DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX VII

FINAL REPORT - DSR PERFORMANCE STANDARDS SUBCOMMITTEE DATED MARCH 1995

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Utah Demand Side Resource Program Performance Standards

Report to the DSR Cost Recovery Collaborative from the Performance Standards Subcommittee

March 1995

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Introduction

This report to the Demand Side Resource (DSR) Cost Recovery Collaborative provides recommended performance standards for use in determining DSR programs eligible for cost recovery. The report is comprised of the following sections:

- Synopsis;
- Mandate;
- Current Practice for Assessing Successful DSR Acquisition;
- Recommended Economic Tests for DSR Programs Assessment; and,
- Recommended Performance Standards and Guidelines for Assessing Successful DSR Acquisition.

Synopsis

The performance standards subcommittee recommends the adoption of five cost-effectiveness tests for the review and analysis of DSR programs. The tests provide information on the DSR program's life cycle impact on the PacifiCorp system revenue requirement, on total costs for energy services to ratepayers, on total costs for energy related services to society, on Utah jurisdiction rate levels, and on participants in the DSR program.

The purpose and application of each test is fully explored and equations for each test are provided and all terms defined. We consider the equations and guidelines provided in this report to be subject to revision and refinement as necessary. We also recommend the development of a computer model which will include refinements to the equations recommended in this report and will compute equation results and allow for sensitivity analysis.

We recommend the use of all five tests because all perspectives will provide relevant information in determining the value and success of a program. This multi-perspective approach requires PacifiCorp and the Commission to consider tradeoffs between the perspectives and among impacts. We provide guidance regarding the analysis of tradeoffs.

In addition to the test information, we recommend the analysis of actual DSR acquisitions relative to PacifiCorp's least cost plan analysis for use in determining cost recovery in a rate case.

We recommend that this report serve as official reporting guidelines to be used by PacifiCorp for presentation of information regarding the costs and benefits of Utah DSR. Such information is provided for integrated resource planning, for regulatory approval of programs for implementation, in contracts for acquisition of DSR, for DSR program evaluation reports, and for providing cost recovery in a rate case.

We recommend that the Commission request, in writing, that PacifiCorp file DSR information in the manner specified in this report.

Mandate

In the Joint Recommendation for Docket No. 92-2035-04, *"In the Matter of Rate Making Treatment of Demand-Side Resources and the Analysis of Regulatory Changes to Encourage Implementation of Integrated Resource Planning"*, the signing parties proposed to develop performance standards for Commission consideration in determining post-1994 program eligibility for cost recovery. The Utah Public Service Commission approved the Joint Recommendation in its February 10, 1994 order, including the directive to develop performance standards. The Cost Recovery Collaborative, formed in response to the Commission order approving the Joint Recommendation, formed this subcommittee to develop performance standards for DSR.

The Performance Standards Subcommittee defined the following goal:

> *To recommend to the Commission the adoption of consistent methods and standards by which demand side resource acquisitions are determined to be in the public interest. To this end, we will define and recommend DSR performance standards which employ consistent methods and that provide guidelines for the Company and Regulators for integrated resource planning, DSR program approval, evaluation and cost recovery purposes.*

Three additional issues were assigned to the Performance Standards Subcommittee in the Demand Side Resource Evaluation Task Force (DSRETF) Final Report to the Commission dated May 20, 1994. The three tasks are listed as tasks 3, 4 and 5 and discussed on pages 19-22 of the DSRETF Final Report to the Commission. Briefly stated here, they are to:

- *Determine what methods are most appropriate for evaluation of the success of the DSR programs.*
- *Determine what perspective should be taken when evaluating the cost-effectiveness of such measures and programs.*
- *Determine how demand side resources can be consistently compared to supply side resources.*

We will address all three of these issues in the context of developing the performance standards for DSR recommended in this report.

Current Practice for Assessing Successful DSR Acquisition

Commission Guidance

To date, the Utah Public Service Commission has not formally adopted a method of analysis for use in approving proposed DSR programs and contracts, for assessment of verified[1] DSR savings or for DSR program cost recovery purposes. However, the Commission's June 18, 1992 Report and Order on Standards and Guidelines for Integrated Resources Planning for PacifiCorp provided preliminary Commission thinking on how to judge the success of DSR programs and requested that the CRC make further recommendations. The Commission's Order states:

> "that the integrated resource planning process must evaluate all known resources on a consistent and comparable basis in order to meet current and future customers electric energy service needs at the lowest total cost to the utility and its customers,"[2]

The Order defines lowest cost as:

> "the Total Resource Costs defined as the discounted sum of the direct costs of production and consumption of electric energy services incurred by the utility and its ratepayers."[3]

In addition, the Commission directed parties to evaluate DSR acquisitions from a variety of perspectives, including the utility system as a whole as well as different classes of ratepayers. A description of how social concerns might affect cost effectiveness estimates of resource options was also to be included in the evaluation.

To date, absent further formal rules on use of economic tests, such information has been provided by PacifiCorp and regulators to the Commission for consideration in the approval of programs for implementation and in tariffs governing the acquisition of DSR.

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[1] The term "verified" energy savings will be used in this paper to refer to "ex post" energy savings as distinguished from "ex ante" engineering estimates. Ex ante engineering estimates are predictions of DSR performance based on computer modeling prior to project installation. Ex post savings are determined by applying samples of metered data, survey research and analysis of actual bills to the ex ante engineering estimates after the installation is complete or actual conditions can be taken into account.

[2] page 16 of Commission's June 18, 1992 Report and Order on Standards and Guidelines for PacifiCorp.

[3] see page 25, <u>Ibid</u>

Comparison of Supply Side Resources and Demand Side Resources

At the heart of current economic analysis of demand side resources is a comparison to supply-side resource alternatives. Demand side and supply side resources differ in four major ways: 1) costs are borne differently; 2) benefits accrue differently; 3) investment risk is different; 4) resources characteristics are very different.

Costs borne differently: The allowed cost of supply side investment is borne in its entirety and relatively equally by all ratepayers to the extent that the rate change associated with the investment is spread according to cost of service. However, the spread of the allowed cost of a demand side investment is dependent upon program design. For energy service charge programs or lease contracts, costs are borne unequally among customers, with current participants contributing a greater portion of the cost than the non-participant. Non-participants bear the cost to the extent that rates increase as a result of the DSR investment and that this increase is translated into higher bills for the non-participant. For programs that do not require the participant to pay for the energy conservation item installed, costs can be spread relatively equally among ratepayers; however, benefits will then accrue unevenly.

Benefits accrue differently: When a DSR program design does not require the participant to pay for part of the cost of the energy conservation item installed, and the cost is spread equally among all ratepayers, then participants benefit to a greater extent than non-participants. The participant benefits through reduced bills.

Benefits are also unevenly distributed because revenues increase when a supply side resource comes on line and the revenues offset some of the cost of the investment, and this offset is shared relatively equally by all ratepayers. Since no new revenues from electric sales offset the cost of DSR, and indeed successful DSR will reduce revenues or slow revenue growth, there may be upward impact on rates which could then fall unequally among customers.

For example, if a DSR program causes average rates to increase for all customers relative to a supply side alternative, but average bills to decrease, a participant in a company-sponsored DSR program would benefit from lower bills. However, non-participants would incur a higher bill when rates are reset at a higher level at the next rate case. The amount of the impact would vary depending on the spread of the costs between the participant and the non-participant: the greater the contribution by the participant, the less the impact on rising bills for current non-participants.[4]

Because rates are not reset in-between rate cases, PacifiCorp may suffer a loss of revenues in-between rate cases that would have contributed to fixed costs. Earnings on the lost sales are also lost; thus shareholders earn less in-between rate cases from DSR than from SSR.

The essence of these first two distinctions between supply side and demand side resource

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[4] See separate report on spread of costs and non-participant impacts.

investment is that supply side investments can be economically assessed from one perspective because the impact of the costs and benefits on ratepayers and shareholders can be evaluated from one perspective. Alternatively, the economic impact of demand side resource investment must be viewed from several perspectives in order to get a full picture of the costs and benefits of the resource across stakeholders.

Investment Risk is Different: The third distinction to be considered is how risk is defined for supply versus demand side investments to meet load growth.

Ultimate cost per kWh or kW is uncertain for either investment. However, the uncertainty lies in knowing the cost of a supply side investment whereas the uncertainty lies in knowing the amount and persistence of the kWh and kW of a demand side resource.

Risk associated with the lead time for bringing on a supply versus demand side resource also differs. Shorter lead time may have more value than long lead time due to the uncertainty of cost recovery and to the better match of loads to resources which mitigates errors in load forecasts.

