermediate~~ resources in the west by the summer of 2011 or 2012 to address contract expirations and load growth and integrate renewable resources. Refine the size and type (base load vs. peaking) after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts. Coal resources will be required to indicate how they will indemnify the customers and shareholders for the CO_2 risk and cost greater than what the company would otherwise be exposed to with a gas resource, and must be consistent with state law and greenhouse gas emission control requirements.

Staff does not believe Pacific Power's proposed modifications resolve the carbon-related concerns identified by the parties. Even if sellers could provide the necessary security for indemnification, Staff has remaining concerns about coal plants as part of the best cost/risk portfolio. Staff cites emissions performance standards in California and Washington, potential for such a standard in Oregon and elsewhere, and concerns about surplus energy sales in light of greenhouse gas regulations and renewable resource requirements. Staff also finds adding unsequestered coal plants to serve Oregon loads is inconsistent with state energy policy. Staff recommends the Commission not acknowledge Action Items 7, 8, 9 and 11.[13]

DISCUSSION

I. Adherence of the Plan to Integrated Resource Planning Guidelines

In considering whether to acknowledge a resource plan, we review the plan for adherence to our guidelines for resource planning.

Guideline 1: Substantive Requirements

Order No. 07-002 lays out four substantive requirements. We address each separately, followed by our disposition.

Guideline 1a

Under Guideline 1a, all resources must be evaluated on a consistent and comparable basis. First, we generally address Pacific Power's compliance with the four identified requirements listed under Guideline 1a. We then address, by resource type, the parties' comments on whether Pacific Power's IRP meets Guideline 1a.

[13] Additional discussion of these exceptions begins on page 30 of this order.

Identified Requirements:

In docket UM 1056, we identified four requirements a utility must meet to ensure that all resources are evaluated on a consistent and comparable basis. We address each in turn:

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power … and demand-side options which focus on conservation and demand response.*

Staff and RNP find the Company falls short of this standard for renewable resources. Specifically, the Company modeled wind resources to serve as a "proxy" for all renewable resources. Staff and RFP recommend that in the next planning cycle, Pacific Power also model other renewable resources such as geothermal, biomass and solar. Wind facilities have far lower capacity factors than most renewable resources and solar energy production better matches peak demand. According to Staff, if a utility assumes all, or virtually all, of its incremental renewable resources will be wind plants, the utility will likely overstate the capacity needed from other types of resources.

The IRP also did not fully consider IGCC plants with carbon capture and sequestration (CCS) technology. Specifically, the Company did not allow its CEM to select IGCC plants equipped with CCS, except for the Emissions Performance Standard scenario. Staff notes that the technology to capture CO_2 emissions from pulverized coal plants is less advanced compared to IGCC facilities. Pacific Power explains that CCS technology and costs are speculative. However, the Company agreed to modify its Action Plan to address this issue, pursuant to Staff's recommended amendment:

> In the next planning cycle, include IGCC plants with carbon capture and sequestration as a resource option for selection.

Staff also recommends further consideration of nuclear passive safety and pumped storage technologies in the next planning cycle.

- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*

Staff finds the Company met this requirement with the exception of testing intermediate-term market purchases, IGCC plants equipped with CCS technology, and renewable resources other than wind.

- *Consistent assumptions and methods should be used for evaluation of all resources.*

Staff finds the resource plan meets this requirement, with the exception of conservation and demand response resources. Specifically, Staff and other parties maintain the Company did not use consistent methods to evaluate the risk reduction benefits of these resources compared to supply-side options. The Company agreed with Staff's modifications to the Action Plan to improve analysis for the next planning cycle.[14]

- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

Staff finds that Pacific Power's resource plan meets this requirement. The Company applied its after-tax WACC of 7.1 percent to discount all cost streams.

Compliance with Guideline 1a by Resource:

Below we address by resource type how the IRP met Guideline 1a.[15]

Renewable resources – Staff and other parties find the modeling results supportive of acquiring the 2,000 MW in the action plan *at a minimum* on a best cost/risk basis. Staff also finds the Company's analysis of wind integration costs reasonable. Addressing a requirement from the last planning cycle, the IRP includes a discussion of how various thermal resources affect wind integration costs. Staff recommends a more thorough discussion in the next resource plan. Staff notes that state mandates to acquire renewable resources impose constraints on the planning process that require utilities to deviate from a strict comparability standard for evaluating resource choices.

Market purchases – In the previous plan, the Company included 1,200 MW of short-term market purchases as "planned resources" based on historic purchase levels found to be routinely cost-effective. These amounts were included in all portfolios considered. Staff does not object to Pacific Power's general modeling approach for the 2007 IRP, whereby the Company evaluated cost and risk metrics for portfolios with various amounts of short-term market purchases. However, Staff is not persuaded that the amount of market purchases in the preferred portfolio represents the best cost/risk trade-off.

Short-term market purchases in the preferred portfolio peak at 660 MW in 2013, representing only about half the amount included in the prior plan. On the east side of the system, such purchases range from a low of just 3 MW in 2013 to less than 200 MW per year for the rest of the 10-year resource acquisition period. On the west side, short-term purchases range from a low of 64 MW in 2011 to a high of 657 MW in 2013.

[14] *See* discussion under Guidelines 6 and 7.

[15] We address conservation and demand-side resources under Guidelines 6 and 7.

The Company states that less reliance on short-term purchases tends to reduce market price risk exposure, but can increase or decrease mean stochastic cost depending on the make-up of the portfolio. The Company chose a resource strategy that reduces reliance on the market and exposure to market price risk.

Staff finds without merit the Company's assertion that renewable portfolio standards are a source of market price risk and uncertainty. Staff points to the Company's own market price forecasting model which indicates that adding renewable resources decreases average market prices. In final comments, Staff notes that the Northwest Power and Conservation Council attributes its projected 9 percent decrease in mid-Columbia market prices to renewable portfolio standards. Staff recommends the Company take a hard look at low market price scenarios in analyzing its resource choices. Such possible futures point out the risks of capital-intensive, base load resources.

The Company explains that renewable energy itself is not the issue; however, a shifting resource mix, including natural gas plant expansion and a reduction in coal development, is a source of risk and uncertainty. Further, due to their intermittency, the addition of wind resources may cause utilities to rely on market purchases.

