ORDER NO. **94-590**

ENTERED APR 06 1994

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 551

In the Matter of the Investigation into the Calculation and Use of Cost-Effectiveness Levels for Conservation.	)))	ORDER

DISPOSITION: GUIDELINES ADOPTED

The Public Utility Commission of Oregon (Commission) opened this proceeding at a public meeting on February 9, 1993. The Commission held a prehearing conference on April 21, 1993, to discuss procedural issues. Participants met informally at five workshops to identify and discuss the issues to be addressed in the investigation and to review the proposed guidelines. Participants also filed written comments on the issues and on the draft order. A public meeting to consider the proposed guidelines was held on March 17, 1994.

PacifiCorp (Pacific); Portland General Electric Company (PGE); Idaho Power Company (IPCo); Northwest Natural Gas Company (Northwest); Cascade Natural Gas Corporation (Cascade); WP Natural Gas; the Northwest Power Planning Council (Council); the Solar Energy Association of Oregon (SEA of O); Oregon Housing and Community Services; Sun, Wind and Fire; Puget Sound Power & Light Company; Pacific Northwest Utilities Conference Committee; Portland Energy Office; Proven Alternatives; Eugene Water and Electric Board; the Northwest Conservation Act Coalition; Citizens' Utility Board; Northwest Environmental Advocates; General Electric Company; and the staffs of the Commission and the Oregon Department of Energy (staff) petitioned to intervene, filed written comments, or participated in the workshops.

BACKGROUND

Cost-effectiveness levels or limits are used in utility least-cost planning and conservation program design to identify cost-effective resources. The cost-effectiveness limit for a conservation measure or program reflects the value to the energy utility of avoiding the use of other resources to provide energy services to its customers. Utilities have generally calculated conservation cost-effectiveness limits based on their estimated avoided costs of energy and capacity, adjusted for sales for resale opportunities, line loss savings, and the ten percent conservation cost advantage. The limits are different for measures and programs with different expected lives and load factors (which reflect relative capacity and energy savings). All conservation resources that cost less than the cost-effectiveness limits are considered cost-effective to acquire.

During the review of Pacific's 1992 least-cost plan, SEA of O and the staff raised several questions about the company's cost-effectiveness tests. In its recommendations on the plan, the staff stated that it would propose opening a docket to examine and resolve issues affecting the calculation of conservation cost effectiveness. The staff made the recommendation to open a docket to investigate the calculation and use of conservation cost-effectiveness levels at the February 9, 1993, public meeting. We adopted the staff recommendation and initiated this proceeding.

ISSUES LIST, GUIDELINES, AND COMMENTS

The staff's recommendation to initiate this docket included an initial list of issues to be addressed in this proceeding. Participants proposed modifications to the list in written comments and through discussions at the workshops. The final list of issues was agreed to by all participants at the second workshop. The issues focus on determining the value of conservation savings to the utility (avoided costs related to conservation) and on application of the cost-effectiveness tests. The issues have provided a focus for the oral and written comments submitted and the guidelines developed during this proceeding.

We believe the guidelines developed by participants in response to the issues raised in this proceeding will provide greater clarity and consistency in the calculation and use of conservation cost-effectiveness limits and cost-effectiveness tests. We, therefore, adopt the 15 guidelines following the issues identified below.

1. Under what circumstances should the load and fuel price forecasts used to determine avoided costs differ from the base case forecasts in the utility's least-cost plan?

Load and fuel price forecasts used to determine avoided costs can differ from the base case forecasts in the utility's least-cost plan under the following circumstances:

- **a. When the source forecasts (e.g., DRI, GRI, Wharton) change significantly;**
- **b. When the preferred resource strategy and action plan are based on forecasts other than the "base" forecast;**
- **c. When it is shown that other circumstances have changed significantly, e.g., a Btu tax or other policy changes are implemented;**

d. **When utility avoided cost figures are to be used for interfuel cost comparisons; or**

e. **When a utility's load or fuel price forecasts in its unacknowledged least-cost plan are considered unacceptable for calculating avoided costs.**

The staff believes that, with limited exceptions, the load and fuel price forecasts used to determine avoided costs should be based on the base case forecasts in the utility's least-cost plan. The exceptions to this premise are incorporated in the guideline. The utility's base case should be clearly identified in its least-cost plan.

Northwest's comments expressed concern over the importance of ensuring comparability between gas and electric utility avoided cost estimates. The staff shared Northwest's concerns about the need to maintain avoided cost comparability for interfuel cost comparison. Item 1d is included in the guideline to recognize that it may be necessary to revise utility-specific electric and gas price forecasts, load forecasts, and other critical variables used in calculating avoided costs when the cost estimates are to be used for interfuel comparisons. However, the staff emphasized that the comparability issue should not become the primary determinant of utility planning methodologies.

SEA of O articulated several points in its comments that are discussed elsewhere in this order. SEA of O's comment that cost effectiveness should be evaluated from a societal perspective, rather than the utility's perspective is addressed in Issues 7, 11, and 12 below. Its comment that there is a need to include the value conservation provides in reducing risk and uncertainty is discussed in Issue 6.

The staff agreed with SEA of O that there is a need to understand how cost effectiveness is derived from avoided cost. The staff proposed that calculations of new cost-effectiveness limits for individual measures and programs be required in utility compliance filings within 60 days of the issuance of the UM 551 order. The staff and other parties would have the opportunity to review these filings for consistency with the guidelines adopted in this docket.

The staff also agreed with SEA of O that it is necessary to know what forecast will be used when a utility's least-cost plan is not acknowledged. A plan may not be acknowledged for a variety of reasons that are unrelated to the utility's load and fuel price forecasts. In that case, the staff supported the use of the utility's base case forecast used in the unacknowledged plan. If a utility's load or fuel price forecasts in its least-cost plan were unacceptable, then these would need to be revised before the Commission could approve the utility's avoided costs. Item 1e was added to the guideline to recognize this exception.