Differences in risk of cost recovery and the impact of this risk on reliability and finances is also important. There is substantial uncertainty on the future structure of the electric industry and therefore on the impact of changes on the ability of the utility to recover costs. For example, supply side resources provide the Company with a revenue generating, physical asset which earns a return and can be sold for market value if necessary. DSR investment creates a "regulatory asset" which may or may not earn a return (depending on regulatory treatment) and which may or may not be sold for recovery of the costs if necessary (depending on how the program is structured).

Different resource characteristics: Supply side and Demand side resources have different non-cost characteristics. For example, the resources have different capabilities regarding dispatchability and environmental impact.

The essence of these last two distinctions is that all economic assessment of a supply side investment versus a demand side investment is subject to assumptions made regarding cost of supply, deliverability of demand and risk associated with recovery of costs.

Currently, we assume that supply side costs are known with perfect certainty[5] and that demand side resources will accrue as ex post engineering estimates predict and for the full life of the product installed.

We also assume that risk of cost recovery is equivalent for supply side resources and demand side resources.

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[5] As captured in avoided supply costs used to evaluate demand side resource benefits and as reflected in IRP supply side cost assumptions.

We also assume that dispatch and environmental characteristics are captured in the IRP analysis of supply versus demand side resources. Resource characteristic differences are also taken into account in program design. For example, if a dispatchable resource is required, a DSR load management program like an irrigation load control program can be implemented. Additionally, at the implementation, acquisition and evaluation stages, total resource cost analysis currently provides DSR with a 10% adder to avoided costs to account for unquantified environmental benefits.

Given the distinctions between supply side and demand side resources and the assumptions regarding comparison of demand side and supply side resources, the subcommittee advocates the adoption of a variety of economic tests to compute the impacts of DSR given several points of view. We believe this will enable the consistent comparison of supply side and demand side resources on a forward going basis. We define the tests, inputs to the tests, and recommend how the tests should be used in the various stages of DSR acquisition.

Current PacifiCorp Analysis

DSR is evaluated at five different stages in the process of DSR identification and acquisition:

1. At the ***planning stage*** in the integrated resource plan (IRP) process; this is the point where demand side and supply side resources compete, based on lowest cost, to meet forecasted load growth.
2. at the ***implementation stage*** when specific programs, tariffs, and contracts are proposed and reviewed for approval by regulators that the programs are found to be in the public interest and consistent with the IRP; information is provided to regulators at this stage by PacifiCorp in response to the Utah Standard Information Request.
3. at the ***acquisition stage*** when measure funding limits are established and DSR energy service charge and other acquisition contracts are signed;
4. at the ***evaluation stage***, when actual costs and verified energy savings estimates are available; and,
5. at the ***cost recovery stage*** when DSR acquisition costs are evaluated for recovery of costs in a rate case setting.

Total Resource Cost analysis is performed by PacifiCorp at the first four stages. Additional perspectives are provided at the planning, implementation and evaluation stages.

One of this subcommittee's initial tasks was to determine how PacifiCorp performed total resource cost (TRC) analysis at each stage of DSR analysis. This task would assure that whatever performance standard was adopted, actual achievements could then be compared to planned achievements in a consistent manner. A preliminary analysis, provided in Attachment A, pages 1-3, provides a description of the inputs into the TRC formula at the planning stage, the implementation and acquisition stages, and the evaluation stage.

At the planning stage, i.e., in the IRP selection process, PacifiCorp currently inputs life-cycle levelized cost per MWh (over a 50 year period) for each potential resource, both for supply-side and demand-side resources. This levelized cost per MWh for DSR is computed based on the present value of total resource cost (including administration costs) of a program rather than utility cost, in order to compare it on an equivalent basis with supply-side resources which are computed based on the total cost of the resource. Total resource cost is the sum of the utility's cost and the participating customer's cost. For SSR, there are no "participants" so total resource cost and utility cost are equal. Given these costs, specified resource characteristics, and the demand forecast for additional load, the IRP selects the optimum type and amount of resources to meet load.

But at the implementation stage, it should be noted that actual supply side investments are evaluated using different methods than demand side investments. Supply side investment alternatives are compared to "incremental" costs and judged or ranked based on internal rate of return. Demand side investment alternatives are compared to "avoided supply costs".[6]

At the planning stage, PacifiCorp looks at the impact on revenue requirements as well as total resource costs. At the implementation stage and the evaluation stage, PacifiCorp examines the expected impact of a program on system revenue requirements, total resource costs, participants and non-participants. At the acquisition stage, only total resource cost analysis is conducted. We will discuss these perspectives in greater detail later in this report.

We consider all of these stages to be important in developing performance standards and we want to assure methodological consistency at each stage so that we are always comparing apples to apples as we move sequentially from planning to rate making. In examining how DSR is currently evaluated at each step in the PacifiCorp DSR development process, the subcommittee determined that it is not clear that inputs for the same equations are consistently applied at each stage. Rather than focus on past practice, the subcommittee recommends guidelines on a forward going basis for inputs and equations to be used for all stages. This approach should mitigate what inconsistency might be in place. The subcommittee also reviewed the Oregon UM 551 order on conservation cost-effectiveness to assure regional consistency of equations and input guidelines to the extent practicable.

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[6] Avoided supply costs are the same as the rates to PURPA qualifying facilities which are less than one megawatt in size plus a value for secondary sales plus avoided transmission and distribution costs plus a 10% adder.

Recommended Economic "Tests" for DSR Program Assessment

As noted above, the economic analysis of DSR varies depending on who incurs the costs, who receives benefits, and upon the resultant impact examined. A collaborative of California state officials, regulators, utilities and other interested parties developed a series of tests representing a variety of perspectives which resulted in a report entitled *Standard Practice Manual, Economic Analysis of Demand-Side Management Programs*. The perspectives and the resultant formulas were developed in 1983 and revised in 1987 in order to provide standardization for the review, approval and evaluation of utility-sponsored DSR programs.

The California tests examine a given DSR program's impact on (1) utility costs, i.e., revenue requirement and average customer bills, (2) participant costs, (3) average rates (indicating non-participant impacts as noted earlier), (4) total resource costs, i.e., efficiency of providing energy services to ratepayers as a whole, and (5) total resource costs for energy services to society. These tests are used throughout the nation, as well as by PacifiCorp, with varying degrees of adherence to the specific formulas or nomenclature developed in the 1987 California *Standard Practice Manual.*

A detailed description of the calculation and meaning of the tests we recommend follows. Specific equations and sources for inputs to be used by PacifiCorp in each test are provided in the Appendix to this report. Both the following information and the equations and input definitions in the Appendix are drawn from the California *Standard Practice Manual,* from presentation materials of Barakat & Chamberlin, Inc, and from PacifiCorp evaluation reports. Additionally, the subcommittee revised the ratepayer impact measure test to be consistent with the proposed lost revenue and cost accounting mechanism for Utah DSR investments; the subcommittee also redefines the total resource cost and societal cost perspectives to reflect a Utah version of total resource cost and a PacifiCorp version of total resource cost.

UTILITY COST TEST: IMPACT ON REVENUE REQUIREMENT

The **Utility Cost test (UC)** evaluates the effect of the DSR acquisition on revenue requirements and, hence, on average bills, relative to an alternative supply-side resource.[7] Briefly, costs are measured by direct costs of program implementation to the utility and benefits are measured by the product of net energy and demand savings at the point of generation times the avoided energy and demand costs of generation, transmission and distribution.

If the net present value of UC is positive or the benefit cost ratio is greater than one, then the DSR investment reduces revenue requirement and reduces average customer bills relative to

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[7] *Cost-Effectiveness Analysis for DSM Programs,* presentation materials by Patricia Herman, Barakat & Chamberlin, Inc, page 1-37.

the supply-side alternative measured by avoided cost. The benefit cost ratio gives an indication as to whether the revenue requirement increases or decreases and the net present value gives an indication of the magnitude of the change. UC analysis also produces a "levelized cost per kWh or per kW" figure for comparison and ranking of alternative investments over the life cycle of the investments.

The UC test mirrors supply-side investment analysis in the sense that only utility system costs and benefits are considered in the economic evaluation of the investment. No other impacts of the program are included.

PacifiCorp performs some type of UC analysis at the planning, implementation, acquisition and evaluation stages of DSR program analysis because it is a component in RIM analysis which is a component in TRC analysis (described in greater detail further on in this report) which is computed at all stages.