In addition, Staff finds the resource plan fails to meet Guideline 1 with respect to intermediate-term purchases. The Company responds that its RFP for base load resources addresses intermediate-term purchases; bids that provide at least 100 MW of capacity for a term of at least five years are eligible. According to Staff, addressing intermediate-term purchases in the RFP is insufficient.

Staff notes Portland General Electric Company's analysis of intermediate-term purchases in its current IRP, and its forthcoming RFP to solicit power purchase agreements for a term of six to 10 years.[16] Pacific Power agreed to Staff's proposed addition to the Action Plan to address this issue in the future:

> In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.

Distributed generation - The Company included dispatchable standby generation and combined heat and power (CHP) plants as resources for the CEM to select. The preferred portfolio includes 100 MW of CHP resources. Although the preferred portfolio does not include dispatchable standby generation, the Company plans to pursue these resources in a forthcoming RFP. The Company addressed in a separate analysis potential reduction in transmission and distribution costs associated with CHP

[16] *See* docket UM 1345.

facilities, pursuant to a requirement in Order No. 06-029. Dispatchable standby generation, CHP and solar energy resources were included in the Company's six-state DSM assessment published after the IRP was filed. The Company will use information from this study in its next resource plan.

Thermal resources[17] - For its initial analysis, the Company allowed the CEM to select unsequestered, supercritical pulverized coal plants, unsequestered IGCC plants, natural gas-fired CCCTs and simple-cycle combustion turbines. The Company evaluated portfolios with and without such resources. Sequestered IGCC plants were an option for selection only for the Emissions Performance Standard scenario. However, such a plant was not part of the resulting portfolio.[18] The Company determined that the earliest in-service date of passive safety nuclear technology is outside the 10-year acquisition horizon.

Staff and other parties point out the need to consider the future role of coal and other base load plants given both existing and potential Renewable Portfolio Standards and greenhouse gas regulations.

Transmission - Staff finds the modeling of transmission options in the current IRP meets the Commission's resource comparability standard as well as the requirement from the last planning cycle to analyze transmission resources to reach resources that are shorter term or lower cost.[19]

Guideline 1b

Under Guideline 1b, risk and uncertainty must be considered. At a minimum, electric utilities should address the following sources of risk and uncertainty: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with regulation of greenhouse gas emissions.

Pacific Power's stochastic modeling addresses five of the six minimum sources of risk and uncertainty that the plan must consider: load requirements, hydroelectric generation, plant forced outages, fuel prices and electricity prices. To address the cost to comply with future regulation of greenhouse gas emissions, the Company conducted the Commission-required scenario analyses (0, $10, $25 and $40 per ton of CO_2 in 1990 dollars), modeled both cap-and-trade and tax strategies, and analyzed a portfolio that would comply with a regional emissions performance standard. The Company also performed sensitivity studies with various combinations of low, medium and high levels of the following factors: load growth, natural gas and electricity prices, CO_2 compliance costs, renewable portfolio standards, renewable energy tax credits and achievable market potential for demand response programs.

[17] Additional discussion on thermal resources begins on page 26 of this order.
[18] Likely because the scenario was run at a CO_2 adder of only $8 per ton.
[19] We address this issue further under Guideline 5.

Also under Guideline 1b, utilities should identify in their plans any additional sources of risk and uncertainty. Additional sources of risk and uncertainty identified in the plan are capital costs, coal prices, the level of achievable DSM potential, availability of federal tax credits for renewable energy resources, and renewable portfolio standards.

Guideline 1c

Under Guideline 1c, the primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. In selecting its preferred portfolio, the Company considered both expected costs and associated risks and uncertainties, relying heavily on the stochastic analysis results of the Group 2 risk analysis portfolios. Through 2011, the Company plans to acquire renewable, DSM and CHP resources to diversify its portfolio and help comply with RPS requirements and future CO_2 regulations. From 2012 to 2014, the Company plans to acquire long-term assets with "complementary risk profiles" (supercritical pulverized coal and natural gas-fired CCCTs), along with short-term market transactions that provide planning flexibility. Over the long term, the Company plans to reduce its reliance on short-term market purchases and include "flexible long-term assets with a small emissions footprint."[20]

Pacific Power used a 20-year study period for portfolio modeling and a real-levelized revenue requirement methodology to address end effects. The Company used the stochastic mean PVRR as the key cost metric. The plan estimated future costs for all long lived and short-lived resources.

The Company used standard deviation of stochastic production costs as the measure of cost variability. For measuring bad outcomes, the Company measures Upper-Tail PVRR and includes its preferred "Risk Exposure" metric (Upper-Tail PVRR minus overall mean PVRR). The IRP includes a cursory discussion of hedging. Staff recommends a more robust discussion of hedging in future resource plans. The Company provides cost and risk metrics for each portfolio and explains its rationale for the preferred portfolio.

Guideline 1d

Under Guideline 1d, the plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. Pacific Power filed the plan prior to enactment of SB 838, Oregon's Renewable Energy Act. Staff finds reasonable the Company's responses to how the plan meets the renewable resource requirements of West Coast states through 2014 and pending federal RPS bills. The Company notes that its first RPS compliance plan is due January 1, 2010.

[20] IRP at 202.

HB 3543 (2007 Session) established a state policy to stop the growth of Oregon greenhouse gas emissions by 2010; cut them 10 percent below 1990 levels by 2020; and reduce them at least 75 percent below 1990 levels by 2050. The legislation did not establish specific mechanisms for achieving these goals. Pacific Power estimates that its preferred portfolio would increase its CO_2 emissions about 8 percent by 2018 compared to today.[21] Therefore, Staff and other parties find the Action Plan inconsistent with the goals for reducing greenhouse gas emissions in HB 3543.

Oregon is a member of the Western Climate Initiative, which plans to establish by August 2008 a cap-and-trade system or other market mechanism to meet a regional emissions reduction goal of 15 percent below 2005 levels by 2020. Legislation to adopt the proposed mechanism in Oregon is expected to be considered in the 2009 Session. In adopting the Western Commissions' Joint Action Framework on Climate Change in 2006, the Oregon Commission committed to "Explore the development and implementation of greenhouse gas emissions standards for new long-term power supplies."[22]

Commission Disposition

We conclude that Pacific Power's 2007 resource plan meets the substantive requirements in Order No. 07-002 with the following exceptions:

The IRP falls short of Guideline 1a in modeling conservation, demand response resources, renewable resources other than wind, intermediate-term market purchases, and IGCC plants equipped with CCS technology.

