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Decision 94-10-059 October 26, 1994

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's own motion to establish rules and procedures governing utility demand-side management.	R.91-08-003 (Filed August 7, 1991)
Order Instituting Investigation on the Commission's own motion to establish procedures governing demand-side management and the competitive procurement thereof.	I.91-08-002 (Filed August 7, 1991)

INTERIM OPINION ON DSM
SHAREHOLDER INCENTIVES: IMPLEMENTATION PHASE

(See Attachment 7 for List of Appearances.)

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INTERIM OPINION ON DSM
SHAREHOLDER INCENTIVES: IMPLEMENTATION PHASE

I. Overview and Summary[1]

By this order, we adopt demand-side management (DSM) shareholder incentive mechanisms for Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and Southern California Gas Company (SoCal) for the 1995 program year.[2] Unless otherwise directed by this Commission, these mechanisms will be in effect through the 1997 program year.

Since the mid-1970's, in response to both Legislative and Commission mandates, California investor-owned utilities have administered programs designed to encourage customers to implement cost-effective demand-side management (DSM). DSM programs focus on the customer side of the utility meter and include programs for load management and energy efficiency, among others. With few exceptions, utility DSM expenditures are financed by ratepayers. The majority of these programs are designed to produce a return to ratepayers in the form of resource savings, that is, by producing load reductions that are less costly to achieve than the alternative of producing more kilowatt-hours (kWh) or kW via supply-side alternatives.

In 1990, after observing that utility commitment to tapping these potential ratepayer benefits was waning, we began

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[1] Attachment 5 explains each technical acronym or other abbreviation that appears in this decision.

[2] We refer to PG&E, SDG&E, SCE, and SoCal collectively as "the utilities" throughout this order.

to experiment with various types of performance-based incentive mechanisms for DSM. For those DSM programs that provide resource benefits, i.e., that avoid or defer more costly supply-side alternatives, we experimented with various forms of mechanisms that would "share the savings" between ratepayers and shareholders. For programs that served equity concerns or provided informational services, we experimented with performance adder mechanisms. Under these mechanisms, earnings were based on parameters designed to encourage broad customer participation.

The DSM incentive mechanisms for each utility have been modified at different times over the 1990-1994 experimental period. Each utility's incentive mechanism is different. In most cases, the specific incentive features included in the mechanisms have been the product of negotiations and settlements among parties to our 1990 DSM incentive proceeding and to subsequent general rate cases.[3]

When we first established shared-savings mechanisms in 1990, the methods and protocols for measuring per unit savings from DSM were still in their early development stages. As a result, these initial shared-savings mechanisms did not require that forecasted per unit savings be adjusted "ex post" by the results of measurement studies conducted after program implementation. For each program year, utilities were authorized

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[3] We established the first set of experimental incentive mechanisms in Application (A.) 90-04-034 et al. (See D.90-08-068 and D.90-12-071.) SCE's experimental incentive mechanism was subsequently revised in its 1992 general rate case proceeding. PG&E's and SDG&E's mechanisms were revised in their 1993 general rate cases. SoCal shifted to a shared-savings approach for resource programs in its recent 1994 general rate case.

all of their earnings one year after program implementation, based on verified program costs and program participation. During this experimental period, the utilities were required to conduct ex post studies to measure per unit savings, and to incorporate those results into their forecasts of DSM on a prospective basis.

By 1993, ex post measurement had reached a stage where specific protocols could be adopted. In Decision (D.) 93-05-063, we established ex post measurement protocols for measuring per unit savings after program implementation, both in terms of the first-year load impacts and the persistence of those impacts over time. Beginning with the 1994 program year, all earnings must be based upon verified per unit savings, as measured by the protocols over a 7 to 10-year period. Earnings are now authorized and recovered in four equal installments over that period, based on measurement study results.

In D.93-09-078, we evaluated the accomplishments of our experimental incentive approach, and concluded that this approach should continue into the future, under the current regulatory framework. The purpose of this phase of the proceeding is to proceed with the next generation of shared-savings incentive mechanisms, based on all that we have learned during the experimental period. It is also our first opportunity to integrate the ex post measurement protocols into both the earnings and penalty calculations for future shared-savings mechanisms.

During this evaluation process, we have learned two major lessons. First, the development of a performance-based incentive mechanism cannot be done in a policy vacuum; rather, it is dependent upon the resolution of several issues that require policy judgments. For any incentive mechanism, these issues generally concern the standard of performance that forms the basis for rewards and penalties, and how the utility should be held accountable to that performance. Designing a performance-based incentive mechanism also requires judgments about the relative risks and rewards of the mechanism, given its specific performance features.

For the DSM shared-savings mechanism in particular, incentive design requires policy judgments on what type of performance standard will best promote least-cost resource procurement objectives. Incentive design also requires policy judgments on how DSM performance risks should be allocated between ratepayers and shareholders, particularly in light of our recently adopted ex post measurement protocols. In addition to assessing the relative risks and rewards inherent in the DSM incentive mechanism itself, we must also evaluate whether DSM risks and rewards are generally comparable to those associated with supply-side alternatives. This is because the purpose of a DSM incentive mechanism is to offset financial and regulatory biases that favor supply-side resources.[4] We have made such judgments in reaching today's determinations.

We have also learned that evaluating the potential impact of a performance-based incentive mechanism is a very complex process, and one that requires extensive thought and

[4] In D.93-09-078, we determined that such biases do exist under the current regulatory framework, and should be offset by DSM incentives. See Section II below.

analysis. To fully understand both the policy and implementation implications of the proposals presented in this proceeding, we have evaluated each of them both qualitatively and quantitatively under several different scenarios. We commend all the parties for contributing to the development of the record in this proceeding, which we believe includes some of the best analytical work done on performance-based incentive design to date.

In today's decision, we establish several basic policy principles with respect to the design of shared-savings mechanisms. While least-cost planning and forecasting is part of our current regulatory framework, we believe that least-cost procurement is best achieved by motivating utilities to maximize DSM benefits whenever and wherever those opportunities actually exist in the market. Once a minimum level of performance has been met, we believe that utilities should be able to increase earnings if and only if they increase net benefits (savings minus costs) to ratepayers, and should receive less earnings for reduced benefits. We also believe that the relationship between earnings and net benefits should be proportional, e.g., a 10% increase (decrease) in net benefits should increase (decrease) earnings by 10%. In addition, the rates at which utilities earn (or are penalized) should be the same across programs or portfolios and across utilities.

Utilities should be accountable not only for achieving net benefits, but also for guaranteeing the cost-effectiveness of DSM activities. Ratepayers should not continue financing DSM investments without adequate protection against the potential losses associated with performance risk. With the adoption of our ex post measurement protocols, we now have the means of providing such protection. Accordingly, we expect utilities to compensate ratepayers for 100% of losses (i.e., negative net benefits), up to the total amount of DSM program costs recovered in rates.

These principles, coupled with our ex post measurement protocols, result in a substantial shift of DSM performance risk from ratepayers to shareholders. Utilities should be given the opportunity to effectively manage these risks, to the benefit of both ratepayers and shareholders, through portfolio diversification. Accordingly, the incentive mechanism adopted today is applied on a portfolio, rather than a program-specific, basis. We establish the earnings opportunity under our adopted DSM incentive mechanism in a manner that is designed both to balance the risks inherent in the mechanism and to offset existing financial and regulatory biases in favor of supply-side procurement.

Our adopted shared-savings mechanism applies to two separate portfolios: one for residential and one for nonresidential DSM programs. Before any earnings can accrue, the utility must achieve 75% of forecasted performance for each portfolio, as verified in the first earnings claim.

For the first time, utilities must also guarantee that ratepayers pay no more for each portfolio than the supply-side resources that DSM is designed to replace. Accordingly, the utility will reimburse ratepayers if verified savings from DSM do not exceed costs, as measured over all four earnings claims, i.e., over a 7 to 10-year period. These penalties will accrue for each portfolio at a 100% rate, up to the total amount of DSM expenditures recovered in rates. For portfolio performance that achieves or exceeds the 75% threshold, utilities will earn at a fixed rate of 30%.

Based on 1994 program estimates, shareholders would receive $89 million, or 30% of the $295 million in net benefits produced by these programs if actual is equal to target performance. This amount would be recovered in four equal installments over a 7 to 10-year measurement period, based on the results of ex post measurement studies. Should verified savings from these programs be less than costs, utilities would be liable for up to $215 million in penalties. If actual performance is twice the forecast, then shareholders would receive $177 million in earnings, or 30% of the $590 million in net benefits produced by the programs. Table 1 presents both the statewide and utility-specific estimates of earnings and penalties at different levels of performance, based on 1994 program year estimates.

The estimates presented in Table 1 do not reflect any measurement costs associated with implementing DSM programs. In D.93-05-063, we identified this phase of the proceeding as the forum for considering the treatment of these costs for both program funding and earnings claims purposes. Today's decision requires that the performance earnings basis for each program year (both portfolios combined) must be adjusted to reflect the measurement and evaluation costs associated with that program year. We also modify DSM Rule 6 to require that DSM programs subject to shared-savings treatment be cost-effective on an aggregated basis when estimated measurement costs are included, as an additional condition for funding.

TABLE 1

EARNINGS AND PENALTY ESTIMATES FOR 1994 DSM PORTFOLIOS
AT DIFFERENT LEVELS OF PERFORMANCE
($ millions, pre-tax)
Based on Adopted Shared-Savings Mechanism

Recorded Performance (% of Forecast)	PG&E	SCE	SDG&E	SoCal	Statewide Total
200%	97	47	19	14	177
150%	73	35	15	10	133
100%	49	23	10	7	89
50%	0	0	0	0	0
30%	0	0	0	0	0
-30%	-49	-23	-10	-7	-89
-50%	-81	-39	-16	-12	-148
-90%	-119	-51	-25	-20	-215
-150%	-119	-51	-25	-20	-215
Forecasted Performance:	162	78	32	23	295
Forecasted Net Benefits:	137	73	29	23	262

NOTE: The estimates for 30% and 50% assume that performance falls within the deadband in the first earnings claim.

Forecasted net benefits are based on total resource costs and benefits, not including measurement costs.

Earnings and penalties would be recovered over a 7 to 10-year period.

These estimates do not include the effect of including measurement costs on forecasted performance or earnings.

Today's decision also modifies current performance adder incentive mechanisms. These mechanisms traditionally apply to DSM programs that serve equity goals or provide services whose long-term savings are difficult to quantify. Our adopted performance adder mechanisms incorporate performance factors that will motivate the utilities to reduce the cost and increase the amount of kilowatt-hour savings generated by these programs. On a statewide basis, shareholders could earn approximately $4.6 million from these programs, assuming that actual performance is equal to target. This figure is also based on 1994 program estimates.

The shared-savings incentive mechanism adopted today will apply to the utilities' retrofit and new construction energy efficiency programs. We will consider extending them to fuel substitution and load management programs once certain implementation issues have been resolved, as described in this decision. Direct assistance and energy management services programs will be subject to performance adder treatment.

We recognize that the utility's role in DSM programs and the current regulatory framework may fundamentally change with electric industry restructuring.[5] We therefore leave open the option to revisit the incentive mechanisms adopted by today's decision before 1997. Section IV below describes the procedures for reexamining these incentives, should circumstances warrant an earlier revisit.

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[5] We are considering electric industry restructuring proposals in Rulemaking (R.) 94-04-031 and the accompanying Investigation (I.) 94-04-032.

II. Background

Under the current regulatory framework, California investor-owned utilities meet their customers' energy needs by acquiring and delivering energy resources on their behalf.[6] In order to ensure that those needs are met at least cost, and in an environmentally sensitive manner, Commission policy and California law require utilities to consider cost-effective DSM as an alternative to generating power or purchasing power elsewhere. In particular, Public Utilities (PU) Code § 701.1 states, in part:

> "The Legislature finds and declares that, in addition to other ratepayer protection objectives, a principal goal of electric and natural gas utilities' resource planning and investment shall be to minimize the cost to society of the reliable energy services that are provided by natural gas and electricity, and to improve the environment and to encourage the diversity of energy sources through improvements in energy efficiency and development of renewable energy resources, such as wind, solar, biomass, and geothermal energy.
>
> "The Legislature further finds and declares that, in addition to any appropriate investments in energy production, electrical and natural gas utilities should seek to exploit all practicable and cost-effective

[6] For noncore gas customers, however, utilities are no longer in the business of resource acquisition. Rather, the utility provides a transportation function for these customers, who acquire gas on their own behalf. In R.94-04-031 and I.94-04-032, we are considering a similar role for the utility in the electric industry.

> conservation and improvements in the efficiency of energy use and distribution that offer equivalent or better system reliability, and which are not being exploited by any other entity."

Consistent with these directives, our DSM rules state:[7]

> "The Commission's goal for utility resource procurement is reliable, least-cost, environmentally sensitive energy service. Using energy more efficiently constitutes an important means of achieving this goal. The utilities should treat energy efficiency improvements and energy conservation as viable alternatives to supply-side resource options." (Rule 1)

Since the mid-1970's, utilities have administered programs designed to encourage customers to implement cost-effective DSM by offering rebate programs, financing programs, and information services. Direct assistance programs have also been offered to provide these same services on a nondiscriminatory basis to low-income and other target groups. With few exceptions, utility expenditures on DSM are financed by ratepayers. Proposed DSM programs are reviewed by the Commission in each utility's general rate case and, if approved, the associated costs are included in the utility's revenue requirements. These revenue requirements are, in turn, recovered in base rates.

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[7] Beginning with D.92-02-075, we have refined our policies and rules governing the evaluation, funding, and implementation of DSM programs and associated shareholder incentives. The most recent version of our DSM rules is appended to D.93-11-017.

Because DSM expenditures are typically expensed, rather than ratebased, utility shareholders do not earn a return on DSM under traditional cost-of-service ratemaking. Utility ratepayers, on the other hand, receive a return in the form of resource savings. These savings occur when DSM programs produce load reductions that are less costly to achieve than the alternative of producing more kWh or kW via supply-side alternatives.

The concept of sharing resource savings with utility shareholders was first raised in 1989 in response to the Commission's observations that utility commitment to tapping these potential ratepayer benefits was waning. (See D.89-05-067.) Since early 1990, the Commission has experimented with various types of DSM shareholder incentive mechanisms for the utilities. These include shared-savings mechanisms, where ratepayers and shareholders share the net benefits (resource savings minus costs) produced by the programs, and performance adder mechanisms, where utilities earn based on performance parameters related to customer participation.

Initially, we adopted simple shared-savings mechanisms that awarded a fixed percentage of DSM net benefits (savings minus costs) to shareholders, after certain minimum performance levels had been met. Performance was measured by verifying program participation (i.e., measures installed or number of program participants) and program costs one year after program implementation. Since the methods and protocols for measuring per unit savings from DSM were not yet adequately developed or standardized, earnings calculations were based on forecasted, not verified, per unit savings. For each program year, earnings were

CASE 1D

All Programs Fall Outside Deadband
Performance Earnings Rate is Nonlinear
Sum PEB_r is Positive

	Program A	Program B	Program C	Program D	Sum of A - D	Portfolio
(1) PEB_f	62.5	62.5	62.5	62.5	250	250
(2) PEB_r	50	35	80	-10	155	155
(2) ÷ (1)	0.8	0.56	1.28	-0.16		0.62
EARNINGS	15	10.5	24	-10	39.5	46.5

ASSUMPTIONS: MPS = 50%
PER = 30% for PEB_r above MPS
100% for negative PEB_r

PEB_f = Forecasted Performance Earnings Basis (Net Benefits)

PEB_r = Realized Performance Earnings Basis (Net Benefits) authorized in a lump sum, one year after program implementation. At the utility's option, earnings were recovered in rates over a one to three-year period.

Beginning in 1992, we experimented with methods that would link the earnings opportunity from DSM more explicitly to that of comparable supply-side alternatives. We established this linkage by applying the utility's authorized rate of return to DSM program costs, and established the resulting earnings level as the target, or forecasted earnings opportunity under the mechanism. Under this approach, a utility's actual earnings would depend not only on the performance actually achieved, but on the relationship between that performance and forecasted accomplishments. Some of the shared-savings mechanisms since 1992 have been applied on a program-specific basis, and some on portfolios of aggregated DSM programs.

During 1993, the Commission reviewed the results of the experiments and concluded that:

> "On balance, there are disincentives to DSM created by both regulation and the private profit-making nature of the firm that limit utility shareholders and management's interest in pursuing all practicable, cost-effective and reliable DSM." (D.93-09-078, mimeo., Conclusion of Law 1.)
>
> "Under the current regulatory framework, DSM shareholder incentives are necessary and appropriate to increase the private value of DSM to a utility by bringing that value more in line with its social value." (Ibid., Conclusion of Law 3.)

In reaching its determination, the Commission stated that incentives "have contributed to the utilities' revitalized interest in pursuing cost-effective DSM in a manner that yields significant net benefits to all ratepayers." (Ibid., p. 1.)

Also during 1993, the Commission adopted ex post measurement protocols to verify per unit estimates of DSM savings and net benefits. (See D.93-05-063.) Beginning with the 1994 program year, all shareholder earnings claims are contingent upon the results of measurement studies performed over a 7 to 10-year period after program implementation. Earnings claims for any particular program year are authorized and recovered in four equal installments over the same period.

The Commission initiated this phase of the proceeding to determine the most appropriate level and design of the next generation of DSM incentive mechanisms. In D.93-09-078, the Commission invited parties to participate in workshops to identify implementation issues and potential areas of consensus prior to evidentiary hearings. (Ibid., pp. 44-45.) For this purpose, the Commission Advisory and Compliance Division (CACD) held ten days of workshops during the last quarter of 1993.

