ORDER NO. 07-002

ENTERED 01/08/07

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

UM 1056

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| In the Matter of | ) | |
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| PUBLIC UTILITY COMMISSION OF OREGON | ) | ORDER |
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| Investigation Into Integrated Resource Planning. | ) | |
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DISPOSITION: GUIDELINES ADOPTED; RULEMAKING AND INVESTIGATION OPENED

The Public Utility Commission of Oregon (Commission) opened this docket to investigate whether the requirements for least-cost planning, first established in Order No. 89-507, should be revised. Following a suspension of proceedings pending decisions in other active dockets,[1] we issued Order No. 05-133, which instructed the parties in this docket to "focus on cost, not market." In so doing, we expressed a goal that utility resource plans should identify resources that provide the best mix of cost and risk.

Following that decision, proceedings in this docket began again with numerous workshops and conferences. The process culminated with written opening and reply comments, which were filed in September 2005. The intervening parties who filed comments are Idaho Power Company, Northwest Independent Power Producers (NIPPC), Avista Corporation, Citizens' Utility Board of Oregon (CUB), Renewable Northwest Project (RNP), Northwest Energy Coalition (NWEC)[2], Industrial Customers of Northwest Utilities (ICNU), PacifiCorp, Portland General Electric Company (PGE), Northwest Natural Gas Company (NW Natural), Cascade Natural Gas Corporation (Cascade), Oregon Department of Energy (ODOE), and Commission staff (Staff).

**<u>Integrated Resource Planning Goals</u>**

In Order No. 89-507, the Commission adopted "least-cost planning" as the preferred approach to utility resource planning. The key procedural elements were identified as:

1. Significant public and other utility involvement in plan preparation.

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[1] These dockets included rulemakings regarding resource valuation (AR 417) and market options (AR 441), as well as an investigation into new resource development (UM 1066).

[2] CUB, RNP and NWEC filed joint opening and reply comments. These comments will be referred to as "Coalition" comments.

2. Protection of competitive secrets.
3. Opportunity for parties to request supplemental orders to clarify or modify Commission's directives.

The Commission also identified key substantive elements of a least-cost plan:

1. All resources must be evaluated on a consistent and comparable basis.
2. Uncertainty must be considered.
3. The primary goal is least cost to the utility and its ratepayers, consistent with the long-run public interest.
4. The plan must be consistent with Oregon's energy policy.

Once a plan was completed, the Commission would review it for adherence to the principles outlined in Order No. 89-507. The Commission would either acknowledge the plan, or return it to the utility with comments. Acknowledgment did not guarantee favorable ratemaking treatment, but meant simply that the plan seemed reasonable at the time acknowledgment was given. *Id*. at 11. With some refinements, this approach to utility planning has been used since 1989.

We opened this docket to provide an opportunity to update the utility planning process.[3] Initially, the parties worked from an issues list which identified 26 issues. After numerous workshops, parties filed opening and reply comments that focused mainly on requirements and guidelines proposed by Staff.

We have considered all of the parties' comments and adopt the IRP guidelines set forth in Appendix A. These guidelines, and direction provided herein, supersede those adopted in previous orders.[4] In the following discussion, we set forth each guideline and address comments filed by parties and the rationale for Commission adoption. We do not, however, summarize and address all of the comments. These IRP guidelines take into account the experience we have gained since we adopted the initial guidelines in 1989. We also address issues raised by parties on the meaning of Commission acknowledgment of an IRP, and the effective dates of the guidelines.

Finally, we will open two proceedings. First, we will initiate a rulemaking docket to promulgate rules consistent with our order. Specifically, a rule must be adopted that requires the filing of an IRP two years after Commission action on the previous plan, with a yearly update to be provided to the Commission. Second, we will open a proceeding to examine the treatment of carbon dioxide ($CO_2$) risk in IRPs. Among other things, this investigation will address the $CO_2$ value that a utility should use for its base case, what $CO_2$

[3] One such update involves terminology. We now refer to this planning process as "integrated resource planning" (IRP), a term that emphasizes that all available resources should be considered and that recognizes that "least-cost" is not the only criterion for selecting the best portfolio of resources. As discussed below, the risks and uncertainties associated with any portfolio must also be weighed.

[4] However, any specific requirements for a utility's next planning cycle that were adopted in the utility's last acknowledgment order from the Commission remain in effect.

costs should be used for sensitivity analysis, and what analysis of "trigger point" values should be required.[5]

## Adopted IRP Guidelines

### Guideline 1: Substantive Requirements

This first guideline carries forward the four substantive elements identified by the Commission in 1989. Before addressing those elements, we want to affirm our belief that the utility resource planning process adopted in Order No. 89-507 works. We want to assure the parties that we are not making a wholesale change in our IRP requirements. However, we are adding detail on the information and analysis we believe we need in order to consider acknowledgment of a plan. We expect utilities to meet all the applicable provisions of these guidelines.

We now turn to the four substantive requirements for an IRP:

a. *All resources must be evaluated on a consistent and comparable basis.*

- *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 – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*

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

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

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

<u>Comment</u>

This first requirement is identical to one adopted in 1989. We have not included the footnote in Staff's proposed guidelines to explain what is meant by the term "resource." While we agree with the definition and examples given in the proposed footnote,

[5] In adopting the Joint Action Framework on Climate Change at our public meeting on November 21, 2006, we committed to exploring a $CO_2$ emissions standard for long-term power supplies. We expect such an investigation to follow the proceeding to examine $CO_2$ risk in IRPs, and not to delay its resolution.

we believe the meaning of the term is adequately addressed in the first bullet (as modified to add gas storage to the list of possible resources).

The parties raised three issues regarding this requirement. First, PGE recommends that, rather than requiring consideration of all "known" resources, the first bullet should be revised to require only consideration of "all commercially or near-commercially viable resources." PGE Reply Comments at 4. Staff opposes PGE's recommendation, noting that it is important to consider resources that are just beginning to be commercialized, as well as others that are expected to become available during the planning horizon. Staff Reply Comments at 2. We agree with Staff. We do not want utilities to limit their consideration to currently available resources, but rather to include all those that are expected to become available. We prefer the IRP be inclusive of all such resources and allow the parties to debate in the planning process whether it is reasonable to rely on a new technology.