The Commission supports agreed-upon Action Plan modifications 1 through 5, above, related to these deficiencies. Regarding Guideline 1d, we note that Oregon HB 3543 was enacted after Pacific Power filed its 2007 IRP. While we must evaluate the IRP in the context of what is known today, the law does not establish binding emissions reductions. Therefore, we do not agree with Staff and other parties that the plan is inconsistent with the statute. At the same time, the IRP did not evaluate a portfolio that reduces the Company's greenhouse gas emissions consistent with the goals expressed in the law. We agree with the proposed resolution of this issue for the 2007 IRP Update and the next planning cycle, as set forth in agreed-upon Action Plan modification 6.

Pursuant to Staff's and RNP's recommendation, for the next Action Plan Update and planning cycle, we will add a requirement that the Company model other renewable resources in addition to wind. We also agree with Staff that the next resource

[21] Based on the average adder level evaluated.
[22] *See* Regular Agenda Item 5, November 21, 2006, Public Meeting.

plan should include a more substantive discussion of hedging as specified by Guideline 1c.

Finally, the Commission takes note of Staff's comments regarding the appropriate level of market purchases. We will review this issue further in forthcoming decisions related to resource acquisitions, and require the Company to further analyze and discuss short-term market purchase issues in the next IRP.

Guidelines 2 and 3 (Procedural Requirements)

Guidelines 2 and 3 lay out procedural requirements and specify procedures for filing and review of resource plans. Energy utilities must file an integrated resource plan within two years of the previous acknowledgment order. Pacific Power filed this plan about four months after the Commission entered its acknowledgment order on the Company's 2004 plan.[23] Pacific Power's filing was timely under Order No. 07-002.

The Commission and the public must be involved in the utility's planning process. Pacific Power held 13 public input meetings beginning December 7, 2005, and five technical workshops. Pacific Power distributed a draft of its plan for comment by participants on April 20, 2007, before submitting its final plan to the Commission on May 30, 2007.

The Commission held a Public Meeting regarding Pacific Power's plan on September 5, 2007. On September 19, 2007, CUB, ODOE, RNP and NWEC submitted written comments to the Commission regarding the plan. Pacific Power filed a reply on October 12, 2007. Staff filed its initial comments and recommendations on October 31, 2007.

RNP and NWEC filed additional comments on November 21, 2007, responding to Pacific Power and supporting Staff's initial analysis and recommendations. ODOE filed supplemental testimony on risks related to global warming from new coal plants. Staff filed its final recommendations and proposed order on December 14, 2007. The Commission held a Public Meeting on December 19, 2007, to consider comments on the proposed order.

Commission Disposition

We conclude that Pacific Power's 2007 IRP meets the Commission's procedural requirements.

[23] The Commission entered Order No. 06-029 in docket LC 39 on January 23, 2006.

Guideline 4: Plan Components

Guideline 4 identifies 14 separate elements that a plan must include to meet the Commission's IRP guidelines. These elements, set forth in Guidelines 4a to 4n, incorporate what we minimally expect from an IRP.

Guidelines 4a and 4b

Regarding Guideline 4a, Appendix I of Pacific Power's IRP is an explanation of how the utility met each of the substantive and procedural requirements in Order No. 07-002, as well as requirements from the last planning cycle. In compliance with Guideline 4b, the Company included high and low growth scenarios in its Alternative Future scenarios and included loads among its stochastic risk parameters in testing all Risk Analysis portfolios.

Guideline 4c

Guideline 4c addresses the Company's projected load-resource balance given existing resources, resources needed to bridge the gap, and modeling of existing transmission as well as transmission associated with the tested portfolios. Pacific Power estimates that it will become energy deficit on an average annual basis system-wide by 2009. The Company provides load projections based on its March 2007 forecast for two timeframes — the first 10 years (2007 to 2016) and the latter half of the study period (2016 to 2026).

The Company projects it will become capacity deficit in 2010, based on the single peak hour of the year and a 12 percent capacity reserve margin. The Company estimates the deficit will grow from 791 MW in 2010 to 2,400 MW in 2012, and to nearly 3,200 MW in 2016.

Energy needs. Pacific Power projects energy consumption to grow system-wide at an average annual rate of 2.4 percent from 2007 through 2016. Staff notes that this rate is higher than the 10-year average rate of 2.1 percent in the Company's 2004 IRP, as well as the actual average rate of 1.6 percent during the period 1995-2005. For the second half of the study period, the Company projects a 2.0 percent system-wide growth rate.

Energy consumption in the east is expected to grow four times faster than in the west — 3.2 percent versus 0.8 percent per year, respectively. Pacific Power expects Wyoming to grow at a faster rate than any other state — 5.6 percent per year on average. However, the Company expects Utah, with its larger customer base, to have the largest increase in annual loads (in megawatt-hours). In the west, Washington's load is forecast to grow at 1.3 percent per year on average, leading California and Oregon. With its larger customer base, Oregon represents the bulk of the annual growth on the west side (in megawatt-hours), but has the lowest average energy growth rate (0.6 percent).

Capacity needs. Pacific Power forecasts coincident peak loads to grow by 2.6 percent system-wide from 2007-2016.[24] For comparison, historical peak load growth in summer (1995-2007) has been 2.2 percent on average. By control area, the Company expects peak loads to grow by 3.2 percent in the east and 1.2 percent in the west. Total peak load growth is forecast to be 240 MW annually. Oregon is expected to contribute only 25 MW, or about 10 percent.

Staff does not believe the Company substantiated its projected overall increase in energy consumption of 2.4 percent. Staff is skeptical of the projected increase in Wyoming loads, primarily the result of expected electrification of the oil and gas fields. Staff notes that, according to the Company's predictions, loads will grow 50 percent faster than the average historical growth rate.

Further, Staff questions whether the projected increase in Wyoming loads represents long-term growth or a short-term spike that will not be sustained over time. In the absence of the Wyoming anomaly, overall growth in energy and capacity would be around 2 percent — closer to actual growth from 1995 to 2005. Projected peak growth also is skewed by the abnormal growth rate in Wyoming. If Wyoming peak growth instead is consistent with the system average, the result would be near 2.1 percent overall and more consistent with historical peak load growth of 2.2 percent.

