BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 43

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2007 Integrated Resource Plan.	))))))	ORDER

DISPOSITION: PLAN NOT ACKNOWLEDGED; NEW PLAN TO BE SUBMITTED WITHIN 18 MONTHS

INTRODUCTION

On June 29, 2007, Portland General Electric (PGE or the company) filed its Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) 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.

PGE satisfied the procedural requirements of Order No. 07-002 relating to its planning process. However, as explained in the analysis below, the plan does not satisfy a number of substantive requirements of the order. Accordingly, we decline to acknowledge the plan, as discussed below.

Despite this conclusion, we find that the renewable resource actions in the plan are reasonable. The Oregon Renewable Energy Act (SB 838) imposes mandatory renewable resource levels beginning in 2011 based on retail loads, and the company's analysis shows that its current resources and planned acquisitions are expected to meet the requirements of SB 838 through 2015.

Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare an IRP 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

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[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.

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.[2]

The Commission "acknowledges" resource plans that satisfy the procedural and substantive requirements of Order No. 07-002 (Guidelines), and that seem reasonable at the time acknowledgment is given.

PGE's 2007 IRP

PGE's IRP projects its energy and capacity needs. Specifically, PGE targets 2012 as the year when its load-resource gap becomes large enough (818 average megawatts, or MWa) that significant new supply actions are necessary. PGE explains that this expected deficiency is based on load growth and the fact that a number of contracts (approximately 300 MWa) are expiring by 2012. The company also cites a favorable business environment, gains in productivity and emerging sectors creating new growth, and the continuing strong performance in the high tech sector as support for its robust growth predictions.

PGE adds that the expiring contracts described above represent approximately 800 megawatts (MW) of capacity. The actions PGE proposes for meeting its energy deficit will provide approximately 904 MW of capacity on an annual average basis. The company estimates it will need an additional 748 MW of capacity to meet winter needs and an additional 536 MW to meet its summer peak.

Implementation Actions for PGE's Preferred Resource Strategy

PGE selected the Diverse + Contracts portfolio as its preferred course of action to meet its projected resource needs. The portfolio includes the following resource additions from 2007 to 2015:

Energy actions that total 903 average megawatts (MWa):

- 323 MWa of renewable resources by 2012
- 130 MWa of energy efficiency by 2012
- 70 MWa through renewal of existing contracts (hydro)
- 372 MWa through new contracts, including 180 MWa of purchase power agreements (PPAs) of up to 5-year terms and 192 MWa of PPAs of 5- to 20-year terms
- 7 MWa through upgrades of existing generation sources

[2] *See* Order No. 07-002.

Capacity actions that total 1,653 megawatts (MW), including capacity value of the above energy actions plus the following:

- 80 MW of dispatchable standby generation, typically diesel-fired
- 35 MW from a curtailable tariff and critical peak pricing enabled by implementation of advanced metering infrastructure
- 25 MW of direct load control
- 100 MW from dual-purpose simple-cycle combustion turbines (SCCTs)
- 299 MW of bi-seasonal demand and supply
- 210 MW of winter-only peak supply

Transmission Actions

- Continue to evaluate the Southern Crossing project and actively work with Bonneville Power Administration (BPA) and others in the region to develop capacity.

The company filed the following Action Plan to implement its preferred portfolio:

1. Energy efficiency acquired by the Energy Trust of Oregon (ETO) through Public Purpose funds.
    - Size: 85 MWa
    - Resource evaluated in IRP: 85 MWa embedded in load forecast
    - Timing: 2007 through 2012
    - Location: PGE system

2. Pursue 45 MWa of additional energy efficiency through a proposed tariff.
    - Size: 45 MWa
    - Resource evaluated in IRP: Contracts
    - Timing: 2008 through 2012
    - Location: PGE system

3. Invest in efficiency upgrades at the Coyote gas plant and the Pelton Round Butte and Sullivan hydro plants.
    - Size: 7 MWa
    - Resource evaluated in IRP: Contracts
    - Timing: By 2012
    - Location: PGE system

4. Renegotiate hydro contracts that expire by 2012.
   - Size: 70 MWa
   - Resource evaluated in IRP: Contracts
   - Timing: 2011
   - Location: PGE system

5. Complete phases II and III of the Biglow Canyon wind project.
   - Size: 105 MWa
   - Resource evaluated in IRP: Tier I wind
   - Timing: 2009, 2010
   - Location: Columbia Gorge

6. Pursue power purchase agreements with a term of up to five years as a hedge against load uncertainty.
   - Size: 180 MWa
   - Resource evaluated in IRP: Assumed spot market behavior
   - Timing: Ongoing
   - Location: Delivered to PGE system