Second, PacifiCorp disagrees with Staff's recommendation, stated in the second bullet, that utilities compare resource durations as part of the IRP. PacifiCorp submits that it is more appropriate to consider resource duration as part of the procurement process, not the IRP. PacifiCorp Opening Comments at 7. For this reason, PacifiCorp would also exclude consideration of short-term purchases. PacifiCorp Opening Comments at 9. The Coalition responds that the duration of a resource is important during IRP evaluation, as resources with shorter lead times and tenure provide optionality. Coalition Opening Comments at 5. Staff agrees and notes the benefits of market purchases demonstrated in PacifiCorp's last IRP. Staff Reply Comments at 3. We conclude that the lead-time and duration of a resource is important and should be examined during the IRP process. Such analysis will help the utility to determine the value of maintaining flexibility versus committing to long-term resources.

Third, with regard to the fourth bullet, Staff and PacifiCorp disagree about whether the appropriate discount rate is a real or nominal rate. A real rate is equivalent to a nominal rate adjusted to remove the effects of inflation. Staff recommends that the Commission retain the requirement adopted in Order No. 91-1552 and reaffirmed in Order No. 93-695 that the real after-tax marginal WACC be used to discount future resource costs. Staff Reply Comments at 4. PacifiCorp states that it uses the after-tax marginal WACC (which we understand to be the <u>nominal</u> after-tax marginal WACC) to discount expected future resource costs and that it only uses the real rate to convert the present value of those costs into a real levelized stream. PacifiCorp Opening comments at 7.

The orders cited by Staff focus on whether a utility-specific discount rate or a social discount rate should be used (Order No. 91-1552) and whether a different rate should be applied to environmental costs (Order No. 93-695). They do not discuss the reasons for requiring the use of a real instead of nominal rate. A real rate should be used to discount future costs that are expressed in real terms, while the corresponding nominal rate should be used to discount costs that are stated in nominal terms. Accordingly, we use the general term "after-tax marginal WACC" in the guideline and expect utilities to use the value, real or nominal, that corresponds to how future costs are expressed.

*b. Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*

    1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*

    2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

<u>Comment</u>

Staff, citing the Northwest Power and Conservation Council, characterizes risk as a measure of bad outcomes associated with a resource plan, and uncertainty as a measure of the quality of information about an event or outcome. Staff Opening Comments at 1. ODOE suggests replacing "risk" with "annual cost volatility" and requiring electric utilities to address certain "scenario risks" in their plans. ODOE notes that historical records can be used to analyze factors that lead to annual cost volatility, but that there is no credible way to accurately forecast certain scenario risks. ODOE Reply Comments at 1-2. ODOE's comments are consistent with the view that the difference between risk (or "annual cost volatility") and uncertainty is that probabilities that different outcomes will occur can be reasonably assigned for a risk, but not for an uncertainty. We agree with ODOE's discussion of the issues but decline to adopt its suggested changes. We find that the bullets, as shown, give sufficient guidance for consideration of risk and uncertainty under either Staff's or ODOE's characterization of the two concepts.

*c. 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.*[6]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

[6] We sometimes refer to this portfolio as the "best cost/risk portfolio."

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

<u>Comment</u>

This third substantive requirement, while different from the one adopted in 1989, is similar to what we have been asking utilities to do in recent IRPs. Parties suggested numerous changes. At the outset, ICNU prefers the continued use of "least cost" over "the best combination of expected costs and associated risks" to describe the desired selection of a portfolio of resources. ICNU Reply Comments at 6. ICNU explains that such focus has placed too much emphasis on risks that have not materialized, such as $CO_2$ regulatory costs. ICNU Opening Comments at 9. We disagree. The goal of the IRP is to help identify the lowest realized cost over the planning horizon. To accomplish this, risks must be considered, as one resource decision with the lowest expected cost might, due to associated risks, result in higher costs than other resource strategies.[7] We also reject ICNU's recommendation that the IRP process should focus more on the near-term impacts of a utility's proposed resource plan. We acknowledge the uncertainty associated with utility resource planning. The use of discount rates, however, provides the appropriate weighting of costs incurred at different times.

Both PacifiCorp and the Coalition address resource flexibility. For reasons previously discussed on page 4, PacifiCorp proposes eliminating short-term power purchases from the second bullet. Conversely, the Coalition suggests adding the consideration of resource flexibility to the third bullet. While we agree with the Coalition, we conclude that no changes are necessary. The requirement of utilities to examine duration, and evaluate all supply options, is established and discussed under the first substantive requirement.

[7] We have, however, dropped from this third substantive requirement the proposal set forth in Staff's recommendation for analysis of compliance costs related to global warming. Such costs are added as a source of risk or uncertainty in the second substantive requirement discussed above.

As to the second bullet, NW Natural also recommends that the term "Total Resource Cost" be used instead of revenue requirement. NW Natural Opening Comments at 4. The use of revenue requirement, or cost to the utility, as the key cost metric means that any subsidies should be recognized. For example, in an electric utility's plan, the cost of new wind resources will be lower if the utility can take advantage of federal production tax credits. NW Natural's concern is that unsubsidized costs should be used in inter-fuel cost comparisons. Because one of our agency objectives is to determine "whether to promote the direct use of natural gas to meet customer needs over its use to generate electricity," we defer, to a later date, our consideration of addressing fuel switching in an IRP.