Natural gas growth stations. Staff disagrees with Pacific Power's new approach for modeling how it will meet loads in the second half of the study period (years 11 through 20). Instead of modeling energy purchases at forward market prices for serving these loads, as in previous plans, the current IRP uses natural gas-fired "growth stations." Staff is concerned that the new method may skew the analysis where the timing of "growth stations" differs among portfolios tested. Further, the addition of growth stations creates CO_2 allowance credits that skew results. Staff recommends the Company model market purchases for the later years of the plan in order to consistently compare portfolios, and not inappropriately weight resource decisions in the distant future.

Transmission. The Company modeled existing transmission rights and future transmission additions associated with the portfolios tested.

Guidelines 4l and 4m

Regarding Guideline 4l, selection of a portfolio that represents the best combination of expected costs, risks and uncertainties for the utility and its customers, Pacific Power estimates future revenue requirements over a 20-year study period to

[24] Coincident peak load occurs in summer driven by air conditioning.

compare the costs and risks of candidate portfolios. One hundred stochastic runs over the study period are conducted for each of five modeled levels of CO_2 adders, ranging from zero to $61 per ton (levelized, in 2008 dollars). The Company calculates PVRR two ways: assuming a *direct* tax adder and a cap-and-trade compliance strategy whose trading values are equivalent to the tax adders. The cap-and-trade results generally yield the same cost and risk rankings as the direct tax adder cases. Stochastic Mean PVRR, the average of 100 modeled PVRR outcomes, is the Company's primary cost metric.

The Company's favored risk metric, "Risk Exposure," is defined as the Upper-Tail PVRR minus the mean PVRR. The Upper-Tail PVRR is the mean of the worst 5 percent of the model PVRR outcomes. Other risk measures displayed in the IRP are the Upper-Tail PVRR by itself and the 95^{th} Percentile, which is the 95^{th} highest PVRR out of the 100 runs.

Staff does not agree with Pacific Power that "Risk Exposure" (Upper-Tail PVRR minus mean PVRR) constitutes the best risk measure. Staff explains that this metric is more a measure of variability than either the probability of having a bad outcome or the degree of a bad outcome that might occur. By focusing on variability, the Risk Exposure ranking of a portfolio can be excellent even though the portfolio's mean PVRR is so high that its 95^{th} Percentile and Upper-Tail PVRR values are, unsatisfactorily, very high. Staff recommends that for future plans, Pacific Power rank portfolios using both 95^{th} Percentile and Upper-Tail PVRR metrics. The Company's Risk Exposure metric can be dropped altogether, as long as the Company continues to provide standard deviation values to indicate a portfolio's PVRR variability.

Also related to Guideline 4l, parties question the economic life of coal plants given potential CO_2 regulation. Staff notes that the advantages of Pacific Power's preferred portfolio shrink, or even disappear, absent an assumed 40-year economic life. In addition, Staff, RNP and CUB find that the IRP does not adequately address the capital cost risk of new coal plants. Staff disagrees with the Company that capital cost risk should only be evaluated in the RFP process. Staff notes that the Company's current RFP for base load resources allows bidders (and the Company) to index a sizable portion of their bid (or benchmark cost estimates) to specific market indices. Further, the Company does not commit to be held to its cost estimates for its benchmark resources when it comes time to put any such resources into rates.

Guideline 4m requires the utility to identify and explain whether the selected portfolio is inconsistent with state and federal energy policies and related barriers to implementation. The plan was filed before Oregon adopted a Renewable Portfolio Standard (SB 838) and emissions reduction goals for greenhouse gases (HB 3543). The Company agrees to an addition to the Action Plan toward consistency with state policy in HB 3543.

Staff finds that the plan meets other applicable requirements under Guideline 4, with the exceptions noted under Guideline 1a that also are applicable to Guideline 4h.

Commission Disposition

Pacific Power's plan provides the required elements under Guideline 4, with exceptions noted under Guideline 1a.

Related to Guideline 4c, we share Staff's skepticism of the Company's projected load growth rates. In particular, we note historical growth rates and Staff's concern that such growth may not materialize or be sustained. We also note Staff's concerns about using natural gas "growth stations" for the last half of the study period, as well as parties' concerns related to capital cost risks and assumed economic lives of coal plants. Pacific Power should further review these issues in the next planning cycle.

Regarding Guideline 4l, we take note of Staff's criticism of Pacific Power's preferred "Risk Exposure" measure. We agree that the 95^{th} Percentile and Upper-Tail PVRR are more appropriate measures of risk for ratepayers. We direct the Company to rank portfolios according to these metrics in the next IRP, and explain any inconsistencies between portfolios that rank highest according to these measures and the Company's preferred portfolio. Related to Guideline 4m, the Commission supports the agreed-upon modification to address Oregon HB 3543. Docket AR 518 will address utility compliance plans for SB 838. However, we expect IRPs to continue to analyze renewable resources on a best cost/risk basis, including evaluating the costs, risks and uncertainties of developing renewable resources beyond the amount needed to meet the mandatory minimum standards.

Guideline 5: Transmission

Guideline 5 requires that all costs to a utility of new resources, including costs for fuel transportation and electricity transmission, be recognized in the IRP process.

Staff finds that the Company met this guideline; further, that it improved its analysis of transmission options compared to previous plans. Rather than simply including transmission to bring electricity from new proxy plants to loads, the Company included 10 transmission projects as resource options for the CEM to select to enhance transfer capability and reliability and increase access to markets. The projects included those targeted for evaluation under commitments made by MidAmerican Energy Holdings Company. All portfolios included the Path C and Craig-Hayden projects.

Based on initial modeling results, eight transmission projects were part of all Group 2 risk analysis portfolios, including the preferred portfolio. The Company also performed a sensitivity study on a regional transmission project similar to the Frontier Line project, which would connect Wyoming generation with load centers in Utah, California and Nevada.

Commission Disposition

We conclude that the plan complies with Guideline 5.

Guideline 6: Conservation

Guideline 6 requires utilities to ensure that a conservation potential study is conducted periodically for its entire service territory. Guideline 6 also requires Pacific Power to determine the amount of conservation resources in the best cost/risk portfolio and include in its Action Plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.[25]

Staff finds that Pacific Power's IRP, as filed, does not satisfy Guideline 6. First, the filed IRP did not identify conservation potential in Oregon, beyond what the ETO expects to acquire with public purpose funds. Second, while the Company conducted a six-state DSM study, the study excluded conservation potential in Oregon.