PacifiCorp presents the specific results of UC analysis for regulatory review at two stages of DSR program analysis. UC results are first presented to regulators at the time a program or contract is provided to the Commission for regulatory approval. This analysis is provided in Utah's *Standard Data Request* filings when the Company requests Commission approval of a DSR program or contract. Generally all inputs are proforma expectations based on engineering estimates for generic installations, market penetration analysis and currently available avoided cost estimates. The Company also presents the results of UC analysis for regulatory review using verified energy savings from actual program installations. This analysis is provided to regulators in the Company's annual evaluation of each program.

PARTICIPANT COST TEST: IMPACT ON DSR PROGRAM PARTICIPATION

The **Participant Cost test (PC)** evaluates the costs and benefits from the participant's perspective. **PC** analysis indicates how economically attractive a DSR program is from the participants' point of view and therefore how likely a program is to attract participation and achieve the necessary market penetration in order to acquire a given level of DSR. Briefly, costs include all participant out of pocket expenses to fund the energy efficiency project. Benefits are measured by the annual gross energy savings valued at current and forecasted retail rates over the life of the program savings. Benefits additionally include other direct, measurable cost savings, such as operation and maintenance cost savings.

If the net present value of **PC** is positive or the benefit cost ratio is greater than one, then the DSR investment is cost-effective to participants as a whole, and indicates that the participant has an economic interest in participating. **PC** analysis also produces a "discounted payback" figure in years which can give a sense for how attractive the program is to the participant. Further research and analysis could determine whether the discounted payback could be increased without sacrifice to program participation in order to reduce non-participant impacts.

As noted above, **PC** analysis is an important program design tool to ensure that the program is attractive enough to encourage participation yet at the same time encourage maximum contribution by the participant to the cost of the DSR program in order to mitigate possible rate impacts to non-participating utility customers. The trade-offs between increasing participation and reducing the non-participant impacts apparent from RIM analysis is discussed in detail on pages 16 and 17 of this report.

PC analysis is additionally important because its costs and benefits are considered in the TRC test defined later in this report.

PacifiCorp performs some type of **PC** analysis at all stages of DSR program analysis, that is, at the planning stage in IRP, at the implementation stage both when requesting Commission approval to implement a program or contract and also in designing and implementing a DSR program tariff, and finally, at the evaluation stage. This is because components of **PC** analysis, like UC, are included in the TRC which is computed at all stages. Specific results of the **PC** analysis are currently presented to regulators at two stages: At the implementation stage when the Company requests Commission approval through its Utah *Standard Data Request* filing and at the evaluation stage in the annual evaluation reports.

RATEPAYER IMPACT MEASURE TEST: IMPACT ON RATES AND NON-PARTICIPATING CUSTOMERS' BILLS

The **Ratepayer Impact Measure test (RIM)** traditionally measures what happens to average total system cost per kWh due to changes in utility revenues and operating costs caused by the program. The test indicates the direction and magnitude of the expected change in average system rate levels. The test can also provide the cost per kWh required to reset revenues with revenue requirement over the life of the DSR program. This test traditionally indicates the impact on the system wide non-participant's average bill.

We recommend a version of this test that will examine the impact on the Utah jurisdiction non-participant's average bill. Since the traditional computation of RIM is a component of TRC, we will discuss both the traditional computation and the Utah jurisdiction computation. We recommend that the traditional computation continue to be computed for input in TRC calculations. However, when RIM results are presented for regulatory review, we recommend that the Utah jurisdiction computation be employed. We will make the distinction between the two computations by referring to the computation of RIM for purposes of computing TRC as the "traditional" calculation of RIM.

Traditionally, **RIM** benefits are measured by system avoided cost as defined and calculated in the UC test. **RIM** costs are defined as the UC costs plus the value of revenue loss. Revenue loss is measured by the annual net energy savings for the program valued at forecasted retail rates. The difference between gross energy savings, upon which PC benefits are computed, and net energy savings, upon which **RIM** is computed, is caused by netting out energy savings associated with free-rider and load building impacts from gross energy savings for the **RIM** analysis. This test relies upon both a forecast of retail rates as well as a forecast of avoided costs (discussed under **UC**) for the utility over a period of 15 to 20 years: two cost streams that are difficult to quantify with certainty. Since **RIM** results are sensitive to this uncertainty, test results must be viewed more cautiously than the other test results. However, it is an important tool of analysis because it is the only economic test presented in this paper that attempts to measure the impact to utility customers not participating in utility sponsored DSR programs.

If the net present value of **RIM** is positive or the benefit cost ratio is greater than one, then the DSR investment reduces average system costs per kWh, and thus average system rate levels, relative to the supply side alternative measured in avoided cost. Alternatively, if the net present value of **RIM** is negative or the benefit cost ratio is less than 1, then the DSR investment increases system costs per kWh relative to the supply side alternative measured in avoided cost. This latter case is generally the case when forecasted values of prices always exceed forecasted values of avoided costs over the life of the program savings. This is also PacifiCorp's current expectation of the forecasts for their system.

RIM analysis also produces the "life cycle revenue impact" (LRI) of the program which measures the one time rate change required to reset the present value of revenues with the present value of revenue requirement over the life of the program. LRI is equal to the net present value of **RIM** divided by the discounted system energy sales over the life of the program savings.

PacifiCorp performs some type of **RIM** analysis at all stages of DSR program analysis because it is a component in TRC. Although a form of RIM analysis is used as a screening tool at the IRP level, it is not used as a screening tool when actually acquiring resources. PacifiCorp may have performed analysis at the IRP level similar to the Annual Revenue Impact (ARI) analysis noted in the Appendix which looks at annual revenue impacts on a nominal basis. Different inputs were used than noted in the Appendix and the specific results were not presented for regulatory review.

Specific results of **RIM** analysis are currently presented to regulators at two stages: At the implementation stage when the Company requests Commission approval through its Utah *Standard Data Request* filing and at the evaluation stage in the annual evaluation reports.

Since DSR costs are assigned situs, the subcommittee recommends that **RIM** analysis be conducted on a Utah jurisdictional basis. We recommend that the test reflect the accounting and lost revenue mechanisms proposed in the Joint Recommendation. The primary distinction in the Utah jurisdictional perspective is the amount of revenues assumed to be lost over the course of DSR acquisition. Under the Utah definition of **RIM**, one year of revenues would be added to revenue requirement in addition to DSR acquisition costs bulked up for carrying charges and taxes. The equations in the Appendix reflect our recommended version of **RIM.**

However, as noted earlier, for use in computing TRC, **RIM** should be computed including all revenue loss over the life of the program. This approach will ensure consistency of TRC results reported from the planning through to the cost recovery stages and avoid unnecessary confusion.

TOTAL RESOURCE COST TEST (Utah Version): IMPACT ON EFFICIENCY OF PROVIDING ENERGY SERVICES TO RATEPAYERS

The **Total Resource Cost test (TRC)** measures the effect of the program on the cost to serve the "average" ratepayer relative to a supply-side alternative. This test attempts to combine the costs and benefits associated with participants, and with all customers. Cost is measured as the sum of the costs associated with the PC and traditional RIM perspectives, with one little twist: Participant costs are net of "other participant benefits" defined in the OBR_t term. Benefits are measured as the sum of the benefits associated with the PC and RIM perspectives. The result of this summation is that benefits are equal to avoided costs as measured in UC plus the value of the energy savings associated with free riders; costs are equal to UC costs plus the difference between net and gross savings so that the test ultimately evaluates the total cost of the program against the avoided system cost benefits plus direct project-associated non-energy benefits accruing to the participant.

If the net present value of **TRC** is positive or the benefit cost ratio is greater than one, then the DSR investment reduces revenue requirement and reduces average customer bills relative to the supply-side alternative measured by avoided cost. **TRC** analysis evaluates the impact of the DSR program on the costs of providing energy services to the average ratepayer. **TRC** analysis also produces a "levelized cost per kWh or per kW" figure for comparison and ranking of alternative investments over the life cycle of the investments.

This test attempts to mirror supply-side investment in that the full cost of the investment, regardless of who pays, is examined in comparison to the benefits to the "average" ratepayer. The total resource costs of demand-side programs are used in the IRP selection process for comparable evaluation of demand-side and supply-side options.

PacifiCorp presents the specific results of **TRC** analysis for regulatory review at all stages of DSR program analysis. PacifiCorp first presents the results of **TRC** analysis at the IRP stage during subgroup meetings in the public advisory process. Levelized **TRC** per kWh is presented in the final IRP report alongside the levelized costs of supply side resources. PacifiCorp also presents the results of **TRC** to regulators at the time a program or contract is provided to the Commission for regulatory approval. This analysis is provided in Utah's *Standard Data Request* filings when the Company requests Commission approval of a DSR program or contract. Generally all inputs are proforma expectations based on engineering estimates for generic installations, market penetration analysis and currently available avoided cost estimates. The Company also presents the results of **TRC** analysis for regulatory review using verified energy savings from actual program installations. This analysis is provided to regulators in the Company's annual evaluation of each program.