As a result of this informal process, the utilities, the California Energy Commission (CEC), and the Natural Resources Defense Council (NRDC) developed a joint proposal for implementation of shareholder incentives. These parties are referred to collectively as Panel 1. In addition, all workshop participants reached consensus on the basic terms and definitions, as well as on the specific performance scenarios, to be used in comparing proposed incentive mechanisms.

Consensus direct testimony was jointly filed on February 14, 1994 by Panel 1, Division of Ratepayer Advocates (DRA), Toward Utility Ratemaking Normalization (TURN), and NRDC.

The Wisconsin Energy Conservation Corporation (WECC), working as an independent contractor to CACD, included its recommendations in that filing. Nonconsensus direct testimony was subsequently filed by SCE, SDG&E, PG&E, SoCal, NRDC, CEC, TURN, and DRA.

On March 4, 1994, the assigned Administrative Law Judge (ALJ) held a prehearing conference (PHC) to address procedural issues. At the PHC, the ALJ identified several issues that needed to be addressed or clarified, based on her review of the direct testimony. Parties met for an additional three days of workshops to coordinate their responses. Supplemental testimony was jointly submitted by Panel 1, DRA, and TURN on April 14, 1994. Rebuttal testimony was filed by Panel 1, DRA, TURN, and SESCO, Inc. (SESCO) on April 22, 1994.[8]

Fifteen days of evidentiary hearings were held during early May, 1994. Opening and reply briefs were filed by PG&E, SCE, SDG&E, SoCal, DRA, CEC, NRDC, TURN, and SESCO.

III. Issues

As described above, parties reached agreement on the terms and definitions to be used in developing and comparing proposals, but there was limited agreement on the resolution of

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[8] SESCO's participation in this phase of the proceeding was limited to attending the additional set of workshops on March 22-24, 1994. With the permission of the ALJ, SESCO was allowed to submit rebuttal testimony limited to the specific issues addressed in those workshops. Much of SESCO's testimony and brief address competitive bidding and other issues that go beyond the scope of these workshops and this proceeding. We limit our discussion of SESCO's affirmative showing to those issues that fall within the scope of the ALJ's directions.

specific issues. The major issues to be determined in this phase of the proceeding are:

- o How should shared-savings incentive mechanisms be structured, and what programs should be eligible for that treatment?
- o How should performance adder incentive mechanisms be structured, and what programs should be eligible for that treatment?
- o How much flexibility should utilities have to shift funding among programs and to exceed authorized funding levels?

In addition, the issue of whether and how measurement costs should be considered for DSM program funding and earnings claim purposes was deferred to this phase. (See D.93-05-063, mimeo., p. 64.) Finally, in D.93-09-078, we identified this phase of the proceeding as the forum for considering certain federal standards under Sections 111 and 115 of the Energy Policy Act of 1992.

This section summarizes the key differences among the parties. The discussion that follows focuses on the major areas of contention in this phase of the proceeding. For the sake of brevity, we will refer to parties' positions within that discussion, but refrain from reiterating the arguments of each party on each individual issue.

A. <u>Shared-Savings Incentive Mechanisms</u>

Most of the testimony addressed parties' proposals for shared-savings incentive mechanisms.[9] Before turning to specific proposals, we review some of the common terminology used to describe a shared-savings mechanism. For this purpose, we will use a graphical depiction of the Panel 1 proposal, presented in Figures 1-A and 1-B.

Figure 1-B presents a graph of potential earnings and penalties as a function of performance, which we refer to as the shared-savings curve. The dollar figures presented in Figure 1-B represent the levels of penalties or rewards assuming that the Panel 1 proposal were applied to estimated 1994 program costs and benefits for all four utilities.

To fully define a shared-savings curve, one needs to (1) define the x-axis, (2) establish the slope of the curve at every point, and (3) establish the height of the curve along the y-axis. The x-axis is defined as the ratio between realized and forecasted (or target) performance earnings basis. Performance is defined in terms of the net benefits (resource benefits minus costs) to ratepayers from avoiding or deferring the need for more costly supply-side resources. Forecasts of performance are made prior to program implementation, while realized performance is measured after program implementation, using our adopted ex post measurement protocols. For example, at the 100% point along the x-axis, realized net benefits are equal to forecasted, or target, net benefits.

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[9] Parties' proposals for performance adder mechanisms are addressed in Section B below.

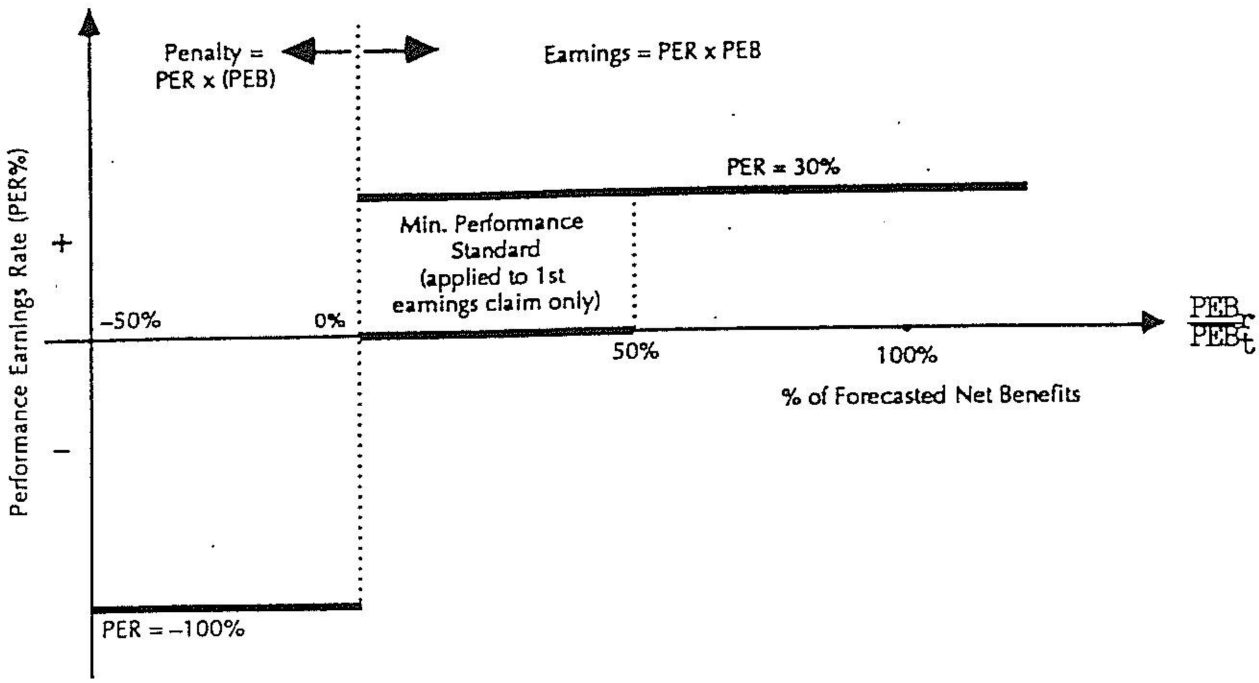
The performance earnings rate is the slope of the shared-savings curve. This represents the rate at which DSM net benefits are shared between shareholders and ratepayers at any point along the curve. Figure 1-A presents these rates for the Panel 1 proposal. As shown in the graph, performance below 0% is subject to penalties at a 100% rate. Performance at or above 50% of target (the minimum performance standard) is awarded earnings at a 30% rate. The rate for performance within the 0% to 49% range is zero. We refer to this range as the "deadband" because there are no penalties or earnings for performance that falls within this range.

Curves with the same slope can be plotted at various heights along the y-axis, each representing very different levels of potential penalties and earnings. Therefore, one also needs to establish the height of the shared-savings curve along the y-axis to fully define the curve. As discussed below, there are basically two ways to do this. One can first establish the performance earnings rate (i.e., the slope) at target performance (100% along the x-axis), and then multiply target performance by that rate. For example, if the performance earnings rate at target is established at 30%, and target performance is $213 million in net benefits, then the height of the curve is approximately $64 million, as shown in Figure 1-B. This is the approach taken by Panel 1 and others. We refer to the height of the curve at target as the target earnings level.

Figure 1-A

Panel 1 Recommended Shared-Savings Mechanism

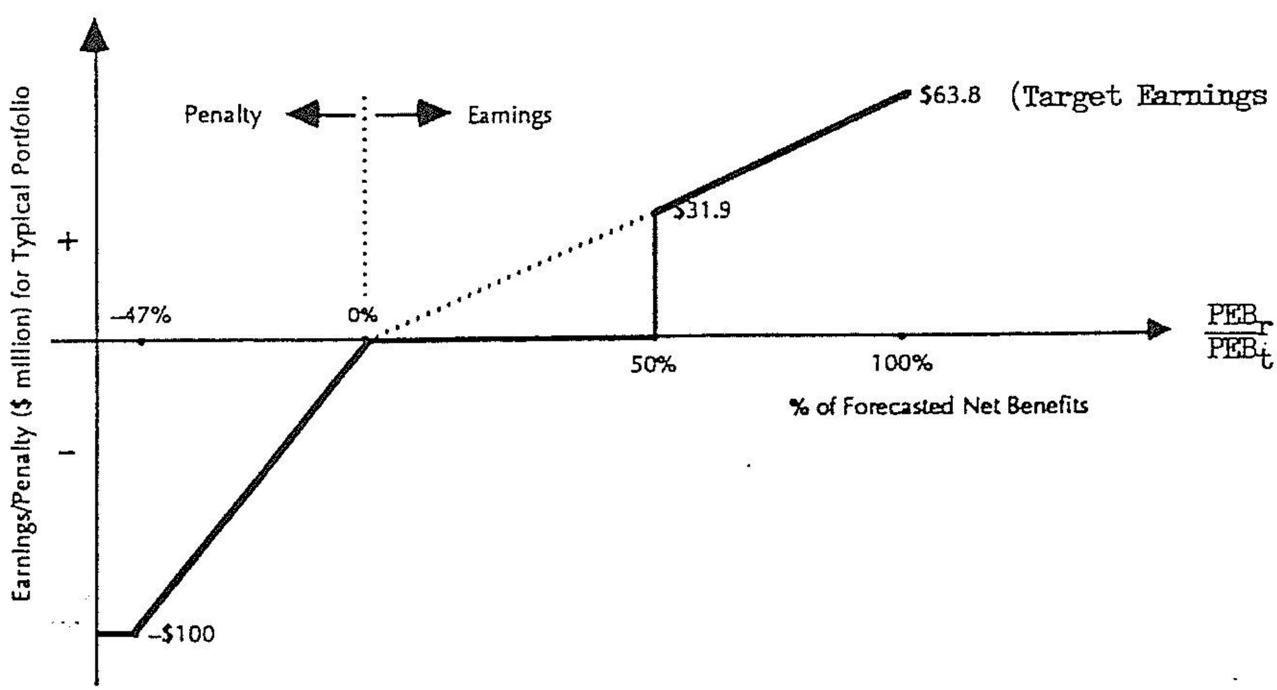
(Applied at Portfolio Level)



PER = Performance Earnings Rate (slope)
PEB_r = Realized Performance Earnings Basis
PEB_t = Target (forecasted) Performance Earnings Basis

Figure 1-B

Potential Earnings and Penalty for a Typical Portfolio



(Target Earnings Level)

Source: Exhibit 345

Alternatively, one can first establish the target earnings level and then derive the performance earnings rate by dividing target earnings by target performance. In the example in Figure 1-B, if we first established the target earnings level at $64 million, and then divide by target performance of $213 million, we would derive a 30% performance earnings rate at target. This is the methodology recommended by DRA.

An incentive mechanism can also include caps on earnings or penalties, or both. Alternatively, the earnings rates (slope of the curve) can decline at certain levels of performance. In Figure 1-B, penalties are capped at $100 million.

As described below, parties present a wide range of proposals on most of the major features of a shared-savings mechanism. A summary comparison of the parties' proposals is depicted in Figure 2.[10]

1. <u>Performance Earnings Basis</u>

All parties agree that the performance earnings basis of a shared-savings incentive mechanism should be based on net benefits. However, there is disagreement on how different cost components should be considered in calculating net benefits. From the total resource cost (TRC) perspective, one looks at the total cost of implementing a program, including utility program costs and the participating customer's out-of-pocket expenses.

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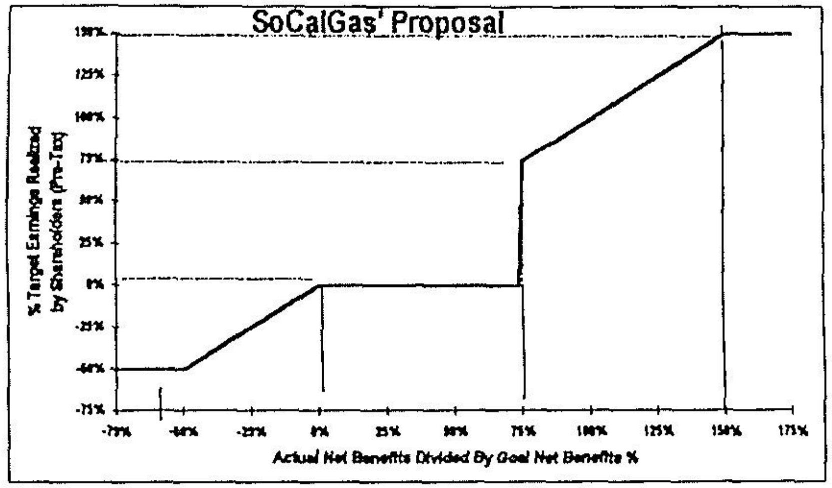
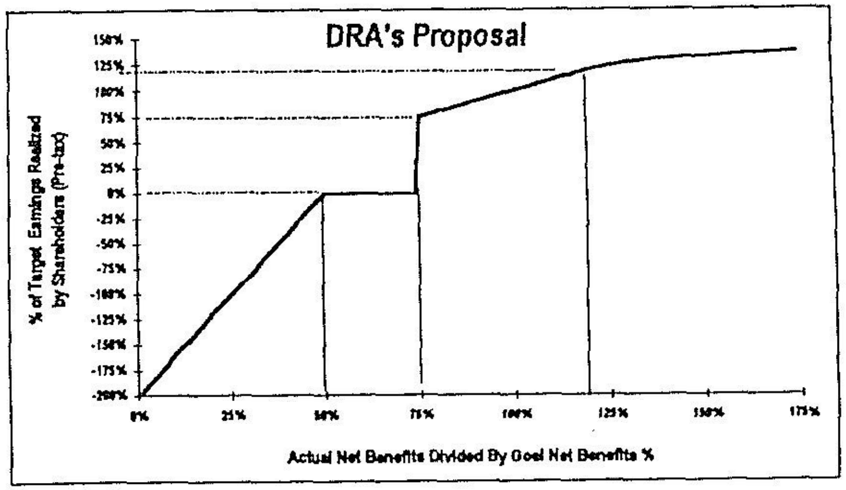
[10] TURN's proposal is not depicted in Figure 2, but can easily be drawn as follows: At 100% along the x-axis, the percent of earnings realized would be zero. Above and below this point, the slope of the curve would be 0.10. (See Reporter's Transcript (RT) p. 4733.)