7. Pursue intermediate-term power purchase agreements (6- to 10-year terms) to reduce reliance on short-term markets, serve as a bridging strategy, and allow economic dispatch of the Beaver plant for capacity needs.
   - Size: 192 MWa
   - Resource evaluated in IRP: Contracts
   - Timing: By 2015
   - Location: Delivered to PGE system

8. Procure 218 MWa of additional renewable resources to meet Oregon Renewable Energy Act target of 15 percent of energy requirements from renewable resources by 2015.
   - Size: 218 MWa
   - Resource evaluated in IRP: Tier II wind, biomass, geothermal
   - Timing: By 2015
   - Location: Pacific Northwest

9. Continue expansion of dispatchable standby generation program at rate of 13.5 MW per year.
   - Size: 80 MW
   - Resource evaluated in IRP: PGE estimate of potential amount and cost

- Timing: Ongoing
- Location: PGE System

10. Propose a curtailable tariff for the largest customers; propose a critical peak pricing tariff for small customers upon approval of advanced metering infrastructure.
    - Size: 35 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: PGE System

11. Issue a Request for Proposal (RFP) for direct load control.
    - Size: 25 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: PGE System

12. Issue a RFP for dual-purpose simple-cycle combustion turbines (capacity and wind following).
    - Size: 100 MW
    - Resource evaluated in IRP: SCCT GE 7A, LM6000, LMS100
    - Timing: 2012
    - Location: PGE System

13. Issue a RFP for bi-seasonal supply or demand side to meet peak loads.
    - Size: 299 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: Delivered to PGE system

14. Issue a RFP for winter-only peak supply.
    - Size: 210 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: Delivered to PGE system

15. Transmission
    - Continue to investigate Southern Crossing project
    - Continue regional planning activities with BPA and others

Parties' Recommendations

Only Staff and the Renewable Northwest Project (RNP) filed comments. In addition to supporting Staff's initial comments and recommendations, RNP states that, pursuant to Guideline 1a, in the next planning cycle the company should include a more thorough evaluation of both generation and direct use applications for solar energy resources. RNP states an assessment of solar thermal water heating potential should be included.

Staff's Final Recommendations

Staff recommends the Commission not acknowledge PGE's 2007 IRP but find the renewable actions in the plan reasonable for the following reasons:

1. The plan does not satisfy a number of substantive requirements under Guidelines 1a and 1c. The plan also does not satisfy Guidelines 4c, 4h and 4l or Guideline 11. But for the planning horizon Guideline 1c, Staff concludes that the plan meets Guidelines 5 (transmission), 6 (conservation), 7 (demand response), and 12 (distributed generation).

2. Because the company did not perform its analyses over a 20-year planning horizon, as specified in Guideline 1c, it is not possible for Staff to conclude that the action plan is reasonable. However, Staff concludes that the renewable resource actions are reasonable. SB 838 imposes mandatory renewable resource levels beginning in 2011 based on retail loads, and the company's analysis shows that its current resources and planned acquisitions are expected to meet these requirements through 2015.

3. To satisfy Guidelines 1c and 4l, the company must demonstrate that the selected portfolio of resources represents the best combination of expected cost and associated risks and uncertainties for the utility and its customers. Because the company did not conduct sufficient analyses over the required 20-year planning horizon, it failed to make this demonstration for its preferred portfolio.

4. The plan does not fully satisfy the requirements of Guideline 13 (resource acquisition) because (1) in identifying a capacity benchmark resource, PGE identified a size and type of resource but did not identify a specific location and (2) PGE's evaluation of pros and cons of owning a resource versus purchasing power from another party should be more rigorous.

Staff further recommends the Commission require the company to submit a new plan within one year of this order that is in accordance with Order No. 07-002 and with the following requirements:

1. Conduct portfolio analysis over a 20-year planning horizon, including:
   - Applying the company's 20-year load forecast
   - Determination of the levels of peaking capacity and energy capability expected over the 20-year planning horizon, given existing resources and accounting for retirements and contract expirations
   - Identification of capacity and energy needed to bridge the gap between expected loads and resources
   - Modeling of all supply-side and demand-side resources expected to become available to meet energy needs for at least the first 10 years of the planning horizon. (*i.e.*, a minimum 10-year resource acquisition period)
   - Modeling of future transmission additions associated with the resource portfolios tested

2. Include in the analysis a wind integration study that has been vetted by regional stakeholders.

3. Present the results of all analyses relevant to portfolio selection in a tabular format, showing how well each portfolio did under each of the analyses. Explain how the analysis results support the conclusion that the preferred portfolio and resulting action plan represent the best combination of cost and associated risks and uncertainties for the utility and its customers. In the event that alternative approaches for measuring risk yield disparate results, assess the relative merits of those approaches.