PacifiCorp and Avista raise questions as to whether certain requirements apply to both gas and electric utilities. For example, PacifiCorp contends that the analysis of gas storage and pipelines should be required only for gas utilities. PacifiCorp Opening Comments at 8. Similarly, Avista questions why a gas utility should examine global warming. Avista Opening Comments at 3. We conclude that the type of resource, not the type of utility, determines the types of required analysis. For example, an electric utility considering a gas-fired plant should evaluate gas storage and pipelines. Similarly, a gas utility must consider global warming compliance costs if it is exposed to them through resource decisions.[8]

We agree with PacifiCorp and ODOE that utilities should not be required to analyze how their preferred portfolio would change over a range of reasonable discount rates, as proposed by Staff. PacifiCorp Opening Comments at 8; ODOE Reply Comments at 2-3; Staff Reply Comments at 4. We are not convinced there is sufficient risk associated with the discount rate, especially compared to the sources of risk and uncertainty identified in Guideline 1(b), to warrant requiring a discount rate sensitivity analysis.

ODOE also recommends the IRP include risk analysis that is explicit enough for use in a Request for Proposals (RFP) bid evaluation. ODOE Reply Comments at 2. We find ODOE's suggestion unnecessary given our decision in Order No. 06-446, where we addressed the issue in adopting guidelines for competitive bidding.

Finally, ODOE suggests changes to the last bullet. Specifically, ODOE recommends that the two measures of PVRR risks be modified so that one measures the annual variability of costs through the 20-year planning horizon, and the other measures the severity of bad outcomes by using, for example, the expected value of the worst 10 percent of outcomes. We decline to decide exactly how the measures of PVRR risk should be defined, leaving it to the interactive process of developing an IRP to make the best assessment of appropriate risk measures.

*d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

[8] Again, the global warming compliance cost issue has been moved to the second substantive requirement.

Comment

The parties had a variety of different ways to express this final requirement. We make it parallel to the requirement in our 1989 order, but add that the IRP must meet both Oregon and federal policies.

We will adopt Guideline 1, consistent with the changes made above.

**Guideline 2: Procedural Requirements.**

*a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

*b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

*c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

Comment

Many of these procedural requirements are similar to ones the Commission adopted in Order No. 89-507. While we made some editing changes to the Staff proposal, we generally maintained the intent demonstrated by Staff in its proposed guideline. We deleted the proposed requirement that interim reports be provided to the public. We are uncertain whether this proposal calls for new written reports prepared by the utility or simply endorses the currently-used advisory group process. Advisory groups provide a good vehicle for interaction between the utility and the public during the preparation of the IRP, and we expect the utilities to provide written information during that process. We decline, however, to mandate the development and distribution of interim reports.

We will adopt Guideline 2 as written above.

**Guideline 3:  Plan Filing, Review, and Updates.**

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order.  If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment.  The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan.  The update is due on or before the acknowledgment order anniversary date.  Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP.  The utility must summarize the update at a Commission public meeting.  The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*

- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource* *acquisitions, resource costs, and transmission availability; and*

- *Justifies any deviations from the acknowledged action plan.*

Comment

In this guideline, "acknowledgment" generally means a Commission decision on acknowledgment, even if the Commission did not acknowledge the plan in full (*i.e.,* deem it reasonable, based on information available at the time). In several instances, we specifically refer to the "acknowledgment order" for this reason.

Parties generally agree on the timing of IRP filings, although they differ somewhat on the precise period (two or three years) and when the clock starts (at the time of filing or acknowledgment). We adopt a requirement that a new plan be filed within two years of the date of the previous acknowledgment order. PGE recommended three years. PGE Reply Comments Attachment at 5. We will consider extending the term to three years in the future if we find that the annual updates provide enough information on the status of, and need for changes in, the current plan. If a utility identifies changes in its action plan in the annual update, we will consider its request to acknowledge the revised plan, although we may be unable to acknowledge the plan without the additional information and analysis provided by a new IRP filing. In addition, PacifiCorp asks that utilities be able to request a waiver of the annual update requirement. PacifiCorp Opening Comments at 11. We will consider any proposal for a waiver process in the rulemaking discussed below, but it is unlikely that we will approve waiver requests until we have more experience with the annual updates.

Avista and Cascade question the need for annual updates by natural gas utilities. Avista Opening Comments at 3; Cascade Reply Comments at 3. We do not share Avista's opinion that we're effectively creating an annual IRP process. Rather, we are requesting utilities to annually report on actions they have taken to implement the acknowledged IRP, identify any changes in conditions that affect the action plan, and justify any deviations from the action plan—either ones that have occurred or ones that are proposed for the future. We may dispense with this requirement for gas utilities in the future if we find that the information is adequately provided through other annual filings.

Avista also questions the need for a six-month IRP comment period. Concerned that such a lengthy period could disadvantage the next IRP planning cycle, Avista proposes a three month review. Alternatively, Avista requests the guidelines allow the comment deadline be a negotiated time period that would take into account the unique characteristics of a given utility's planning process. Avista Opening Comments at 4. Staff opposes a shortened time period for review. Staff notes that, because the IRP analysis has become more complex, the parties need more than three months to make informal requests, review the material, and provide both initial and reply comments. Staff Reply Comments at 9. We agree with Staff and decline Avista's proposed changes. The IRP process has become more complex, with more analysis of risk and uncertainty in resource acquisition strategies.

In light of this fact, and the process needed to allow an opportunity to fully review and comment on an IRP, we retain the proposed six-month review period.

We will open a rulemaking proceeding to incorporate this guideline into an administrative rule that clearly sets forth the timelines for filing IRPs and for filing annual updates. Accordingly, we will adopt Guideline 3 as written above. We anticipate that some changes will occur during the rulemaking process, but we want the general intent of the guideline to remain.

Finally, if a utility knows that a change has occurred which is causing a significant deviation from its IRP or its action plan, it should provide us with that information as soon as possible.