FIGURE 2

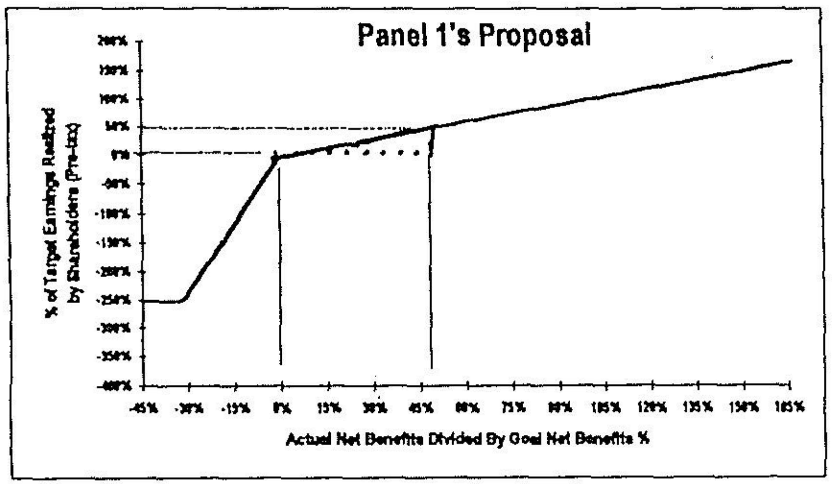
SUMMARY COMPARISON OF PARTIES' SHARED SAVINGS PROPOSALS



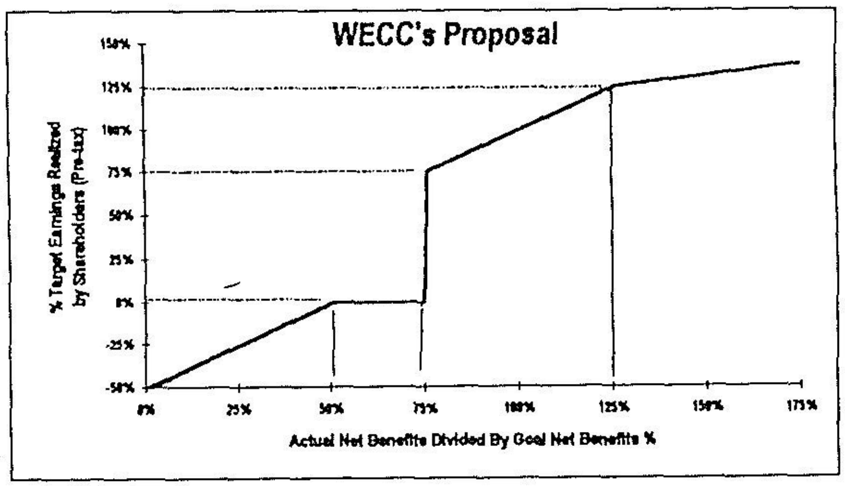
TEL	20% of TRC Net Benefits + 10% UC Net Benefits
MPS	75% of Net Benefits Forecast; applied across all four earnings claims
Deadband	0% to 75% of Net Benefits Forecast; applied across all four earnings claims
Max. Upside	150% of TEL
Max. Downside	50% of TEL; penalties/"refunds" limited to the first two earnings claims; *potential compounding effect across multiple program years*
Applicability	Deadband and earnings zones applied at the program level *Penalties applied at the total portfolio level*



TEL	13% of Net Incremental Measure Costs for SoCalGas *18% of Net Incremental Measure Costs for PG&E, SCE & SDG&E*
MPS	75% of Net Benefits Forecast; applied across all four earnings claims
Deadband	50% to 75% of Net Benefits Forecast; applied across all four earnings claims
Max. Upside	No cap on earnings, but earnings rate declines sharply beyond 115% of TEL
Max. Downside	200% of TEL; penalties/"refunds" applied to all four earnings claims; potential compounding effect across multiple program years
Applicability	Individual program level



TEL	*0.30 * (50% of TRC Net Benefits + 50% UC Net Benefits)*
MPS	50% of Net Benefits Forecast; applied to the first earnings claim only
Deadband	*0% to 50% of Net Benefits Forecast; applied to the first earnings claim only*
Max. Upside	No cap on earnings, but earnings are essentially limited by authorized program funding
Max. Downside	100% of program costs; "cost-effectiveness guarantee" *over the measurement period;* potential compounding effect across multiple program years
Applicability	Residential and non residential portfolios



TEL	20% of TRC Net Benefits + 10% UC Net Benefits
MPS	75% of Net Benefits Forecast; applied across all four earnings claims
Deadband	50% to 75% of Net Benefits Forecast; applied across all four earnings claims
Max. Upside	No cap on earnings, but earnings rate declines sharply beyond 125% of TEL
Max. Downside	50% of TEL; penalties/"refunds" limited to the first two earnings claims; potential compounding effect across multiple program years
Applicability	Individual program level

Source: Exhibit 343A

From the utility cost (UC) perspective, one looks only at the costs reflected in the utility's revenue requirement, which does not include the participating customer's out-of-pocket expenses.[11]

Under the Panel 1 proposal, the performance earnings basis gives equal weight to the TRC and UC cost components in deriving net benefits. DRA, WECC, and SoCal recommend that the TRC and UC components be weighted 2/3 and 1/3, respectively. Under each of these weighting proposals, earnings would include the results of individual programs that both pass the TRC test and produce a positive performance earnings basis. Similarly, the calculation of penalties would include the results of individual programs that do not pass the TRC test and produce a negative performance earnings basis. However, under the Panel 1 TRC "trigger" proposal, the calculation of earnings would not include the results of programs that produced a positive performance earnings basis, but did not pass the TRC test. This could happen under certain circumstances due to the weighting of UC and TRC costs in the calculation of performance earnings basis. (RT at 3892-3896.)

TURN and SESCO, on the other hand, do not recommend a weighting approach. TURN proposes that the performance earnings basis only consider the UC components. SESCO recommends that the

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[11] More specifically, under the TRC approach, net benefits equals resource benefits (net of free riders) less program administration and incremental measure costs. Under the UC approach, the cost components are program administration costs and program incentives (which are usually significantly less then the incremental measure cost).

calculation of net benefits be based solely upon the TRC test. (Exhibit (Exh.) 373, p. 10; Exh. 378, pp. 3-5; Exh. 340, p. 4.)

Most parties agree that SoCal should be allowed to earn on electric savings associated with gas energy efficiency measures, and vice versa for SCE. For example, under this approach both the gas (from space heating) and electric (from air conditioning) savings associated with weatherization measures would be included in the calculation of performance earnings basis. DRA supports this approach only if the measures are implemented as a result of a coordinated utility program. SCE believes it is inappropriate to claim earnings for savings from the other fuel because those savings are secondary and uncertain.

As discussed in Section D below, parties also present different positions on the treatment of measurement costs for earnings claim purposes.

2. Minimum Performance Standards and Deadband Ranges

Despite their differences on how to define the performance earnings basis, all parties agree that a utility should achieve a minimum percentage of forecasted net benefits before it is eligible for shared savings. Consequently, all shared-savings proposals include penalty and deadband ranges up to a minimum performance standard (MPS). However, parties disagree on the level of the MPS and the corresponding deadband ranges. As described above, Panel 1 believes that a 50% MPS with a 0% to 49% deadband range is appropriate. SoCal recommends a 75% MPS with a 0% to 74% deadband range. DRA and WECC recommend an MPS of 75% with a deadband range of 50% to 74%. Under TURN's proposal, penalties would accrue at any point below the 100%

level, i.e., the deadband is the single point where realized equals forecasted net benefits. SESCO supports TURN's approach. (See SESCO Opening Brief, p. 7.)

Parties also disagree on the parameters of performance to which the MPS should be applied and, consequently, on the application of the MPS across earnings claims. Prior to 1994, shareholder earnings were authorized in a single earnings claim, after the utilities verified program costs and program participation (i.e., the number of customers served or measures installed). By definition, the MPS applied only to those performance parameters and to the first (and only) earnings claim. With the adoption of ex post measurement protocols, there are other possible applications.

Panel 1 would continue to apply the MPS to verified program costs and program participation relative to forecasted amounts. Under the adopted ex post measurement protocols, these parameters are verified in the first earnings claim which occurs one year after program implementation.

Under the Panel 1 proposal, programs falling within the deadband at the first earnings claim would no longer be eligible for earnings, even if subsequent measurement results would pull them out of that range. However, these programs would still be subject to penalties in future earnings claims if the results of subsequent measurement studies indicated that they were not cost-effective. (RT at 4307.)[12]

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[12] As discussed below, the MPS and associated deadband range would apply to each portfolio of programs under the Panel 1 proposal, and not to each individual program.

Under DRA's proposal, the MPS would also apply to first-year per-unit savings (verified in year 2) as well as to the persistence of those savings measured in years 5 and 10 after program implementation. Hence, programs could become ineligible for any earnings at any of the four earnings claims.

SoCal and WECC recommend a hybrid approach: For earnings calculations, the MPS would be applied across all four earnings claims, consistent with DRA's recommendation. For the purpose of calculating penalties, however, SoCal and WECC would apply the MPS to the first two earnings claims only, which is where program participation, program costs and first-year per unit savings are verified. Programs falling into the deadband range would be ineligible for either earnings or penalties. WECC also recommends that earnings levels at each claim be established by taking 25% of the recorded earnings basis at that claim.[13]

3. Eligibility and Program Applicability

All parties agree that retrofit energy efficiency programs should continue to be eligible for shared-savings incentives. Parties disagree on whether (and how) to include new construction programs, certain types of load management and fuel

[13] We recently addressed a similar proposal and rejected it in favor of full true-up procedures. (See D.94-05-063, mimeo., pp. 6-8.) We reaffirm our decision in D.94-05-063 by requiring that the calculation of earnings or penalties in each claim subtract out the earnings (or penalties) recovered in previous claims. Whereas in D.94-05-063 we determined that our adopted measurement and evaluation protocols did not require that previously paid out earnings be returned to ratepayers (or that penalties be incurred), today's decision does extend the true-up provisions to those circumstances for program year 1995 and beyond. (See Section 5.b(4) below.)

substitution programs under a shared-savings approach. (Exh. 340, p. 6.) SoCal also proposes that the utility should be able to opt out of eligibility for any particular program, at the utility's discretion.

In particular, SoCal argues that applying a shared-savings approach to new construction programs would introduce too much risk, thereby discouraging the utility from pursuing these lost opportunities. (Exh. 343, pp. 21-22.) Instead, SoCal proposes a performance adder mechanism for new construction that would base earnings on a percentage of program expenditures. The percentage would increase as a function of how far the program exceeds current efficiency standards. (Ibid., pp. 60-61.)

With regard to load management and fuel substitution programs, both SoCal and TURN argue that there are currently no disincentives to pursuing either load management or fuel substitution activities. Therefore, they recommend that these programs continue to be ineligible for incentives. SoCal also raises concerns that thermal energy storage, which is currently classified as a load management program, is being implemented by SCE to promote electric technologies and fuel switching. SoCal argues that allowing incentives for thermal energy storage would inappropriately tilt the playing field in favor of electrotechnologies. (Ibid., p. 17; RT at 4314-4318.)

DRA recommends that thermal energy storage be removed from its current classification as load management, and reclassified as a measure under retrofit energy efficiency, new construction or fuel substitution programs, whichever is applicable. (RT at 4318-4319; Exh. 340A, p. 6.) DRA believes that all other programs currently classified as load management suffer from intractable problems of measuring costs and benefits, and should not be eligible for earnings for that reason. (Exh. 340A, pp. 6-7; RT at 4322-4325.) DRA recommends that fuel substitution programs should be eligible for shared-savings, subject to two conditions: First, eligibility should be conditioned upon the establishment of ex post measurement protocols appropriate for these programs. Second, SCE and SoCal should not be authorized to include fuel substitution programs for any kind of shareholder incentives at this time. DRA believes that this second condition would avoid the market share disputes between these two single-fuel utilities. (Exh. 341, pp. 59-61.)

Panel 1 recommends that shared-savings treatment should be afforded to all energy efficiency, load management or fuel substitution programs that provide measurable net benefits and for which measurement protocols can be adopted. Panel 1 would delegate the initial development of specific protocols to the California DSM Measurement Advisory Committee (CADMAC), subject to subsequent Commission approval. (RT at 4324.) To be eligible for shareholder incentives, all fuel substitution programs would be required to pass the adopted three-prong test on a prospective basis, consistent with the Commission's funding rules. (Exh. 340A, pp. 6-7.)

Parties also disagree on whether the adopted incentive mechanism should apply to each program on an individual basis or to a portfolio of programs. DRA and WECC support applying the shareholder mechanism individually to each of the following programs: Residential Weatherization Retrofit Incentives, Residential Appliance Efficiency Incentives, Residential New

Construction, Commercial Energy Efficiency Incentives, Industrial Energy Efficiency Incentives, Agricultural Energy Efficiency Incentives, and Nonresidential New Construction. SESCO supports this approach. (SESCO Opening Brief, p. 7.)

Panel 1 prefers an approach where performance, rewards and penalties are measured on an aggregated basis for two portfolios: one consisting of all the residential programs and the other consisting of all the nonresidential programs. SoCal recommends a hybrid approach, where penalties are applied on the portfolio level (consisting of both residential and nonresidential programs) and minimum performance requirements and rewards are applied on the program-specific level.

4. **Target Earnings Level and <u>Performance Earnings Rates</u>**

Most of the testimony focuses on the appropriate earnings level and associated performance earnings rates at forecasted or target performance. For all four utilities, the Panel 1, SoCal, and WECC shared-savings proposals create significantly higher earnings opportunity (at target) relative to the mechanisms in place during the 1990-1994 period. TURN's and DRA's shared-savings proposals generally maintain or increase the earnings potential relative to the 1990-1994 period, but reduce earnings potential for some utilities when their recommendations concerning performance adder incentives are considered.[14]

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[14] See Exh. 337, pp. A-33 to A-36; RT at 3717-3721. Although TURN Witness Coyle stated during cross-examination that TURN does not have a specific recommendation for SoCal (RT at 4749-4750), TURN jointly sponsored the figures in Exh. 337. We present and discuss them in this decision to illustrate the impact of TURN's proposal if it were applied to SoCal, and not to imply TURN's endorsement of

A comparison of recommended target earnings levels for DSM programs given shared-savings and performance adder treatment is presented in Table 2, by utility. These figures are based on 1994 program year estimates. The amounts would be recovered in four installments over 7 to 10 years, assuming that verified performance is equal to target. Parties' recommendations on performance earnings rates are summarized in Table 3. Although Panel 1, SoCal, and WECC recommend identical performance earnings rates for shared-savings programs, their recommended target earnings levels differ due to differences in their definition of performance earnings basis, and their different positions on program eligibility. When adjusted for these differences, their recommended target earnings levels for shared-savings programs would be identical.

Parties arrive at their recommendations using very different approaches. Under the DRA approach, the performance earnings rate at target is derived from the target earnings level, which is determined as follows: First, DRA establishes the earnings rate associated with a rate-based plant at 36%. DRA then adjusts that rate downward by 50-65 percent to account for DRA's consideration of relative risks between supply- and demand-side resources. That adjusted rate (referred to as the target earnings rate) is then applied to the estimated costs of DSM measures included in each of the utility's proposed programs.' The product of the target earnings rate and the estimated measure costs yields the target earnings level for each program.

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these levels for SoCal.

TABLE 2

COMPARISON OF HISTORICAL AND RECOMMENDED TARGET EARNINGS LEVELS
(pre-tax $ million, 1994)

	1990-1992 Average	1993-1994 Average	PANEL 1 1/	SOCAL	DRA	TURN 4/	WECC
PG&E							
-shared savings	33.9	12.5	52.7	31.1	28.3	21.5	48.9
-perf. adder	2.5	7.8	2.0	6.0	2.0	2.0	2.0
Total	36.4	20.3	54.7	37.1	30.3	23.5	50.9
SCE	2/						
-shared savings	7.4	5.4	24.0	20.5	8.0	8.7	23.3
-perf. adder	.8	1.1	1.7	2.6	1.7	1.7	1.7
Total	8.2	6.5	25.7	23.1	9.7	10.4	25.0
SDG&E							
-shared savings	5.8	2.7	10.3	7.8	5.8	4.0	9.7
-perf. adder	.1	1.4	.2	.9	.2	.2	.2
Total	5.9	4.1	10.5	8.7	6.0	4.2	9.9
SoCal		3/					
-shared savings	1.7	1.9	7.1	5.3	1.7	2.5	7.0
-perf. adder	1.5	1.7	.8	1.7	.8	.8	.8
Total	3.2	3.6	7.9	7.0	2.5	3.3	7.8
Statewide Totals	53.7	34.5	98.8	75.9	48.5	41.4	93.6

NOTE: The target earnings levels in this table were developed based on the utilities' 1994 program year data. These amounts would be recovered in four installments over a 7 to 10-year measurement period, assuming that verified performance is equal to target.

1/ PANEL 1 consists of PG&E, SCE, SDG&E, CEC, and NRDC

2/ Prior to 1992, SCE's DSM programs were given either amortization or performance adder treatment. The average over the 1990-1992 period reflects 1990-1991 earnings under the amortization treatment, since that treatment was given to programs with resource value.

Footnotes of Table 2 Cont'd

3/ Prior to 1994, SoCal's DSM programs were given variable-rate-of-return or performance adder treatment. The averages over the 1990-1992 and 1993-1994 periods reflect earnings under the variable-rate-of-return treatment, since that treatment was given to programs with resource value.

4/ Under TURN's proposal, utilities would not earn anything at target. At any point above target, the utility would earn at a 10% rate. (See Table 4.) For comparative purposes, we apply this rate to TURN's definition of performance earnings basis and include the results in this table.

Sources: Exhibit 337, pp. A-3 to A-8; A-33 to A-36.

TABLE 3

COMPARISON OF RECOMMENDED TARGET
PERFORMANCE EARNINGS RATES (PER_t)

	PANEL 1	SOCAL	WECC	DRA 1/	TURN 3/
PG&E	30%	30%	30%	17%	10%
SCE	30%	30%	30%	10%	10%
SDG&E	30%	30%	30%	18%	10%
SoCal	30%	30%	30%	7%	10%

DRA'S RECOMMENDED PER_t BY PROGRAM 2/

Program:	PG&E	SCE	SDG&E	SOCAL
Residential Weatherization Retrofit	11%	NA	NA	3%
Residential Appliance Efficiency	13	11%	21%	47%
Commercial Energy Efficiency	29%	7%	18%	6%
Industrial Energy Efficiency	21%	7%	NA	7%
Agricultural Energy Efficiency	16%	11%	NA	NA
Residential New Construction	56%	96%	85%	32%
Nonresidential New Construction	6%	22%	7%	3%
TOTAL	17%	10%	18%	7%

NA = not applicable

1/ Total average percentage rates for DRA, by utility, were calculated from Exhibit 337, Joint Tables C-1 to C-4 as the sum of target earnings level for retrofit energy efficiency

Footnotes of Table 3 Cont'd

incentives and new construction programs (line 18) divided by the performance earnings basis (line 19).

2/ From Exh. 350; all other proposals apply the same rate (shown above) to each program or portfolio of programs.

3/ Under TURN's proposal, utilities would not earn anything at target. At any point above target, the utility would earn at a 10% rate. (See Table 4.) For comparative purposes, we present the 10% rate in this table.

Performance earning rates (at target) are the result of dividing the target earnings level calculated above by the forecast of target net benefits (expressed as the performance earnings basis) for each proposed program. This two-step process can be expressed in equation form, as follows:

$$(1) \quad TEL = TER \times IMC$$

$$(2) \quad PER_t = \frac{TEL}{PEB_t}$$

Where TEL = target earnings level

TER = target earnings rate (as derived from a supply-side earnings comparability assessment)

IMC = incremental costs of DSM program measures

PEB_t = performance earnings basis at target (forecasted)

PER_t = performance earnings rate (i.e., slope of the shared-savings curve) at target.

Under the DRA approach, both the target earnings level and the resulting performance earnings rates vary by program. (See Table 3.)