PacifiCorp's version of **TRC** includes a 10% adder to avoided costs and includes the costs and benefits of supplemental funding. We recommend that a distinction be made between PacifiCorp's **TRC** and the Utah recommended version of **TRC** which does not include the adder nor supplemental spending as a benefit. To denote this distinction, the PacifiCorp version will be noted as **PTRC** and the Utah version will be noted as **UTRC**.

It is unclear whether the current computation of **TRC** is consistent from planning through to implementation and evaluation. The components in **TRC** that lack clarity involve both cost and benefit terms. On the cost side, it is unclear if taxes and carrying charges are treated consistently at all stages and it is unclear whether participant costs are always net of participant benefits at each stage. Additionally, we need to understand how administrative costs are computed and to determine if evaluation costs bulk-up program costs at each stage. On the benefits side, it is unclear if "background" conservation and "free rider" estimates are treated consistently at each stage. It is also unclear how demand savings are estimated in the planning stage.

We expect that adoption of the equations presented in this report, along with necessary modifications made in the development of a computer model for these equations, will mitigate our concern with inconsistent application of TRC terms.

TOTAL RESOURCE COST TEST (PacifiCorp Version): IMPACT ON EFFICIENCY OF PROVIDING ENERGY SERVICES TO SOCIETY

The **Societal Cost test** as described in the California Standard Practice Manuel, is a variant of the TRC test and treats costs and benefits the same as in TRC; however, indirect project associated non-energy or external costs and benefits for DSR are included in the equation and a societal discount rate may be employed.

As noted above, PacifiCorp's interpretation of TRC includes a 10% adder to the benefits of DSR programs and includes indirect non-energy benefits associated with supplemental funding by netting them out of the cost side of the equation. Although this is not a strict interpretation of TRC as defined in the California Standard Practice Manual, which includes direct costs and benefits only, it is not quite a Societal Cost perspective either, because a societal discount rate is not employed.

We recommend that PacifiCorp's practice of TRC analysis be continued and for consistency, remain a TRC form of analysis and denoted as PTRC.

Recommended Performance Standards

The Performance Standards Subcommittee has been requested to review regulatory standards for evaluating demand side resources and to make recommendations on how best to judge the performance of these resources. We have just described five economic tests that have traditionally been used by the regulatory community to judge the cost-effectiveness of DSR and have provided recommended equations in the Appendix for how these tests should be performed by PacifiCorp for Utah DSR. We recommend adoption of the five tests as noted above. Test results should be computed and reviewed on a per program basis. We recommend that the results of the tests be presented to regulators at the following stages and expressed in the following forms:

Economic Test	Stages	Forms
Utility Cost test	Implementation, Evaluation, Cost Recovery	NPV, BCR, levelized cost per kW, kWh
Participant Cost test	Implementation, Evaluation, Cost Recovery	NPV, BCR, discounted payback, kW, kWh
Utah Ratepayer Impact test	Implementation, Evaluation, Cost Recovery	NPV, BCR, life cycle revenue impact per kW, kWh
Utah Total Resource Cost test	Implementation, Evaluation, Cost Recovery	NPV, BCR, levelized cost per kW, kWh
PacifiCorp Total Resource Cost test	Planning, Implementation, Acquisition, Evaluation, Cost Recovery	NPV, BCR, levelized cost per kW, kWh

The subcommittee recommends the use of the five tests because these perspectives will provide relevant information in determining the value and success of a program. This multi-perspective approach requires PacifiCorp and the Commission to consider tradeoffs between the perspectives and among impacts at each stage of analysis.

It is expected that the most critical decisions on acquisition of DSR occur at the planning and acquisition levels. Because PTRC is the primary test used at the planning stage, we recommend that it also govern acquisitions. Should the primary test at the planning level change, we recommend change of the primary test at the acquisition stage; analysis at these two stages must be consistent. That is, the economic test used to determine the measure funding limits in a filed DSR tariff must be consistent with the economic perspective used to set goals in the IRP analysis. This policy will ensure that DSR acquisitions planned for are the ones actually acquired.

It is envisioned that at the implementation stage, all test results should be provided and the program should pass all tests except for RIM. RIM test results should be considered in the DSR program approval process in order to assess that implementation of the program is in the public interest. Such assessment should include analysis of the proposed program's impact on the cumulative price impact of all approved DSR programs.

All tests should also be presented at the evaluation stage. At this stage we recommend that PacifiCorp explain actions to be taken which are consistent with test results. For example, a marginal UTRC result may indicate the need for program design modification.

In a rate case, the information from evaluation reports together with analysis of PacifiCorp's implementation of its least cost plan will be used to determine recovery of costs booked. It is expected that the report recommended in the 1995-1996 Joint Agreement to be conducted by the Office of Energy and Resource Planning and the Division of Public Utilities will assist in this analysis.

Guidance on Review of Test Results: Hierarchy and Interaction

A basic hierarchy was indicated by the Commission for comparing supply side and demand side resources in the IRP to meet load growth. The Commission directed the Company to determine the costs incurred by the utility, that is, the present value of total revenue requirements of the Company's various resource acquisition strategies. If different strategies have the same total resource costs, the Company was directed to choose that strategy that has the lowest total revenue requirement.[8]

Given the Commission's preliminary direction, we will attempt to further explain and delineate a hierarchy for allowed cost recovery of DSR expenditures and lost revenues.

The first issue regarding cost recovery of DSR expenditures is whether the Company has obtained the least cost combination of SSR and DSR. This least cost combination is determined through the IRP process. Utah IRP Standards and Guidelines require that resources selected to meet load growth be based on minimizing total resource costs. PacifiCorp's current and the subcommittee's recommended interpretation of total resource cost for IRP is to include a 10% adder and allow supplemental costs to be included as a reduction to cost through the "other benefits" term. This by definition is equal to the PTRC test described in this report. Thus, the PTRC test should be passed for DSR expenditures to be recovered in rates. This is also the analysis conducted at the point of acquisition and therefore should be met at the point of cost recovery.

The PTRC test which includes external benefits and costs of resource acquisitions is also an important tool to assess environmental risk mitigation strategies. The IRP Standards and Guidelines require that the Company analyze resource acquisition strategies that will lower the risk that future environmental regulations will result in higher costs to the Company. Commission

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[8] see page 17, Ibid

Standards and Guidelines require that the Company attempt to quantify external costs associated with the acquisition of new resources and analyze strategies that will mitigate the risk that those costs will be internalize through new environmental regulations.

However, it is conceivable that a program could fail this test and still be allowed recovery of costs. An example might be a program that is in an early stage of implementation, a ramp-up stage, which could cause high administrative costs relative to the level of acquired savings at the point in time of a rate case. This type of circumstance will need to be considered in a review of cost allowance. Thus, the PTRC is a critical test for recovery of costs; however, circumstances as noted above should also be considered in the final determination of cost recovery.

The UTRC test provides information on how cost-effective the DSR program is in comparison to a supply side alternative based on the costs and benefits of the reduction in electricity consumption to all ratepayers. This test provides useful comparison to the levelized cost of a supply-side investment. Additionally, this perspective will provide useful information on the impact of supplemental spending on the cost-effectiveness of a given program design. PTRC includes indirect, non-energy related benefits associated with supplemental funding whereas UTRC does not. A comparison of the two results will provide PacifiCorp and regulators with information regarding the value of supplemental funding, which may increase participation rates, in comparison to the cost of providing supplemental funding..

The UC test, which measures the cost of DSR from the utility's perspective, must pass in order for the resource to be deemed lowest cost. This cost test is extremely important. The goal is to minimize the cost of acquiring DSR to the utility and its ratepayers while achieving the requisite amount of DSR that is specified under the IRP. This can be done by lowering administrative and evaluation costs, as well as incentive payments, by achieving savings where marginal costs are highest and by having the participant contribute as large a share as is possible. A tradeoff occurs in that by increasing participant charges and decreasing administrative costs, lower participation rates can result and lead to the failure to acquire the requisite amount of DSR. There could be some instances where the Commission would be willing to tolerate lower DSR acquisitions if it could be shown that utility costs were substantially lowered and that non-participants were greatly benefited. It is envisioned that such a strategy would receive prior Commission approval rather than the Company justify, after the fact, its failure to achieve DSR acquisition goals.