Pacific generally agreed with the staff that, if significant changes in assumptions or circumstances occur, then avoided costs can be adjusted accordingly. In addition, Pacific stated that the base integrated resource plan modeling runs should be used to calculate avoided cost. The staff agreed with Pacific but did not revise the guideline, which only addresses conditions for using different forecasts for the utility's least-cost plan and avoided costs.

We agree that, with the exceptions listed in the guideline above, the utilities' load and fuel price forecasts used to determine avoided costs should be consistent with the base case forecasts in the utilities' least-cost plans. We also adopt the staff's recommendation that, within 60 days of the effective date of this order, gas and electric utilities file documents detailing revised cost-effectiveness limits for individual demand-side measures and programs that are consistent with the guidelines adopted in this order.

2. Should demand-side measures be included in the resource stack used to compute avoided costs?

Avoided cost calculations should be based on the marginal costs of a fully-integrated resource stack, which includes both supply- and demand-side resources.

The staff stated that avoided cost estimates (and the cost-effectiveness limits derived from them) should provide a signal about what resources belong in the resource stack or portfolio that is least-cost for a utility and its customers. In general, any resource costing less than avoided costs (with any adjustments necessary to make the subject resource comparable to the avoidable resource) should be acquired, assuming that delay in acquiring the resource will not lower costs even more.

The staff argued that a portfolio limited to supply-side resources would not be least-cost, and avoided costs based on it would not correctly indicate what resources should be acquired. The staff illustrated its point with a simple example that assumes continuous supply curves for both supply- and demand-side resources. Assume that the incremental cost of the supply-side resource stack needed to meet load is 5 cents per kilowatt-hour (kWh), i.e., the highest-cost resource in the portfolio costs 5 cents per kWh. Acquiring all demand-side measures up to 5 cents per kWh would displace some of the supply-side resources, so that the most expensive of the remaining supply-side resources would cost something less, say 4 cents per kWh. The portfolio would then contain some demand-side measures that cost 5 cents per kWh and exclude some supply-side resources that cost just over 4 cents per kWh. However, replacing a 5 cent demand-side measure with a 4 cent supply-side resource would reduce total cost. When it is no longer possible to replace a demand-side measure with a lower cost supply-side resource, total cost would be minimized. At that point, the resource stack would be fully integrated, and the incremental cost of the demand- and supply-side resources would be the same (at, say, 4.7 cents per kWh).

The only parties disagreeing that an integrated resource stack should be used to compute avoided costs were SEA of O and Northwest. Using the staff's example, SEA of O's concern is that a 4.8 cent demand-side resource would not be deemed cost-effective using an integrated resource stack, even though it is cheaper than the incremental (5 cent) resource in a supply-side resource stack. According to SEA of O, it is wrong to use an integrated resource stack because 4.8 cent lost opportunity measures would not be implemented even though 5 cent supply-side resources will be acquired eventually. SEA of O also stated that it would be "less concerned" about this issue if risk and externality adders were applied to the costs of supply-side resources.

How to recognize the value of conservation in mitigating risk and avoiding external costs is addressed in this order under Issues 6 and 12, and we view it as an issue that is separate from whether to use an integrated or supply-side resource stack to compute avoided costs. SEA of O argued for the use of a supply-side resource stack even if risk and externality adders are applied, but it never explained how its approach would lead to a least-cost mix of resources, i.e., why it would make sense to acquire a 4.8 cent demand-side resource when supply-side resources costing no more than 4.7 cents per kWh are available.

Northwest also disagreed with the staff's position. The company offered the example of two electric utilities that are identical except for a difference in potential savings from low-cost energy efficiency improvements. Northwest asserted that the marginal demand-side resource should cost the same for each utility and that use of an integrated resource stack is inappropriate if it yields differing cost estimates for otherwise identical resources.

We disagree with Northwest. Avoided costs should be lower for the utility with greater access to low-cost resources. That does not mean that otherwise identical resources would have different cost estimates because the incremental resource for each utility would be different.

We agree that avoided costs and cost-effectiveness levels should be based on the marginal costs of an integrated resource stack.

3. How should utilities identify avoidable transmission and distribution (T&D) costs?

Utilities' avoided costs for conservation should include avoidable T&D costs consistent with each company's most recent Long-Run Incremental Cost (LRIC) estimates used to set rates or otherwise adopted by the Commission. When particular programs or measures provide geographically-specific T&D savings, the utility should adjust the T&D estimate included in the calculation of the conservation cost-effectiveness limit to evaluate the cost effectiveness of the program.

The staff believes that avoided costs used to determine conservation cost effectiveness should include all costs that can be avoided by the utility, including avoidable T&D costs. For consistency with T&D estimates used in other forums, the staff proposed that T&D costs used to determine general cost-effectiveness limits should be based on the most recent estimates adopted by the Commission. In situations where the utility wants to reflect specific estimates of T&D cost savings to evaluate the cost effectiveness of conservation measures and programs in certain geographic areas, the utility may propose a revised cost-effectiveness limit.

Parties generally agreed with the staff's recommendation. PGE proposed wording changes that helped to clarify the guideline.

SEA of O suggested that the staff should determine the value of avoided distribution cost. The staff reviews utility distribution cost estimates when LRIC studies are filed to support proposed Commission action (usually in a general rate case).

We concur with the approach to including avoidable T&D costs in cost-effectiveness limits proposed in this guideline.

4. What is the value of conservation regarding reliability before new capacity is required? (For example, utilities generally assign zero value to capacity until the year of load/resource balance.)