TURN develops its recommendation based on an assessment of a fair return. Since TURN believes that the relative risk to shareholders of proceeding with DSM is "trivial," TURN believes that it is fair to test whether the utilities can achieve 1990-1992 DSM accomplishments with a lower level of shared savings. As a result, TURN recommends a 10% fixed performance earnings rate across programs and utilities. (Exh. 373, pp. 6-10; Exh. 374, pp. 7-8.)

WECC, on the other hand, argues that the earnings potential from DSM under future shared-savings mechanisms should at least be comparable to the shareholder value realized during the 1990-1992 period. WECC bases its analysis on the report it prepared for CACD in early 1993, pursuant to Legislative mandate.[15] WECC develops its proposed target earnings level and performance earnings rate by assessing the earnings per share recorded during the 1990-1992 period. Based on this analysis and its assessment of relative changes in the benefits, costs, and risks from the proposed level of DSM efforts and the proposed incentive mechanism, WECC concludes that a target performance rate of 30% is reasonable. SESCO supports a rate of at least 30%, but preferably higher (SESCO Opening Brief, p. 5).

Panel 1 applies a combination of approaches to develop its performance earnings rate and target earnings level. First, Panel 1 argues that a 30% target earnings rate is fair, given the overall risk/reward profile of the Panel 1 incentive mechanism, especially the 100% cost-effectiveness guarantee. (See below.) Panel 1 argues that the 30% rate is reasonably comparable to the earnings potential associated with a rate-based plant. Finally, Panel 1 compares its recommended target earnings opportunity with WECC's recorded data on DSM-related earnings per share over the 1990-1992 period. Panel 1 concludes that its proposal would

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[15] WECC prepared an evaluation of the 1990-1992 experimental incentive mechanisms pursuant to PU Code § 746(d) and our directives in D.90-08-068 (mimeo., p. 40). WECC's report, Evaluation of DSM Shareholder Incentive Mechanisms was filed on January 8, 1993. This report was entered into evidence during a previous phase of this proceeding as Exh. 301.

provide sufficient motivation for utility management to pursue cost-effective DSM.

Under the Panel 1 approach, the target earnings rate is not used to establish target earnings level, as it is under DRA's approach. Instead, the target earnings rate becomes the DSM performance earnings rate at target. Target earnings level is simply the product of that performance earnings rate times target performance, as illustrated in our earlier example. As a result, there is a single performance earnings rate for each program or portfolio, and across utilities.

Parties also disagree on what earnings rates should be applied at levels of performance beyond the deadband range. Panel 1 recommends that the rate be fixed at all levels beyond the deadband, without any cap other than the cap imposed by limited DSM funding. Under SoCal's proposal, earnings are capped at 150% of the target earnings level. DRA's proposed earnings rate sharply declines beyond 115% of target performance, and WECC's rate sharply declines beyond 125% of target. (See Figure 2.)

The penalty side of the incentive mechanism also varies among the proposals. As described above, under the Panel 1 proposal, the penalty rate for negative net benefits (as expressed by the performance earnings basis) is 100%. SESCO supports this penalty rate. (See SESCO Opening Brief, p. 5.) In other words, the utility guarantees program cost-effectiveness such that ratepayers are reimbursed 100% for any investment losses (i.e., negative net benefits). The level of penalties is capped at the total level of utility costs, that is, the amount that the utility recovered in rates to pay for the program.

Based on 1994 data this corresponds to a cap of approximately 250% of target earnings level.

Penalty rates under the DRA proposal vary by program and utility, and are capped at 200% of target earnings. WECC and SoCal apply a fixed penalty rate of 30% and cap penalties at 50% of target earnings. Panel 1 and DRA calculate penalties based on ex post measurement results over all four earnings claims. WECC and SoCal, on the other hand, recommend that penalties be limited to the first two earnings claims.

Tables 4A-4D present earnings and penalty estimates under recommended shared-savings proposals, by utility, based on 1994 program estimates. As shown in these tables, the combination of proposed target earnings levels, earnings and penalty rates, yield very different upside and downside potential across the various shared-savings mechanisms.

5. **Discussion**

As described in our DSM rules, shareholder incentives are a means of achieving our goal for utility resource procurement, namely, to provide ratepayers with reliable, least-cost, and environmentally sensitive energy service. We recognize that the role of utilities in DSM may change with industry restructuring; however, as long as the utilities remain in the business of procuring resources to meet some or all of their customers' energy needs, we expect them to do so in a manner that is consistent with this objective.

More recently, we have determined that the 1990-1992 collaborative experiment in DSM shareholder incentives was a success: Shareholder incentives have contributed to the

TABLE 4A

EARNINGS AND PENALTY ESTIMATES FOR 1994 DSM PORTFOLIOS
AT DIFFERENT LEVELS OF PERFORMANCE
($ millions, pre-tax)
Based on the Recommended Shared-Savings Mechanisms

PACIFIC GAS & ELECTRIC COMPANY

Recorded PEB (% of Forecast)	Panel 1	SoCal	DRA	TURN	WECC
200%	105	73	40	21	70
150%	79	73	37	11	64
100%	53	49	28	0	49
50%	26	0	14	-11	0
-30%	0	0	-34	-15	-10
-30	-53	-15	-56	-28	-25
-50%	-88	-24	-56	-32	-25
-90%	-119	-24	-56	-41	-25
-150%	-119	-24	-56	-54	-25
Forecasted PEB:	176	162	162	215	162

NOTE: For comparative purposes, these calculations include both retrofit and new construction programs, and assume that the MPS is applied across all four earnings claims.

PEB = Performance Earnings Basis

Sources: Exh. 348 A, B, C, and Exh. 337, Joint Tables C-1 to C-4

TABLE 4B

EARNINGS AND PENALTY ESTIMATES FOR 1994 DSM PORTFOLIOS
AT DIFFERENT LEVELS OF PERFORMANCE
($ millions, pre-tax)
Based on the Recommended Shared-Savings Mechanisms

SOUTHERN CALIFORNIA EDISON COMPANY

Recorded PEB (% of Forecast)	Panel 1	SoCal	DRA	TURN	WECC
200%	48	35	12	9	34
150	36	35	11	4	31
100%	24	23	8	0	23
50%	12	0	4	-4	0
-30%	0	0	-10	-6	-5
-30	-24	-7	-16	-11	-12
-50%	-40	-12	-16	-13	-12
-90%	-51	-12	-16	-17	-12
-150%	-51	-12	-16	-32	-12
Forecasted PEB:	80	78	78	87	78

NOTE: For comparative purposes, these calculations include both retrofit and new construction programs, and assume that the MPS is applied across all four earnings claims.

PEB = Performance Earnings Basis

Sources: Exh. 348 A, B, C, and Exh. 337, Joint Tables C-1 to C-4

TABLE 4C

EARNINGS AND PENALTY ESTIMATES FOR 1994 DSM PORTFOLIOS
AT DIFFERENT LEVELS OF PERFORMANCE
($ millions, pre-tax)
Based on the Recommended Shared-Savings Mechanisms

SAN DIEGO GAS & ELECTRIC COMPANY

Recorded PEB (% of Forecast)	Panel 1	SoCal	DRA	TURN	WECC
200%	21	14	8	4	14
150	15	14	8	2	13
100%	10	10	6	0	10
50%	5	0	3	-2	0
-30%	0	0	-7	-3	-2
-30	-10	-3	-12	-5	-10
-50%	-17	-5	-12	-6	-5
-90%	-25	-5	-12	-8	-5
-150%	-25	-5	-12	-10	-5
Forecasted PEB:	34	32	32	40	32

NOTE: For comparative purposes, these calculations include both retrofit and new construction programs, and assume that the MPS is applied across all four earnings claims.

PEB = Performance Earnings Basis

Sources: Exh. 348 A, B, C, and Exh. 337, Joint Tables C-1 to C-4

TABLE 4D

EARNINGS AND PENALTY ESTIMATES FOR 1994 DSM PORTFOLIOS
AT DIFFERENT LEVELS OF PERFORMANCE
($ millions, pre-tax)
Based on the Recommended Shared-Savings Mechanisms

SOUTHERN CALIFORNIA GAS COMPANY

Recorded PEB (% of Forecast)	Panel 1	SoCal	DRA	TURN	WECC
200%	14	11	3	3	10
150	11	11	2	1	9
100%	7	7	2	0	7
50%	4	0	1	-1	0
-30%	0	0	-2	-2	-1
-30	-7	-7	-3	-3	-4
-50%	-12	-4	-3	-4	-4
-90%	-20	-4	-3	-5	-4
-150%	-20	-4	-3	-6	-4
Forecasted PEB:	24	23	23	25	23

NOTE: For comparative purposes, these calculations include both retrofit and new construction programs, and assume that the MPS is applied across all four earnings claims.

PEB = Performance Earnings Basis

Sources: Exh. 348 A, B, C, and Exh. 337, Joint Tables C-1 to C-4

utilities' revitalized interest in pursuing cost-effective DSM in a manner that has produced significant net benefits to all ratepayers. (See D.93-09-078.) Our task today is to build upon that success by adopting performance-based incentive mechanisms that improve upon those we have experimented with in the past.

As reflected by the range of proposals presented in this proceeding, a shared-savings incentive mechanism can be designed in a variety of ways. However, incentive design is not just a technical choice. It reflects the designer's policy judgments on what standard of performance should form the basis for rewards and penalties, and how the utility should be held accountable for that performance. Different incentive designs will also motivate utilities in different ways with respect to least-cost resource procurement. Finally, each incentive mechanism will create a different opportunity for earnings and balance risks and rewards differently, depending on the specific features of that mechanism. We discuss our views on these issues in the following sections.

a. <u>Least-Cost Resource Procurement</u>

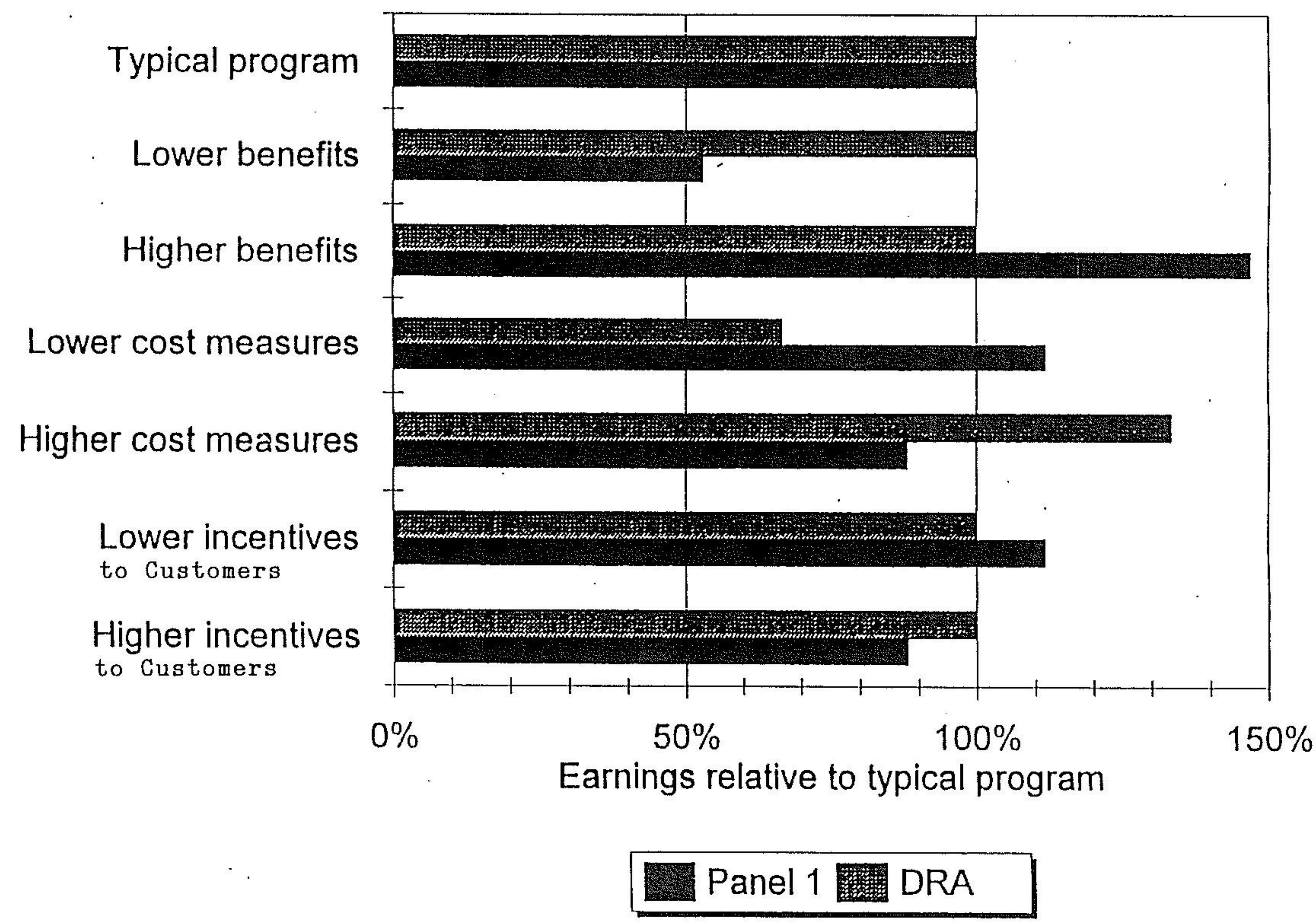
In order to promote our goal of least-cost resource procurement, a DSM incentive mechanism should motivate utilities to acquire resource benefits at the lowest possible costs. Utilities should be able to increase earnings only if they increase net benefits (savings minus costs) to ratepayers, and should receive less earnings for reduced net benefits. All of the proposed incentive mechanisms have this effect beyond the deadband range, except for DRA's proposal. (Exh. 360, pp. 16-19; RT 4896-4897.)

As illustrated in Figure 3 and Table 5, under DRA's proposed incentive mechanism, utility earnings are unaffected by changes in resource benefits or program incentive costs, as long as the utility forecasts that change accurately. Earnings under the DRA mechanism actually increase when measure costs increase and decrease when less expensive measures are implemented. This is because DRA calculates the target earnings level from program incremental measure costs times an earnings rate (0.18 in the examples illustrated in Figure 3 and Table 5.) Therefore, as long as the utility forecasts incremental measure costs accurately, earnings do not change even if resource benefits or customer incentives are very different across programs, or from one program year to another. Because of the way the target earnings level is derived under DRA's proposal, earnings will increase with higher incremental measure costs, and vice versa. Under other proposals, utility earnings increase as either resource benefits increase or costs decrease (and vice versa).

Moreover, in contrast to other proposals, DRA's approach produces lower performance earnings rates for programs that are more cost-effective from a total resource perspective, and higher earnings rates for programs that are less cost-effective. (Exh. 336, Joint Table 7; RT p. 3830.) In some cases, the earnings rates for marginally cost-effective programs

FIGURE 3

Target Earnings for Program Variations



Source: Exhibit 360; Numerical basis presented in Table 5.

Table 5 (See Figure 3)

GENERIC PROGRAM EXAMPLES APPLIED TO DRA MECHANISM

Assuming accurate forecast

	(A) Typical program	(B) Lower benefits	(C) Higher benefits	(D) Lower cost measures	(E) Higher cost measures	(F) Lower incentives	(G) Higher incentives
RECORDED COSTS AND BENEFITS							
Administrative costs	25	25	25	25	25	25	25
Program incentives	75	75	75	75	75	25	125
Program Cost	100	100	100	100	100	50	150
Incremental Measure Costs	150	150	150	100	200	150	150
Net Resource Benefits	350	250	450	350	350	350	350
COST-EFFECTIVENESS (without earnings)							
Net TRC Benefits	175	75	275	225	125	175	175
Net UC Benefits	250	150	350	250	250	300	200
TRC BCR	2.00	1.43	2.57	2.80	1.56	2.00	2.00
UC BCR	3.50	2.50	4.50	3.50	3.50	7.00	2.33
SHAREHOLDER EARNINGS							
Target Earnings Level	27	27	27	18	36	27	27
Performance Earnings Basis	200	100	300	233	167	217	183
Performance Earnings Rate	13.5%	27.0%	9.0%	7.7%	21.6%	12.5%	14.7%
COST-EFFECTIVENESS (with earnings)							
Net TRC Benefits	148	48	248	207	89	148	148
Net UC Benefits	223	123	323	232	214	273	173
TRC BCR	1.73	1.24	2.23	2.45	1.34	1.73	1.73
UC BCR	2.76	1.97	3.54	2.97	2.57	4.55	1.98

GENERIC PROGRAM EXAMPLES APPLIED TO PANEL 1 MECHANISM

	(A) Typical program	(B) Lower benefits	(C) Higher benefits	(D) Lower cost measures	(E) Higher cost measures	(F) Lower incentives	(G) Higher incentives
COSTS AND BENEFITS							
Administrative costs	25	25	25	25	25	25	25
Program incentives	75	75	75	75	75	25	125
Program Cost	100	100	100	100	100	50	150
Incremental Measure Costs	150	150	150	100	200	150	150
Net Resource Benefits	350	250	450	350	350	350	350
COST-EFFECTIVENESS (without earnings)							
Net TRC Benefits	175	75	275	225	125	175	175
Net UC Benefits	250	150	350	250	250	300	200
TRC BCR	2.00	1.43	2.57	2.80	1.56	2.00	2.00
UC BCR	3.50	2.50	4.50	3.50	3.50	7.00	2.33
SHAREHOLDER EARNINGS							
Target Earnings Level	64	34	94	71	56	71	56
Performance Earnings Basis	213	113	313	238	188	238	188
Performance Earnings Rate	30%	30%	30%	30%	30%	30%	30%
COST-EFFECTIVENESS (with earnings)							
Net TRC Benefits	111	41	181	154	69	104	119
Net UC Benefits	186	116	256	179	194	229	144
TRC BCR	1.47	1.20	1.67	1.78	1.24	1.42	1.51
UC BCR	2.14	1.87	2.32	2.04	2.24	2.89	1.70

Source: Exhibit 360

would be well over 80% under DRA's proposed approach.[16] DRA Witness Schultz acknowledged that, based on the examples in his supplemental testimony (Exh. 377), DRA's mechanism would motivate the utility to scale up programs that would maximize earnings opportunity, but not necessarily maximize net benefits to ratepayers. (RT at 5125-5131, 5157-5159.)