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

*a. An explanation of how the utility met each of the substantive and procedural requirements;*

*b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

*c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

*d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

*e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

Comment

This guideline incorporates what we minimally expect from an IRP. We urge the utilities to provide more, rather than less, information. We have clarified Staff's proposed guideline requiring evaluation of portfolios under "possible economic, environmental, and social circumstances" by requiring evaluation "over the range of identified risks and uncertainties." *See* Guideline 4(i). The substantive requirements in Guideline 1 call for utilities to identify and analyze risks and uncertainties they face. We consider the testing of how alternative resource portfolios fare under different assumptions about the future to be one of the key steps in the planning process. Furthermore, since load growth is one of the uncertainties a utility must address, we have adopted ODOE's language in Guideline 4(b) that a range of load forecasts be included in the IRP. ODOE Reply Comments Attachment at 3. Utilities should augment stochastic load risk analysis by evaluating candidate portfolios under a high load forecast and a low load forecast as part of their scenario analysis.  A utility may select a specific high load iteration and low load iteration from its stochastic load risk analysis or develop separate high load and low load forecasts.  In either case, the utility should discuss key assumptions that would drive the realization of these potential futures.

We decline to adopt other language changes suggested for this guideline.  The Coalition proposes including requirements that utilities consider the full range of renewable resources, not just wind, and that no artificial caps be imposed on the amount of renewable resources in a portfolio.  Coalition Opening Comments at 4 and Reply Comments Attachment at 3.  We agree with the Coalition's points but believe they are covered elsewhere, *e.g.*, in the Guideline 1(a) provision that "all known resources . . . should be considered."  The Coalition also recommends that subsection (c) include modeling of availability or capacity on existing transmission lines in addition to modeling of all existing transmission rights (Coalition Reply Comments Attachment at 3), but we view the term "existing transmission rights" as covering availability or capacity on existing lines.

ODOE proposes detailed requirements for the risk analysis in subsection (l). ODOE Reply Comments at 2 and Attachment at 4.  Again, what are set out above are minimum requirements.  If a party believes it needs more information for a specific IRP, it may ask the utility to provide such information and, as needed, explain why the information is relevant in its recommendation on acknowledgment of the plan.

Finally, PacifiCorp believes that any discussion of inconsistencies of its preferred portfolio with state policies should be limited to Oregon's policies.  PacifiCorp Reply Comments Attachment at 4.  We disagree.  We want to know whether policies in other states may be obstacles to implementation of the plan.  For example, if an electric utility plans to make sales in a state with policies in place, or under consideration, that may restrict sales from certain types of power plants, we want to see that restriction considered in the plan.

We will adopt Guideline 4 above.

**Guideline 5:  Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered.  In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.*

Comment

All the costs to a utility of new resources, including costs for fuel transportation and electricity transmission, should be recognized in the IRP process.  We agree that fuel transportation and electric transmission options should be considered in the IRPs. For natural gas utilities, this means gas transportation; for electric utilities, it means transportation of coal and natural gas to generating plants as well as electricity transmission. We include coal and gas transportation to electric generators because these fuel inputs have a significant effect on overall costs. As noted in the guideline, investment in transportation and transmission facilities, aside from what is required to operate and integrate an identified generating resource, can provide several benefits to the utility system.

We decline to adopt Staff's proposal that utilities analyze, in the IRPs, their ability to defer distribution plant investment through strategic use or development of demand response, on-site generation, gas storage, and other resources. We agree with PacifiCorp that it is impractical to do this type of distribution-level planning in the IRP. PacifiCorp Opening Comments at 15. However, we believe that utilities should have processes in place outside the IRPs to examine demand- and supply-side options for delaying upcoming distribution investments.[9]

We will adopt Guideline 5 as set forth above.

**Guideline 6: Conservation.**

*a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

*b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

*c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*
- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

[9] Among our agency objectives is to "[e]nsure that utilities appropriately consider energy efficiency, distributed resources, and pricing options as alternatives to distribution and transmission investments." We expect Staff to explore these issues in a future proceeding.

Comment

Conservation programs for customers of PGE and PacifiCorp in Oregon are funded through a public purpose charge and administered by the Energy Trust of Oregon (Trust). The public purpose charge and the share designated for conservation are specified in ORS 757.612, so the two utilities at this time do not control the level of funding for the programs.[10] NW Natural and Cascade contract with the Trust to run conservation programs, but they themselves set the level of funding, with Commission approval. Therefore, these two natural gas utilities fall under subsection (b) of this guideline, as opposed to subsection (c), meaning that they should target all best cost/risk portfolio conservation regardless of the amount of funding they now provide to the Trust. PGE and PacifiCorp, for its Oregon operations, come under subsection (c). They should perform two analyses. First, they should determine the amount of conservation that would be included in the best cost/risk portfolio and action plan if there were no constraint on conservation program funding. Second, they should use the Trust's projections for conservation acquisition to determine the best portfolio and associated action plan, recognizing the benefits of conservation in their portfolio modeling. PacifiCorp also should include, in its action plan, all best cost/risk portfolio conservation in its other state jurisdictions, where it has more control over the level of program funding.

We believe that an assessment of conservation potential in the utility's service territory should be conducted periodically. PacifiCorp suggests that there is little value in preparing such a study more than once every 5 to 7 years, because good studies are expensive and because market characteristics do not change enough to invalidate the results before then. The company also argues that each state should determine how often the assessment is done there because the state bears the costs of the study. PacifiCorp Opening Comments at 17. We are not requiring that a new study be prepared for each planning cycle. If a utility chooses not to update its conservation supply curves, however, other parties may be able to argue that the action plan is deficient as a result. Where an outside entity, like the Trust, administers a utility's conservation programs, the two parties should coordinate in conducting the assessment of conservation potential. The utility, however, is responsible for ensuring that the study is done.

We agree with Staff that electric utilities should "consider the availability of public purpose funds in assessing the optimal level of new renewable resources to acquire." Staff Opening Comments at 11-12. We do not believe, however, that this consideration needs to be established as a guideline. We have already stated that the IRP analysis should focus on costs to the utility, *e.g.*, in Guideline 1(c). In the IRP, therefore, the cost of renewable resources should be reduced by the amount of any public purpose funds applied, recognizing that the total funding available is limited. Further, the utility should consider funding available from other sources—for example, rate credits from the Bonneville Power Administration and state and federal tax credits.

[10] The Commission's authority to change the level of the public purpose charge or to allow other conservation program spending by PGE and PacifiCorp is the subject of UM 1169, which is on hold pending the completion of this proceeding.