Further, parties assert that modeling of conservation resources in the IRP is flawed. Specifically, the Company did not analyze varying amounts of conservation using supply curves, or its potential risk reduction benefits other than performing a stochastic analysis on the preferred portfolio with and without 100 MW conservation "decrements" of various shapes to determine whether they would lower the cost of market purchases (by reducing spot market purchases) and operating power plants (by optimizing operation of existing and new resources in the portfolio).

Pacific Power states that resource deferral benefits associated with conservation in the Action Plan are reflected in its modeling to the extent that conservation is reflected in the retail load forecast. Staff points out that only "base case" conservation is reflected in the load forecast; "planned" conservation is not. Therefore, the Company did not consider any benefit for deferring or avoiding new power plants and transmission. Nor did the Company address how new conservation resources might change the resource makeup of the portfolio.

Further, Pacific Power did not appropriately account for the benefits of conservation in reducing risk and uncertainty. Staff notes the Commission's rules

[25] Senate Bill 838, enacted shortly after Pacific Power filed its IRP, includes a provision that allows Pacific Power (and Portland General Electric Company) to request Commission approval to increase funding for cost-effective conservation beyond the public purpose charge.

requiring an explicit discount for this purpose.[26] Staff concludes that the preferred portfolio does not include all best cost/risk conservation resources.

Pacific Power agrees to amend its Action Plan to include 50 average megawatts (MWa) of additional conservation in Oregon based on the ETO's estimates of conservation potential in Pacific Power's Oregon service area.

Pacific Power agreed in the last planning cycle to evaluate whether it was preferable to use supply curves for various types of conservation resources, model them as portfolio options that compete with supply-side options, and analyze cost and risk reduction benefits. The Company did not use this method in the 2007 IRP because its six-state DSM assessment was not completed until after the IRP was filed. Agreed-upon modifications to Action Item 2 address this issue for the next planning cycle.

Commission Disposition

We share Staff's concerns regarding underestimating the risk-adjusted, cost-effective conservation throughout the Company's service area. We support the agreed-upon modifications to Action Item 2 to address incremental conservation in Oregon and modeling conservation resources in the next planning cycle.

Guideline 7: Demand Response

As applicable to electric utilities like Pacific Power, Guideline 7 requires an IRP to evaluate demand response resources as an option for meeting energy, capacity, and transmission needs.

Pursuant to a requirement from the last planning cycle, Pacific Power included supply curves for curtailable rates, demand buyback and critical peak pricing (Class 3 DSM) in its capacity expansion optimization modeling. However, only Class 1 resources (*i.e.*, dispatchable load control, scheduled irrigation and thermal energy storage) were included in the development of final portfolios for risk analysis. In other words, Class 3 programs were screened out before the Company reviewed these resource options for their potential risk mitigation value.[27] Further, Pacific Power used proxy values for Class 1 DSM resources that screened out many of these resources as well. Therefore, the amounts and types of resources that the model was permitted to choose did not comprise all of the resources that otherwise might be selected for the best cost/risk portfolio.

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[26] *See* OAR 860-030-0010(6).

[27] Pacific Power conducted a sensitivity analysis of Class 3 DSM on one of the original portfolios and found little impact on risk performance, including cost and reliability. For example, energy not served decreased by only 0.1 percent. However, given the fuel price, capital cost and regulatory risks of supply-side options, Staff finds the results supportive of including Class 3 DSM resources in risk analysis portfolios.

As is the case with conservation, analysis of demand response resources in the IRP suffers from lack of timely DSM study results. However, Staff is cautious of certain findings in the study – specifically, the reported low level of achievable demand response potential, particularly in the western control area. The Company agreed to modify Action Items 3 and 4 to address Staff's concerns.

Commission Disposition

We share Staff's concerns that the IRP may have underestimated the level of risk-adjusted, cost-effective demand response. We also share Staff's skepticism about the amount of achievable potential from demand response resources based on the six-state DSM study. We therefore support the agreed-upon modifications to Action Items 3 and 4 related to demand response resources.

Guideline 8: Environmental Costs

Guideline 8 requires utilities to include in their base-case analyses the regulatory compliance costs expected for CO_2, sulfur oxides, and mercury emissions.

Staff finds the IRP meets the Commission's current guidelines for analyzing environmental costs. Pacific Power modeled both a CO_2 emissions tax and a cap-and-trade strategy using the Company's base-case adder and the adder levels required under Order No. 07-002. Parties argued that the Company also should have tested higher adder levels, considering current proposals to reduce emissions of greenhouse gases.

The Company reported PVRR and CO_2 emissions results for each simulation, as well as averages across all CO_2 adders. Averaging effectively assumes that all adder levels are equally likely. RNP asserts that the Company should have used a median value, rather than an average that skews results toward a lower adder level.

The Company also tested the resource mix impacts of increasing the CO_2 adder by $5 increments to see which resources would be replaced, and also conducted limited "trigger point" analysis. In addition, the Company developed and evaluated a portfolio that would comply with a regional emissions performance standard. The simulation excluded pulverized coal and unsequestered IGCC plants.

The Company agreed to add two items to its IRP Action Plan pursuant to Staff recommendations related to Guideline 8:

> For the next planning cycle, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.

> Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emissions rates to short-term market transactions.

Regarding mercury, variable operating and maintenance costs of existing coal plants and coal proxy resources included the cost of complying with the federal Clean Air Mercury Rule. The Company also accounted for mercury allowances under a federal cap and trade program expected to begin in 2010. Some states have opted out of the federal program in order to adopt stricter standards.

Commission Disposition

We conclude that Pacific Power's IRP meets the current requirements under Guideline 8.[28] We support the agreed-upon modifications to Pacific Power's Action Plan.

Guideline 9: Direct Access Loads

Guideline 9 requires an electric utility's load-resource balance to exclude customer loads that are effectively committed to service by an alternative service provider.

Staff finds the IRP complies with this guideline. The Company does not offer a permanent opt-out from cost-of-service rates. Therefore, Pacific Power plans for all Oregon loads, including those customers who have selected service from alternative electricity suppliers.