DRA justifies these differential earnings rates by arguing that the utility would otherwise be motivated to "cream skim," i.e., to pursue the most cost-effective programs first. (Exh. 341, pp. 51-52.) However, as we stated in D.92-02-075, the utility's pursuit of the most cost-effective measures first is not per se undesirable:

> "For DSM resource programs, we see no reason to constrain a utility from first pursuing the most cost-effective program in one sector (over a less cost-effective program in another sector), if doing so does not create lost opportunities in either sector. Constraints of that nature would inappropriately reduce the potential net benefits that all ratepayers realize from cost-effective DSM." (D.92-02-075, mimeo., pp. 55-56.)

To vary earnings rates as DRA proposes would promote the same type of constraint that we rejected in

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[16] See Table 3 for residential new construction programs and RT at 4936-4937. Recall that the performance earnings rates under DRA's proposal are calculated by dividing target earnings (which are a function of measure costs) by forecasted performance earnings basis (at target). Therefore, the higher the forecasted performance earnings basis i.e., the higher the forecasted net benefits, the lower the performance earnings rate, and vice versa.

D.92-02-075, albeit in the form of an incentive rather than a mandate. As discussed in Section 5.b.(3) below, we believe that our concerns over lost opportunities can be effectively addressed in other ways.

On the penalty side, DRA's approach produces penalty rates that are difficult to explain, let alone justify. For example, had the DRA proposed mechanism been applied to SCE's 1992 programs, SCE would have been penalized at an effective rate of 1025% (i.e., penalties of $2.5 million on net losses of $245,000) on its nonresidential new construction programs. (See Exh. 349A.) For the examples presented in Exh. 346, the effective penalty rate under DRA's proposal ranged from 53% to 225%.[17] As illustrated in the earnings matrix for a typical program, under DRA's approach average penalty rates would range from 2646% to 1.1%, depending on the level of program performance (relative to forecast) at any point in time. (RT at 4436-4437; Exh. 360, pp. 14-15; see also Exh. 337A-1, JT Table F-3.) The WECC approach produces similar variations in the penalty range. (Exh. 337-A2, JT Table F-4.)

Moreover, the penalty rates under the DRA approach would be lower for less cost-effective programs than for those that perform better. (RT at 4358.) For example, PG&E would be penalized $25 million if its 1994 commercial energy efficiency program produced $10.3 million in negative net benefits, or at a penalty rate of 243%. However, if the same program produced

[17] See RT at 5166. Under DRA's proposed variation to one of the example presented in Exh. 346, the effective penalty rate would be 270%. Under a different hypothetical, DRA's effective penalty rate would be 90%. (RT 3969-3970.)

$30 million in negative net benefits, the penalty rate would drop to 83%. The penalty rates also vary significantly across utilities for the same program. In the above example, SCE would be penalized at a rate of 45% if its commercial energy efficiency program produced losses of $10.3 million, and at a rate of 15% if losses were $30 million. (See Exh. 377 and Exh. 337, Joint Table C-2.)

One outgrowth of these complexities is that it becomes very difficult for program managers or field personnel to evaluate the impact of their work on earnings. One would need to know the percent of actual performance earnings basis relative to the forecast for the program in question, which changes over time under the DRA mechanism. (Exh. 360, p. 14; RT at 4436, 4443.) In order to evaluate where to invest additional DSM funds to produce the most net benefits, one would also need to know the percent of actual performance earnings basis relative to the forecast for <u>every other program</u>. After assessing that relative performance, one would then need to compare the corresponding marginal earnings rates, which will also vary by program. (RT at 5200-5203.) Even with DRA's detailed earnings matrices, DRA Witness Schultz could not readily determine what the earnings rates would be for a specific program and where a utility should put additional dollars if it wanted to maximize earnings. (RT at 5129, 5194-5200.)

Under all other proposals, the earnings and penalty rates are consistent across programs or portfolios and vary predictably. For example, Panel 1's performance rates are 30% beyond the deadband range, 0% within the deadband, and -100% in the event that the portfolio of programs produces negative net benefits. SoCal's performance rates are similar, except that the rate when net benefits are negative would be -30%. These rates do not vary by program. Shareholder earnings vary in direct proportion to achieved net benefits, such that the utility only earns more when DSM programs produce higher net benefits (and vice versa). Programs with the highest earnings opportunity are those that yield the highest net benefits. The greater the net losses from a program, the greater will be the reduction in earnings.

Because of the way in which the DRA mechanism derives the target earnings level and performance earnings rates, DRA's mechanism is also more susceptible to gaming than other proposals. The DRA mechanism produces higher earnings where increases in the forecast of incremental costs are accompanied by decreases in the actual incremental costs. Hence, a utility can earn more under the DRA mechanism by deliberately forecasting a higher-cost mix of measures when it expects to actually implement a lower-cost mix. Similarly, utilities can benefit from underforecasting resource benefits or overestimating the level of program incentives needed to obtain a given level of savings. (RT at 4473-4474, 5118; 5220-5221.)[18]

We conclude that the DRA approach to deriving performance earnings rates does not further our least-cost

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[18] For a more detailed description of how gaming can occur under the DRA mechanism, see Exh. 360, pp. 24-28. Under all proposals, utilities have some incentive to underestimate performance (as measured by net benefits) to the extent that earnings are dependent on minimum performance levels. However, only DRA's approach also creates gaming opportunities that are related to performance and earnings beyond the deadband range.

resource procurement objectives. While DRA argues that its mechanism is intended to motivate the utility to pursue all cost-effective DSM opportunities (RT at 4940-4941), its effect is quite different. As described above, under the DRA mechanism, earnings and penalties are essentially unrelated to the level of net benefits produced. DRA's approach to deriving performance earnings rates gives the utility a clear signal to design a less cost-effective program (thereby receiving a higher earnings rate) and to pursue programs with relatively low net benefits over those with greater net benefits. From a program manager's perspective, DRA's approach makes it difficult to assess how much impact his or her decisions are having on earnings at any given point in time. Moreover, DRA's approach creates opportunities for utilities to game forecasts in a manner that is very difficult, if not impossible, to distinguish from good performance.

For the above reasons, we reject DRA's method of deriving performance earnings rates from a target earnings level based on forecasted measure costs. Instead, we will link earnings directly to net benefits by establishing performance earnings rates beyond the deadband range independent of the forecast of program costs or benefits. The appropriate level of those rates is dependent on our assessment of utility accountability, the overall balance of risk and rewards in the incentive mechanism, and earnings on comparable supply-side investments. We address these issues in the following sections.

As discussed in Section 4 above, DRA and others recommend either capping earnings or significantly reducing performance earnings rates at levels above target. These parties argue that a limit to earnings potential is desirable to discourage windfall profits from gaming forecasts or from runaway programs. (Exh. 341, pp. 40-41; Exh. 343, p. 35.) DRA defines a runaway program as one where participation levels are much higher than forecasted, due to factors that have little to do with utilities' actions or efforts. (RT at 4955.)

However, as DRA acknowledges, the declining rate or cap cannot distinguish between a runaway program and a program that is simply successful beyond expectations. (RT at 5027-5028.) In any event, DRA is unaware of the existence of any runaway program in the past, and if there was one, its benefits could easily be absorbed into the long-run DSM resource planning goals. (RT at 5026, 5111.) As for potential windfall profits from gaming, we have already eliminated major incentives for underforecasting performance by electing to establish performance rates independent from forecasted DSM costs and benefits. Moreover, as PG&E and others point out, DSM funding limits have and will continue to place an effective cap on utility spending as well as on runaway programs or windfall profits, should they manifest themselves in the future. (PG&E Opening Brief, p. 44; Exh. 363, p. 35.)

While the advantages to reducing incentives rates above target are questionable, the disadvantage is clear: It will discourage the utility from continuing to pursue all cost-effective DSM. This is because the marginal benefit of doing so decreases with additional effort. Not only is this inconsistent with the intent of PU Code § 701.1(b), it simply does not make any sense to award proportionately less earnings (or none at all) for providing ratepayers with greater levels of net benefits. An incentive mechanism should provide a consistent incentive for the utility to maximize ratepayer net benefits through DSM programs. A fixed earnings rate above the deadband will accomplish this objective. As discussed below, we similarly adopt a fixed rate on the penalty side, limited only by the total size of utility program expenditures recovered in rates. We are satisfied that concerns over the reasonableness of extreme performance at either end of the range (either penalties or rewards) can be addressed in our annual review of DSM earnings claims.

b. Utility Accountability

All parties agree that the performance earnings basis under a shared-savings mechanism should be expressed in terms of net benefits. However, there is disagreement on how different cost components should be considered in calculating those net benefits. Moreover, one of the major issues dividing parties is the extent to which shareholder earnings should be contingent upon achieving forecasted (or target) net benefits.

Parties also disagree on whether the utility should be accountable to portfolio or program-specific performance. Finally, parties disagree on whether the utility should be responsible for guaranteeing the cost-effectiveness of ratepayer-funded DSM. We address each of these issues below.

(1) Performance Earnings Basis

In a variety of forums, we have discussed the dual-cost issue unique to DSM resource options. (See, for example, D.92-09-080, mimeo., pp. 56-58.) In various pilot bidding decisions, and in our DSM rules, we have reiterated our position that the TRC test should be the primary indicator of DSM program cost-effectiveness. At the same time, we have incorporated the UC test into DSM funding and bid evaluation procedures to encourage the utility to minimize program costs as it strives to maximize resource benefits. Arguments in support of TURN's and SESCO's proposals to focus on only one set of costs have been rejected in the past. (D.93-11-017, mimeo., Attachment 1, Rule 6; D.92-09-080, mimeo., pp. 70-73; D.92-03-038, mimeo., pp. 39-42.)

TURN and SESCO have provided no compelling reasons to change our policy of considering both the TRC and UC tests of cost-effectiveness.[19] This leaves us with the issue of how to consider the dual-cost nature of DSM in the context of establishing a basis for earnings or penalties. In a bidding context, we have rejected a weighted average approach in favor of alternative methods for considering both tests. These include ranking proposals by TRC test results, and using the UC test as a tiebreaker, or ranking proposals by their relative "bang for the buck," i.e., TRC net benefits divided by UC costs. (D.92-03-038, mimeo., p. 42; D.92-09-080, mimeo., pp. 72-77.) However, these approaches are not applicable to a performance earnings basis, because the purpose here is to establish the value of net benefits, rather than a relative rank among competing programs or bidders. For example, the bang-for-the buck approach results in a ratio (e.g., 2.5), and not a dollar value.

Although the weighted average approach does not make the tradeoff between TRC and UC tests as explicit as we would like, we believe that it is a reasonable basis for

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[19] In fact, TURN does not provide any specific arguments in support of its proposal. (See Exhs. 373, 374, and TURN Opening Brief.)

calculating earnings and penalties. We will adopt the WECC, DRA, and SoCal proposal to weigh the TRC cost components more heavily than the UC cost components. This appropriately reflects our stated policy that the overall purpose of DSM procurement is to acquire the most economically efficient project from a total resource perspective. At the same time, by considering the UC test in the performance earnings basis, utilities will be encouraged to maximize the efficiency with which they achieve resource benefits with program expenditures. (D.92-09-081, mimeo., p. 71.)

We agree with Panel 1 that earnings should only be based on programs that pass the TRC test of cost-effectiveness on an ex post basis.[20] We recognize that the probability of a program yielding a positive performance earnings basis and not passing this test may be small, particularly with the weighting that we adopt. (RT at 4843-4844). Nonetheless, the trigger would have reduced PG&E's performance earnings basis by $3.3 million, had it been applied to the example presented in DRA's supplemental testimony. (Exh. 377; RT at 5154-5156.) It would have reduced shareholder earnings by $15 million in the example presented in Exh. 375. We believe that ratepayers should be fully protected against the possibility of paying out earnings on a program that does not perform better than the supply-side resource it was intended to replace.

[20] Per late-filed Exh. 395, the TRC trigger would take into account all program costs paid and savings from measures completed in each year, consistent with the current program accounting methodology for all four utilities.

As Panel 1 proposes, individual programs should be evaluated for TRC cost-effectiveness across all earnings claims on an ex post basis. (RT at 3741-3742.) However, we will not aggregate commercial, industrial, and agricultural energy efficiency programs together for this purpose, as implied by Panel 1's testimony. (Exh. 346, p. 18.) Each of these represents a distinct program category under our rules and definitions, and should be subject to the ex post TRC trigger on an individual basis.

While our adoption of an ex post TRC trigger will involve some more complexity in the assessment of earnings, as SCE opines, we believe that the protection provided ratepayers is worth the effort. Moreover, the utilities will need to conduct, evaluate, and present the results of program-specific ex post measurement studies in the planning stage. Under our DSM rules, all programs must pass the TRC (and UC) tests of cost-effectiveness on a prospective basis in order to be eligible for funding. Clearly, utilities will need to evaluate and present ex post results on a disaggregated basis to provide justification for their savings forecasts in our DSM funding proceedings. Encouraging utility managers to maintain or improve program TRC cost-effectiveness throughout the implementation period is a logical corollary to this requirement.

By D.93-11-017, we clarified that all cost-effectiveness tests and program analysis for funding purposes should also be conducted at the individual measure, program component and element level, except for new construction programs. Respondents and other parties are currently evaluating how to implement these rules for the next funding cycle. In particular, the allocation of administrative costs among the various program components needs to be made more consistent, especially between gas and electric technologies that are currently aggregated for planning and implementation purposes by combined utilities. (RT at 4333-4341.) We direct CACD to coordinate workshops on implementation issues related to these requirements. Specifically, we expect parties to work towards developing a standard practice for allocating costs among program components, measures and elements for the purpose of reporting the results of both ex ante and ex post cost-effectiveness tests. While none of the parties have proposed that the ex post TRC trigger apply to this level of disaggregation, we may consider expanding it to these components in our 1997 review of today's adopted mechanisms, once we have gained more experience in implementing this aspect of our Rules.

With regard to the inclusion of savings from the other fuel source, we note that it is the current practice of PG&E, SDG&E, and SoCal to include such savings in the calculation of net benefits, consistent with the Standard Practice Manual methodology for the TRC test.[21] Only SCE has chosen to exclude gas savings associated with electric measures because SCE does not currently have a weatherization program, and gas savings

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[21] The Standard Practice Manual is a joint CEC/CPUC staff publication that presents a cost-benefit methodology for the evaluation of DSM programs. It is the product of workshops among the staffs of the CEC and this Commission, the major utilities, and interested parties. The most recent version of this manual is entitled: Standard Practice Manual: Economic Analysis of Demand-Side Management Programs (December 1987).

associated with its other programs are very small. (RT at 4795-4797, 5092-5093.)

SCE presents no reasons why we should deviate from this standard practice for the purpose of calculating earnings, other than implementation problems that are easily disposed of: SoCal ratepayers would pay shareholder incentives only for electric savings realized by SoCal ratepayers as a result of the installation of energy efficiency measures as part of (for example) SoCal's weatherization program. SCE ratepayers would be involved in SoCal's programs only to the extent they are also SoCal ratepayers, and then, only in their role as SoCal ratepayers. To the extent SCE pursues gas savings from the installation of electric energy efficiency devices, the converse would apply. Only the utility under whose program or funding source a given home is weatherized could claim credit for all energy savings realized by that home.

We have already ruled that SCE and SoCal should coordinate their energy efficiency programs, and we expect that coordination to extend to the calculation of energy savings under today's adopted incentive mechanisms. (See D.93-11-017, mimeo., p. 16; Ordering Paragraph 1.)[22] This includes using consistent sets of electric and gas marginal costs. However, we agree with DRA that it is premature to allow SoCal to market electric energy efficiency measures, or SCE to market gas technologies, with ratepayer funds. Our intent in requiring SoCal and SCE to coordinate their DSM programs was to avoid

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[22] Our directives for coordination implicitly include the understanding that SoCal and SCE must comply with applicable laws, including antitrust laws.

placing ratepayers in the position of funding interutility competition for increased market share. (Ibid., Conclusion of Law 7.) We may reconsider SoCal's recommendation when SCE and SoCal demonstrate that they have coordinated sufficiently to pursue both gas and electric energy efficiency in a fuel-blind manner. Until that time, however, SoCal's recommendation would lead to the sort of ratepayer-funded competition between single-fuel utilities that we clearly intend to prohibit.

In its comments on the ALJ's proposed decision, SoCal argues that our approval of SCE's ENvest program puts SoCal at a significant competitive disadvantage because it allows SCE to market gas measures as part of that program. ENvest is a pilot program funded primarily by SCE shareholders that will be evaluated upon its completion at the end of 1995. Our resolution approving ENvest states that SCE must conduct the pilot in a fuel-neutral manner, and articulates our clear expectation that SCE will coordinate with SoCal, where appropriate. (See Resolution E-3337, p. 10.) We note that SoCal has filed for approval of a similar pilot. (See Advice Letter 2329-G.) SoCal's request in this proceeding goes far beyond the ENvest pilot by requesting carte blanche authority to use ratepayer funds to expand market share.