Staff notes that requirement 1, above, also addresses its concern related to the planning horizon for analyses of conservation, demand response, reliability, distributed generation and transmission. Staff believes that the other requirements under Guideline 11 (reliability) are self-evident and therefore require no explicit condition.

The Commission adopted a fossil-fuel generation efficiency standard for resource planning, pursuant to the Energy Policy Act of 2005, approximately five months after PGE filed its 2007 IRP. Staff therefore recommends the standard adopted in Order No. 07-499 first be addressed in the next resource plan.

Staff further recommends the Commission direct that the plan include an assessment of transmission resources needed to meet the action plan, as well as estimates for costs and timing.

DISCUSSION

Adherence of the Plan to IRP Guidelines

In considering whether to acknowledge a resource plan, this Commission reviews 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. The identified requirements provide:

- *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 finds that PGE did not meet this requirement. The company chose to consider only technologies that would be commercially available in the timeline of the next RFP in its portfolio analysis. The company cites this limitation on what was included in portfolio analysis as a reason for not considering long-term resource additions beyond 2012. PGE does discuss in its IRP many emerging technologies that may present potential sources of new energy supply for future resource plans. Nevertheless, the company did not consider all known resources as required. Staff points out that the Commission previously rejected PGE's recommendation that only commercially viable, or near-commercially viable, resources be considered, stating that the IRP should include all resources "that are expected to become available."[3]

In addition, Staff agrees with RNP that PGE should more thoroughly evaluate both generation and direct use of solar energy resources.[4] Both Staff and RNP praise the company for including biomass and geothermal when it modeled renewable resources in the portfolios.

Guideline 1a also requires:

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

Staff concludes that the company has not met this requirement. All of PGE's portfolios were constructed to meet loads only through 2014, which represent the target end date for its proposed actions. Further, the company froze long-term resource additions after 2012 and only considered technologies expected to be commercially viable by that date. PGE states that the magnitude of the resource gap is great enough in 2012 that actions cannot be postponed further. The constructed portfolios were modeled for power supply for 20 years at the fixed 2014 load. Market purchases were the only resources modeled beyond 2012. Therefore, according to Staff, the company did not sufficiently address different technologies, lead times, in-service dates and durations.

Staff provides the following assessments by resource category:

Demand-Side Management. The company includes in its modeling and action plan all of the achievable cost-effective conservation identified through 2012. However, there was no assessment of cost-effective conservation beyond 2012. In its analysis of capacity needs, the company includes dispatchable standby generation, direct load control and critical peak pricing through 2012.

Renewable Resources. The company modeled wind, biomass and geothermal resources. PGE contracted with EnerNex in February 2007 to perform a wind integration study. Due to the need for PGE to develop a new dispatch model for EnerNex's use, EnerNex has not completed the study. In lieu of the completed study, PGE used an integration cost of $6/MWh for Tier I wind and $10/MWh for Tier II wind, which the company states is consistent with analysis by the Northwest Power and Conservation Council (Council).[5] RNP objects, stating "$10/MWh is higher than the high end of the Council's reported range and is inconsistent with other analyses done around the region." The company stands by the values used in the IRP. In addition, PGE

[3] *See* Order No. 07-002 at 4.
[4] RNP points out that the analysis should reflect the expected cost of solar energy measures to the company – that is, after subsidies and customer contributions have been taken into account.
[5] PGE evaluated wind on two tiers for expected capital costs and capacity factors. Tier I is expansion of PGE's Biglow Canyon Project and Tier II includes all other wind resources. *See* IRP at 104.

performed sensitivity studies and concluded that, in the range of $6/MWh to $14/MWh, there is no change to the company's proposed Action Plan.

Wind is one of the least costly ways to meet the requirements of the state's renewable portfolio standard (RPS). Lacking an integration study, the company risks over- or under-estimating the most cost-effective amount of wind to incorporate in its portfolio of renewable resources. The company originally anticipated it would have a completed wind integration study to use in its analysis for this IRP and agrees to the following condition:

> In the next planning cycle, include in the analysis a wind integration study that has been vetted by regional stakeholders.

Market Purchases. All 13 portfolios the company considered include approximately 180 MWa of short- and mid-term market purchases. PGE states this is necessary because commercial and industrial customers have the option of choosing an alternative electricity service supplier with one year notice. Long-term power purchase agreements (PPAs) were included in two of the portfolios. In this IRP, PGE changed its characterization of the Beaver plant from an energy resource to a capacity resource in order to allow economic dispatch of the facility to provide a better assessment of its resource need from an economic perspective. The intent is to protect ratepayers from high spot market purchases.