We will adopt Guideline 6 above.

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

Comment

ICNU believes that rate design should not be included as a potential demand-side resource in the IRP process, arguing that some industrial customers would be unable to respond to the price signals or would otherwise be disadvantaged, and that using rate design to influence usage would be a departure from cost-based rates. ICNU Opening Comments at 11-12. Staff notes, however, that all the examples in its comments of using rate design to achieve demand response are voluntary programs. Staff Reply Comments at 12. We have made it clear in the guideline that the rate options considered in the planning process should be voluntary. We also expect that any rate design option will be linked to the cost of alternative resources and, therefore, be cost-based.

Staff points out the possible concern that acknowledgment of an IRP, which includes a rate design option in the action plan, would be considered ratemaking. Staff Reply Comments at 12. As we stated in Order No. 89-507 and reiterate here, the Commission does not make ratemaking decisions in the IRP process. Acknowledgment of the company's plan means only that we consider it reasonable at the time of our decision. Acknowledgement would not allow the rate design option into effect. The utility would need to seek tariff approval to accomplish that, and in the review process we would consider the IRP analysis and the Commission order on acknowledgment as evidence on whether the rate option is reasonable.

PacifiCorp recommends that this guideline be limited to firm demand response resources, which we take to mean measures like direct load control and interruptible rates where the utility knows what response it will get from customers who signed up in advance. PacifiCorp Reply Comments Attachment at 5. PGE also claims that voluntary programs cannot provide a firm basis for planning. PGE Reply Comments at 5. We disagree that utilities should only consider firm demand response resources in their IRPs. Customer response to voluntary programs can be predicted, albeit with less precision than for the output of a thermal resource. Utilities have learned to model and operate their systems with other resources, like wind, whose output at a particular time cannot be predicted with great certainty. Demand response measures are no different in this regard.

We note that the language of the guideline that demand response resources should be evaluated "on par" with other resource options is key. Utilities should develop supply curves for demand response options, just as they do for other demand- and supply-side resources. Furthermore, they should include them in portfolio modeling, instead of just adjusting the load forecast, in order to recognize the benefits of demand response in reducing risk.

We will adopt Guideline 7 above.

**Guideline 8: Environmental Costs.**

*Utilities should include in their base-case analyses the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

Comment

ICNU agrees that the IRP process should include the actual environmental costs of resources, including the costs of complying with existing federal and state environmental laws. ICNU contends, however, that it is inappropriate to require customers to pay higher rates by including the costs of complying with environmental regulations that have not yet been enacted. Rather than attempting to mitigate alleged social and environmental problems, the IRP process should, according to ICNU, be focused on ensuring that utilities only develop the lowest cost electric resources. ICNU Opening Comments at 7-9. Staff and the Coalition disagree. Staff explains that ICNU's arguments are based on a misunderstanding of the role the consideration of external environmental costs plays in the IRP process. Staff Reply Comments at 13-15. The Coalition adds that IRPs must include consideration of anticipated regulation that will directly impact ratepayers. Coalition Reply Comments at 2.

Contrary to ICNU's assertion, this guideline does not force customers to pay higher electric rates by including the costs of complying with environmental laws that have not yet been enacted. As Staff notes, this Commission previously concluded that we have no authority to impose external environmental costs on a utility, either directly by requiring the utility or its customers to pay the external costs, or indirectly by penalizing the utility for choosing a resource with higher external costs. *See* Order No. 93-695 at 2-3. Rather, this guideline requires utilities, when considering long-term resource commitments, to take into account the risks that external costs may be internalized in the future. Such analysis is necessary to allow meaningful integrated resource planning.

The Coalition believes that probability weightings should be assigned to the various $CO_2$ adders specified in Order No. 93-695 for the utilities' risk analysis. Coalition Opening Comments at 3. Staff disagrees, noting that there is no good basis for assigning probabilities and that it is more informative to determine what $CO_2$ cost would trigger a change in the preferred portfolio. Staff Reply Comments at 16-17. We agree with Staff, especially with respect to the value of the "trigger point" analysis. It may be easier to conclude that a trigger point $CO_2$ value is well above or well below reasonable values for $CO_2$ costs and thereby decide which portfolio is best in terms of $CO_2$ risk, than it would be to determine the "right" value for $CO_2$ costs.

The Coalition also recommends that we open a proceeding to establish the $CO_2$ value that a utility should use for its base case. Coalition Opening Comments at 2. We agree and will open an investigation into the treatment of $CO_2$ risk in IRP.[11] In the meantime, a utility should use its expected cost for $CO_2$ in its base case and analyze the range of $CO_2$ costs set forth in Order No. 93-695.

The investigation will cover not just the base case value for $CO_2$ but also the sensitivity analyses that should be conducted. It will address what $CO_2$ costs should be used for sensitivity analysis,[12] as well as what analysis of trigger point values should be required. Sensitivity analyses on $CO_2$ costs normally assume the base case values for other variables. Once a potential trigger point is identified, however, it may be useful to treat it like a new base case value for $CO_2$ and conduct sensitivity analyses for other variables (such as loads and fuel prices) around that trigger point $CO_2$ value to help determine which portfolio is best.

No parties disagree with Staff's proposal for utilities to include compliance costs for nitrogen oxides, sulfur oxides, and mercury in the base-case and sensitivity analyses, and to eliminate the analysis of total suspended particulates, as required by Order No. 93-695. We concur with Staff and adopt its recommendations.

PacifiCorp objects to the proposal that compliance cost projections consider damages from pollution and estimates of mitigation costs. Because regulatory bodies already consider human health and environmental impacts when setting emission control levels, PacifiCorp contends that utilities already consider damage costs associated with emissions when they determine compliance costs, and that no separate analysis of damage or mitigation costs should be required. PacifiCorp Opening Comments at 18. Staff agrees that damage and mitigation costs are taken into account in setting emission requirements, but points out that tomorrow's emission requirements may not be the same as today due to changes in estimated costs for damages and mitigation. While Staff continues to believe that estimates of actual mitigation costs for pollution damages indicate the maximum costs that could be included in future rates, Staff proposes that such consideration be discretionary. Staff Reply Comments at 15-16. We agree. We also expect the utilities to explain the basis for their compliance cost projections, but find it unnecessary to include such language in the guideline itself. Further, we note that utilities need not undertake their own studies of such costs, and may rely on studies published by reliable sources.