Commission Disposition

We conclude that Pacific Power's 2007 IRP complies with Guideline 9.

Guideline 10: Multi-state Utilities

Guideline 10 requires multi-state utilities, like Pacific Power, to plan their generation and transmission systems on an integrated system basis that achieves a best cost/risk portfolio for their retail customers.

Pacific Power conducted planning on a system-wide basis, as specified under this guideline.

[28] We note that the Commission is reviewing the modification of Guideline 8 in docket UM 1302.

Commission Disposition

Pacific Power's 2007 IRP is in compliance with Guideline 10 related to planning on a system-wide basis. However, as explained elsewhere in this order, we do not find that Pacific Power's preferred portfolio represents the best cost/risk portfolio for all its retail customers.

Guideline 11: Reliability

Under Guideline 11, electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered, including loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy. The plan should demonstrate that the selected portfolio achieves the utility's stated reliability, risk and cost objectives.

Staff finds the reliability analysis in the 2007 IRP a significant improvement over prior plans, responsive to Guideline 11 and the Commission's directives from the last planning cycle. Pacific Power evaluated a subset of portfolios at both a 12 percent and a 15 percent planning reserve margin, and one portfolio at an 18 percent planning margin. In addition, the Company evaluated loss of load probability and average and worst-case energy not served. Ultimately, Pacific Power selected a portfolio with a 12 percent planning reserve margin. The Company concludes: "Pacific Power's view is that supply reliability is not materially impacted by a swing in the margin from 15 to 12 percent."[29]

Pursuant to a requirement from the last planning cycle, the Company analyzed a portfolio to meet the average of the eight-hour, system super-peak period, rather than the single peak hour of the year. After seeing the results of this analysis, as well as other reliability data in the IRP, Staff remains skeptical of a planning reserve margin based on the single peak hour of the year as the preferred reliability metric. Staff notes that loss of load probability analysis accounts for all hours where resources are insufficient to meet loads. Pacific Power agreed to modify its Action Plan to address this issue in the next planning cycle:

> For the next planning cycle, further develop with stakeholders use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.

Pursuant to another requirement from the last planning cycle, the Company included the maximum available amount of Class 3 DSM based on the proxy supply curves developed by a third party.

[29] IRP at 203.

Commission Disposition

We conclude that Pacific Power's 2007 IRP meets Guideline 11. We support the agreed-upon modification to the Action Plan.

Guideline 12: Distributed Generation

Guideline 12 requires electric utilities to evaluate distributed generation technologies on par with other supply-side resources and consider the additional benefits of distributed generation. If possible, the utility should quantify such benefits.

Pacific Power evaluated combined heat and power (CHP, or cogeneration) and dispatchable customer standby (diesel) generation resources. The Company's preferred portfolio includes 100 MW of CHP resources. The preferred portfolio does not include dispatchable standby generation. However, the Company plans to include this resource in a forthcoming RFP for DSM resources.

Pursuant to a requirement from the last planning cycle, the Company conducted a sensitivity analysis on the potential of CHP to reduce generation and transmission costs. The Company found significant cost offsets and savings so long as the customer agrees to be interrupted if the CHP unit is off-line at a time where the distribution system cannot serve the load.

RNP recommends the Company's next plan address distributed solar resources, including generation and direct use applications, based on the cost to the utility after subsidies. Staff notes that CHP, solar and dispatchable standby generation resources are evaluated in the six-state DSM report. However, Staff is skeptical about findings that show achievable potential in the west from all of these sources at only 79 MW over the next 20 years.

Commission Disposition

We conclude that Pacific Power's 2007 IRP meets Guideline 12. We continue to encourage the Company to pursue all types of distributed generation resources and account for all the potential benefits. Pacific Power's next plan should further evaluate solar direct use and generating resources.

Guideline 13: Resource Acquisition

Guideline 13 establishes certain requirements for each resource in its action plans. These requirements include identification of a proposed acquisition strategy, an assessment of the advantages and disadvantages of owning a resource instead of purchasing power, and identification of any benchmark resources it plans to consider in competitive bidding.

The Company provided its acquisition strategy for its Action Plan and a brief assessment of the advantages and disadvantages of owning vs. purchasing resources. The plan also identifies benchmark resources for the current RFP for base load resources.

Commission Disposition

We conclude that Pacific Power's 2007 IRP meets Guideline 13.

II. Exceptions: Action Items 7, 8, 9 and 11

In considering acknowledgment of the IRP Action Plan, the Commission considers whether it seems reasonable at the time acknowledgment is given, including adherence to the principles outlined in Order No. 07-002. Staff proposes exceptions to the IRP acknowledgment for Action Items 7, 8, 9 and 11. In addition to deficiencies noted under individual guidelines, Staff and other parties cite additional concerns that lead them to conclude that some or all of these Action Items do not seem reasonable at this time.

Until such time as IGCC technology is further commercialized, the Commission directed the Company to fully explore other types of resources in line with its seasonal, peak-hour needs, including natural gas-fired peakers, additional market purchases, demand response, conservation and distributed generation.[30] The Company conducted analyses aimed at satisfying this requirement, including testing a portfolio that excluded pulverized coal plants and a portfolio[31] that delayed pulverized coal plants until 2015. The Company found the cost and risk metrics of these portfolios less attractive than its preferred portfolio.

Action Items 7 and 8

Pacific Power's Action Item 7 is to procure a 550 MW base load/intermediate load resource in the east by the summer of 2012, modeled as a natural gas-fired plant. Action Item 8 is to procure a 350 MW base load/intermediate load resource in the east by the summer of 2012, modeled as a pulverized coal plant.

Staff finds reasonable Pacific Power's plans to acquire a thermal resource on the east side of its system in 2012. The Company's load and resource balances under a 12 percent planning margin demonstrate the Company is capacity deficit system-wide beginning 2010. The Company expects the deficit to grow to 2,446 MW in 2012. The eastern portion of the system accounts for most of the capacity needed.

[30] *See* Order No. 06-029 at 51 and Order No. 07-018 at 8.
[31] The portfolio was tested at a 12 percent and a 15 percent planning reserve margin.