The PC test must yield positive results if the program is to be economically attractive to the participant. However, this test only includes benefits and costs to the participant that can be quantified; there could be instances where the benefits can not be quantified and yet produce real benefit to the participant. In such cases failure to pass this test would not be grounds for imprudence. However, programs which failed the participant test would require close scrutiny. The Company would have to show that the participant made a fully informed decision to participate and that these unquantified benefits were paid for by the participant before cost recovery would be allowed. Benefits that do not relate to energy savings should not be funded by other ratepayers. Thus, the PC test is neither a necessary nor sufficient condition for cost recovery. It is a very important test for review of program design, and should be reviewed in conjunction with review of RIM results as noted in the following discussion.

The RIM test is perhaps the most controversial of the cost-effectiveness tests. Passage of RIM is not a necessary condition for recovery of costs. In fact, the failure of the RIM test is expected in most DSR programs where rates are above the marginal costs that are avoided by the utility. The passage of the RIM test, in most all cases, is a sufficient condition for allowing costs in rates.

The RIM test, though not essential for a determination of cost recovery, is an important cost-effectiveness test from a public policy perspective because there is a tradeoff between PC analysis and RIM analysis with regard to determining the appropriate incentives to attract participation yet minimize rate impacts to other customers.

For example, an energy service charge program that consistently yields a relatively high PC benefit cost ratio indicates that the participant may be able to bear a higher percentage of the cost of the program. Sensitivity analysis should be conducted to determine the tradeoff between DSR participation rates and rate impacts on non-participants. As the participant bears a higher portion of the cost of a program, upward impact on average rates in the long run is reduced. The tradeoff is presented by the test results of the RIM test, i.e., a higher BCR_{RIM}. It is the interplay between the results of the PC and RIM tests that allows one to balance long run impacts on non-participants with the design of a DSR acquisition program that captures the least cost amount of DSR as determined by the Company's IRP. Again, the tradeoff here is that higher required participant contributions can result in lower participation rates for DSR programs and result in the failure to acquire the appropriate amount of DSR relative to SSR.

Summary of Recommended Performance Standards

1. **Planning Stage:** At IRP stage, levelized PTRC should be used. PTRC should include taxes, revenue requirement, carrying charges and background conservation. PacifiCorp's previous definition of TRC is equivalent to the recommended definition of PTRC.

2. **Implementation Stage:** All tests should be provided to regulators in the Standard Data Request Response and should be computed per the equations in the Appendix of this report. At this stage the proposed program must pass all tests except for the RIM test. LRI for RIM should be provided for each program along with the cumulative LRI from Utah approved programs. Analysis of this cumulative impact should be available for review each time a program is proposed, in each evaluation report, and in a rate case setting for analysis of costs to be recovered in rates.

3. **Acquisition Stage:** The economic perspective conducted at the IRP level determines the economic perspective which governs acquisition. Currently, PTRC is the analytical basis for comparing demand side and supply side resources at the IRP stage and therefore should be used to establish measure funding limits which govern acquisition. If the type of analysis used to establish planned DSR targets changes from PTRC, the analysis must also be changed at the acquisition stage. For example, if lost revenue analysis is conducted at the IRP level, the Utah version of RIM needs to be incorporated into the tariff requirements of all programs.

4. **Evaluation Stage:** All tests will be provided for regulatory review at the evaluation stage in the annual evaluation reports. An assessment of the test results and of necessary changes to improve test results will be included. BCR, NPV, levelized cost for UTRC, PTRC, and UC will be included, and LRI for RIM per program and cumulatively will be provided. At this point, if a program does not pass a test, or passes marginally, PacifiCorp needs to discuss what actions will be taken in order to address the issue.

5. **Cost Recovery:** At the cost recovery stage, allowance of costs booked will be based on the performance of the economic tests per program respective of the hierarchy discussed above. Additionally, success will be measured by a comparison of IRP analysis and actual supply and demand side resource acquisitions. In addition to the test results, an analysis of planned versus achieved DSR acquisitions will be used. Review of the test results will need to consider whether a program is in an early implementation phase or a full implementation phase; programs which are in a full implementation phase will be expected to perform best.

6. Conservation Cost-effectiveness spreadsheets need to be provided to regulators each time the economic test results are presented for regulatory review.

7. A computer model based on the equations in this report and which enables sensitivity analysis should be developed over the coming year.

APPENDIX: RECOMMENDED ECONOMIC TEST EQUATIONS AND INPUTS

UTILITY COST TEST

The current and recommended equations and sources for inputs for UC are as follows:

$NPV_{UC} = B_{UC} - C_{UC}$

$BCR_{UC} = B_{UC} / C_{UC}$

$LC_{UC} = LCUC_{UC} / IMP$

where:

NPV_{UC} = Net present value of utility costs

BCR_{UC} = Benefit-cost ratio of utility costs

LC_{UC} = Levelized cost per kW or kWh over life of program savings

B_{UC} = Utility system benefits of the program, measured by the present value of avoided generation, transmission and distribution costs multiplied by the annual expected kWh and kW savings (net of free riders and load building impacts) over the life of the program.

C_{UC} = Present value of the direct utility costs to implement a program net of the Energy Service charge payments by participating customers.

$LCUC_{UC}$ = Total utility costs used for levelization

IMP = Total discounted load impacts in kW or kWh over life of program savings

These terms are further defined by the following equations:

$$B_{UC} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{At}}{(1+d)^{t-1}}$$

$$C_{UC} = \sum_{t=1}^{N} \frac{UC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCUC_{UC} = \sum_{t=1}^{N} \frac{UC_t + INC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{N} \mid \langle \sum_{t=1}^{N} \Delta EN_{it} \rangle \text{ or } \langle \Delta DN_{it} \text{ where I = peak period} \rangle}{(1+d)^{t-1}}$$

where:

UACt = Utility avoided generation, transmission and distribution supply costs in year t.

Current and Recommended Inputs: The avoided cost of generation is based on the most recently available forecasted rates for PURPA Qualifying Facilities standard rate tariff. The value of secondary sales, made possible by DSR freeing up generation, is added to the PURPA rates. Additionally, transmission and distribution avoided demand costs are also added to the PURPA rates. The avoided transmission and distribution costs come from PacifiCorp's Marginal Cost analysis.

Recommended Guidelines: Each time **UC** analysis is presented for regulatory review, it is expected to employ the most currently available avoided cost values and current cost of capital and inflation assumptions. The "Conservation Cost-effectiveness Spreadsheet" provides the relevant avoided cost values and all assumptions regarding avoided cost and needs to be included as an attachment whenever the **UC** test is presented for regulatory review. If a contract was approved based on a previously published avoided cost which was current at the time of contract selection but no longer reflective of avoided costs, the avoided costs used in that analysis may be used to perform additional **UC** test results but may not supplant current avoided cost analysis. This guideline applies both to proforma estimates of a program's expected performance when filing for Commission approval of programs and contracts and to annual evaluations to verify program or contract performance. A sample of the Conservation Cost-Effectiveness spreadsheet is included as Attachment C.

UAC_{At} = The avoided supply costs of the alternate utility fuel company. This term should be included for fuel substitution programs.

Current Inputs: Unclear

Recommended Inputs: Mountain Fuel avoided supply costs are best represented by the most recently available IRP avoided costs. See Attachment D.

d = Discount rate for present value computation.

Current and Recommended Inputs: PacifiCorp's most recently available after-tax real cost of capital as shown on conservation cost-effectiveness spreadsheets. Theoretically, since utility costs are bulked up for taxes, we should be using a pre-tax cost of capital, however, for consistency with the Oregon order which requires grossing up for taxes and use of an after-tax cost of capital, we will accept this practice.

UC_t = Utility cost is measured by *net utility cost.* Net utility cost is total program cost to the utility, including administrative costs, installation costs, monitoring and evaluation costs, all bulked up for taxes and revenue requirement, but *net of energy service charge payments* to the utility from the participant.

INC_t = Incentive payments PacifiCorp provides to the participant. Examples include the showerhead program and the FinAnswer programs. In the showerhead program, the incentive is the cost of the showerhead which the participant receives free of charge. In the FinAnswer programs, the lower interest rate is translated into an incentive payment.

UIC_t = Utility increased costs for supply. This term must be included for load building, load management and load retention programs. For programs without such impacts, the term can be ignored. This term is not included for computation of levelized cost per kW or kWh.