Finally, as SoCal and others point out, there are significant differences among utilities in the treatment of certain benefit and cost components for the purpose of calculation net benefits. Some utilities include environmental benefits, avoided transmission and distribution costs, and others do not. (RT at 5093; Exhs. 386-389.) There are also differences among the parties on whether to subtract earnings from the numerator (benefits) or add them to the denominator (costs) when calculating benefit-cost ratios. (RT at 4395-4400; Exh. 380.) While these issues were not addressed in this phase of the proceeding, they are methodological considerations that may have major impacts on future calculations of earnings, or program evaluation. Therefore, we direct interested parties to also develop consensus and nonconsensus positions on these issues in the CACD workshops discussed above.

Within 180 days from the effective date of this order, CACD shall file a workshop report describing the consensus and nonconsensus positions of parties on (1) a standard practice for reporting cost-effectiveness results at the DSM program component, measure and element level and (2) the treatment of various benefit and cost components in the calculation of net benefits or benefit-cost ratios, as described above. Copies of this report shall be served on all parties to this proceeding and the 1995 Annual Earnings Assessment Proceeding (AEAP). We emphasize that the workshops should focus on the limited issues described in today's order, and not become the forum for relitigating policy rules or standard practice methods that this Commission has already adopted.

(2) **Accountability to Forecasts**

The incentive feature that directly affects the impact of pre-implementation forecasts on earnings is the MPS and associated deadband range. These features are always set relative to forecasted performance. (RT at 3810.) Any program (or portfolio) that falls below the MPS and within the deadband range loses any future opportunity for earnings. The higher the MPS and the more earnings claims it applies to, the greater the possibility of program performance falling into this deadband range.[23]

DRA's proposal strongly emphasizes utility accountability to pre-implementation forecasts, based on DRA's belief that least-cost resource additions should be acquired at the approximate level, and at the approximate relative cost-effectiveness, identified in the resource plan. DRA therefore defines ratepayer benefits and utility performance in terms of the quantity of least-cost DSM resources that had been planned in the resource planning context. (Ex. 340, p. 1; RT at 5078-5079.)

As described in Section 2 above, DRA's proposal establishes a 75% MPS that is applied across all four earnings claims. DRA's proposal also subjects the utility to penalties if performance falls below 50% of the forecast, even if net benefits are positive. WECC's proposal is similar to DRA's approach, except that, under the WECC proposal, penalties are not calculated beyond the second earnings claim.

TURN's proposal also places significant emphasis on pre-implementation forecasts, since the utility only earns when actual performance exceeds 100% of the forecast, and incurs penalties when performance is at any point below target.[24]

Panel 1 takes a different approach towards accountability than TURN, DRA, and WECC. Panel 1 argues that

[23] Parties also differ on whether the MPS should be applied at the portfolio or program level of aggregation. We address this issue in Section 5.b.(3) below.

[24] TURN does not present a position on how these performance features would apply across earnings claims.

utilities should be accountable for achieving net benefits and guaranteeing the cost-effectiveness of DSM activities. Hence, under the Panel 1 proposal, utilities earn when net benefits are positive, and pay penalties for losses (negative benefits), as measured over all four earnings claims. As described in Section 4 above, the utility reimburses to ratepayers all costs recovered in rates that exceed the lifecycle benefits of the program. There is a pre-established performance threshold before any earnings accrue, but that level is lower than other proposals (50%) and is limited to the achievement of forecasted program costs and program participation, rather than lifecycle per unit energy savings.

SoCal's approach to accountability is a hybrid of the DRA and Panel 1 approaches. Like Panel 1, SoCal sets the lower point of the deadband range at 0%, so that penalties do not accrue unless there are actual losses. However, SoCal's upper point of the range (the MPS) is set at the higher level of 75%. Like DRA, SoCal applies the MPS across all four earnings claims. However, SoCal limits the application (as WECC does) to the first two claims for the purpose of calculating penalties, and does not include the Panel 1 cost-effectiveness guarantee.

As a general policy, we believe that performance-based incentives should align utility rewards and penalties as clearly as possible with performance objectives. We believe that least-cost procurement objectives are best achieved when utilities are motivated to maximize the resource benefits while minimizing the costs of ratepayer-funded DSM. While least-cost planning and forecasting is part of our current regulatory framework, we do not believe that risks and rewards under the next generation of shared-savings incentive mechanisms should be strongly linked to the achievement of those forecasts, for the following reasons.

First, the DSM forecasts and resource plans produced in the state's least-cost planning forums are not intended to serve as prescriptive plans for DSM funding or implementation purposes. Instead, the statewide planning process produces an overall goal (in terms of energy and capacity savings from utility DSM activities) for each utility over a 10 to 15-year period, based on analyses of utility program designs that are feasible and cost-effective. Moreover, these goals are considered to represent a <u>floor</u> amount of cost-effective energy efficiency that each utility can and should pursue.[25]

While utility DSM funding requests are expected to be generally consistent with longer-term planning objectives, neither the California Energy Commission, nor this Commission, specifically prescribes the program activities or levels that must be implemented each year to achieve this goal. Meeting resource planning goals requires utilities to provide a level of total program load impacts over entire sectors over a number of years. A shortfall in one program in one year can be compensated for by other programs or other years that exceed their goals. Accordingly, utilities have been given considerable flexibility to change the design, mix or level of DSM activities from one year to the next. We do not believe that today's consideration of incentive mechanisms should change the role or purpose of these planning forecasts.

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[25] See <u>The 1992 Electricity Report</u>, January 1993, prepared by the CEC; pp. 5-12 to 5-15.

SoCal and others argue that a strong linkage to forecasts is necessary if this Commission wants DSM to be a legitimate and reliable component of the utility's resource plan. (SoCal Opening Brief, pp. 13-14; RT at 4066.) We disagree. We believe that DSM will establish itself as an integral part of the utility's resource plan by aligning shareholders' and ratepayers' interests in the procurement of least-cost resources. The resulting level and mix of DSM may, in fact, be significantly different from forecasted amounts. However, we do not consider this to be a necessary failure of incentives; rather it may reflect the limitations of such forecasts.

Moreover, with our ex post measurement protocols in place to verify energy savings, we are able to move away from the use of pre-implementation targets to set incentive levels. Emphasis on pre-implementation targets (and the achievement of those targets) was a more logical framework in an ex ante world because actual savings were not measured beyond the verification of program costs and participation. However, in an ex post world, this framework can and should be reevaluated. As one witness succinctly put it: "It is better to not spend as much energy setting the target and, instead, spend energy performing the task." (SCE Witness Gudger, RT at 4612.) We agree. The primary focus of least-cost resource procurement should be on actually acquiring the most net benefits for ratepayers, and not on forecasting.

Second, the evidence in this proceeding convinces us that overemphasis on pre-implementation forecasts would hold utility earnings hostage to unreasonably small variations in program performance. Under TURN's proposal, even the smallest variation in lifetime program savings (e.g., 1%) would result in penalties. (RT at 4733.) Under the DRA, WECC, and SoCal proposals, a program with an uncertainty of +/- 20% in lifetime savings (including actual uncertainty, measurement uncertainty, and transient variations) would have to have a TRC benefit-cost ratio of greater than 3.0 before the utility could be confident of getting <u>any</u> earnings. (Exh. 360, pp. 30-31; RT at 4760-4762.) To be confident of earning on a program with a TRC benefit-cost ratio of 1.2, a utility would have to be almost certain (+/- 4%) of the savings estimate. Even with that level of accuracy in the estimate of actual savings, measurement uncertainty could result in no earnings (-5%) or a penalty (-8%).

With these types of consequences from relatively small forecasting errors, utilities would be strongly motivated to underestimate DSM savings potential in establishing the MPS (or to overstate measurement results), and our forecasting and earnings verification proceedings would become that much more contentious. (RT at 3799-3800.) The evidence indicates that supply-side resources have never been subjected to such an intense level of scrutiny, despite the substantial uncertainty in both cost and resource value. (Exh. 337, pp. C-1 to C-9, D-1-1 to D-1-12; RT at 5034-5035, 5046-5047.)

Third, proposals that emphasize accountability to forecasts can also produce unreasonable levels of penalties or rewards, relative to the actual net benefits or losses produced. For example, under the TURN proposal, a utility would incur a penalty of $1 million for producing $9 million in net benefits, if the pre-implementation forecast of net benefits was $10 million. DRA's and WECC's proposal to set the lower end of the deadband at 50% (rather than 0%) can result in significant penalties even when the program yields significant net benefits. For example, in the scenario presented by Exh. 381, shareholders would be penalized $2.3 million because actual net benefits fell below 50% of forecast, even though ratepayers receive verified, cost-effective resource value of $45 million. (RT at 5047-5048.) While the utility should earn less when positive net benefits are lower than forecasted, we find it unreasonable to levy monetary penalties when positive net benefits accrue to ratepayers, i.e., when the program is still a better investment for ratepayers than the supply-side resource that it is replacing.

Under the DRA mechanism, a utility actually receives a lower rate of return for pursuing greater amounts of cost-effective resources than it would for a less cost-effective program that's closer to target. (RT at 5063.) DRA's approach to accountability can also result in disproportionately high penalties, relative to the actual net losses incurred. Under the scenario presented in DRA's supplemental testimony, PG&E would be penalized $52 million for a program with negative net benefits of $9 million. (Exh. 377.) In some cases, the penalty can be large enough to make a program more cost-effective for utility customers when it fails than when it succeeds. (Exh. 360, pp. 34-35.)

SCE's 1992 and 1993 residential new construction program results provide a good example of these problems. Under the proposed DRA mechanism, SCE's 1992 residential new construction program would be assessed a penalty of $1.4 million despite the fact that it provided more than three times the benefits of the 1993 residential new construction program, which would be awarded earnings of $11.6 million. Inclusion of earnings results in the former program being substantially cost-effective to ratepayers and the latter program being noncost-effective by a wide margin. (Exh. 349A.)

Moreover, under both the TURN and DRA approach to accountability, two utilities (or a single utility in consecutive years) can implement programs which promote identical measures, incur identical costs, provide identical benefits, and yet receive very different earnings, depending on the utility's relative ability to accurately forecast those benefits. (RT at 4114.) For example, the first utility may have overforecast benefits by a factor of two, failing to foresee a dramatic decline in new construction. The second utility may have underestimated benefits, based on a more pessimistic forecast of construction activities. In this example, the first utility could incur substantial penalties under the DRA or TURN mechanism, while the second utility could receive substantial earnings.

Accountability to forecasts in the manner prescribed by DRA and SoCal would also place an unreasonable amount of "all or nothing" pressure on ex post measurement efforts, particularly in later years of the measurement period. Under both the DRA and SoCal approaches, the utility runs the risk of returning <u>all</u> previously recovered earnings if measurement studies in the 5th or 9th year after program implementation indicate that net benefits are 74% of forecast. However, at 75% of forecast, earnings accrue at the full share rate. Under other proposals, earnings in each claim would still be tied to the results of measurement studies (and in some cases previously paid-out earnings would have to be returned to ratepayers). However, this does not create the "all or nothing" outcome described above. We believe that putting evaluation activities under this degree of earnings pressure would unnecessarily undermine the major focus of program evaluation.

Table 6 presents an example to illustrate the problem with applying a relatively high MPS across all four earnings claims. Under the DRA and SoCal approach, the utility would be required to return over $50 million in previously paid-out earnings, just because measured savings fell a percentage point below the 75% threshold. As a result, the utility shareholders receive no earnings from a program (or portfolio) that yields $222 million in net benefits and that has achieved close to 100% of forecasted program participation. Under the Panel 1 approach, the reductions in realized savings (relative to forecasted amounts) would be accounted for at each earnings claim. However, the utility would not be at risk of forfeiting all previous earnings in the final year, as long as the program or portfolio was cost-effective.[26] (RT 3807-3811, 3991-3992.)

For the above reasons, we conclude that utility accountability under a DSM shared-savings incentive mechanism should be defined primarily in terms of realized rather than forecasted net benefits. However, we also believe that earnings should begin to accrue only after the utility has met a

[26] Had participation levels decreased (or program costs increased) such that overall net benefits were below the MPS at the first earnings claim, then the program or portfolio would not have been eligible for any earnings under the Panel 1 proposal.

TABLE 6

Example of Earnings Levels at Four Earnings Claims: Comparison of MPS Application Across Proposals
($ million)

Earnings Claim	Recorded PEB	Recorded PEB/PEB_t	Earnings: DRA/SoCal Proposal[1/]	Earnings: Panel 1 Proposal
1	$283	94%	$21.2	$21.2
2	$267	89%	$18.8	$18.8
3	$233	78%	$12.5	$12.5
4	$222	74%	$-52.5	$ 7.5
Total Earnings			0.0	$60.0
Resulting PER			0%	30%

Assumptions: PEB_t = $300 million (across all proposals)
PER_t = 30% (across all proposals)

MPS = 75% for DRA and SoCal applied across all four earnings claims

MPS = 50% for Panel 1 applied to the first earnings claim

1/ SoCal applies the MPS differently than DRA when performance falls into the penalty range. However, for performance within or above the deadband (as is the case in this example), the SoCal and DRA application of the MPS is identical.

minimum threshold of performance, consistent with PU Code § 746(B). We agree with CEC and others that, as a preliminary hurdle for realizing any earnings, this threshold should continue to be established by linking performance to factors that the utility can influence, e.g., through effective program design, cost controls or marketing strategies. (CEC Opening Brief, pp. 19, 23; Exh. 361, p. 27.)[27] We continue this approach by establishing a MPS for the first earnings claim only. For the reasons discussed above, the deadband range should begin at 0% of forecasted performance.

For the upper end of the deadband range, parties have proposed MPS levels ranging from 50% to 75% in this proceeding, which are comparable to the MPS levels currently in place. (See Exh. 340.) However, the deadband range applies on a program-specific basis under current incentive mechanisms. As discussed below, we adopt the portfolio approach in this decision. Based on historical experience, it appears to be of little challenge to achieve a 50% MPS at the first earnings claim when that threshold is applied to residential and nonresidential portfolios. With the exception of SCE in 1992, all of the utilities would have easily achieved this standard over the 1991-1993 period. (See Exhs. 370, 371, and 372.) We believe that a MPS should provide enough of a challenge to motivate the utility to actively increase program participation and reduce costs, but still represent a reasonable opportunity for achieving earnings

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[27] Beyond and below the deadband range, however, earnings and penalties become a function of a much broader set of factors, some of which are under the utilities' control and some that are not. (See Sections b.(4) and c. below.)

for superior performance. In our judgment, an MPS at the higher range of proposals, i.e., 75%, represents a more reasonable threshold of minimum performance when the incentive mechanism is applied at a portfolio level. We adopt this level for the shared-savings mechanisms authorized today.

(3) Portfolio vs. Program-Specific Performance

In the past, shared-savings mechanisms have been applied both on a program-specific level, and to portfolios of aggregated programs. Under a program-specific approach, earnings and penalties are calculated based on individual program-by-program performance. Under a portfolio approach, the net benefits (as measured by the performance earnings basis) of all programs in the portfolio are aggregated before determining where performance lies along the shared-savings curve, and before applying the appropriate shared-savings rate.[28] The case examples in Attachment 1 illustrate the difference between a program-specific and portfolio application of the incentive mechanism, as proposed in this proceeding.

Panel 1 proposes to move to a portfolio approach for all utilities, while DRA advocates a program-specific approach. SoCal and WECC recommend a hybrid approach,

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[28] Depending on the mechanism, a portfolio approach may apply the MPS on a program-specific level while still calculating the performance earnings rate and associated earnings (or penalties) on a portfolio basis. This is the approach taken for PG&E's and SoCal's current shared-savings mechanisms, where earnings rates are calculated using the methodology proposed by DRA in this proceeding. The Panel 1 approach would apply both the shared-savings curve and MPS on a portfolio basis, whereas the DRA approach would apply them both on a program-specific level.

where earnings are calculated based on program-specific performance, but penalties are calculated on a portfolio basis.

We believe that a portfolio approach has several advantages over a program-specific application of the incentive mechanism. First, the portfolio approach gives the utility flexibility to quickly respond to changing market conditions, and maximize ratepayer benefits in the process:

> "For example, for the last few years residential new construction activity has been weaker than anticipated. With individual program penalties, additional utility resources and efforts have been required to try to achieve greater market penetration in a soft market. The use of portfolios allow the utilities to continue to focus on the markets with the greatest potential benefits at a given point in time, thereby delivering the greatest bang for the buck for ratepayers...." (Exh. 345, p. 16.)

Some parties argue that the fund shifting flexibility given the utilities provides this type of response capability. However, even though the utility may be able to shift funds in and out of programs, it is unlikely to do so if the result will be zero earnings (because the MPS was not achieved) or penalties. We believe that it is more reasonable to encourage the utilities to pursue more benefits for all ratepayers than to be forced to pursue a less cost-effective program just to meet a program-specific minimum performance target. (RT at 4301-4302.)

Second, under a portfolio approach, the utility is more likely to pursue creative changes to programs or pursue new programs that have the potential for increasing net benefits. (RT at 3913-3914.) Since the success of such changes will be uncertain, they are more likely to be pursued in an environment where the downside risks of any one particular program can be reduced via diversification. Applying the shared-savings incentive mechanism on a portfolio basis serves this purpose.

A simple example illustrates how portfolios diversify risks. Suppose the utility modifies a program with the expectation that these changes will increase forecasted net benefits from $100 to $125. The utility also implements a more "tried and true" program that achieves its forecast of $125. In this hypothetical example, we assume a 75% MPS and a 30% performance earnings rate. Had the utility not experimented with new measures or program design, it would have earned $67.50 (0.3 x $225), assuming performance at target for both programs. With experimentation, the utility expects to earn $75 (0.3 x $250.)