[11] In Order No. 06-446 on competitive bidding, we stated in guideline 9(b) that the modeling and decision criteria the utilities use to select the final short-list of bids must be consistent with what they used for the acknowledged IRP Action Plan. Therefore, decisions in this forthcoming proceeding would extend to resource acquisition.

[12] This goes beyond the simple updating from 1990 dollars to current year dollars recommended by Staff and PacifiCorp. Staff Opening Comments at 15 and Reply Comments at 17, and PacifiCorp Opening Comments at 18.

Finally, we clarify that this analysis applies to gas utilities if it affects their portfolio. We previously addressed this issue under Guideline 1(c).

We will adopt Guideline 8 as set forth above.

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

Comment

Parties disagree on the treatment of direct access loads. ICNU argues that electric utilities should not include (*i.e.*, not plan to serve) the expected level of direct access load, noting that 11.3 percent of PGE's eligible load elected to take service from electricity service suppliers (ESSs) in 2005. ICNU Opening Comments at 10-11. PGE states that utilities should not acquire long-term resources to serve expected direct access customers, but should be prepared to serve those loads with short-term resources as needed. PGE Reply Comments at 4-5 and Attachment at 6. PacifiCorp believes that it should plan to serve the entire forecasted load in its Oregon service territory, because it remains obligated to offer all its Oregon customers a cost-of-service option. PacifiCorp Opening Comments at 18 and 25-26. Staff recommends that the utilities plan to serve all customer loads except those participating in PGE's five-year opt-out program, which allows a customer to remain on direct access without a transition adjustment after the fifth year and requires a two-year advance notice before returning to a cost-of-service rate. Staff Reply Comments at 18.

We generally agree with the position taken by Staff and PacifiCorp. Because direct access customers have a right to return to cost-of-service rates, the utilities should plan to serve them in the long run. We consider a customer signed up for direct access under the existing one- or three-year options as "effectively committed to service" from an ESS only during that contract period. We believe that customers in PGE's five-year opt-out, however, are "effectively committed to service" under direct access and should be excluded from the IRP load-resource balance over the planning horizon, until they provide notice of their return to cost-of-service status. We take no position in these guidelines on whether the utilities should plan to serve direct access loads with long- or short-term resources.

In response to concerns about the applicability of an initial version of this guideline to natural gas utilities, Staff removed the reference to them in the guideline proposed in its reply comments. We agree it should be limited to electric utilities. Staff, however, asked that we instruct the natural gas utilities to discuss, in their IRPs, what would happen if all or a portion of bypass or transportation customers in their service territories switched to firm sales service. Staff Reply Comments at 18. In general, the companies' tariffs provide that those customers would pay the incremental cost of service. We decline to require this analysis in each IRP and instead encourage Staff and the companies to explore this issue outside the IRP process.

We will adopt Guideline 9 as set forth above.

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.*

Comment

Parties commenting on this guideline generally agree that multi-state utilities should plan on an integrated system basis. *See, e.g.*, PacifiCorp Opening Comments at 14 and Idaho Power Reply Comments at 4. Avista and Cascade, however, express concern that the guideline calls for analysis of planning or resource requirements in other states that have no effect on Oregon. Avista recommends that the guideline be revised to focus on common costs. Avista Opening Comments at 4 and Cascade Reply Comments at 6. Staff questions the meaning of Avista's suggestion for conservation, because the costs of conservation are usually charged to each state on a *situs* basis even though the costs of the supply-side resource displaced are allocated to all customers. Staff instead proposes the following language to address the concern raised by Avista and Cascade:

> If there is a resource need in a state other than Oregon, and the other state does not require that the resource plan include a means to satisfy that need, the Commission will not require the plan to include such analysis if the plan demonstrates that the full costs of that resource will be directly assigned to the other state and Oregon customers will bear no costs directly or indirectly.

Staff Reply Comments at 18-19 and Attachment at 6.

We agree with Staff's language in principle, but we are uncertain what resource needs in an integrated system could be addressed without any cost consequences for Oregon. Conservation costs may be charged on a *situs* basis, but the level of activity in other states affects what other resource costs are incurred in a multi-state system and allocated to Oregon. Other states may have preferences about what resources are acquired to meet their needs, but as long as those choices affect the costs and risks borne by Oregon customers, we will make our own judgment about what resource mix is best. As a result, we are skeptical that Staff's language has much practical significance and do not believe it rises to the level of an IRP guideline.

We will adopt guideline 10 as set forth above.

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability,* *expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

Comment

Parties disagree about how specific this guideline should be for electric utilities. PacifiCorp notes that there are a number of resource adequacy measures, each with advantages and disadvantages, and that it is difficult to determine an optimal level of reliability. It recommends that the Commission not be too prescriptive at this time and allow parties to continue to explore reliability issues in the IRP process. PacifiCorp Opening Comments at 19-20. PGE proposes a more generally stated guideline, calling for the utility to "develop and support the capacity planning assumption used in the plan, including an analysis of reliability standards[.]" PGE Reply Comments Attachment at 8. Staff, however, explains that the analysis called for in the guideline is needed to enable the Commission to assess the tradeoff between higher reliability and higher cost, by providing information on how the best portfolios fare on different reliability measures. Staff also notes that PacifiCorp provided this data for its 2004 IRP in response to Staff's information requests. Staff Opening Comments at 18-19 and Reply Comments at 19-21.