Distributed Generation. The company included in its Action Plan 80 MW of dispatchable standby generation. This represents most of the identified dispatchable standby generation available between now and 2012. PGE considers this resource a key component of its capacity portfolio. PGE did not include combined heat and power (CHP) as a resource in any of the portfolios it modeled. The company cites several obstacles to successful implementation of CHP projects in its territory, but commits to continued exploration of CHP potential.

Fossil-Fuel Resources. The company considered both coal and natural gas in the evaluated portfolios. The coal technologies included supercritical pulverized coal plants without sequestration and integrated gasification combined cycle (IGCC) plants with and without sequestration. Both SCCT and combined-cycle combustion turbine (CCCT) gas plants were considered for capacity actions but only CCCT plants were included in portfolios for energy analysis. The company's Action Plan includes 100 MW from SCCTs.

Nuclear Resources. PGE did not evaluate any portfolios that included nuclear resources, citing significant legal and public barriers to nuclear technology. The company plans to consider advanced nuclear technologies in future IRPs, but recognizes that siting within Oregon is currently not possible until a Federal spent fuel repository is available. Staff recommends PGE include nuclear resources as an option in future plans.

Transmission. PGE modeled the cost of transmission using BPA's standard transmission tariff rates. PGE also evaluated transmission capacity and determined there is adequate capacity through 2012.

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

Staff agrees with the company's assessment that it met this requirement.

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

The company applied its after-tax WACC of 7.59 percent to discount all cost streams.

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.

Staff believes that the IRP meets the guideline. However, some of the risk studies presented in the IRP are more illuminating than others. Staff concludes that the company did not adequately describe how it weighted these analyses and other more subjective criteria in choosing the preferred portfolio. We address this issue further under Guideline 4.

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 PGE's plan include the availability of federal tax credits for renewable energy resources, renewable portfolio standards, and what the company identifies as "Scenario Risk" and "Paradigm Risk." The company describes "Scenario Risk" as uncertainty that arises from fundamental or structural changes in the relationships among the fundamental drivers in power costs over time. "Paradigm Risk" is described as the occurrence of an event that radically changes one or more of the fundamental assumptions of the analysis.

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. This guideline specifically calls for a planning horizon of 20 years.

Staff believes that PGE's plan does not meet the threshold Commission goal of long-term planning specified by this guideline. Staff concludes that PGE's treatment of the planning horizon provides no analysis of the likely circumstance that the company must acquire or build resources to meet customer loads beyond 2012.

In the IRP, PGE states there is too much uncertainty in future technologies to make assumptions other than market purchases beyond 2012. The company further states that resource plans should focus on resource decisions and actions that need to be made in the next few years. PGE explains that it "froze loads in 2012[6], in order to avoid making our analysis less exact by either assuming a large future resource deficit period or significant market purchases to meet load growth beyond our target implementation period." *See* PGE's Reply to Staff's Comments at 2.

According to Staff, PGE presents a false choice. Utilities should perform long-term load projections for the 20-year planning horizon established by the Commission and model actual resource options for meeting loads at least in the first half of the planning period. Recognizing the level of uncertainty in loads and resource choices in the out-years—years 11 through 20, it is reasonable to use market purchases in the model to meet projected loads in these later years.

Staff recommends the Commission require the following condition to address this issue in the next planning cycle pursuant to Guideline 3e:[7]

> Conduct portfolio analysis over a 20-year planning horizon, including:
>
> - Applying the company's 20-year load forecast;
> - Determining the levels of peaking capacity and energy capability expected over the 20-year planning horizon, given existing resources and accounting for retirements and contract expirations;
> - Identifying capacity and energy needed to bridge the gap between expected loads and resources;
> - Modeling of all supply-side and demand-side resources expected to become available to meet energy needs for at least the first 10 years of the planning horizon. (*i.e.*, a minimum 10-year resource acquisition period); and
> - Modeling of future transmission additions associated with the resource portfolios tested.

[6] PGE later corrected the statement in its reply to Staff's comments. As correctly stated in its 2007 IRP, PGE froze long-term resource additions in 2012 and froze loads in 2014.

[7] Under Guideline 3e, "The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

Guideline 1d

Under Guideline 1d, the plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. PGE filed its resource plan only a few weeks after SB 838 was signed into law. Staff notes that the company's cost/risk analysis supported inclusion of 323 MWa of additional renewable resources in the preferred portfolio by 2012, representing an estimated 16.8 percent of its load served by renewable resources by 2015. This exceeds the statutory requirement of 15 percent of load served by renewable resources by that year.