The terms above are further defined in the equations below. The avoided cost terms are further determined by costing period to reflect time-variant costs of supply as follows:

$$\mathbf{UAC_t} = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times K_{it}) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

$\mathbf{UAC_{At}}$ = (Same as UAC_t formula above except with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UC_t = \sum_{t=1}^{I} (IC_t + DFC_t + CC_t + T_t + (ESc_t - LC_t))$$

$$UIC_t = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times (K_{it}-1)) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times (K_{it}-1))$$

where:

ΔEN_{it}	=	Reduction in net energy use in costing period I in year t
ΔDN_{it}	=	Reduction in net demand in costing period I in year t
$MC{:}E_{it}$	=	Marginal cost of energy in costing period I in year t
$MC{:}D_{it}$	=	Marginal cost of demand in costing period I in year t
K_{it}	=	1 when ΔEN_{it} or ΔDN_{it} is positive in year t, and zero otherwise
IC_t	=	Installed Cost of Project; dollar rebate for rebate programs; measure costs for direct install
DFC_t	=	Deferred Costs, Administration, Overhead and Evaluation
T_t	=	Taxes
CC_t	=	Carrying Charge
ESc_t	=	Energy Service Charge payments
LC_t	=	Loan cost to PacifiCorp (net present value of loaning ESc_t)

PARTICIPANT COST TEST

The current and recommended equations and sources for inputs for **PC** are as follows:

$\mathbf{NPV_{PC}}$	=	$\mathbf{B_{PC} - C_{PC}}$
$\mathbf{NPV_{AVP}}$	=	$\mathbf{B_{PC} - C_{PC} / P}$
$\mathbf{BCR_{PC}}$	=	$\mathbf{B_{PC} / C_{PC}}$
$\mathbf{DP_{PC}}$	=	**Min j such that Bj > or = Cj**

where:

$\mathbf{NPV_{PC}}$	=	Net present value to all participants
$\mathbf{NPV_{AVP}}$	=	Net present value to the average participant
$\mathbf{BCR_{PC}}$	=	Benefit-cost ratio to participants
$\mathbf{DP_{PC}}$	=	Discounted payback in years
$\mathbf{B_{PC}}$	=	Benefits to participants, measured as the present value of gross energy and demand savings multiplied by forecasted weighted average retail tail block rates over the life of program savings plus other bill reductions.
$\mathbf{C_{PC}}$	=	Out of pocket costs to participants
Bj	=	Cumulative benefits to participants in year j
Cj	=	Cumulative costs to participants in year j
P	=	Number of program participants
j	=	First year in which discounted cumulative benefits are greater than or equal to discounted cumulative costs

These terms are further defined as follows:

$$B_{PC} = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{At} + PAC_{At}}{(1+d)^{t-1}}$$

$$C_{PC} = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

where:

BR_t = Bill reductions in year t

BI_t = Bill increases in year t

TC_t = Tax credits in year t; There are no state or federal taxes currently available

INC_t = Incentives paid to the participant by PacifiCorp in year t

PC_t = Participant costs in year t

PAC_{At} = Participant avoided costs in year t for alternate fuel devices (cost of alternate device not chosen). This term is included for fuel substitution programs.

AB_{At} = Avoided bill from alternate fuel in year t

Current Inputs: Unclear

Recommended Inputs: Current and forecasted retail prices from Mountain Fuel most recently available IRP. See Attachment D.

These terms are further defined as follows:

$$BR_t = \sum_{t=1}^{I} (\Delta EG_{it} \times RT{:}E_{it} \times K_{it}) + \sum_{t=1}^{I} (\Delta DG_{it} \times RT{:}D_{it} \times K_{it}) + OBR_t$$

AB_t = Use BR_t formula but with rates appropriate for alternate fuel utility

$$BI_t = \sum_{t=1}^{I} (\Delta EG_{it} \times RT{:}E_{it} \times K_{it} - 1) + \sum_{t=1}^{I} (\Delta DG_{it} \times RT{:}D_{it} \times K_{it} - 1) + OBI_t$$

where:

ΔEG_{it}	=	Reduction in gross energy use in year t
ΔDG_{it}	=	Reduction in gross billing demand in year t
$RP{:}E_{it}$	=	Retail average tail block price for energy in year t
$RP{:}D_{it}$	=	Retail average tail block price for demand in year t
K_{it}	=	1 when ΔEG_{it} or ΔDG_{it} is positive in year t, and zero otherwise
OBR_t	=	Other bill reductions or avoided bill payments (water bill savings that accrue to participant, operation and maintenance bill reductions, customer charges, standby rates). These benefits will include non-direct, unmeasured benefits, such as non-energy or non-measurable benefits related to supplemental spending by the participant when PC is incorporated into PTRC. That is, if the participant chooses to implement a non-cost-effective measure as measured by direct energy or energy related benefits, this is measured as an out-of-pocket cost to the participant. The subcommittee recommends that supplemental spending analysis be included in the PTRC test and not in the UTRC test. The discussion above is consistent with a recent Oregon order allowing quantified non-energy benefits to the participant in the TRC analysis provided that the non-energy benefits are significant and there is a reasonable and practical method for calculating them.[9]
OBI_t	=	Other bill increases (customer charges, standby rates)

[9] Oregon Public Utility Commission, UM 551, Order No. 94-590; *In the Matter of the Investigation into the Calculation and Use of Cost-Effectiveness Levels for Conservation,* April 6, 1994, pages 14 and 15.

RATEPAYER IMPACT MEASURE TEST

The current and recommended equations and sources for inputs for **RIM** are as follows:

$$LRI_{RIM} = (B_{RIM} - C_{RIM}) / E$$

$$ARI_{RIM} = (B_{RIMt} - C_{RIMt}) / E_t \qquad \text{for } t = 1,\ldots,N$$

$$NPV_{RIM} = B_{RIM} - C_{RIM}$$

$$BCR_{RIM} = B_{RIM} / C_{RIM}$$

where:

LRI_{RIM} = Life cycle revenue (rate) impact per kWh, per kW or per customer

ARI_{RIM} = Annual revenue (rate) impact per kWh, per kW or per customer

NPV_{RIM} = Net present value of revenue/rate levels

BCR_{RIM} = Benefit-cost ratio for rate levels

B_{RIM} = Benefits to rate levels

C_{RIM} = Costs to rate levels

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{At}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + UC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{At}}{(1+d)^{t-1}}$$

$$E_{RIM} = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

where:

UACt	=	Utility avoided generation, transmission and distribution supply costs in year t. Previously defined under the UC test.
UIC_t	=	Utility increased costs for supply. This term must be included for load building, load management and load retention programs. For programs without such impacts, the term can be ignored.
RG_t	=	Net revenue gain from increased sales in year t. This term should be included for load building or load retention programs.
RL_t	=	Net revenue loss from reduced sales in year one only. Revenue loss is net of free-riders and load building impacts.
UC_t	=	Utility program cost in year t; measured by *net utility cost.* Previously defined under the UC test.
E_t	=	System sales in kWh, kW or therms in year t or first year customers. Most recent IRP data for forecasted sales in Utah over life of program savings is source for this term.
UAC_{At}	=	Utility avoided supply costs for the alternate fuel in year t. Previously defined in UC test.
RL_{At}	=	Revenue loss from avoided bill payments for alternate fuel in year t; (i.e., device not chosen in a fuel substitution program).

The revenue impact terms (RG_t, RL_t, and RL_{At}) are the same as the bill impact terms in PC except that the net impact to load are used instead of gross impacts and except that only one year of RL is used. If a net-to-gross ratio is used to differentiate savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

$$RG_t = BI_t * \text{(net-to-gross ratio)}$$

$$RL_1 = BR_1 * \text{(net-to-gross ratio)}$$

$$RL_{At} = AB_{At} * \text{(net-to-gross ratio)}$$

UTAH TOTAL RESOURCE COST TEST

The recommended equations and sources for inputs for **UTRC** at all stages are as follows:

$$NPV_{UTRC} = B_{UTRC} - C_{UTRC}$$

$$BCR_{UTRC} = B_{UTRC} / C_{UTRC}$$

$$LC_{UTRC} = LCUTRC \ / \ IMP$$

where:

NPV_{UTRC}	=	Net present value of utility costs
BCR_{UTRC}	=	Benefit-cost ratio of utility costs
LC_{UTRC}	=	Levelized cost per unit of utility cost of the resource
B_{UTRC}	=	Benefits of the program
C_{UTRC}	=	Costs of the program.
LCUTRC	=	Total resource costs used for levelization
IMP	=	Total discounted load impacts in kW or kWh over life of program savings

These terms are further defined as follows:

$$B_{UTRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{At} + PAC_{At}}{(1+d)^{t-1}}$$

$$C_{UTRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCUTRC = \sum_{t=1}^{N} \frac{UC_t + PC_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{N} \left| \left\langle \sum_{t=1}^{N} \Delta EN_{it} \right\rangle \text{ or } \left\langle \Delta DN_{it} \text{ where I = peak period} \right\rangle \right.}{(1+d)^{t-1}}$$

where:

UACt = Utility avoided generation, transmission and distribution supply costs in year t.