We are concerned about being too prescriptive in these guidelines, but we believe the specific analysis recommended by Staff is needed and we have adopted it for the most part in this guideline. We have not included Staff's list of factors that should be included in the analysis, *e.g.*, varying loads and forced outages, because we identified them in Guideline 1 as sources of risk or uncertainty that should be examined in portfolio modeling. We also decline to adopt a provision recommended by the Coalition that electric utilities take into account regional resource adequacy efforts and other utilities' resource plans (Coalition Opening Comments at 6) because we expect the utilities will do that when assessing the market conditions they face.

We will adopt Guideline 11 as set forth above.

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

<u>Comment</u>

Distributed generation produces electricity at or near where it is used. Aside from helping to meet a utility's need for energy and capacity resources, distributed generation can reduce transmission and distribution system costs, improve reliability, and provide other benefits. Staff Opening Comments at 16-17. The guideline above is essentially the same as the one proposed by Staff. As discussed under Guideline 7, the language that distributed generation should be evaluated "on par" with other resources means that the utility should develop supply curves for different technologies and include the resources in portfolio modeling.

PacifiCorp recommends that assessment of distributed generation should be limited to "commercially available, economic" technologies, based on "their actual operating characteristics." PacifiCorp Reply Comments Attachment at 6. We take the company to mean technologies that are commercially available at the time the IRP is prepared. We disagree with PacifiCorp's recommendation. We rejected a similar suggestion by PGE for the language of Guideline 1(a) above, concluding that utilities should consider all resources that are likely to be commercially available during the planning period. PacifiCorp also points out that it is difficult to forecast a reliable amount of distributed generation for planning purposes because its use depends on decisions by individual customers. PacifiCorp Opening Comments at 20. However, Staff notes that if a customer using on-site generation to meet all or a portion of its load moves away or goes out of business, the load disappears along with the resource. Staff Reply Comments at 11. Furthermore, as discussed under Guideline 7, customer response to the costs and benefits (including any utility incentives) of distributed generation can be predicted, to some degree.

We will adopt Guideline 12 as set forth above.

**Guideline 13: Resource Acquisition.**

*a. An electric utility should, in its IRP:*

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

*b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

Comment

We believe the competitive bidding guidelines adopted in Order No. 06-446, docket UM 1182, address several of the issues raised by the parties here, and we modify Staff's proposed guideline on resource acquisition accordingly.[13] Because Order No. 06-446 states that Commission approval of an RFP depends, in part, on how well it aligns with the utility's acknowledged IRP (RFP Guideline 7), we do not include a guideline here that a bidding process should follow IRP acknowledgment. Furthermore, RFP Guideline 9(b) states that the portfolio modeling and decision criteria used to select the final short-list in the bidding process must be consistent with that used in the IRP, so we do not repeat that here.

Our bidding guidelines state that, as a general matter, an electric utility must issue an RFP for all Major Resource acquisitions identified in its last acknowledged IRP, where Major Resources are those with durations greater than 5 years and quantities greater than 100 MW (RFP Guideline 1). Even with this presumption that Major Resources will be acquired through competitive bidding, we believe that the utility should explain in its IRP how it intends to acquire resources targeted in the action plan, for two reasons. First, some resources, such as demand response, may not qualify as Major Resources and competitive bidding may not be the best way to acquire them. Second, bidding may not be appropriate for some Major Resources, such as a large jointly-owned thermal plant.[14] And it may be impractical to consider all options for meeting an identified resource need in the same RFP. For example, a power purchase that could delay the need for a new generating resource may not be reasonably available from bidders enough in advance of need to compete with long lead-time generating plants in an RFP process.

Parties disagree about the need for an electric utility to state in its IRP whether it intends to consider a utility-owned resource in any RFP and, for a utility-owned site, what the transmission arrangements would be. NIPPC believes this information would provide valuable signals to potential bidders. NIPPC Opening Comments at 1-2. PacifiCorp, however, claims that it does not have an "intent to own" at the IRP stage, because it cannot determine whether it is better to own a resource or purchase power from another party until it evaluates the bids in an RFP. PacifiCorp Reply Comments at 4-5. We understand PacifiCorp's argument but ask that utilities identify, in the IRP, any Benchmark Resources they plan at that time to consider in an RFP. A Benchmark Resource, as defined in the competitive bidding guidelines, is a site-specific, self-build option that the utility commits to develop if it is selected through the RFP. Order No. 06-446 at 5. Under RFP Guideline 8, the utility must provide, to the Commission and the IE, information on transmission arrangements for any Benchmark Resources prior to the opening of bidding. For reasons stated by PacifiCorp in its reply comments, we will not require the utilities to describe the transmission arrangements in the IRP. We do adopt the Coalition's recommendation that a utility assess, in the IRP, the pros and cons of owning a resource instead of purchasing power. Coalition Opening Comments at 5. PacifiCorp does not oppose such a guideline.

[13] For clarity, we refer to the guidelines adopted in Order No. 06-446 as "RFP Guidelines."

[14] For this reason, Guideline 2(b) of the bidding order provides an opportunity to receive Commission acknowledgment of an exception to the RFP requirement when the IRP Action Plan identifies an alternative acquisition method for a Major Resource.

PacifiCorp Reply Comments at 6. We believe that the pros and cons should be evaluated from the perspective of the utility and its customers and that this assessment should be rigorous enough to provide a basis for evaluation and scoring criteria in any subsequent RFP.

We will adopt Guideline 13 above.

## Other Issues

### Acknowledgement

In adopting the original least cost planning requirements, this Commission emphasized that acknowledgement did not constitute rate-making. *See* Order No. 89-507 at 6. As noted above, decisions on whether to include, in rates, the costs associated with new resources can only be made in a rate proceeding. Acknowledgement, however, is relevant to the question of rate-making treatment. As the Commission previously explained:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission[.] Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly, inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan.

Order No. 89-507 at 7.

No party seeks fundamental changes to this principle, and we adhere to the definition of acknowledgement, as presented above. We provide further guidance on the meaning of Commission acknowledgment, however, in response to the following comments.