Demand-side resources (DSR) can provide the utility with increased reliability before new resources are brought on line. The value of DSR that is not sold is reasonably represented by the price of sold or purchased wholesale <u>firm</u> energy/commodity and capacity.

The staff noted that utilities often buy and sell capacity and firm energy/commodity. Recent laws and changes at the Federal Energy Regulatory Commission will reinforce this trend. DSR is typically treated as a firm resource for calculating load/resource balance. DSR reduces the need for or allows for the sale of firm energy/commodity and capacity.

In the past the value of conservation before resources were required was set at the short-term cost of production or the non-firm energy sales price, whichever was higher. This implicitly assumes a zero value for capacity. The staff proposed to substitute the value midway between recent firm sales and purchase prices. The proposed method would allow the use of firm energy/commodity contracts or nonfirm sales plus capacity contracts. This assumes conservation is as reliable as generation for capacity and firm energy.

The staff also suggested that purchase costs should include transmission costs and sales prices should be net of transmission costs. In calculating near-term DSR value, greater weight should be given to recent contracts and to contracts with durations similar to the period until resources are required. If the utility is unlikely to make any sales, only firm purchase prices should be used.

PGE disagreed with the staff's position for several reasons: the sales increments are larger than annual conservation acquisitions; prices are too speculative; the effect of using firm vs nonfirm sales for resale is infinitesimal over a one- to two-year deficit period; and short-term sales for resale provide the correct proxy value for reliability in the calculation of cost-effectiveness limits.

We disagree with PGE. Utilities can adjust the size of purchases based on planned DSR acquisition. For example, PGE is currently buying firm energy and capacity to replace the loss of Trojan. PGE planned to acquire 20 average megawatts (MWa) of DSR in 1994 when the company negotiated these purchases. This allowed the company to reduce the size of its purchases by 20 MWa. In addition, the prices of firm purchases and sales are no more speculative than many other assumptions in determining the value of conservation. PGE did not provide any evidence that the difference between short-term firm and nonfirm sales for resale prices is infinitesimal. That assertion would be relevant to an argument that nonfirm sales should be used as a proxy because it is somehow difficult to use firm sales or purchases to value reliability. PGE, however, did not make that claim, and we do not believe it would be difficult to use firm sales or purchases for the calculation. Finally, PGE expressed concern "that not all energy efficiency programs provide the same level of reliability and that an overall reliability adjustment fails to give recognition to the different values of various programs." As a solution PGE proposed continuing the current practice of using short-term sales for resale as the correct proxy value for DSR reliability. The effect of using this value is to assign a zero value to capacity or firmness. We agree with the staff that the different reliability contributions of various programs or measures should instead be recognized by applying the capacity savings of the programs or measures (determined through the use of conservation load factors or other methods, as discussed under Issue 8) to the capacity value ($/kW) derived from firm sales or purchases.

Pacific asserted that "Demand-side resources are unlikely to be as useful in meeting capacity requirements, and their value would therefore be lower than that of the SCE (Southern California Edison) purchase. Thus a value between zero and the price of the recent firm wholesale capacity purchases would provide a reasonable approximation for the capacity value of a demand-side resource prior to load resource balance."

Pacific has not shown why planned DSR does not displace the need for capacity purchases on a megawatt for megawatt basis. If DSR does not displace capacity equivalently, the capacity value of conservation has been calculated incorrectly. Pacific's recent winter capacity purchase from SCE could have been reduced or delayed if Pacific had planned more DSR for the 1993-1997 period. Planned conservation also allows additional sales of capacity or firm energy in the period before new resources are on line. There is an active market for capacity and firm energy in the western U.S. Pacific commonly makes such sales and purchases.

The Council indicated in its response to Issues 4, 5, and 6 that the value of conservation during surplus conditions should be treated like excess generating capacity during surplus conditions. The Council observed that PGE's Boardman plant was allowed into rates long before PGE was deficit. The Council also opposed a zero value for capacity in the cost-effectiveness limit. The Council argued that the market price of wholesale firm energy is a reasonable measure of the minimum value of conservation, while the maximum value is represented by the full cost of the next identified resource, provided it is not too far off in the future.

Conservation in Oregon is already treated in rates similar to supply-side resources. We agree with the Council that the full cost of the next identified resource can represent a reasonable value for increased reliability when a utility is adding resources. When loads and resources are roughly balanced, DSR can also allow reduced purchases or increased sales while keeping reliability constant. If a utility does not need new resources, the value of increased reliability from DSR will be less than the cost of new resources. Here again, DSR allows reduced purchases or increased sales.

At this time, we support the staff 's recommendation that the price from recent firm wholesale sales or purchases provides the best estimate of the reliability value of DSR before new resources are on line.

5. What is the wholesale resale value of saved energy and capacity?

Before new resources are brought on line, the value of saved energy and capacity is best approximated by the wholesale price of sales and purchases of firm energy/commodity and capacity.

PGE proposed a revised guideline which in effect would assign a zero value to the capacity or firmness of conservation before new resources are on line. We believe this value is too low.

Pacific indicated that the addition of a firm demand-side resource does not necessarily make possible corresponding additional wholesale sales--firm or non-firm. Pacific stated that the value of such wholesale sales is best approximated for each utility using a production cost model or nonfirm sales prices, whichever is higher. Again, this effectively assigns a zero value for conservation capacity before new resources are required.

SEA of O indicated that the value for capacity savings should be determined from the value for firm, shaped power sales for resale. This is consistent with the proposed guideline.

As discussed in Issue 4 above, we adopt the staff's recommendation that firm energy transactions are a good approximation of the value of conservation before new resources are brought on line.