However, Staff is not convinced that the Company should acquire *two* base load/intermediate load resources in the east in 2012. As was the case with the Company's 2004 IRP and current RFP, Staff asserts the Company has not demonstrated that base load resources are the appropriate strategy for meeting the highly seasonal, peak-hour needs on the east side of its system. Further, Staff raises concerns about the Company's analysis of estimated load growth as well as the levels of conservation, demand response, renewable resources and market purchases in the Action Plan. Parties also raise concerns about these resources getting short-changed in the preferred portfolio.

Assuming economic dispatch, the Company's energy balance shows its annual system energy impacts on potential forced retirement of existing coal plants. Under forthcoming CO_2 regulation, if new coal plants are not banned outright, CO_2 cost adders (under a tax or a cap-and-trade regime) may cause such retirements as new coal plants operate and emit large quantities of CO_2. Parties also raise concerns about the risk to ratepayers of pulverized coal resources considering the Company's existing carbon exposure and rising CO_2 emissions under the preferred portfolio.

CUB criticizes the Company's simulation of a cap-and-trade regime with its steady CO_2 emissions cap at 2000 levels. CUB notes that serious proposals to address climate change include a cap that declines over time. Pacific Power acknowledges that the cap used in the IRP is less stringent than some recent regulatory proposals. However, the Company asserts that the tax scenario in the IRP is equivalent to the Company having no allowances for CO_2 emissions.

Parties find other key IRP assumptions unrealistic, including the $8 per ton base-case CO_2 adder, accumulation and sale of emissions allowance credits (in cap-and-trade scenarios), and buyers willing and able to take the carbon burden associated with sales from Pacific Power's unsequestered coal plants – with no consequences for the sale price. Parties find that the models produce results that appear unlikely in the real world – in particular, that the cost of portfolios with two new, unsequestered coal plants goes down as CO_2 regulatory costs go up.

Parties also raise concerns about Pacific Power's modeling of CO_2 emissions for short-term market transactions. Specifically, the assumed emissions rate for market sales is higher than the assumed emissions rate for market purchases. However, the assumed price paid for the power is unaffected by the disparity in CO_2 intensity. Parties find it unlikely that market volumes and prices will be the same for power with widely differing CO_2 content.

Pacific Power explains that its CEM and PaR models were unable to model CO_2 emissions costs other than as a dispatch cost adder (*i.e.*, tax). However, the models perform expansion and dispatch functions identically under both cap-and-trade and CO_2 tax scenarios. The models also do not have the capability to track CO_2

emissions associated with non-firm imports and exports. The Company therefore estimated offline the CO_2 footprint of generation used to serve load, by applying system emissions factors to aggregated wholesale purchases and sales.

ODOE states that future CO_2 regulations are unlikely to give Pacific Power free allowances to cover the emissions of any new coal resources, which would not be on line until 2012 at the earliest. In fact, ODOE maintains that Pacific Power will likely be required to replace the output of existing coal-fired plants with low or zero carbon resources. Further, ODOE argues that investments in new coal plants may lead to higher borrowing costs.

Staff recommended the following modification to the Action Plan in lieu of Action Items 7 and 8:

> Procure flexible resources in the east (other than coal plants) by the summer of 2012. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.

Action Item 9

Pacific Power's Action Item 9 is to procure a 550 MW base load/ intermediate load resource in the east by the summer of 2014, modeled as a pulverized coal plant. Parties raise the same concerns as above. Staff recommended the following modification:

> Procure ~~a 550 MW base load/intermediate load~~ resources in the east by the summer of 2014 other than pulverized coal plants. Refine the size and type (base load vs. peaking) of resources needed after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.

Action Item 11

Pacific Power's Action Item 11 is to procure a 600 MW base load/intermediate load resource in the west by the summer of 2011-2012, modeled as a CCCT with duct firing.

Staff notes that, under *critical* hydro conditions and before adding any resources, on an average annual basis the Company already is energy-deficit in the west, and becomes slightly energy-deficit system-wide in 2009. Under *average* hydro conditions, used in portfolio analysis and selection, the Company becomes slightly energy-deficit system-wide in 2010. However, after adding the west-side proxy CCCT and the east-side proxy plants in the preferred portfolio, by 2012 the Company expects its system to be energy surplus by 2,000 MWa under average hydro conditions.

Pacific Power states that the west-side CCCT is needed regardless of the renewable resources required under the Oregon RPS. The Company projects a sizable capacity deficit system-wide in 2012 caused in part by expiration of west-side wholesale purchase contracts. The Company also points out the dispatch flexibility benefits of a natural gas-fired plant in integrating the renewable resources that are part of the preferred portfolio. In addition, the Company maintains that the incremental Oregon conservation it agreed to include in the Action Plan would affect only the level of short-term market purchases in the western control area, and not the size or timing of the proposed natural gas-fired power plant in the west. The Company explains that the 50 MWa of conservation is the forecasted total in 2016; in 2011, the estimate is 23 MWa. In addition, the Company believes reducing market purchases rather than the size of the gas plant would achieve better results on a cost, risk and reliability basis.

Staff is not convinced that the Company needs a 600 MW base load plant in the west given the projected system-wide energy surpluses that would result from implementation of the preferred portfolio. Staff also is not convinced that the Company selected the appropriate amounts of market purchases, both short- and intermediate-term. Further, parties maintain that the IRP did not appropriately evaluate conservation and demand response resources that may economically reduce the size of any thermal resource needed, or sufficiently account for the on-peak capacity value of renewable resources other than wind that may be acquired.

Based on initial analysis requested from Pacific Power, Staff questions whether it makes sense to install a large CCCT unit in the west, rather than less costly peaking units in the east, where most of the load growth is projected. Under a cap-and-trade CO_2 adder of $8 per ton, substituting intercooled aeroderivative simple-cycle combustion turbines in the east, in lieu of the proposed western CCCT, added only 0.75% to the estimated PVRR of the preferred portfolio. The impact under a straight carbon tax strategy was even smaller.