First, PacifiCorp recommends that, if the Commission decides to acknowledge an IRP, it should make clear that it will not revisit, in a subsequent proceeding, the question of what was known and knowable at the time of that IRP planning cycle. PacifiCorp explains that, if parties are allowed in a subsequent rate proceeding to present information that was previously available but withheld during an IRP proceeding, the IRP process will ultimately have little value to the Commission, the utilities, and interested parties. PacifiCorp Opening Comments at 22. Staff, ICNU, and the Coalition disagree. Staff contends PacifiCorp's proposal is inconsistent with the premise that ratemaking treatment is decided entirely in a rate proceeding. Staff Reply Comments at 24. ICNU contends that linking the record in an IRP proceeding to a prudence review will unduly limit the Commission's ability to conduct a prudence review. ICNU Reply Comments at 3. The

Coalition argues that, in order to adopt PacifiCorp's proposal, the IRP process would have to be redefined to enlarge the scope of discovery. Coalition Reply Comments at 3.

PacifiCorp is correct that a prudence determination will be based on an evaluation of what was known and knowable to the utility at the time when the decision was made. We decline PacifiCorp's request, however, to base that examination solely on information presented during the IRP process. As the Coalition notes, the nature of an IRP proceeding is fundamentally different than that of a contested rate case proceeding. While interested parties are able to participate in the IRP process and obtain information from the utilities, they do not have the full opportunity to conduct discovery and obtain access to all critical information that is "knowable" at the time. Consequently, we oppose using information presented in an IRP proceeding to serve as the evidentiary record in a prudence review proceeding.

Second, PGE believes that the IRP process should "ultimately lead to acknowledgement." PGE Opening Comments at 7. ICNU objects to PGE's proposed language and argues that its adoption would imply that the Commission should acknowledge any IRP presented by the utilities. ICNU Reply Comments at 6. We agree that IRP acknowledgment is the ultimate goal of the process, but not the required outcome. Because the success of an IRP depends in large part on the actions of the utility, acknowledgement is not a result we can guarantee.

Third, ICNU recommends that acknowledgement be limited to generic resources, rather than specific utility resource proposals. ICNU claims that the consideration of specific resources may transform the IRP into a form of resource pre-approval. ICNU Opening Comments at 6-7. To keep the IRP process separate from the procurement process, we prefer to acknowledge general, not specific resources, in the IRP process. We note, however, that circumstances might arise to justify acknowledgement of a specific resource. For example, in Order No. 06-446, we stated that a utility may request, in an IRP, that the Commission acknowledge an exception to the RFP requirement for a Major Resource.

Fourth, the Coalition argues that acknowledgement of a plan applies to the plan as a whole, with its different resources making up a package of elements that together provide customers the best combination of cost and risk. Coalition Opening Comments at 3. We agree that, in an IRP, the Commission looks at the reasonableness of individual actions in the context of the entire plan. Moreover, in any subsequent prudence review, the Commission will examine whether the utility is pursuing its resource plan. This does not mean, however, that the Commission cannot assess the prudence of an individual resource decision unless a utility completes all actions in its IRP Action Plan. As PacifiCorp notes, because resource acquisitions are on different schedules, the prudence of an initial decision cannot depend upon subsequent decisions yet to be completed.

**Effective Dates of Guidelines**

With the exceptions noted below for the timing of filings, the guidelines adopted in this order are effective immediately. We realize that Idaho Power recently filed its latest IRP for review and that PacifiCorp is far along in preparing a filing for early 2007. However, the guidelines set forth the information and analysis we need in order to make a decision on acknowledgment, and those two utilities should supplement their filings as needed to meet them.

Guideline 3(a) calls for each utility to file a new IRP within two years of its previous IRP acknowledgment order. Three utilities can meet this requirement easily: Avista's last plan was acknowledged in October 2006; Idaho Power filed its current IRP for review in October 2006, about 16 months after our order acknowledging its previous plan; and PacifiCorp is scheduled to file a new plan in early 2007, about one year after its last acknowledgment order. The other three utilities are expected to file new IRPs in either the second quarter (PGE) or third quarter (NW Natural and Cascade) of 2007, and we will consider them in compliance with this guideline if they meet this schedule.[15]

Guideline 3(f) requires an annual update on or before the anniversary date of the last acknowledgment order. Avista should provide its first update under this guideline by the end of October 2007. The other five utilities should begin filing updates on the first anniversary of the acknowledgment orders issued for the IRPs that have been filed or will be filed under the schedule described above.

## CONCLUSION

We will adopt all of the guidelines discussed above, and set forth in Appendix A.

We expect that the adoption of these guidelines will make the IRP and its action plan more useful to the Commission, to the public and to the utilities. We appreciate the hard work done by all the parties in providing guidance, comment and argument to the Commission as we worked through this process.

[15] NW Natural and Cascade may meet the two-year requirement anyway, because their last plans were acknowledged in August 2005.

**ORDER**

IT IS ORDERED that:

1. The IRP Guidelines, attached as Appendix A, are adopted.

2. A rulemaking docket is opened to incorporate the procedures found in Guideline 3 into administrative rules.

3. An investigation is opened to examine the treatment of $CO_2$ risk in integrated resource planning.

Made, entered, and effective JAN 0 8 2007.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

**Adopted IRP Guidelines**

## Guideline 1: Substantive Requirements

a. *All resources must be evaluated on a consistent and comparable basis.*

- *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 – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*

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

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

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

b. *Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*

  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*

  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

c. *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.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

**Guideline 2: Procedural Requirements.**

*a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

*b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and*

[1] We sometimes refer to this portfolio as the “best cost/risk portfolio.”

*action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

c. *The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

**Guideline 3: Plan Filing, Review, and Updates.**

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*

- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*

- *Justifies any deviations from the acknowledged action plan.*

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

*a. An explanation of how the utility met each of the substantive and procedural requirements;*

*b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

*c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

*d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

*e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

**Guideline 5: Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.*

**Guideline 6: Conservation.**

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

**Guideline 8: Environmental Costs.**

*Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.*

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

**Guideline 13: Resource Acquisition.**

*a. An electric utility should, in its IRP:*

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

*b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*