However, it turns out that the modifications were not successful, and realized net benefits from the first program are $70. The second program performs at target. Under a program-specific approach, the utility would receive a total of $37.50 (0.3 x $125) in earnings from the second program. No earnings would accrue from the first program because its performance fell below the 75% MPS.

Under a portfolio approach, the utility would receive earnings of $59 (0.3 x $195). While there is still a downside risk to experimentation under the portfolio approach, it is significantly less than under the program-specific approach. In this example, a 22% reduction in net benefits costs the utility a proportionate reduction in earnings (relative to the forecast), as compared to a 50% reduction under the program-specific approach. In either case, ratepayers still receive a significant level of net benefits, even though they are lower than projected.

Finally, the portfolio approach emphasizes the aggregate results of utility efforts to procure resource value, which we believe are what count the most. In aggregate, the relative proportion of resource value procured from (for example) efficient appliance replacement versus weatherization makes very little difference from a least-cost procurement perspective. (RT at 4093, 5325.) While we agree with DRA that specific DSM measures produce different dimensions of resource value (i.e., capacity versus energy savings as reflected in program load factors), we note that the calculation of net benefits already reflects those differences through the application of time-differentiated energy and capacity avoided costs. (RT at 5102-5104.)[29] We do not believe that the emphasis on maximizing aggregate net benefits will compromise overall least-cost procurement objectives.

We do, however, agree with DRA and others that lost opportunities should not be ignored in the process of maximizing net benefits. However, we do not find that a program-specific application of minimum performance levels is an effective way to achieve this result. With the exception of new construction, current program categories do not distinguish

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[29] Moreover, applying program-specific performance goals does not constrain the utility from changing the mix of measures within programs, or from allocating up to 130% more funding to one program in a manner that can alter actual load factors, relative to planned. (RT at 5124.)

between lost market opportunities and other types of DSM activities. (RT at 4119-4123, 4172-4173.) As a result, a program-specific application of the MPS would not inhibit a utility from pursuing the most cost-effective retrofit applications within a program category at the expense of marketing to customers that are remodeling or replacing equipment. Nor would it necessarily encourage marketing efforts that capture those lost opportunities, relative to the portfolio approach.

In the case of new construction, where the program category does coincide with potential lost opportunities, a program-specific MPS is one way to ensure that the utility does not neglect such opportunities. However, because new construction is highly susceptible to changing market conditions, this approach has a significant drawback. Compared to other types of programs, customer or vendor participation is particularly difficult to forecast with any accuracy. As a result, the utility is at risk of losing all earnings from cost-effective new construction programs due to factors completely beyond its influence, e.g., an unforeseen downturn in construction activity.

For example, for program year 1992, SCE did not anticipate the downturn in the housing market, and significantly underestimated program participation. Nevertheless, $1.8 million in net benefits were achieved under the program, based on verified program costs and participation. (Exh. 349A, Exh. 392, p. 2.) Had a program-specific MPS been applied to the first earnings claim, SCE would not have received any earnings for its new construction activities. Under the portfolio approach, earnings would be significantly lower than estimated, but they are still proportionate to actual achievements.[30]

We are also not convinced that the utility will be strongly motivated to overlook lost opportunities under a portfolio approach, as some parties suggest. Even though the portfolio approach does not prohibit the utility from, for example, shifting the majority of funds away from new construction or the remodeling market into retrofit applications (assuming that the latter are more cost-effective in the short run), the utility does not benefit in the longer term by doing so. An incentive structure that pays earnings in direct proportion to the net benefits generated will motivate the utility to go after every cost-effective opportunity. Ignoring lost opportunities is therefore undesirable from the utility's perspective because any future opportunity to generate net benefits from those activities are either forgone altogether or more expensive to capture in the future.

Moreover, compared to a program-specific application of the incentive mechanism, the portfolio approach creates less disincentive to ignore lost opportunities that produce relatively low net benefits in the short run. (Exh. 343F, RT at 3913-3915, 4301, 4589-4592.) As described by SCE Witness Gudger:

[30] With or without an MPS, the utility has an opportunity to gain from unexpected upturns in construction activity. However, the point here is that a program-specific MPS can completely wipe out any earnings from the program, rather than reduce them proportionately.

> "...we are obligated to serve all of our customers. And in providing that service, we have to provide a portfolio of DSM programs, some of which are very cost-effective--I can think of our motors rebate program with manufacturers. It has a TRC of around eight. And some of which are only marginally cost-effective, some of the new construction programs.
>
> "It seems to us that the portfolio mechanism that we have proposed allows us to run all these programs simultaneously whereas the program that we have today which is more program-based rather than portfolio-based causes us to look very carefully at programs that are marginal programs such as some of the new construction, especially with the Commission's requirement that the programs for new construction pass a TRC [test]." (RT at 4619.)

Finally, our rules clearly state that the utility should pursue only the most cost-effective programs first, if doing so does not create lost opportunities in the process. (Rule 3.) We expect utilities to design and implement DSM programs with this directive in mind. In the past, we have required the utilities to develop and report their strategies for capturing lost opportunities in proceedings where they apply for funding or earnings claims. (See Rule 2.) We will continue that practice by requiring the utilities to report their strategies and accomplishments in capturing lost opportunities on an annual basis, beginning with the 1995 AEAP.

We direct CACD to conduct workshops to develop consistent reporting requirements and format for these filings. Within 120 days from the effective date of this order, CACD shall file a report at the Commission Docket Office describing the positions of the parties on these requirements and CACD's recommendations. Copies of CACD's workshop report should be served on all appearances and the state service list in this proceeding. We will consider revisiting the issue of portfolio versus program application of the incentive mechanism in our 1997 review, should we find that the utilities have neglected to pursue cost-effective lost opportunities to the detriment of ratepayers.

Proponents of a program-specific approach also argue that program-specific minimum performance levels will allocate DSM efforts more equitably across certain classes of customers, e.g., residential and low-income customer classes. (RT at 4119-4123, 4093-4095.) With regard to low-income customers, we note that the programs receiving shared-savings treatment are not designed to serve those equity objectives; rather, we authorize funding separately under direct assistance programs for this purpose. (See Section B below.) As discussed above, we do not believe that separate program-specific targets are a necessary feature of least-cost resource procurement. Concerns over potential inequities between the residential and nonresidential classes are better addressed by establishing two separate portfolios, as proposed by Panel 1.

The hybrid approach proposed by SoCal and WECC does not offer any advantages with respect to capturing lost opportunities or addressing equity issues across customer classes. Moreover, by applying a portfolio approach only when net benefits are negative, the SoCal and WECC approach ignores the reducing effect that portfolio aggregation can have on the earnings side. As SoCal illustrates in Exh. 382, the performance of programs in the deadband (zero earnings range) can pull up the lower-performing programs when performance results are aggregated. (RT at 4818, 4964-4965.) For this reason, SoCal and WECC propose that a portfolio approach apply when net earnings are (in aggregate) negative.

However, the opposite effect can occur when program results are aggregated on the earnings side, i.e., program performance in the deadband range will pull down those results, thereby reducing earnings relative to a program-specific approach. (RT at 4765; Exh. 337A.)[31] In effect, by applying the portfolio only to the penalty side of their proposed incentive mechanisms, SoCal and WECC propose to "cherry pick" the potential effects of portfolios when programs fall into the deadband range. We reject this selective application of portfolio aggregation.

(4) **Cost-Effectiveness Guarantee**

In order to be eligible for ratepayer funding, DSM programs that are subject to shared-savings incentives must be cost-effective on a forecasted basis. Per Rule 6, each program must pass both the TRC and UC tests of cost-effectiveness as a condition for funding. With the exception of new construction programs, these requirements extend to the program element, component or measure level. Ratepayers put up funding for these programs with that expectation, and all parties agree that these requirements would continue for funding purposes.

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[31] The potential for this effect (on either the earnings or penalty side) is greater the higher the MPS and when the MPS is applied to more than the first earnings claim. See Attachment 1.

However, once a DSM program is implemented there is currently no guarantee that ratepayers will be protected from investment losses on an ex post basis, that is, from actual program costs being larger than realized resource benefits over the life of the measures. Under previous shared-savings mechanisms, all risk of losses (i.e., negative net benefits) beyond the first earnings claim have been borne by ratepayers. Now that we have protocols in place to measure losses due to factors other than program costs and program participation, parties propose different allocations of this risk.

SoCal and WECC propose that losses measured through the second earnings claim (i.e., due to differences between realized and forecasted program costs, program participation and first-year load impacts) be shared 30% by utility shareholders, and 70% by ratepayers. Ratepayers would bear 100% of the risk of any losses due to differences between realized and forecasted savings persistence, which would be measured in the third and fourth earnings claims.

Under TURN's proposal, all losses would be shared 10% by shareholders and 90% by ratepayers, although TURN does not specify over which claims the penalties will be calculated. DRA would measure penalties over all four claims. However, as described in Section 5.a. above, the share rate will vary significantly within and across programs and utilities because that rate varies as a function of the target earnings level and the relationship between actual and forecasted performance at any point in time.

Only the Panel 1 proposal would require shareholders to consistently compensate ratepayers for 100% of losses (i.e., negative net benefits as measured by the performance earnings basis), up to the total amount of DSM program costs recovered in rates. Losses would be calculated on a portfolio basis over all four earnings claims. Portfolios that fall into the deadband range in the first earnings claim would be subject to the cost-effectiveness guarantee in subsequent claims.

We believe that the Panel 1 proposal most appropriately protects ratepayers against performance risk in an ex post measurement world. In exchange for putting up the funds for utility investments in DSM, ratepayers should be fully protected against losses.[32] The threat of waning utility commitment to DSM does not persuade us to limit the downside risk to ratepayers by arbitrarily ignoring the results of savings persistence studies, as WECC and SoCal propose. As we stated in our decision to link earnings to these studies over a 7 to 10-year period:

> "...we are aware that utility commitment to DSM is an important factor. We have struggled with utility commitment to these programs since DSM incentives began. We also struggle with ensuring that we send the correct signals so that utilities and parties remain enthusiastic through our many decisions about DSM funding and incentive mechanisms. The Commission has labored to

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[32] Panel 1 recommends that the guarantee provisions not apply where major adverse events such as natural disasters, riots, municipalization of utility distribution systems, etc. cause more than 25% of installed DSM measures to be inoperable or no longer on the utility system. (Exh. 345, p. 15.) We will not establish <u>a priori</u> what constitutes such an event, or who should be responsible for losses should one occur. We prefer to consider the ramifications of such events on a case-by-case basis in the appropriate AEAP proceeding.

> gain this utility commitment, and thus far it has been a primary focus. In authorizing incentives for DSM programs after the Collaborative, the Commission implemented what it believed was its part of the bargain. This M&E phase is the utilities' part of the bargain. We cannot accept utilities conveniently using the issue of their commitment to DSM to compromise their duty to be held accountable for DSM energy savings, especially at a time when current funding levels are reaching well over a billion dollars on a combined utility basis, over the next three years." (D.93-05-063, mimeo., p. 51.)

With regard to SoCal's arguments that gas-only utilities should be subject to less risk than combined or electric-only utilities, we note that this difference was already accounted for by our adoption of less stringent measurement protocols. (See D.93-05-063, mimeo., pp. 46-48.) In addition, this differential is diminished by our adoption of SoCal's recommendation to include both gas and electric savings associated with each measure in evaluating net benefits for earnings recovery purposes. (SoCal Opening Brief, p. 21; Exhs. 386 and 389.) The advantages that a combined utility has in averaging gas and electric measure performance are also reduced by our recent rules that require cost-effectiveness testing at the program element or measure level for funding purposes. (See Section (1) above.) Finally, the primary contributors to the risks SoCal describes are eliminated by our decision to apply the incentive mechanism on a portfolio basis and to limit the MPS to the first earnings claim. For these reasons, we believe that the shared-savings incentive mechanism adopted in today's order should be applied to all four utility respondents.

The cost-effectiveness guarantee adopted in today's decision modifies the warranty relationship between the utility and ratepayers as a whole, relative to current practice. Up until now, the savings and economic performance of DSM-related equipment was a risk borne entirely by ratepayers, both in the aggregate and at the individual participant level. The cost-effectiveness guarantee changes this relationship by providing a warranty to all ratepayers that each utility's residential and nonresidential portfolios will be cost-effective.

As several parties point out, the cost-effectiveness guarantee does not warrant performance at the individual participant level. (Exh. 337, pp. B-4 to B-7, G-3 to G-4.) As in the past, manufacturer's warranties would be relied on to provide protection from operational defects, including inaccurate efficiency ratings. However, neither manufacturers nor utilities currently warrant the savings or economic performance of the equipment for individual participants. This is because there is a wide variation in savings per installation due to customer operation variation. (Ibid.)

SESCO points out that energy service companies commonly provide 12-month limited express warranties against defective materials or installations, and sometimes offer minimum shared-savings guarantees to individual customers. (Exh. 378, pp. 7-9.) SESCO argues that the utility DSM programs should be required to provide similar warranties to program participants.

We believe that it is premature to impose these requirements on utility programs. As SoCal and others point out, to provide warranty assurances at the individual customer level, the utility role in energy efficiency would need to take on a very different character than the current one, which primarily involves providing rebates for equipment and measures that meet certain guidelines. The utilities would need to be more directly involved in customer equipment choices, and be given the flexibility to price warranties on a class or customer-specific basis depending on the complexity of the energy efficiency measure. Utilities would also need the flexibility to refuse to offer warranties on specific products known to the utility to be poor performers. (Exh. 362, p. 21; Exh. 343, p. 49; Exh. 337, pp. G-3 to G-4.)

We agree with SoCal that the implications of this involvement, particularly the legal ones, need to be explored fully before making this role a requirement. SCE is currently conducting a DSM "ENvest" pilot in which the utility assumes an expanded warranty role vis-a-vis individual customers. (Exh. 337, pp. H-1 to H-2; Resolution No. E-3337.) If the ENvest pilot program proves successful, we will explore the feasibility and benefits of expanding the concepts behind ENvest, including the warranties provided.

c. Earnings Opportunity, Risks, and Rewards

The role of shareholder incentives is to offset the regulatory and financial biases against DSM (or in favor of supply-side resources) that the utility might have in procuring least-cost resources. In our 1993 evaluation of 1990-1992 experimental incentive mechanisms, we confirmed our expectations that such biases do exist and that shareholder incentives are an effective way to address them. (See D.93-09-078.)

What level of earnings opportunity is sufficient (and not too much) to offset these biases? In the past, we have applied the general rule that the shared-savings rate should be no higher than the utility's authorized rate of return. We set the authorized rate of return as the upper limit because shareholders do not incur any investment opportunity costs with ratepayer-funded DSM, as they do with utility-constructed plants. Parties were asked to consider supply-side comparability by asking the question: "What level of management fees for DSM programs would be comparable to shareholders' earnings on supply-side investments, given the relative risks of each?" (D.92-02-075, mimeo., p. 47.) We developed this interim guideline with the expectation that it would be revisited in this proceeding. Parties have negotiated shared-savings rates consistent with this guideline, and we have adopted the resulting settlements without modifications.

In this phase of the proceeding, several parties urge us to consider the concept of "comparable shareholder value" instead of or in conjunction with our consideration of supply-side earnings comparability. However, because this approach relies on historical evidence of utility management interest, it fails to address the fact that the risk and reward profiles of DSM and alternative investments can change considerably over time. As a result, we do not believe that the levels of earnings achieved in the past are accurate indicators of the level of earnings opportunity that is needed to overcome disincentives to DSM in the future. The comparable shareholder value approach also has the potential disadvantage of ratcheting up or down target earnings levels whenever historical performance (and associated earnings) is significantly different from historical targets. (RT at 4153-4154.) We prefer to assess the appropriate level of target earnings within the overall context of the incentive mechanism being proposed at this time, taking into consideration the relative risks and rewards associated with supply-side alternatives.

At the same time, we acknowledge that our interim rule has its limitations. As DRA and others point out, using the authorized rate of return as the shared-savings rate does not reflect what the utility actually earns on utility-constructed plants. (RT at 5211, Exh. 341, pp. 24-26.) Under cost-of-service ratemaking, earnings accrue on the unamortized portion of rate base throughout the useful life of the plant. Applying the authorized rate of return to DSM net benefits assumes a one-year amortization.

A simple example illustrates how this approach underestimates the total earnings stream from a rate-based plant. Suppose $100 million in plant costs is rate based at an authorized rate of return of 10%. However, assuming a 10-year plant life and straight-line depreciation, earnings on that rate-based facility would actually be $54. Ratebase would decrease by $10 per year (in depreciation), and the 10% rate would be applied to each year-end balance.[33] Hence, the effective earnings rate

[33] In this simplified example, which assumes no time value of money, earnings would be: $10 in year 1 (0.10 x $100), plus $9 in year 2 (0.10 x $90), plus $8 in year 3 (0.10 x $10), etc. See the actual calculations of supply-side earnings rates presented in Exh. 336, Appendix D.

on a $100 million plant investment would be 54%, as compared to the 10% authorized rate of return.

Parties to this proceeding presented a range of 26% to 52% for the effective earnings rate associated with supply-side resources deferred or avoided by DSM investments. Assuming a 10-year average measure life for DSM, DRA calculated an earnings rate of 36% based on the present value of revenue requirement streams associated with a rate-based plant. NRDC and others presented a range of 36% to 52% based on the same methodology, but assuming a broader range of 10-15 years in average measure lives. (Exh. 336, Appendix D; Exh. 341, pp. 25-26; Exh. 358, pp. 19-20.) SCE developed a range of 26% to 39% based on the investment deferral methodology used in avoided cost calculations, consistent with general rate case assumptions. (Exh. 363, pp. 19-20; RT at 4670-4672.)[34]

Target earnings levels increase to a range of $77 million to $153 million on a statewide basis when the effective earnings rate, rather than the authorized rate of return, is considered the starting point for establishing

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[34] The 26%-29% range was derived by dividing SCE's target earnings level estimates ($20-$30 million) by the performance earnings basis for SCE's retrofit and new construction programs. Consistent with today's determinations, we used the WECC definition of performance earnings basis from Exh. 336, Joint Table C-2.

comparable earnings.[35] This compares with a 1990-1994 historical average of approximately $38 million. (See Table 7.)