Staff recommended the following modification to Action Item 11 to address these issues:

> Procure ~~a 600 MW base load/intermediate~~ resources in the west (other than coal plants) by the summer of 2011-2012 <u>to address contract expirations and load growth and integrate renewable resources. Refine the size and type (base load vs. peaking) after updating DSM and renewable resource analyses, accounting for changes in resources, and refining load forecasts.</u>

Commission Disposition

We adopt Staff's recommended exceptions to the Action Plan. We would have acknowledged Action Items 7, 8, 9 and 11 with Staff's proposed modifications. Pacific Power did not object to Staff's proposal except for explicitly excluding coal plants from consideration. Instead, as noted on pages 11 and 12 above, Pacific Power requests acknowledgment of an approach that would require anyone bidding a coal plant to agree to hold the Company and customers harmless from the difference between the CO_2 risk associated with a natural gas-fired resource and the CO_2 risk associated with a coal resource. The Company does not claim that bidders would in fact be able to provide this indemnification but it does believe that this approach would provide bidders an opportunity to be creative in addressing the CO_2 risk of coal resources. Pacific Power asserts that this approach would better maintain the integrity of its current RFP and would comply with existing procurement rules and legislation. The Company acknowledges that it must still meet state emission restrictions on the use of new coal units to meet load, such as in California and Washington.

Pacific Power's indemnification proposal comes too late in the IRP review process. It raises complex issues that have not been thoroughly vetted. If executed, such an indemnification agreement could lead to protracted disputes over interpretation. Further, an effective indemnification agreement requires appropriate security. However, the Company has not explained the nature or means of such security. While we do not dismiss Pacific Power's concept, we cannot at this time conceive how it would work in practice. We therefore do not acknowledge the Company's indemnification approach.

III. Jurisdiction

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

On April 20, 1989, pursuant to its authority under ORS 756.515, the Commission issued Order No. 89-507 in docket UM 180 adopting least-cost planning for all energy utilities in Oregon. On January 8, 2007, the Commission updated its resource planning guidelines in Order No. 07-002 (docket UM 1056).

CONCLUSION

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

Pacific Power's 2007 Integrated Resource Plan, with the agreed-upon modifications, reasonably adheres to the principles of resource planning set forth in Order

No. 07-002 and should be acknowledged with the following exceptions and requirements for the next planning cycle:

Exceptions:

Action Item 7, Procure a 550 MW base load/intermediate load resource in the east by the summer of 2012, is not acknowledged.

Action Item 8, Procure a 350 MW base load/intermediate load resource in the east by the summer of 2012, is not acknowledged.

Action Item 9, Procure a 550 MW base load/intermediate load resource in the east by the summer of 2014, is not acknowledged.

Action Item 11, Procure a 600 MW base load/intermediate load resource in the west by the summer of 2011-2012, is not acknowledged.

Modifications agreed to by Pacific Power pursuant to Staff's recommendations:

Revised Action Items

1. Action Item 2 - Acquire the base Class 2 DSM (Pacific Power and ETO combined, including energy savings in Oregon beyond that funded by the ETO) of 300 MWa and 200 MWa or more of additional Class 2 DSM if risk-adjusted cost-effective initiatives can be identified. Will work with the ETO to identify such new energy efficiency initiatives and file the necessary tariffs with the Public Utility Commission of Oregon. Will reassess Class 2 objectives upon completion of system-wide DSM potential study. Will incorporate potentials study findings into the 2007 update and 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. Modeling also will take into account the benefits of conservation in reducing the costs of complying with Renewable Portfolio Standards.

2. Action Item 3 (New Class 1 DSM Programs) - Targets were established through potential study work performed for the 2007 IRP. Acquire 100 MW or more of additional Class 1 resources if risk-adjusted cost-effective initiatives can be identified. A new potential study is expected to be completed by June 2007, and associated findings will be incorporated into the 2007 update and

the 2008 integrated resource planning processes, including developing supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

3. Action Item 4 (Existing and New Class 3 Programs) - Although not currently in the base resource stack, the company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. Will incorporate potential study findings into the 2007 update and the 2008 integrated resource planning processes, including developing supply curves for Class 3 resources, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits.

Additional Action Items

4. In the next planning cycle, include IGCC plants with carbon capture and sequestration as a resource option for selection.

5. In the next IRP, evaluate intermediate-term market purchases, modeling them as portfolio options that compete with other resource options, and analyze cost and risk.

6. For the 2007 IRP update and next planning cycle, develop a scenario to meet the CO_2 emissions reduction goals in Oregon HB 3543, including development of a compliant portfolio that meets the Commission's best cost/risk standard.

7. For the next planning cycle, further develop with stakeholders use of loss of load probability (LOLP) and energy not served (ENS). Fully develop cost and risk metrics of various LOLP and ENS criteria.

8. For the next planning cycle, consider the impact of forced early retirements of existing coal plants, or retrofits necessary to reduce their CO_2 emissions, under stringent carbon regulation scenarios.

9. Pursue refinement of CO_2 emissions modeling to improve treatment of compliance under various regulatory schemes, including assignment of emissions rates to short-term market transactions.

Requirements for the next planning cycle that the Commission adopts pursuant to Staff's recommendations:

1. For the 2007 IRP Update and next IRP, Pacific Power should model other renewable resources in addition to wind.

2. For the next IRP, Pacific Power should rank portfolios based on the 95^{th} Percentile and Upper-Tail PVRR risk metrics, and explain any inconsistencies between portfolios that rank highest according to these measures and the Company's preferred portfolio.

3. For the next IRP, in response to concerns noted in this order, Pacific Power should further analyze and discuss the use of hedging, the level of short-term market purchases, projected load growth, modeling of resources to meet loads in the later years of the planning horizon, capital cost risks and assumed economic lives of coal plants, and the appropriate level of distributed generation.

Furthermore, pursuant to Order No. 07-499, the next resource plan also must address the following standard:

Each electric utility must consider in its integrated resource plans options to increase fossil fuel generation efficiency and include in the action plan implementation of options that meet the Commission's best cost/risk standard. The utility should also discuss how technological changes or expected state and federal regulations might impact fossil fuel efficiency plans.

Effect of the Plan on Future Rate-making Actions

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

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision- maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission[.]

> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.

See Order No. 89-507 at 6 and 11. The Commission affirmed these principles in docket UM 1056.[32]

This order does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken pursuant to Pacific Power's 2007 IRP. As a legal matter, the Commission must reserve judgment on all rate-making issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged integrated resource plans. Utilities will also be expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

ORDER

IT IS ORDERED that the 2007 Integrated Resource Plan filed by PacifiCorp, dba Pacific Power, on May 30, 2007, is acknowledged in accordance with the terms of this order and Order No. 07-002 as corrected by Order No. 07-047.

Made, entered, and effective APR 24 2008.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

[32] *See* Order No. 07-002 at 24.