In its initial comments, Staff also discusses potential carbon dioxide (CO_2) regulations. House Bill 3543 (HB 3543) was signed into law after PGE filed its plan. This legislation establishes 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. A number of proposals to reduce greenhouse gas emissions are under consideration at the federal level. Staff notes that 58 percent of the energy action items[8] are supplied by renewable resources and energy efficiency, thus helping to position the company for more stringent emissions regulations.

Commission Disposition

We conclude that PGE's 2007 resource plan does not satisfy a number of substantive requirements of Guidelines 1a and 1c for the reasons stated by Staff above. For the next planning cycle, we support the conditions recommended by Staff as stated under Guidelines 1a and 1c.

Guidelines 2 and 3 (Procedural Requirements)

Guidelines 2 and 3 lay out procedural requirements and specify procedures for filing and review of resource plans. PGE satisfied these procedural requirements.

The company filed its 2007 IRP approximately three years after acknowledgment of the last plan. In Order No. 05-1138, the Commission ordered PGE to file its next IRP by December 2006. On November 2, 2006, PGE requested an extension to June 30, 2007 to file its IRP. In Order No. 07-002, the Commission recognized the revised due date.

The company held seven public workshops and a portfolio modeling approach workshop between April 2006 and April 2007. PGE distributed a draft IRP to interested parties for comments on June 5, 2007, and submitted its final plan to the Commission on June 29, 2007.

[8] The company also plans to undertake roughly 700 MW of capacity supply actions as well.

The Commission held a Public Meeting on September 19, 2007, where PGE presented its plan. RNP submitted written comments to the Commission regarding the plan on October 19, 2007. PGE filed a reply on November 13, 2007. Staff filed its initial comments and recommendations on January 4, 2008. On January 22, 2008, RNP filed additional comments supporting Staff's analysis and recommendations and PGE submitted its reply to Staff's comments.

Commission Disposition

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

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, in Appendix A of its IRP filing, PGE details how it met each of the substantive and procedural requirements in Order No. 07-002. In compliance with Guideline 4b, the company tested its portfolios against high and low growth scenarios.

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. PGE chose to focus its analysis on the years 2012 through 2014. This was driven by two factors: load growth and expiration of existing resources. Based on a 2.2 percent growth rate, the company forecasts an energy deficit of 818 MWa and a peak capacity need of 1,540 MW by 2012.

Staff's concerns regarding the planning horizon under Guideline 1c also apply to PGE's approach under Guideline 4c. Staff states that the analysis required under Guideline 4c must be performed for a 20-year planning horizon. Therefore, the analysis must be based on the company's long-term load forecast, the expected energy and capacity from existing resources over the 20-year period considering planned retirements and contract expirations, the energy and capacity needs over the period to bridge the gap, and the associated transmission needed.

Staff considers PGE's predicted growth rate of 2.2 percent not well supported either from a historical perspective or by forecasts from others. The company cites a favorable business environment, gains in productivity and emerging sectors creating new growth, and the continuing strong performance in the high tech sector as support for its robust growth predictions. Other independent reports, however, including the Council's "Biennial Monitoring Report on the 5th Power Plan," estimated electricity growth at just less than one percent for the period. The same report presented figures that show a historical electricity growth rate from 2000 to 2005 of 1.4 percent.

PGE's reliance on short-term power markets for a significant part of its load (approximately 180 MWa out of 818 MWa total) somewhat reduces Staff's concern about the high forecasted growth rate. However, it is important for the company's load forecasts to be correct, not just to facilitate the planning and development cycle for new resources, but also because power cost updates rely on forecasts of load based on the IRP process.

The company modeled existing transmission rights that meet its needs through 2012.

Guideline 4h

Guideline 4h requires the utility to construct resource portfolios that test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and delivery points. For the same reasons Staff cites under Guideline 1a with respect to testing different technologies, lead times, in-service dates and durations, Staff concludes that the IRP does not meet Guideline 4h. The portfolios PGE modeled all contained resources that were added in 2012, PGE's self-identified "watershed" year. Only market purchases were modeled beyond 2012.

Guidelines 4j, k and l

Under Guidelines 4j, k and l, the company is expected to evaluate the costs, risks and uncertainties associated with each portfolio and then evaluate the portfolios against each other. According to Staff, the result of this analysis should be a rank ordering of the portfolios based upon all of the considerations.