Current Inputs: PacifiCorp uses utility avoided cost as defined in the UC test plus a 10% adder at the request of the Northwest Power Planning Council and the Oregon Public Utility Commission. Montana Commission rules request a 15% adder on UTRC, although it is not clear if this request is implemented.

Recommended Inputs: No 10% adder in this test.

Recommended Guidelines: Each time UTRC analysis is presented for regulatory review, it is expected to employ the most recently published avoided cost values and current cost of capital and inflation assumptions. The "Conservation Cost-effectiveness Spreadsheet" provides the relevant avoided cost values and all assumptions regarding avoided cost and needs to be included as an attachment whenever the UTRC test is presented for regulatory review. If a contract was approved based on a previously published avoided cost which was current at the time of contract selection but no longer reflective of avoided costs, the avoided costs used in that analysis may be used to perform additional UTRC test results but may not supplant current avoided cost analysis. This guideline applies both to proforma estimates of a program's expected performance when filing for Commission approval of programs and contracts and to annual evaluations to verify program or contract performance. A sample of the Conservation Cost-Effectiveness spreadsheet is included as Attachment B.

UAC_{At} = The avoided supply costs of the alternate utility fuel company. This term should be included for fuel substitution programs.

Recommended Inputs: Mountain Fuel avoided supply costs are best represented by the most recently available IRP avoided costs.

d = Discount rate for present value computation.

$$\text{IMP} = \frac{\sum_{t=1}^{N} \left| \langle \sum_{t=1}^{N} \Delta EN_{it} \rangle \text{ or } \langle \Delta DN_{it} \text{ where I = peak period} \rangle \right.}{(1+d)^{t-1}}$$

where:

UACt = Utility avoided generation, transmission and distribution supply costs in year t.

Current Inputs: PacifiCorp uses utility avoided cost as defined in the UC test plus a 10% adder at the request of the Northwest Power Planning Council and the Oregon Public Utility Commission. Montana Commission rules request a 15% adder on UTRC, although it is not clear if this request is implemented.

Recommended Inputs: No 10% adder in this test.

Recommended Guidelines: Each time UTRC analysis is presented for regulatory review, it is expected to employ the most recently published avoided cost values and current cost of capital and inflation assumptions. The "Conservation Cost-effectiveness Spreadsheet" provides the relevant avoided cost values and all assumptions regarding avoided cost and needs to be included as an attachment whenever the UTRC test is presented for regulatory review. If a contract was approved based on a previously published avoided cost which was current at the time of contract selection but no longer reflective of avoided costs, the avoided costs used in that analysis may be used to perform additional UTRC test results but may not supplant current avoided cost analysis. This guideline applies both to proforma estimates of a program's expected performance when filing for Commission approval of programs and contracts and to annual evaluations to verify program or contract performance. A sample of the Conservation Cost-Effectiveness spreadsheet is included as Attachment B.

UAC_{At} = The avoided supply costs of the alternate utility fuel company. This term should be included for fuel substitution programs.

Recommended Inputs: Mountain Fuel avoided supply costs are best represented by the most recently available IRP avoided costs. See Attachment C.

d = Discount rate for present value computation.

Recommended Inputs: PacifiCorp's most recently available after-tax real cost of capital as shown on conservation cost-effectiveness spreadsheets. Theoretically, since utility costs are bulked up for taxes, we should be using a pre-tax cost of capital, however, for consistency with the Oregon order which requires grossing up for taxes and use of an after-tax cost of capital, we may want to go along with this.

UC_t = Utility cost is measured by *net utility cost.* Net utility cost is total program cost to the utility, including administrative costs, installation costs, monitoring and evaluation costs, all bulked up for taxes and revenue requirement, but *net of energy service charge payments* to the utility from the participant. See definition under UC Test.

PC_t = Participant direct costs

Recommended Inputs: Net participant cost should be used and should reflect participant cost net of quantified, energy-related benefits such as operation and maintenance benefits and water benefits.

UIC_t = Utility increased costs for supply. This term must be included for load building, load management and load retention programs. For programs without such impacts, the term can be ignored. This term is not included for computation of levelized cost per kW or kWh.

The terms above are further defined in the equations below. The avoided cost terms are further determined by costing period to reflect time-variant costs of supply as follows:

$$UAC_t = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times K_{it}) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

UAC_{At} = (Same as UAC_t formula above except with marginal costs and costing periods appropriate for the alternate fuel utility and no 10% factor.)

$$UC_t = \sum_{t=1}^{I} (IC_t + DFC_t + CC_t + T_t + (ESc_t - LC_t))$$

$$UIC_t = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times (K_{it}-1)) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times (K_{it}-1))$$

where:

ΔEN_{it}	=	Reduction in net energy use in costing period I in year t
ΔDN_{it}	=	Reduction in net demand in costing period I in year t
$MC{:}E_{it}$	=	Marginal cost of energy in costing period I in year t
$MC{:}D_{it}$	=	Marginal cost of demand in costing period I in year t
K_{it}	=	1 when ΔEN_{it} or ΔDN_{it} is positive in year t, and zero otherwise
IC_t	=	Installed Cost of Project
DFC_t	=	Deferred Costs, Administration, Overhead and Evaluation
T_t	=	Taxes
CC_t	=	Carrying Charge
ESc_t	=	Energy Service Charge payments
LC_t	=	Loan cost to PacifiCorp (net present value of loaning ESc_t)

PACIFICORP TOTAL RESOURCE COST TEST

All equations for **PTRC** are identical to UTRC except for two terms. Utility avoided cost includes a 10% adder and supplemental benefits are included in OBR for computation of net participant cost. This test is equivalent to PacifiCorp's previous definition of TRC.

$$\mathbf{UAC_t} = \sum_{t=1}^{I} (\Delta EN_{it} \times (MC{:}E_{it} \times 1.1) \times K_{it}) + \sum_{t=1}^{I} (\Delta DN_{it} \times (MC{:}D_{it} \times 1.1) \times K_{it})$$

ATTACHMENT A

Total Resource Cost Analysis By Stage

Stage	IRP		
DSR Estimates	Technical Potential	Program Potential	Action Plan
Equation	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(First Cost + NPV of O&M costs) where avoided cost includes line losses and assumes a conservation load factor to value capacity benefits.	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(NPV of Revenue requirement) where: avoided cost includes line losses and assumes a conservation load factor to value capacity benefits; and, where: revenue requirement includes taxes.	RIM=[(incremental power cost * savings*(1+.15)+ESc+line losses)-(program investment+(lost revenues@projected retail price by jurisdiction)+income taxes+ +bad debt on ESc(.005)]/annual energy saved
MODEL ASSUMPTIONS			
Revenue Requirements - Deferred - Expensed	No; incremental first cost of measure used. (this is like California Std. Practice Mnuel)	Yes administration, measure costs; not really clear. (page 105) administration; evaluation costs not explicitly addressed.	Yes? Operating revenue, expenses, taxes. ?
Levelization	LC = (first cost + NPV of O&M) * CRF/annual kWh savings	LC=[((deferred utility cost *NPV multiplier)+(loan investment * NPV multiplier)+utility expense+NPV of customer costs) * CRF] / annual energy saved	Unclear; real levelized used for costs, nominal levelized used for price impact analysis.
Taxes	Not included.	Included in NPV multipliers noted above.	Included but not clear how.
Freeriders/Background	Prototype modeling estimates of future efficiency (codes) are given to forecasting department for "frozen efficiency" in load forecasts. Additionally, measures under 10 mills levelized are removed from Tech. potential and netted out of the load forecasts. Commercial only; industrial background is captured in econometric forecasts and no background assumed in residential. (pp. 81-83)	Freeriders subtracted from technical potential for commercial programs, new and existing.	Unclear
Normalization	Yes; based on long-term forecast.	Yes	Unclear
INPUT ASSUMPTIONS			
Discount Rate	Real, after tax 5.23% used for levelization.	Real, after tax 5.23% used for levelization.	Nominal 8.8%
Savings Estimates - Energy	Based on engineering prototypes and conditional demand analysis adjusted for actual consumption, end-use saturation and vacancy rates.	kWh saved= (constant+slope* dUA)*(1-fuel (adj) factor)*(1-take-back factor)*Acceptance factor*penetration factor. Tack-back factor applied to existing buildings, res. and com. only; acceptance factor refers to the % of relevant population eligible for measure; penetration rate refers to % of the market defined by the acceptance factor expected to be reached by program. 6%, 10.5% and 12% line losses added.	Unclear how this was derived, i.e., which forecast used, where initial estimates come from (medium DSR?)
- Capacity	Unclear	Average reduction in four season peak derived from load shapes of programs input to IPM. Relies on load profiles developed for programs which is an aggregate of measure load profiles.	Unclear how this was derived.
Avoided Cost - Energy - Capacity	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation capacity and energy costs based on R-2, transmission, distribution costs and line losses. Unclear what discount rate was used, i.e., RAMPP-2 or current assumptions regarding after tax cost of capital and long-term inflation rate. Secondary sales incl.	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation capacity and energy costs based on R-2, transmission, distribution costs and line losses. Unclear what discount rate was used, i.e., RAMPP-2 or current assumptions regarding after tax cost of capital and long-term inflation rate. Secondary sales incl.	Uses incremental power cost plus line losses (valued at zero) plus 15% to account for deferral of T&D investment and 10% conservation advantage. Capacity estimates unclear.
Prices - Gas - Electric	Unclear how non-energy benefits valued. Since TRC, lost rev's and customer cost savings cancel.	Unclear how non-energy benefits valued. Since TRC, lost rev's and customer cost savings cancel.	Unclear. Average retail price by jurisdiction
Costs - Measures - Administrative	No supplemental measures; no background measures	As proxy for supplemental costs, costs raised by 30% and savings raised by 20%; no background measures.	Supplemental costs reduced; savings reduced. Unclear as to how much reduced. Background measures included?
Benefits			Line losses valued at zero in example; deferred O&M valued at zero in example.