If earnings rates were based on equivalent performance (rather than costs), this starting point would be even higher. This is because, by definition, a cost-effective DSM program must produce higher resource benefits per equivalent costs than the supply-side alternative it is replacing. So, if $10 is earned on a supply-side plant that is estimated to cost $100 and that yields $100 in resource benefits (i.e, it is the avoided plant with a TRC benefit-cost ratio of 1.0), the effective earnings rate on that plant's performance is 10%. However, a DSM program with a TRC benefit-cost ratio of 1.5 will cost the same $100 but produce $150 in resource benefits. If only $10 is earned on that investment, the effective earnings rate on performance is 6.6%. To achieve earnings comparability based on equivalent performance, target earnings would need to be $15 in this example. (Exh. 366, p. 3, Exh. 358, p. 13; RT at 4666-4667, 4891-4892.)

Had this type of earnings comparison been made in the past, we would have seen very clearly that previous DSM mechanisms offered significantly lower earnings opportunity for DSM than for supply-side alternatives. For example, PG&E found that DSM investments provided earnings of 0.26 to 0.29 cents/kWh in comparison to $1.10 to $1.29 cents/kWh on the supply side over

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[35] This range is calculated by applying the range of effective earnings rates (i.e., 26%-52%) to the statewide performance earnings basis of $295.8, based on 1994 program costs and performance. (See Exh. 336, Joint Tables C-1 to C-4; WECC's definition of performance earnings basis for the sum of retrofit and new construction energy efficiency incentive programs.)

TABLE 7

COMPARISON OF SHARED-SAVINGS TARGET EARNINGS LEVELS:
AVOIDED SUPPLY-SIDE INVESTMENT AND
HISTORICAL, PROPOSED AND ADOPTED DSM
(pre-tax $million, 1994)

	Avoided Supply-Side Investments	DSM 1990-1994 Annual Avrg.	DSM-Proposed			
			TURN	DRA	SoCal/WECC PANEL 1	DSM Adopted
PG&E	42.2-84.4	25.3	16.2	29.2	48.7	48.7
SCE	20.2-40.4	6.6	7.8	13.9	23.3	23.3
SDG&E	8.4-16.8	4.5	3.2	5.8	9.7	9.7
SoCal	6.0-12.1	1.7	2.3	2.9	7.0	7.0
Statewide Totals:	76.9-153.8	38.1	29.5	51.8	88.7	88.7

Notes to Table 7:

- The target earnings levels in this table were developed based on the utilities' 1994 program year data. (Exh. 336, Joint Tables C-1 to C-4.) These amounts would be recovered in four installments over a 7 to 10-year period after program implementation, assuming that verified performance is equal to target performance.

- Target earnings levels for avoided supply-side investments were calculated by applying the range of earnings rates presented in this proceeding (0.26-0.52) by the performance earnings basis adopted in this decision.

- For comparative purposes, parties' proposals have been conformed to today's decision by applying proposed target earnings rates to the definition of performance earnings basis adopted in this decision, and by including both retrofit and new construction programs in that calculation. For DRA's proposal we directly apply DRA's recommended target earnings rates to the performance earnings basis, rather than deriving shared-savings rates from a prespecified target earnings level.

Notes to Table 7 cont'd:

- o Under TURN's proposal, utilities would not earn anything at target. At any point above target, the utility would earn at a 10% rate. For comparative purposes, we apply this rate to our adopted, performance earnings basis, and include the results in this table.

- o Historical averages are from Exhibit 337, pp. A-33 to A-36. These amounts were authorized and recovered in the year following program implementation.

the 1990-1992 period. (Exh. 337, pp. C-7 to C-8.) This comparison considered earnings from the full portfolio of PG&E's supply-side resources, including rate-based plant, purchased power and transmission and distribution facilities.

The comparisons presented above are not intended to imply that historical incentive levels were too low or unfair to shareholders. As discussed in this decision, our experimental DSM incentive mechanisms relied exclusively on ex ante assumptions of per-unit load impacts and savings persistence, and placed almost all performance risks on ratepayers. Hence, it was appropriate to establish earnings targets that reflected this relatively low risk to shareholders. However, these comparisons are useful in establishing what the appropriate starting point should be for today's consideration of relative risks and rewards.

Our interim rules provide little guidance on how to compare the earnings opportunity from DSM and supply-side resources in the context of their different (and changing) risk/reward profiles. In D.92-02-075, we acknowledged that one difference in risk relates to who funds the initial investment. However, there are other dimensions to relative risk that must be considered, such as how shareholder earnings vary with project performance and who bears the risk of noncost-effective investments. At the request of the ALJ, parties held supplemental workshops to discuss and characterize these dimensions as they relate to the current ratemaking treatment for supply-side resources. Their findings were jointly submitted in Exh. 337, and are summarized below. (See pp. C-1 to C-5, D-1-1 to D-1-15, H-2 to H-6.)

Under traditional cost-of-service ratemaking, shareholders put up the initial capital for generation, transmission, distribution and storage facilities, and are therefore exposed to potential investment losses if the project does not operate at all, or it is removed from rate base because it goes out of service prematurely. However, as PG&E and SoCal explain in Exh. 337, under applicable PU Code sections, the Commission has the authority to allow utilities to recover close to the full investment costs of abandoned and out-of-service projects. For PG&E, there have been two proceedings relating to prematurely retired plant: Geysers Unit 15 and the Humboldt Bay Nuclear Power Plant. In each case, the Commission allowed PG&E to recover the undepreciated investments over five years with no return. Similarly, the Commission has also allowed SoCal to recover costs for gas transmission, distribution and storage projects that have never became used and useful, but not earn a return on those investments. (Exh. 337, pp. C-2 to C-4, D-1-5 to D-1-7.)

Once a generation, transmission, distribution or storage facility is approved and placed in rate base, shareholder earnings are generally unaffected by changes in resource benefits, fuel prices or administrative costs over a wide range of performance. (Exh. 360, pp. 40-44; Exh. 337, pp. C-1 to C-5.)[36] Although these changes may result in different benefits

[36] While utilities can earn more than their authorized rate of return by reducing operating and maintenance costs (not including fuel) from the forecast adopted in the general rate case, this advantage is usually short-lived. The efficiency improvements will generally be reflected in lower cost projections in the next general rate case cycle (or in a higher overall productivity factor).

than forecast, traditional regulatory approaches do not look back and ascertain if the plant is "hitting target" as is done for DSM. (Exh. 354, p. 6.) Variations between forecasted and actual sales (throughput) also do not affect earnings on electric or core gas facilities, since these sales are currently given full balancing account treatment. The primary performance risk to shareholders relates to factors directly under the utility's influence, i.e., management of system operations and fuel or gas procurement contracts. These issues are reviewed in after-the-fact Commission reasonableness reviews. Over the past 10 years, PG&E has been disallowed less than 1% of electric operating expenses due to these performance factors. (Exh. 337, p. C-4.)

As SoCal points out, the risk and reward relationship for noncore gas sales is quite different. (Exh. 337, pp. D-1-1 to D-1-6.) For this class of customers, utility earnings are affected by variations between estimated and actual throughput fluctuations. Under the recently adopted global settlement, SoCal is at 100% risk for any underrecovery of the noncore revenue requirement over the next five years. However, SoCal would also be able to increase earnings substantially from increased noncore demand. (See D.94-04-088, mimeo. p. 31.) SDG&E and PG&E shareholders are currently at risk for 25% of underrecovery. Since the majority of utility DSM

Similarly, operating and maintenance cost overruns will generally be incorporated into the following rate case cycle, assuming that they are reasonable. As DRA points out, substantial increases can trigger a cost-effectiveness review of these expenditures. (RT at 5035.) Based on historical experience, however, it does not necessarily follow that shareholders will lose their initial investment, should the plant be deemed noncost-effective.

efforts address core gas and electric resource requirements, our consideration of relative risks and rewards focuses on these sectors.

As an alternative to building its own generation facilities, an electric utility can purchase power from independent power producers or other utilities.[37] Under traditional ratemaking treatment, these purchases represent a risk/reward profile similar to core gas procurement contracts. Shareholders do not earn any return on power purchase agreements with independent power producers or other utilities, but neither do they make any initial capital investments or assume a significant degree of forecasting risk. Under current ratemaking treatment, these purchase agreements are subject to balancing account treatment. Therefore, unless the electric utility is found to be imprudent in managing the contract, any differences between actual and forecasted fuel prices or resource benefits that are not assumed by the independent power producer are passed on to ratepayers. Figures 1 and 2 in Attachment 2 illustrate the relationship between earnings and performance for core gas operations, under traditional cost-of-service regulation. These relationships are equally illustrative of traditional ratemaking treatment for electric utility investments and power purchase agreements.

As SoCal explains, ratemaking treatment for core gas procurement is rapidly changing, and with it the risk/reward profile of such resources. While PG&E's core gas purchases

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[37] Gas utilities no longer have the option of investing in gas production facilities, so their only option is to enter into gas purchase agreements.

continue to receive full balancing account treatment subject to reasonableness reviews, SDG&E's and SoCal's core gas purchases now fall under new, performance-based gas procurement framework. As shown in Figure 3 of Attachment 2, shareholder earnings and penalties associated with gas purchases for SoCal and SDG&E are now linked to performance. Performance is defined as the extent to which actual gas purchase prices differ from a market-based benchmark price, rather than a comparison between actual and forecast gas prices.

For the SoCal performance mechanism, there is a deadband between 100% and 104.5% of the benchmark price, wherein shareholders incur neither penalties or earnings, and ratepayers absorb the difference in gas costs. Beyond the deadband, the difference in costs is shared equally by ratepayers and shareholders. Extreme performance at either end of the performance curve could trigger regulatory review. SDG&E's performance mechanism is similar to that of SoCal, and both mechanisms are being tested on an experimental basis.

Similarly, traditional cost-of-service ratemaking for electric utility operations has given way to experiments in performance-based ratemaking. Over the years, the Commission has selectively introduced more linkages between utility earnings and nuclear and coal plant performance. For example, for Mohave Coal Plant Units 1 and 2, shareholder earnings are linked to actual unit heat rates or plant capacity factors, relative to forecast. Earnings from the San Onofre and Palo Verde Nuclear Generating Stations depend on the difference in the cost of energy produced from that plant and the energy obtained from replacement energy sources. (Exh. 337, pp. H-3 to H-4.) For the Diablo Canyon nuclear plant, the utility is paid based on actual plant output. It is estimated that PG&E will recover the full cost of the plant, plus earnings on the cost, plus an additional $173 million if PG&E continues to operate the plant over its 30-year life at the same overall 79% operating capacity factor achieved through December 31, 1993. (Exh. 337, p. C-5; Exh. 360, p. 47; D.88-12-083, CPUC 2d 189, at 242-244.)

More recently, the Commission authorized a generation and dispatch shared-savings mechanism for SDG&E, which applies to the costs subject to Energy Cost Adjustment Clause (ECAC) balancing account treatment. Under this mechanism, SDG&E's shareholders and ratepayers share equally if actual energy costs fall (or increase) within one to six percent of a performance benchmark during the twelve months covered by the ECAC forecast. Below a one percent change, the additional costs or savings over the performance benchmark would be shared by ratepayers seventy percent and shareholders thirty percent. If SDG&E's costs exceed the benchmark by more than six percent, then ratepayers will pay the amount of these costs in excess of six percent subject to an ECAC reasonableness review. If SDG&E's cost fall below the benchmark by more than six percent, resulting in additional savings, ratepayers will automatically receive all of the benefits of the cost reductions beyond the six percent. (See D.93-06-092.)

As described in previous sections, the next generation of DSM incentive mechanisms will have a risk/reward profile different from any of the individual supply-side options discussed above, as well as from the DSM incentive mechanisms we have authorized in the past. Although ratepayers continue to put up the investment capital for DSM programs, shareholders will now be at risk for 100% of any losses to that capital. Unlike a rate-based plant, shareholder earnings will vary in direct proportion to performance, i.e., realized net benefits, even when factors entirely beyond the utility's management control affect that performance. And unlike any of the DSM shared-savings incentives in the past, DSM performance will be measured over a 7 to 10-year period for the purpose of calculating both earnings and penalties, and earnings for each program year will be distributed in four equal installments over that timeframe.

Given the differences in the risk/reward profiles of utility resource choices, what level of earnings opportunity is appropriate for the DSM incentive mechanisms adopted in today's decision? TURN's proposal would result in target earnings of approximately $29.5 million statewide, corresponding to a 10% earnings rate, based on our adopted definition of performance earnings basis.[38] This compares to a historical average of approximately $38 million, and a range of $77 to $154 million in earnings opportunity for avoided supply-side investments. (See Table 7.) TURN argues that, because shareholders do not put up the capital for DSM, utility shareholders are entitled only to a minimal management fee on ratepayers' investment. (Exh. 374, pp. 6-7.) Moreover, TURN points to the lack of earnings potential on power purchase agreements as further support for its position that any return

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[38] As described in Section 4 above, under TURN's proposal the utilities do not earn when performance is exactly at target; but they would earn at a 10% rate at any point above target. We assume that this rate is applied at target performance only for comparative purposes.

above zero on DSM would make DSM more attractive to the utilities than supply-side alternatives. (Exh. 373, p. 5.)

We disagree with TURN's conclusions and recommendations. As described above, the risks to shareholders from a power purchase agreement under traditional balancing account treatment is substantially lower than the risks under the DSM incentive mechanism we adopt today. It is therefore inappropriate to conclude that the earnings opportunity from DSM should be comparable to those types of resource acquisitions. As we have acknowledged in our development of other performance-based ratemaking mechanisms, the imposition of increased performance risks on the utility is appropriately balanced by increased opportunity to earn. We have therefore incorporated such opportunity into recently adopted incentive mechanisms for both gas procurement and electric generation and dispatch. With regard to TURN's assessment of investment risks, we surmise that money managers would demand considerably more than single-digit fees if they earned only in proportion to portfolio gains, as measured over a 7 to 10-year period, and if they were also required to pay for all losses on their clients' investments.

Under DRA's proposal, the level of target earnings corresponding to DRA's proposed target earnings rates would be approximately $52 million statewide. This level also represents a substantial discount below the level of earnings opportunity available from avoided supply-side investments. (See Table 7.) However, DRA's reasons for this level are significantly different than those proffered by TURN. Unlike TURN, DRA believes that the starting point for earnings comparability should be the earnings opportunity from a rate-based plant, assuming a 10-year amortization period. DRA then adjusts that level of earnings opportunity downward by 40-50% because, in DRA's view, current regulations "bias utility management toward choosing demand-side alternatives over supply-side options." (Exh. 341, pp. 31-33.) DRA recommends a further (10-15%) reduction in earnings opportunity based on its assessment of relative performance risks. (Exh. 341, pp. 33-36.)

In D.93-09-078, after considering a wide range of regulatory and financial factors that affected utility resource procurement decisions, including the ones described in DRA's testimony, we concluded that shareholder incentives are needed to offset utility management biases toward choosing supply-side alternatives over demand-side options. (D.93-09-078, mimeo., pp. 8-9, 27-28; RT at 3212 to 3220.) DRA justifies most of its reduction in earnings opportunity by asserting just the opposite. We have already ruled on this issue, and reject DRA's selective (and arbitrary) use of the testimony presented in an earlier phase of this proceeding to support its recommendations in this phase.

Based on the evidence in this proceeding, we also find DRA's assessment of relative performance risks to be selective and incomplete. On the demand side, DRA overstates the risks to ratepayers, thereby understating shareholder risks. Although utility DSM programs can create many ratepayer risks, there was persuasive testimony presented in this proceeding that these risks have been mitigated by general rate case reviews, adoption of the ex post measurement protocols, and the relationship between performance and earnings under the shared savings proposals. (Exh. 360, p. 10; Exh. 354, pp. 3-5, 7-9.)

While DRA disagrees with others on the relative "rigor" of our adopted ex post measurement protocols, DRA still acknowledges that the implementation of ex post measurement protocols has shifted performance risk from ratepayers. (Exh. 341, pp. 34-36.) DRA Witness Schultz further testified upon cross-examination that this shift creates higher shareholder risks due to factors both within and beyond the utility's control. (RT at 5060-5061.)[39] Moreover, DRA's analysis ignores the features inherent in shared-savings proposals that are designed to further shift performance risks to shareholders, such as the Panel 1 cost-effectiveness guarantee that we adopt in today's decision.

In addition, DRA's analysis understates the ratepayer risks, and thereby overstates relative shareholder risks, associated with supply-side options. As discussed above, ratepayers assume significant performance risks under the current ratemaking treatment for many supply-side options, including fuel price forecasting risk and uncertainty in actual plant operating efficiency. DRA acknowledged on cross-examination that the risk that a utility power plant will fail to provide anticipated benefits or be more costly than anticipated is born primarily by ratepayers, assuming prudent utility management of the project. (RT at 4935 to 4936.) DRA also agrees that a utility's capital

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[39] Contrary to DRA's assessment of our adopted ex post protocols, we believe that they are rigorous requirements that will substantially reduce the performance risk to ratepayers from DSM investments, particularly when applied in conjunction with the true-up and cost-effectiveness features of our adopted incentive mechanism. Should DRA desire to provide continued input on the development of future protocols, it should raise its concerns at ongoing Advisory Committee meetings and in our 1997 review of the ex post measurement protocols.