The company provided a rank ordering of the portfolios based on the calculated expected net present value revenue requirement (NPVRR) under 18 "Futures" (*see* IRP Appendix H). PGE also provided analyses of the performance of the portfolios across different sensitivities and discussed the merits of each individual portfolio. However, Staff states it is not clear how the company considered those rankings, along with risks and uncertainties evaluated, to conclude that the Diverse + Contracts portfolio represents the best combination of cost, risk and uncertainty. PGE showed that its Diverse + Contracts portfolio was consistently one of the more robust performers across a wide range of futures, stress testing and measures of risk, but did not provide an analytic path from the various rankings to an overall performance ranking.

Among the risk analyses PGE performed are five scenario studies in which base-case assumptions were altered in limited ways, as well as three stochastic studies founded on the base-case scenario. Staff points out that some studies yielded conflicting results.

To explore how portfolios would perform, given circumstances other than the Reference Case set, PGE constructed 18 alternative Futures for the study period. Staff notes that, at most, these Futures alter only two of the Reference Case elements. Staff raised concerns in this regard considering how high costs might be under the most adverse conditions. Staff also raised concerns with many of the scenario and stochastic studies.[9]

Staff raises the following concerns related to the scenario risk studies:

1. The risk metric applied does not capture the upper end of potential costs. For example, the studies do not consider the possible costs of the portfolio under high gas prices combined with a high CO_2 adder.

2. A relatively unattractive portfolio may get a good "risk" score even though both its worst-Future and Reference Case NPVRR are extremely high.

3. One of the scenario studies looked only at the costs of new resource additions without consideration of existing resources. In reality, however, a portfolio's performance depends on the utility's entire set of resources, not just additions.

Regarding PGE's stochastic analysis, Staff supports the company's use of the TailVaR90 risk metric, which is the mean of the worst 10 percent of the NPVRR outcomes for a given portfolio. However, Staff concludes that the usefulness of the stochastic risk studies is limited because they were conducted under assumptions at or near those of the Reference Case. For example, no study captured stochastic risk—probabilistic, adverse excursions in hydro conditions, loads, and fuel and market prices—under a high CO_2 adder.

Risk involves both scenario and stochastic elements, and these elements may interact. For example, a portfolio that seems to have a low level of stochastic risk under low CO_2 costs and low gas prices may have an unacceptably high risk in a less favorable environment.

Staff recommends the Commission require the following condition for the next planning cycle to address Guideline 4l:

[9] *See* Staff's Initial Comments and Recommendations at 11-15.

> Present the results of all analyses relevant to portfolio selection in a tabular format, showing how well each portfolio did under each of the analyses. Explain how the analysis results support the conclusion that the preferred portfolio and resulting action plan represent the best combination of cost and associated risks and uncertainties for customers. In the event that alternative approaches for measuring risk yield disparate results, assess the relative merits of those approaches.

Regarding Staff's initial comments on analysis of potential costs related to greenhouse gas emissions, Staff concedes that docket UM 1302 will address the issue.

To satisfy guideline 4l, the company must demonstrate that the selected portfolio of resources represents the best combination of expected cost and associated risks and uncertainties for the utility and its customers. The company did not conduct analyses over the required 20-year planning horizon in order to make this demonstration for its preferred portfolio.

Commission Disposition

We conclude that the plan does not comply with Guidelines 4c, 4h or 4l for the reasons cited by Staff. The condition we adopted under Guideline 1c also addresses Staff's concerns related to the planning horizon for the next planning cycle with respect to Guideline 4c. We also adopt Staff's recommended condition related to Guideline 4l.

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 concludes that the company does not meet this guideline with respect to the planning horizon used for the analyses. At the same time, Staff recognizes that approximately three-quarters of PGE's power supply is delivered by BPA and, therefore, the company has little direct control over needed transmission capacity. PGE is participating in regional transmission planning and is currently studying the economic feasibility of a potential transmission expansion project (Southern Crossing). However, according to the company's analysis, transmission constraints have the potential to impact PGE in 2012 and there are no projects in progress.

Staff recommends the Commission require that the next plan include an assessment of transmission resources needed to meet the action plan, as well as estimates for costs and timing.

Commission Disposition

We conclude that the plan does not comply with Guideline 5 with respect to the planning horizon. We adopt Staff's recommended requirement for the next plan related to assessment of transmission resources.

Guideline 6: Conservation

Guideline 6 requires utilities to ensure that a conservation potential study is conducted periodically for its entire service territory. As applicable to electric utilities, Guideline 6 also requires PGE to perform two analyses related to conservation resources.