6. What is the value, if any, of conservation regarding uncertainty about the ability to meet load growth?

The value is generally thought to be positive. Absent better uncertainty analysis in the least-cost planning process, this effect is included within the ten percent conservation cost advantage.

The staff stated that conservation tends to reduce uncertainty about the ability to meet load growth, mainly because acquisition through lost opportunity programs varies directly with the level of economic activity. Pacific pointed out an offsetting uncertainty about the effect of demand-side programs on loads (because of take-back, for example).

Pacific agreed with the staff that any effect of conservation on uncertainty about meeting loads should be included in the ten percent conservation cost advantage. PGE noted that the Council has identified load stability and predictability as a conservation benefit covered by the ten percent adder. PGE argued, however, that the ten percent figure should be revisited as benefits included in it are otherwise quantified and applied. Cascade stated that the ten percent adder previously used to account for external environmental costs should be eliminated for gas utilities because external costs will be recognized under the requirements of the Commission's order in UM 424 (Order No. 93-695). SEA of O, however, asserted that the ten percent adder should be applied after accounting for all quantifiable benefits of conservation, including those related to risk mitigation and externalities.

We disagree with Cascade. We noted in Order No. 93-695 that the ten percent conservation cost advantage covers more than external environmental effects and concluded that electric and gas utilities should continue to apply the ten percent figure. We also concluded in UM 424 that application of the ten percent adder should be reexamined when utility planning methods are better able to account for the advantages of conservation in limiting environmental impact and dealing with uncertainty. Parties may raise the issue in future reviews of the guidelines adopted in Order No. 93-695.

SEA of O also recommended that a utility should account for the risk mitigation value of conservation by setting higher demand-side targets than suggested by its expected economic growth scenario. We believe, however, that this issue should be addressed in the utility's least-cost planning process, not through an arbitrary adjustment of the cost-effectiveness limits.

We support the staff's position that the effect of conservation in reducing uncertainty in meeting load growth is included in the ten percent cost adder and that no separate adjustment is necessary.

7. Is a consistent tax treatment used to assess demand-side and supply-side resources?

As a general principle, tax treatment should be consistent between the two types of resources. Using a revenue requirements approach to calculating Total Resource Cost (TRC) will accomplish this goal. This approach treats taxes on all resources as costs.

In its comments, IPCo asked if conservation TRC should include revenue requirements. The California Standard Practice Manual and the Electric Power Research Institute's End-Use Technical Assessment Guide, which are guides to the calculation of standard demand-side cost-effectiveness tests, do not include revenue requirements in conservation TRC. TRC calculations in these manuals are based on the installed cost of the measure. Revenue requirements under the traditional TRC approaches are considered transfer payments (changes in dollar amounts that flow between the utility and its ratepayers) that are ignored in the calculation. However, revenue requirements of generation, transmission, and distribution are included in the avoided costs used as the basis for the calculation of conservation cost-effectiveness limits.

The staff concluded that, to be consistent, revenue requirements should also be included in the TRC of demand-side resources. The staff cited several reasons for advocating a revenue requirements approach to TRC and thereby including taxes. The staff argued that consistency requires that taxes be treated the same for all resources, which can be categorized as purchased power, purchased savings from energy service companies (ESCOs), utility generating resources, and utility conservation programs. First, it is not practical to remove taxes from purchased power costs or payments to ESCOs. Eliminating corporate income taxes from only utility resources or programs would bias TRC comparisons.

Second, the costs of fuel, pipelines, generating equipment, and demand-side measures can include other taxes as well. Some taxes represent user fees for services, e.g., property taxes that pay for police and fire protection. The choice of how far up the acquisition chain taxes are removed could bias results.

Third, some tax credits are explicitly designed to shift resource choices. The staff argued that it would be counter-productive to try to eliminate the effect on resource choice of the federal 1.5 cent per kWh tax credit on wind. As with taxes, policy-oriented tax credits are also found up the acquisition chain, e.g., federal tax credits for natural gas from coal seams.

Under the staff's proposed approach, the TRC of a demand-side measure or program would include the present value of retail revenue requirements associated with utility program activity plus the participant's costs for the measure, including operating costs, less quantified cost savings and other non-energy benefits.[1] Revenue requirements would include avoidable administrative costs. The participant's portion of measure costs and non-energy benefits and costs would be treated as if expensed. Taxes on all resources would be treated as costs. This approach would allow consistent comparisons of purchased power, savings from ESCOs, utility generated power, and utility conservation program savings. Application of this principle would mean that the Oregon Business Energy Tax Credit (BETC) and federal low-income conservation payments would be treated as real cost reductions. Currently, federal wind tax credits are considered real cost reductions.

SEA of O argued that taxes are transfer payments that should not be included as a cost in TRC, since cost effectiveness should be determined from a societal perspective rather than a utility cost perspective.

Whether taxes are costs or transfers depends on the frame of reference. For example, the Council uses the Northwest as the frame of reference. The goal is to minimize costs to the Northwest society as a whole. Federal taxes are viewed as costs but state and local taxes are viewed as internal transfers. Under the Council's method, the BETC does not reduce the TRC of a resource, but a federal tax credit would. Within this framework, the Council uses the revenue requirements approach to calculate conservation TRC.

ORS 469.020(3) provides only a little guidance on this issue:

> "Cost-effective" means that an energy resource, facility or conservation measure during its life cycle results in delivered power costs **to the ultimate consumer** no greater than the comparable incremental cost of the least cost alternative new energy resource, facility or conservation measure. (Emphasis added)

It is unclear whether the legislature intended taxes to be included in the "costs to the ultimate consumer."

We concur with the staff that consistent treatment of taxes requires that they be included in both demand-side and supply-side resources or excluded from both. Since no party presented a practical method for excluding taxes from power purchases and conservation supplied by ESCOs, the only practical alternative is to include taxes as costs for both demand-side and supply-side resources.

SEA of O also argued that taxes should not be included in TRC calculations because it is inconsistent to discount revenue requirements that include taxes with a discount rate based on the utility's after-tax cost of capital. SEA of O stated the approach results in a bias against capital-intensive resources such as conservation and renewables.

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[1]Recognition of cost savings and other non-energy benefits is discussed in Issues 11 and 12.

The Commission requires utilities to use an after-tax weighted-average cost of capital to discount the revenue requirements of utility resources. We formally adopted this approach at a June 11, 1991, public meeting, and summarized our decision in Order No. 91-1552. Utilities currently discount the revenue requirements of supply-side resource options that include taxes with their after-tax discount rates. We agree with the staff that this approach to discounting revenue requirements should be applied to demand-side as well as supply-side resources.

IPCo noted that supply-side resources are eligible for accelerated tax depreciation, but demand-side resources are amortized in a straight line for tax purposes, resulting in higher revenue requirements.

Tax law does raise the revenue requirements for a conservation measure relative to a supply-side resource with an identical first cost and financing period. Alternatively, if conservation expenditures were expensed, the tax cost of demand-side resources would be less. It would also raise short-term revenue requirements. Similarly, using rebates instead of utility financing and shorter amortization periods for conservation would lower TRC. These trade-offs should be considered in least-cost plans and program design. If changes to current Commission policy were to be made, Order No. 89-1700 would need to be modified.

8. What methods (such as conservation load factors) should be used to determine the capacity savings of different measures or programs?

Different demand-side resources have different effects on capacity requirements. Utilities should use empirically based methods, such as conservation load factors, to quantify capacity impacts. Utilities should use empirical data to support methods which adjust conservation cost-effectiveness calculations based on the effects of specific demand-side resources on capacity requirements.

Methods such as conservation load factors have been used by some utilities to estimate the benefit to the utility from reductions in peak requirements resulting from acquisition of different demand-side resources. They are used as an adjustment to conservation cost-effectiveness limits. The staff advocated the use of conservation load factors or other empirically based methods to better reflect the value of capacity reductions from different demand-side resources.

Pacific supported the use of empirically based data to develop conservation load factors and emphasized the importance of conservation load factors in understanding the capacity effects of various conservation programs.

While PGE supported further exploration on the issue of capacity effects, it urged that utilities be allowed rather than required to use the conservation load factor approach. The company stated that the term "conservation load factor" is unclear and proposed certain wording changes to the guideline.

Although the staff is unacquainted with methods other than the conservation load factor approach, it supported PGE's suggestion to allow utilities the flexibility to explore other approaches to estimate the effects of different demand-side resources on capacity.

SEA of O argued that empirical data often does not exist, and may never exist except in the form of engineering estimates. The staff agreed with the first part of SEA of O's statement, but believes that data on capacity effects can be gathered on almost all programs and measures (or groups of similar measures). The staff recommended that engineering estimates may be used until empirically based data is available.

The Commission agrees that the effects of different demand-side resources on capacity requirements should be evaluated by each utility using empirically based methods and data. Engineering estimates may be used until empirical data is available.

9. Should the underlying avoided cost stream begin in the current year or in the year in which the programs need to be fully implemented?

Utilities should use the avoided cost stream beginning in the current year to assess the cost effectiveness of individual measures and programs.

Demand-side measures and programs are tested for cost effectiveness against utility-specific avoided costs adjusted for certain factors. The issue was raised whether measures or programs should be tested against avoided costs beginning in the year the program is implemented or the year the program is expected to reach maturity or peak savings.

Pacific agreed with the staff that the avoided cost stream used to assess the cost effectiveness of individual measures should begin in the current year. Both SEA of O and the Council argued that conservation programs take time to develop infrastructure, test delivery mechanisms, or transform markets before full program ramp-up can be attained.

The staff did not disagree. However, it stated that, in general, programs which are not cost-effective tested by an avoided cost stream beginning in the current year should be recognized as noncost-effective. If such a program is likely to be cost-effective in the future (because avoided costs rise or program/measure costs fall) and the program cannot be changed frequently (as with building codes and the Super Good Cents program), then it might be allowed under the provisions discussed in Issue 13.

We agree with the staff that utilities should test the cost effectiveness of demand-side measures and programs against the avoided cost stream beginning in the year the program is implemented, unless the measure or program meets one of the exceptions listed in Issue 13.

10. How should the administrative costs of conservation programs be treated in determining cost effectiveness?

Administrative costs should be explicitly included in DSR cost when evaluating the cost effectiveness of programs, consistent with supply-side treatment. Administrative costs should not be applied to individual measures within a program except for those instances where the program consists of a single demand-side measure or where a single demand-side measure has identifiable incremental administrative costs that the utility could avoid by not including that measure.

The comments submitted were generally supportive of the staff's proposed guideline on how utility administrative costs should be treated in determining demand-side measure and program cost effectiveness. Pacific, PGE, and SEA of O, for example, generally agreed with the staff's proposal, but offered revisions to make the guideline more explicit about how to include administrative costs in the evaluation of demand-side measures and programs. The guideline was revised to address these concerns.

We support the treatment of administrative costs expressed in the guideline.

11. It is the Commission's policy to apply a Total Resource Cost Test, i.e., consider a measure cost-effective if the installed cost of the measure is less than the corresponding cost-effectiveness level, regardless of who pays for it. Are there circumstances in which other tests (such as a Utility Cost Test or Ratepayers' Impact Measure (RIM) Test) should be applied?

12. How should the non-energy benefits and costs of measures be treated?

(Combined Guideline for Issues 11 and 12)

The Total Resource Cost test should be used to determine program and measure conservation cost effectiveness. The TRC of a measure or program is the present value of retail revenue requirements plus the participant's cost for the measure(s), including operating costs, less quantified non-energy benefits and cost savings. TRC includes avoidable administrative cost. A program or measure passes the TRC test if the TRC is less than the conservation cost-effectiveness limit (CEL). The CEL is the present value of revenue requirements of avoided utility supply, transmission, and distribution costs and the value of firm wholesale sales or purchases before new resources are on-line. CEL for programs and measures also includes a minimum value of ten percent of these costs to account for risk and uncertainty. Consistent with OAR 860-27-310 (1) (c), the CEL for fuel switching does not include the ten percent adder. Externality values, consistent with the ranges in Order No. 93-695, should be included in the calculation of the CEL or supplied as an alternative CEL calculation. The savings estimate used in applying the TRC test to a measure should reflect interactions with other measures in the utility's program.

A utility should calculate cost savings and other non-energy benefits if they are significant and there is a reasonable and practical method for calculating them.

In general, utilities should set demand-side acquisition targets to minimize total resource cost. If a utility considers rate impacts in setting its demand-side targets, it should justify the decision in its least-cost plan. Utilities should offer incentives to end-users sufficient to meet or exceed acknowledged least-cost plan conservation targets.

This guideline clarifies and extends the Commission's long-standing policy to consider a measure or program cost-effective if the total cost of installing the measures, including the customer's out-of-pocket costs as well as the utility's incentives and administrative costs, is less than the value of the energy savings. The parties addressed two fundamental issues in the use of the TRC test: the treatment of non-energy benefits, and the relevance of other tests for identifying demand-side measures for acquisition.[2] We discuss these issues in turn and explain how utilities should incorporate external environmental costs to comply with Order No. 93-695.

Non-energy benefits. We have generally deemed a measure or program cost-effective if the total cost of the measure(s) is less than the energy benefits. Other customer benefits have been cited but not recognized in the cost-effectiveness test. These non-energy benefits include water savings from low-flow showerheads, maintenance cost savings from replacing incandescents with longer-lived compact fluorescents, improved lighting quality, and other amenities. The parties agree that quantifiable non-energy benefits should be included in determining cost effectiveness, so that a measure or program would be considered cost-effective if total benefits exceed total costs. In other words, measures should be installed if the total cost of acquiring the resource, minus quantified non-energy benefits, is less than the value of the energy savings.

We agree that total costs and total benefits should be weighed in judging cost effectiveness. We do not believe, however, that utility ratepayers in general should subsidize the cost of demand-side measures that exceeds the value of energy savings. If program participants are unwilling to pay that excess cost, then we would question the existence or magnitude of the claimed non-energy benefits. Where the cost effectiveness of a measure or program depends on non-energy benefits, the utility should quantify those benefits or, as discussed in Issue 13, limit program incentives so that customers will choose only those measures where total benefits exceed total costs.

[2]Other issues in determining total resource cost and cost-effectiveness limits are examined elsewhere in this order: the use of a revenue requirements approach (Issue 7), the treatment of administrative cost (Issue 10), avoidable transmission and distribution cost (Issue 3), wholesale prices as proxies for the value of demand-side resources before new resources are needed (Issues 4 and 5), and the ten percent cost advantage (Issue 6).

Other tests for demand-side resources. The Council and SEA of O believe that all cost-effective conservation (identified by applying the TRC test) should be acquired and that rate impacts should not be considered in setting targets for demand-side programs. The Council dismissed the utilities' competitive concerns by suggesting that they work creatively with regulators to devise acquisition methods and regulatory treatment to keep the rate impacts of conservation to a reasonable level. Pacific, however, argued that a variety of tests, including the ratepayer impact test, should be used to gauge cost effectiveness.

In Order No. 89-507, which established requirements for least-cost planning by energy utilities, the Commission stated that the primary planning criterion should be "least cost for the utility and its ratepayers consistent with the long-run public interest." That order was issued at a time when the rate impacts of utility demand-side activities were imperceptible. The staff believes that, with the current ramp-up of utility programs and the prospect of increased competition in electricity supply, it is an opportune time for the Commission to clarify its views on the issue of minimizing costs or rates.

The staff disagrees with the Council and SEA of O. The staff argued that there are two reasons to consider the rate impacts of utility demand-side programs. The first focuses on efficiency: rate impacts may lead customers to switch to energy services or suppliers that are less efficient, i.e., more costly in terms of TRC. The second is an equity concern: participants may receive (through incentives and bill savings) more than the net benefit of acquiring the demand-side resource.

The staff recommends using the TRC test to determine the cost effectiveness of demand-side measures and programs. However, a utility should be able to argue in its least-cost plan that the acquisition targets suggested by a strict cost criterion should be reduced because the rate impacts would cause inefficient switching or be inequitable. A utility arguing that there would be inefficient outcomes would need to show that: (1) the rate impacts would probably cause certain customers to switch, (2) the impact on those customers could not be addressed by offering special contracts, changing rate spread and rate design, or redesigning programs to achieve savings with a greater contribution from participants, and (3) switching to other energy services or providers would raise the TRC of meeting energy needs. A utility proposing to reduce targets because of equity concerns would need to show that the disparity in impacts on different customers cannot be reduced: (1) by offering a broad range of programs, or (2) by making the changes listed in the second criterion for inefficient switching. The staff was unable, however, to recommend a general guideline for concluding that equity impacts are severe enough to reduce targets to acquire cost-effective demand-side resources. That issue should be addressed in the context of each company's least-cost plan.

SEA of O disagrees with the staff proposal on two grounds. First, it argues that the staff is proposing a "no-losers" test. Second, it believes that allowing exceptions to use of the TRC test because of equity concerns is inconsistent with the way other potential subsidy issues are handled. The Council also recommended that we specify how the rate impacts should be measured.

We are not convinced that the rate impacts of near-term demand-side activity will be serious enough to back off from the targets suggested by a TRC criterion, but we believe that utilities and other parties should have the opportunity to make the argument. Each utility's least-cost planning process provides the appropriate forum for this issue. Anyone arguing that rate impacts would cause inefficient switching or be inequitable should make the showings enumerated by the staff above. We will not establish a standard for measuring rate impacts or gauging their severity in this proceeding. Those issues are better addressed when the argument is raised in a specific least-cost plan.

External Costs. Order No. 93-695 states:

> In that proceeding (UM 551), we (the Commissioners) ask utilities to identify the difference in resources that are cost-effective with and without the specific values in the second guideline adopted here . . . our purpose is to insure that we will have enough information to determine prudence in a future rate proceeding.

The staff believes costs related to total suspended particulates (TSP), nitrogen oxides (NO_x) and carbon dioxide (CO_2) are likely to be internalized in some form within the 20-year planning horizon. Sulfur dioxide (SO_2) costs were recently internalized. Internalization of NO_x is anticipated in the 1990 Clean Air Act Amendments. The Clinton plan to achieve 1990 levels of greenhouse gas emissions by 2000 was released in late 1993. The staff argued that limiting each utility's CO_2 emissions to 1990 levels is tantamount to internalization.

We believe that the utilities should provide the information required by Order No. 93-695 in their compliance filings in this proceeding. The utilities should determine the effect of applying each of the six sets of adders given in the second guideline of the order. The adders should be treated as costs imposed on the utilities beginning in 1994. Utilities are not required by Order No. 93-695 to include these adders in the cost-effectiveness levels used to design and run demand-side programs. If external costs are later internalized or scheduled to be internalized and utilities have not acquired all the cost-effective conservation, however, we may exclude some of the cost of supply-side resources during subsequent rate proceedings.

SEA of O proposed that we order utilities to include externality adders in determining the eligibility of demand-side measures for funding in utility programs. As we understand it, SEA of O would not change the CEL but would instead recognize lower emissions from demand-side measures as a non-energy benefit in the TRC test. We view SEA of O's proposal, however, as tantamount to requiring utilities to include externality adders in the CEL, and we do not adopt it.

The Oregon Department of Energy and Oregon Housing and Community Services (ODOE/Housing) proposed additional language to the guideline which states: "Weatherization programs for low income households should include all measures that are shown cost-effective in standard program energy audits." The ODOE/Housing language is consistent with current Commission policy and is addressed in 13g below.

13. Under what conditions should measures that are not cost-effective be included in utility programs?

Measures that are not cost-effective, i.e., those that fail the test described in Issues 11 and 12 above, could be included in utility programs if it is demonstrated that:

a. The measure produces significant non-quantifiable non-energy benefits. In this case, the incentive payment should be set no greater than CEL less the perceived value of bill savings, e.g., two years of bill savings;

b. Inclusion of the measure will increase market acceptance and is expected to lead to reduced cost of the measure;

c. The measure is included for consistency with other DSM programs in the region;

d. Inclusion of the measure helps to increase participation in a cost-effective program;

e. The package of measures cannot be changed frequently, and the measure will be cost-effective during the period the program is offered;

f. The measure or package of measures is included in a pilot or research project intended to be offered to a limited number of customers;

g. The measure is required by law or is consistent with Commission policy and/or direction.

These conditions apply both to measures and programs with the exception of Item 13d. The utility or another party should show that one or more of these factors offsets the likely costs associated with applying measures that are not cost-effective.

The staff argued that under most conditions measures or packages of measures promoted by utilities should be cost-effective under the TRC test described in Issues 11 and 12 above. The staff acknowledged, however, that under some conditions it is appropriate to include measures that are not cost-effective in utility programs. The first condition (Item 13a) addresses non-energy benefits that are not recognized in the TRC test because they are difficult to quantify. Some measures or programs that are not cost-effective under the TRC test would be cost-effective if a value could be assigned to these non-quantifiable benefits. The staff believes that utility incentives can be designed to promote these measures. As noted in the discussion of Issues 11 and 12, measures should be acquired if energy benefits plus non-energy benefits exceed total costs. The staff pointed out that a customer would be inclined to install the measures if utility incentives (a rebate or loan subsidy, for example) plus the value of bill savings plus non-energy benefits exceed total costs. Combining these two principles suggests that utility incentives equal to the cost-effectiveness limit (which measures energy benefits) less the value of bill savings will lead customers to select measures where total benefits exceed total cost. The staff stated that two years of bill savings is a common payback requirement for energy efficiency improvements and could be used to represent the perceived value of bill savings.

The principle behind most of the other conditions is that costs will be lower over time if noncost-effective measures are included now. This could occur if measure or program costs are likely to fall with greater availability and use (Items 13b and 13c); including the measures leads to greater and earlier adoption of other program measures that are cost-effective (Item 13d); or the measures cannot easily be added to a program when they do become cost-effective (Item 13e).

The Commission has approved individual utility filings to include noncost-effective measures for many of the reasons listed in this guideline. The staff argued that this docket is an appropriate forum to adopt a comprehensive list as Commission policy.

Pacific offered three additional conditions under which noncost-effective measures could be included in utility programs. One of the company's suggestions was added as Item 13f above. The second proposal, "Offering the noncost-effective measure or bundles of measures will result in legislative or code adoption that will yield a cost-effective acquisition of resources," is covered by Item 13b. The third suggestion, "If a non-cost-effective measure is an integral component of a larger package of measures that in aggregate are cost-effective," was not added to the guideline. This condition is included in several of the conditions listed above, e.g., Items 13c, d, and e.

Sun, Wind and Fire suggested that an additional condition for inclusion of a measure should be measures with a high market value. This condition is essentially covered in Item 13a above and is not added separately.

We adopt the exceptions to the general cost-effectiveness standard proposed in this guideline.

14. How should the costs of measurement and evaluation of conservation programs be treated in determining cost effectiveness?

The present value of measurement and evaluation revenue requirements attributable to the program should be levelized over the expected program life for TRC calculations.

The staff argued that measurement and evaluation (M&E) costs should be included with other administrative costs in determining program cost effectiveness and that programs should be evaluated over their expected lives. M&E costs are generally concentrated in the first few years of the program when savings are low. In order to avoid burdening the cost-effectiveness evaluation with front-loaded M&E expenses, utilities should estimate the revenue requirements of M&E costs over the program life. The present value of the costs should be levelized and divided by annual savings attributable to the program to estimate the real levelized cost of M&E.

The Council asked for clarification about how M&E costs are applied to program savings. Savings attributable to the program will continue over the lives of all measures installed. If the annual savings are roughly constant, simple levelization of the present value of M&E costs and division by annual savings will yield a reasonable approximation of M&E costs per kWh saved. If necessary, the present value of M&E costs can be converted into more complex patterns of year-by-year costs to match the time stream of annual savings.

PGE indicated that M&E costs should not be amortized over the life of the program, because they are comparable to O&M expenses which should be expensed in the year incurred. PGE's point is a cost recovery issue. This is separate from the issue of including M&E costs in cost-effectiveness calculations, which is the subject of this guideline. The guideline has been changed to clarify this difference.

We believe the approach proposed by the staff for including program M&E costs in TRC calculations is reasonable, and is adopted.

15. Should lost revenues and DSM incentives to utilities be considered in the calculation of DSM measure/program cost effectiveness?

Utilities' lost revenues should not be included in the calculation of TRC, because they represent transfer payments from consumers. DSM incentives increase the present value of revenue requirements and should be recognized as a cost of conservation.

Pacific argued that when calculating the cost to the utility of undertaking a demand-side program, the cost of the incentive is an additional cost associated with the investment. The DSM incentive is an explicit cost that is above and beyond the opportunity cost associated with an alternative investment and should, therefore, be included in the TRC test. In contrast, the lost revenue adjustment is simply an accounting treatment that trues up what would otherwise occur in a normal rate case. Lost revenues should continue to be treated as a transfer payment between ratepayers and the utility rather than a DSM cost.

The staff generally agreed with Pacific. Although current standard calculations of TRC do not include DSM incentives to utilities as costs, consistent application of the revenue requirements approach to TRC would include incentives as costs. To the extent that the utility has a pure shared savings incentive mechanism, however, the company could make a qualitative argument that the incentive would not result in making a cost-effective program noncost-effective.

PGE argued that utility DSR incentives are "simply transfer payments and as such should not be included" in the calculation of cost effectiveness. Although taxes may also be considered transfers, we have determined that they should be included in TRC calculations. Incentive payments are a cost to ratepayers to attract utility capital for DSR. Lost revenues are transfers to other ratepayers, not to utility shareholders or governments, and should not be included in TRC.

SEA of O stated that incentive payments are an administrative cost which should also be counted in the program cost. The staff stated that it views incentive costs as more analogous to a regulatory risk premium on the cost of capital. Incentives to energy service companies would include similar costs. The result of the guideline, however, is consistent with SEA of O's recommendation.

We agree that incentives paid to utilities for implementing DSM programs increase the cost of the investment and should be included in future calculations of TRC.

ADDITIONAL GENERAL COMMENTS

In addition to comments on specific issues, the Council and SEA of O offered general comments for consideration. The Council proposed a guiding principle: Conservation should be treated like generation as much as possible. This principle is consistent with the Commission's first substantive requirement of the least-cost planning process included in its least-cost planning order: "All resources must be evaluated on a consistent and comparable basis." We continue to support this principle.

SEA of O expressed concern that in selecting the UM 551 issue list, the staff did not include all of the concerns SEA of O has expressed in this area. It believes these concerns would largely be addressed if the staff: (1) articulated a definition of cost effectiveness consistent with Oregon statute; (2) enumerated the applications where the cost-effectiveness concept is applied in program planning; and (3) included the cost of environmental externalities as required by statute and Commission order.

In response to SEA of O's concerns, the staff:

1. Included the definition of "cost-effective" as it relates to Oregon statutes in the discussion of Issue 7 above;

2. Stated that the TRC calculations are to be used in least-cost planning, utility acquisition decisions, and rate cases. The goal is to have a consistent metric for all forums; and

3. Pointed out that the Commission's authority and policy is described in Order No. 93-695. According to the Attorney General's Office, the Commission can disallow only costs based on internalized costs. The Commission can require utilities to estimate what resources would have been cost-effective under specific externality assumptions. It cannot require utilities to acquire them. The externality calculations required with utility CEL calculations resulting from this order can be used in later rate cases as evidence of the impact of anticipating that externalities would become internalized.

We concur with the staff's responses to SEA of O.

ORDER

IT IS ORDERED that the guidelines for calculation and use of conservation cost-effectiveness limits described in this order are adopted. Within 60 days of the effective date of this order, electric and natural gas utilities shall file compliance reports showing revised cost-effectiveness limits based on the guidelines adopted in this order. The filings should also include the externality information related to cost-effectiveness levels required by Order No. 93-695, as described in Issues 11/12 of this order.

Made, entered, and effective APR 06 1994.

Joan H. Smith
Chairman

Ron Eachus
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

Roger Hamilton
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 860-14-095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-13-070(2)(a). A party may appeal this order to a court pursuant to ORS 756.580.