Total Resource Cost Analysis By Stage

Stage	IMPLEMENTATION AND ACQUISITION	
DSR Estimates	Program Approval Process	Measure Funding Limits
Equation	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(NPV of Revenue requirement) where: avoided cost includes line losses and assumes a conservation load factor to value capacity benefits; and, where: revenue requirement includes taxes.	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(First Cost + NPV of O&M costs) where avoided cost includes line losses and assumes a conservation load factor to value capacity benefits.
MODEL ASSUMPTIONS		
Revenue Requirements - Deferred - Expensed	Yes All utility program costs Evaluation	No
Levelization	LC=NPV of revenue requirements*CRF/annual energy savings	
Taxes	Included in revenue requirement calc.	Not included in analysis.
Freeriders/Background	Background included in costs.	Background included in costs.
Normalization		
INPUT ASSUMPTIONS		
Discount Rate	Real, after tax.	
Savings Estimates - Energy - Capacity	Based on market potential for territory. Assumed through CLF	DOE-2 modeling and prototype prescriptive estimates. Assumed through CLF?
Avoided Cost - Energy - Capacity	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation, transmission and distribution (with line losses) capacity and energy costs based on most recent IRP avoided cost assumptions and plus updates to cost of capital and inflation.	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation, transmission and distribution (with line losses) capacity and energy costs based on most recent IRP avoided cost assumptions and plus updates to cost of capital and inflation.
Prices - Gas - Electric	Unclear. Marginal retail price by jurisdiction	Unclear. Marginal retail price by rate schedule.
Costs - Measures - Administrative	Supplemental and background included.	Supplemental and background costs included in measure costs.
Benefits		

Total Resource Cost Analysis By Stage

Stage DSR Estimates	EVALUATION
Equation	TRC=NPV of Benefits-NPV of Costs Where Benefits include supplemental costs plus (kWh*AC w/10% and secondary sales with assumec CLF); and where Costs = revenue requirements?
MODEL ASSUMPTIONS	
Revenue Requirements - Deferred - Expensed	Yes?
Levelization	
Taxes	Included?
Freeriders/Background	Background included in costs.
Normalization	
INPUT ASSUMPTIONS	
Discount Rate	Real, after tax.
Savings Estimates - Energy	DOE-2 modeling and prototype prescriptive estimates. Metering and statistical billing analysis.
- Capacity	DOE-2 modeling and prototype prescriptive estimates. Metering and statistical billing analysis.
Avoided Cost - Energy - Capacity	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation, transmission and distribution (with line losses) capacity and energy costs based on most recent IRP avoided cost assumptions and plus updates to cost of capital and inflation.
Prices - Gas - Electric	Unclear. Marginal retail price by rate schedule.
Costs - Measures - Administrative	Supplemental included as a benefit; background measures included in cost side.
Benefits	

PACIFICORP
Conservation Cost Effectiveness
Retrofit Water Heat Measures

RAMPP-2 approved avoided costs with secondary sales

(A) Year	(B) Generation, Transmission & Distribution Marginal Capacity Cost $/KW (EOY$)	(C) Generation, Transmission & Distribution Marginal Capacity Cost Cents/kWh (EOY$)	(D) Marginal Energy w/losses Cents/kWh (EOY$)	(E) Total Marginal Costs Cents/kWh (EOY$)	(F) Plus 10% Conservation Advantage	(G) Present Value Discount Rate 8.79% (to 12/93 $'s)	(H) Present Value Marginal Costs Cents/kWh (to 12/93 $'s)	(I) Sum Conservation Cost Effectiveness Cents/kWh (to 12/93 $'s)	(J) Annual Charge	(K) Real Levelized Cents/kWh	(L) Measure Life Years
		(B) X 100/(8760 x 0.480)		(C)+(D)	(E) x 1.1		(F) x (G)				
1993			1.98	1.98	2.18	1.0000	2.18				1
1994			2.10	2.10	2.31	0.9192	2.12				2
1995			2.14	2.14	2.35	0.8449	1.99				3
1996			2.33	2.33	2.57	0.7767	1.99				4
1997	97.10 ✓	2.31	3.04	5.35	5.88	0.7139	4.20				5
1998	100.41	2.39	3.32	5.70	6.27	0.6562	4.12				6
1999	103.76	2.47	3.64	6.11	6.72	0.6032	4.05	20.651	16.55%	3.418	7
2000	107.39	2.55	3.99	6.55	7.20	0.5545	3.99				8
2001	110.93	2.64	4.36	7.00	7.70	0.5097	3.93				9
2002	114.77	2.73	4.78	7.51	8.26	0.4685	3.87	32.440	12.44%	4.034	10
2003	118.64	2.82	5.21	8.03	8.84	0.4306	3.81				11
2004	122.68	2.92	5.66	8.58	9.43	0.3958	3.73				12
2005	126.89	3.02	6.07	9.09	9.99	0.3639	3.64				13
2006	131.15	3.12	6.47	9.59	10.55	0.3346	3.53				14
2007	135.70	3.23	6.91	10.14	11.15	0.3074	3.43	50.575	9.29%	4.698	15
2008	140.31	3.34	7.40	10.74	11.81	0.2826	3.34				16
2009	145.08	3.45	7.88	11.33	12.47	0.2598	3.24				17
2010	149.92	3.57	8.37	11.93	13.13	0.2388	3.13				18
2011	155.05	3.69	8.88	12.57	13.83	0.2195	3.03				19
2012	160.36	3.81	9.43	13.24	14.57	0.2017	2.94	66.259	7.76%	5.145	20
2013	165.74	3.94	10.01	13.96	15.35	0.1854	2.85				21
2014	171.41	4.08	10.64	14.71	16.18	0.1705	2.76				22
2015	177.28	4.22	11.30	15.51	17.06	0.1567	2.67				23
2016	183.21	4.36	12.00	16.36	17.99	0.1440	2.59				24
2017	189.46	4.51	12.75	17.25	18.98	0.1324	2.51	79.642	6.89%	5.466	25
2018	195.90	4.66	13.54	18.20	20.02	0.1217	2.44				26
2019	202.65	4.82	14.39	19.21	21.13	0.1119	2.36				27
2020	209.49	4.98	15.29	20.27	22.30	0.1028	2.29				28
2021	216.64	5.15	16.25	21.40	23.54	0.0945	2.22				29
2022	224.00	5.33	17.28	22.59	24.85	0.0869	2.16	91.118	6.33%	5.771	30

Annual Charge Formula
k/(1-1/(1+k)^a)/(1+k)

where
a = number of years
k = real cost of capital
5.21%

Footnotes:
Column (B) 1997 Generation Demand Cost is $63.36, from RAMPP-2 avoided costs.
Transmission Demand Cost is $25.70, based on December 1992 dollars, escalated by 3.4% inflation thereafter.
Distribution Demand Cost is $2.65, based on December 1992 dollars, escalated by 3.4% inflation thereafter.
Column (C) Conservation Load Factor = 0.480.
Column (D) 1993-1996 production cost model results, 1997-2022 fuel cost of combined cycle CT. Also includes the capital cost of combined cycle combustion turbine which is in excess of a simple cycle combustion turbine. System-wide secondary energy loss factor of 1.1050, applied to avoided costs.
Column (G) Discount rate for present value calculations is based on the Company's weighted Cost of Capital with after-tax cost of debt.
Column (I) Corresponds to Measure Funding Limit in Tariff.

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ATTACHMENT B