PGE and the ETO have worked together to assess conservation potential for PGE's service territory. Based on that research, PGE concludes there is 125 MWa of achievable cost-effective conservation through 2012. The Trust has projected that funding provided by the public purpose charge will enable it to acquire 65 MWa. Funding allowed by the provisions of SB 838 would allow for acquisition of an additional 45 MWa.

Staff concludes that the Company has met this requirement for the period analyzed. Staff's only concern with this analysis is the study period. According to Staff, conservation planning must be considered over at least the first 10 years of the planning horizon. The condition Staff recommends under Guideline 1c includes conservation resources.

Commission Disposition

We conclude that, except for the planning horizon, PGE's IRP 2007 complies with Guideline 6. The condition imposed under Guideline 1c addresses this issue for the next planning cycle.

Guideline 7: Demand Response

Guideline 7 requires demand response resources be evaluated on par with other options for meeting energy, capacity and transmission needs. Staff concludes that the company has met this requirement for the period analyzed. However, the same concerns related to planning horizon described above apply to the analysis of demand response resources, as well.

Using its Aurora model, the company evaluated firm demand-side capacity resources, such as residential direct load control, on par with supply-side capacity resources. Further, the company evaluated voluntary rate programs such as critical peak pricing for small customers and curtailment tariffs for large customers.

PGE's proposed capacity actions include all firm direct load control considered to be achievable, cost-effective potential by 2012 based on third-party estimates and assuming implementation of advanced metering infrastructure. PGE also plans to acquire an additional 80 MW of dispatchable standby generation at customer sites, based on expanding the program at a rate of 13.5 MW per year.

Commission Disposition

We conclude that, except for the planning horizon used in its analysis, PGE's 2007 IRP complies with Guideline 7.

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.

RNP observes that the Commission is currently reviewing Guideline 8 in docket UM 1302. As a party to that docket, RNP presents a survey of current climate change policy proposals which showed a range of carbon adders from $25/ton to $110/ton (2007 dollars). However, the Commission's current guidelines direct utilities to consider a range of carbon adders up to $40/ton (1990 dollars). Staff concludes that the IRP meets the Commission's current guidelines for analyzing environmental costs.

Commission Disposition

We conclude that the IRP meets the current requirements set forth in Guideline 8.

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 concludes that the IRP complies with this guideline. The company does not plan for five-year opt-out customers (currently approximately 30 MWa).

Commission Disposition

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

Guideline 10: Multi-state Utilities

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

Commission Disposition

Guideline 10 does not apply to PGE.

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 (LOLP), 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 concludes that the reliability analysis in PGE's IRP does not meet these requirements. PGE performed stochastic analysis on LOLP, expected unserved energy (in MWa), and both 95th and 99th Percentile measures of unserved demand (in MW) for its preferred portfolio, as well as adding to this portfolio 100 MW increments of up to 1,000 MW of additional capacity. However, the company chose a single year, 2012, as the basis for the analysis, instead of providing metrics for each year of the study period as directed by the Commission. Further, because the analysis was performed only on PGE's preferred portfolio, Staff points out that there is no basis to compare the required metrics even among top-performing portfolios.

In response to a data request from Staff, the company provided a cost analysis for higher and lower reliability for the preferred portfolio. The company had not included such an analysis in its IRP. The analysis compares costs of the portfolio at various capacity reserve levels, based on the costs of three types of simple-cycle combustion turbines, and the corresponding LOLP.

The company finds the cost analysis supportive of its selected level of capacity reserves – a minimum of 500 MW in winter. This approximates a 12 percent planning reserve margin based on a projected 2012 winter peak-load. Further, 500 MW covers the company's largest generation shaft risks, the Port Westward and Boardman plants.

Commission Disposition

We conclude that PGE's 2007 IRP does not meet Guideline 11.

Guideline 12: Distributed Generation

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

PGE's consideration of distributed generation includes a discussion of combined heat and power and opportunities provided by net metering (*see* IRP Section 7.6). However, these resources were not quantified or included in portfolio modeling.

PGE has partnered with many of its customers to develop dispatchable standby generation. In PGE's previous IRP, the company committed to developing a 30 MW virtual peaking plant. PGE attained its goal in June 2006. PGE estimates that aggressive program continuation will enable acquisition of an additional 80 MW by 2012 and has included this amount in the Action Plan.

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.

Commission Disposition

We conclude that, except for the planning horizon used in its analysis, PGE's 2007 IRP meets Guideline 12. PGE's next plan should further evaluate generation and direct use applications of solar resources, and include solar and combined heat and power resources in portfolio modeling.

Guideline 13: Resource Acquisition

Under Guideline 13, the company is to present an acquisition strategy for its Action Plan. Development of that strategy is to include: (1) an assessment of the advantages/disadvantages of owning a resource versus purchasing power from another party; and (2) identification of any benchmark resource the company plans to consider in a future RFP.

The Company provided its acquisition strategy for its Action Plan but did not fully satisfy the other requirements of the Guideline.

Under the second component of Guideline 13, the Commission specifies that the analysis of the pros and cons of owning a resource instead of purchasing power be rigorous enough to provide a basis for evaluation and scoring criteria in any subsequent RFP.[10] The company discussed these issues in its IRP but did not do so with adequate rigor to use as a basis for scoring criteria.

PGE states it will not include a benchmark resource in its energy RFP but does plan to "determine an internal benchmark resource" for its capacity RFP (*see* IRP at 244). PGE provided the size and general technology, but did not state a specific site. It did state that the resource would be within PGE's system. The Commission states that

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

a Benchmark Resource is "a *site-specific*, self-build option that the utility commits to develop if it is selected through the RFP."[11] (Emphasis added.)

Commission Disposition

We conclude that PGE's IRP does not meet Guideline 13.

Conditions for Acknowledgement of PGE's 2002 IRP

In acknowledging PGE's 2002 least cost plan, the Commission required the company to: (1) commit to initiating discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region; (2) agree to include an action item in its next IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to PGE at a reasonable price; and (3) agree to demonstrate that it has made reasonable efforts to acquire, retain, or option cost effective transmission capacity over the Cascades before issuing its next RFP.[12] The company provided its acquisition strategy for its Action Plan.

PGE discussed its compliance with requirement 1 and 3 in its update to the 2002 least cost plan that was filed with the Commission on March 24, 2006. PGE's current Action Plan demonstrates compliance with requirement 2.

Commission Disposition

We conclude that PGE has met the expectations set by the Commission as a condition of acknowledging PGE's 2002 Least Cost Plan.

CONCLUSION

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

PGE's 2007 IRP does not fully adhere to the principles of resource planning set forth in Order Nos. 07-002 and 07-047 and should not be acknowledged. Notwithstanding this conclusion, the Commission finds the renewable resource actions in the plan to be reasonable for the reasons set forth above.

Furthermore, the Commission imposes the following conditions for the next planning cycle pursuant to Guideline 3e:

1. Conduct portfolio analysis over a 20-year planning horizon, including:

[11] Ibid., at 22-23.
[12] *See* Order No. 04-375.

- Applying the company's 20-year load forecast
- Determining the levels of peaking capacity and energy capability expected over the 20-year planning horizon, given existing resources and accounting for retirements and contract expirations
- Identifying capacity and energy needed to bridge the gap between expected loads and resources
- Modeling of all supply-side and demand-side resources expected to become available to meet energy needs for at least the first 10 years of the planning horizon. (*i.e.*, a minimum 10-year resource acquisition period)
- Modeling of future transmission additions associated with the resource portfolios tested

2. Include in the analysis a wind integration study that has been vetted by regional stakeholders.

3. Present the results of all analyses relevant to portfolio selection in a tabular format, showing how well each portfolio did under each of the analyses. Explain how the analysis results support the conclusion that the preferred portfolio and resulting action plan represent the best combination of cost and associated risks and uncertainties for customers. In the event that alternative approaches for measuring risk yield disparate results, assess the relative merits of those approaches.

4. Include an assessment of transmission resources needed to meet the Action Plan as well as estimates for cost and timing.

5. All assumptions used in the development of the next plan must be updated. These include but are not limited to:
   - Load forecasts
   - Resource costs
   - Fuel forecasts
   - Environmental assumptions
   - Implications of recent research regarding emissions from the Boardman facility
   - Legislative and regulatory changes since last plan, including:

- Fossil fuel generation efficiency standard adopted in Order No. 07-499, and
- Updates to Guideline 8 of Order No. 07-002 as a result of docket UM 1302.

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.[13]

The Commission affirmed these principles in docket UM 1056.[14]

This order does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken pursuant to PGE'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 that may be inconsistent with Commission-acknowledged plans.

[13] *See* Order No. 89-507 at 6 and 11.
[14] *See* Order No. 07-002 at 24.

ORDER

IT IS ORDERED that:

1. The 2007 Integrated Resource Plan filed by Portland General Electric Company on June 29, 2007, is not acknowledged.

2. Notwithstanding the preceding, the Commission finds the renewable resource actions in the plan to be reasonable.

3. Acknowledgment of Portland General Electric Company's next resource plan is subject to the requirements adopted in this order.

4. Portland General Electric Company shall submit a new Integrated Resource Plan within 18 months of the effective date of this order.

Made, entered, and effective MAY 06 2008.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON