investment in a transmission and distribution project would be less risky for shareholders than an investment in a demand-side resource (RT at 5059.) In addition, DRA does not disagree with the factual descriptions of the risks and rewards for DSM and supply-side resources, as presented in the Joint Submission. (Exh. 337; RT at 5036.)

In sum, we find that both DRA's and TURN's recommendations for target earnings and earnings rates are not supported by the record. Performance risks have been significantly shifted from ratepayers to shareholders by the ex post measurement protocols and performance features of our adopted incentive mechanism. At the same time, the adopted incentive mechanism gives utilities the opportunity to effectively manage those risks through portfolio diversification. The evidence in this proceeding indicates that a portfolio approach will substantially reduce utility exposure to penalties, and correspondingly increase the potential for earnings, relative to a program-specific application of the incentive mechanism. (See, for example, Exh. 346, 346B; RT at 3954-3955, 4450-4453.)

As described in Attachment 1, a portfolio approach serves to decrease the absolute level of potential penalties, relative to a program-specific approach, whenever the penalty rate is higher than the earnings rate. This is because the programs performing in the deadband or earnings ranges will "pull up" the performance of the negative ones. In particular, when Panel 1's penalty rate of 100% is applied to aggregated program performance (i.e., on a portfolio basis), shareholders would be liable for 30% of the losses of individual programs if the overall portfolio is cost-effective. If the overall portfolio is not cost-effective, shareholders would be liable for 100% of the portfolio losses. (See Attachment 1, Cases 1C and 1D.)

The evidence in this proceeding also indicates that the probability of falling into the penalty range is reduced under a portfolio approach, although the evidence is far from conclusive on the level of that reduction. Depending upon the number of programs in the portfolio, the TRC ratios of those programs, and the distribution of factors affecting performance, the estimated probability of falling into the penalty range under a portfolio approach ranged from being negligible (less than 1%) to being quite significant (e.g., 50%). (See RT at 5020, 5295; Exh. 390, 390A, 394.)

While we can not predict with any precision the downside risks resulting from the combined features of our adopted incentive mechanism, we do conclude that they will be substantially less than if we applied those features to each individual program, as we have done in the past. Moreover, as discussed in Section 5.a. above, the upside potential from the adopted incentive mechanism is not capped or limited by declining earnings rates as it has been in the past. This serves to increase the overall potential earnings opportunity to shareholders when the utility performs beyond target.

In our judgment, a 30% target earnings rate reasonably balances these considerations in light of the above considerations and our decision to include measurement costs in earnings calculations. (See Section III.D.) At this rate, the utility will receive an opportunity to earn that is significantly higher than current earnings rates, reflecting our observations that the performance risks associated with DSM have been substantially shifted from ratepayers to shareholders. This rate and corresponding target earnings level are also within the range of earnings opportunity afforded to comparable supply-side investments, consistent with our own rules and the standards presented in the Energy Policy Act of 1992.[40] We choose an earnings rate at the lower end of this range to balance the significant risk-mitigating effects that portfolio diversification will have on shareholder exposure. At this rate, target earnings on a statewide basis are estimated at approximately $89 million, based on 1994 program year activities. The potential downside to the utilities is the full $215 million in estimated program costs. Should the utilities exceed their performance targets, they would continue to share net benefits with ratepayers at a 30% rate.

Table 7 compares our adopted target earnings level for shared-savings programs with the earnings opportunity from representative avoided supply-side investments, historical DSM target earnings and the proposals in this proceeding. Table 8 presents statewide estimates of the potential upside and downside earnings levels associated with our adopted mechanism, compared with the proposals presented in this proceeding.

d. Eligibility

Our DSM rules specifically state that "shareholder incentives should be designed to encourage energy efficiency and load management programs that promote energy efficiency." (Rule 16.) Our rules further direct that "incentive mechanisms should be based on a shared-savings approach for programs whose

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[40] We address those guidelines in Section E below.

TABLE 8

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

STATEWIDE TOTALS

Recorded PEB (% of Forecast)	Panel 1	SoCal	DRA	TURN	WECC	Adopted
200%	188	133	163	37	128	177
150%	141	133	58	18	117	133
100%	94	89	44	0	89	89
50%	47	0	22	-18	0	0
-30%	0	0	-53	-26	-18	0
-30%	-94	-32	-87	-47	-46	-89
-50%	-157	-45	-87	-55	-46	-148
-90%	-215	-45	-87	-71	-46	-215
-150%	-215	-45	-87	-102	-46	-215
Forecasted PEB:	314	295	295	367	295	295

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

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

Sources: Exhs. 348 A, B, C, and Exh. 337, Joint Tables C-1 to C-4 savings can be reasonably estimated." (Rule 18.) We established this rule so that, where feasible, shareholder earnings would reflect the value of the energy saved.

In D.92-10-020, we developed cost-effectiveness criteria for new construction programs designed to ensure "that ratepayers' investments in promoting higher efficiency standards will still yield a return in the form of reduced resource costs for the programs overall." (D.92-10-020, mimeo., p. 11.) Rule 11 was thereby modified to require that new construction programs pass the TRC test for both the residential and nonresidential program as a whole, in order to be eligible for funding.

While new construction programs may have lower TRC benefit-cost ratios than other programs, our rules require that they produce net benefits to be eligible for ratepayer funding, and all parties agree that these net benefits are measurable. It is therefore reasonable to count on and expect net benefits when utilities prepare their target earnings filing. SoCal's proposed incentive treatment would fail to ensure that the program's contribution to higher efficiency standards also produces net benefits to ratepayers. This is inconsistent with our rationale for modifying Rule 11. Moreover, as discussed in Section 5.b.(3) above, our decision to adopt a portfolio approach will mitigate the risks of penalties from programs that address lost opportunities, but that have relatively low TRC benefit-cost ratios. Accordingly, we will include new construction programs in the shared-savings mechanism adopted by today's order.

In its comments on the ALJ's proposed decision, SDG&E raises the issue of when to switchover to the new shared-savings mechanism for new construction commitments entered into prior to this decision, but where the actually incentive will not be paid until 1995 or later. In general, we have moved progressively towards a cash accounting basis for the calculation of earnings, which could be interpreted to mean that the new construction program commitments entered into before 1995 but "cashed" in 1995 or beyond would be subject to the mechanism adopted today. However, we agree with SDG&E that the changeover to shared-savings treatment for new construction programs should apply to prospective contracts, i.e., those entered into after the effective date of this order. Accordingly, the utilities should apply their current incentive mechanism to any new construction commitments that were entered into before the effective date of this order, but that have not yet resulted in the installation of measures or incentive payments. All new construction commitments entered into after today's order will be subject to our adopted shared-savings mechanism.

In D.93-09-078, we acknowledged that load management and fuel substitution programs had previously been excluded from incentive treatment under the experimental incentive mechanisms. However, we found it reasonable to consider expanding shareholder incentive programs to these programs, provided that they pass both the TRC and UC tests of cost-effectiveness on a prospective basis. In addition, fuel substitution programs must not increase source-BTU consumption or adversely impact the environment. (Rule 13.) We reasoned that an incentive mechanism which includes only some programs that promote energy efficiency would create perverse results. (D.93-09-078, mimeo., pp. 42-43.)

TURN and SoCal's arguments do not persuade us that these programs should remain ineligible for incentives. While utilities may be motivated to switch fuels or shift load for other reasons, this does not dispute our findings in D.93-09-078 that utilities require incentives to encourage them to create cost-effective resource value in the process. Our findings did not distinguish among the types of DSM activities that can create that value, which is precisely why we believed it was reasonable to consider incentives for all DSM programs that defer the need for more costly supply-side investments. In D.93-11-017, we modified Rule 6 to clarify that some load management and fuel substitution programs could serve this purpose.

SoCal further argues that load management should not be eligible for incentives because, by definition, these activities can result in increased energy consumption. (SoCal Opening Brief, p. 16.) However, these are not the types of load management programs that our incentives are designed to encourage. Rather, they are designed to promote programs that create resource value by avoiding the need for supply-side additions. Our funding rules, coupled with the TRC trigger adopted in today's order, will ensure that load management programs meet that objective before any incentives are awarded.

At the same time, we agree with SoCal that any load management program designed to increase the consumption of electricity and decrease the consumption of gas should be subject to the three-prong test of cost-effectiveness that applies to fuel substitution programs. DRA's proposal to reclassify thermal energy storage as a technology or measure should help address this problem.

With regard to fuel substitution, SoCal argues that utilities are already sufficiently motivated to pursue fuel substitution because doing so would increase fuel consumption at the expense of decreasing consumption on the competing utility's system. However, SoCal's arguments do not apply to a combined utility, since it is simply substituting one fuel of the same utility for another, with benefits to one class of customers and offsetting costs to another. Rather, SoCal's arguments are unique to SCE and SoCal, as single-fuel utilities, and only to the extent that they continue to pursue DSM in an uncoordinated manner. We agree with DRA that incentives should not be extended to fuel substitution programs for SCE and SoCal until they are capable of designing and implementing "fuel-blind" programs, per our recent directives. (D.93-11-017, mimeo., p. 16, Ordering Paragraph 1.)

As DRA and others point out, appropriate ex post measurement protocols need to be developed for fuel substitution programs and certain load management programs before incentives can be extended to these programs. However, DRA's proposed reclassification of thermal energy storage can occur without further delay.[41] To this end, CACD should conduct workshops for the purpose of developing proposed modifications to the current program definitions. CACD's workshop report should be filed at the Commission's Docket Office within ninety (90) days from the

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[41] In its comments on the proposed decision, SCE argues that TES may continue to be classified as a measure or technology under load management programs, in appropriate cases. Workshop participants should address SCE's comments by clearly defining those cases under which TES is considered a measure under load management or any other programs.

effective date of this order, and served on all appearances and the state service list in this proceeding. We emphasize that we will only consider language modifications that address the reclassification of thermal energy storage from a program to a measure, as discussed above.

Development of appropriate measurement protocols will require significantly more effort. We are reluctant to engage parties in this effort until our policies on industry restructuring have been more clearly defined with respect to utility involvement in DSM. We believe that the 1996 Annual Earnings Assessment Proceeding represents a realistic timeframe for considering these implementation issues. The CADMAC should address measurement protocols for load management and fuel substitution programs as part of its filing in that proceeding. In the meantime, we expect the joint subcommittee established in response to D.93-11-017 to continue its effort to resolve coordination issues between SoCal and SCE. (See RT at 4320.) We will consider extending incentives to the fuel substitution programs of SoCal and SCE if and when those coordination issues can be resolved.

Finally, we reject SoCal's recommendation that utilities be allowed to forgo shareholder incentive treatment for individual shared-savings programs, or reclassify these programs to an expense category. Under SoCal's proposal, utilities could remove noncost-effective programs from shareholder incentive treatment, thereby avoiding any potential penalties, and shift all the performance risk back onto ratepayers. We believe that this would defeat the purpose of shareholder incentives, i.e., to encourage performance and efficiency in utility DSM programs, and hold utilities accountable to program results.

In their comments on the ALJ's proposed decision, both SDG&E and SoCal opine that exceptions or adjustments to the adopted shared-savings mechanism should be made for the DSM bidding pilot programs. SCE made a similar proposal in its recent application for approval of contracts resulting from the bidding pilot solicitation. (See D.94-09-041 in A.94-05-016.) We note, however, that none of these parties raised specific concerns related to the application of proposed shareholder incentive mechanisms to bidding pilot programs in their testimony in this phase of the proceeding. Moreover, during the bidding pilot phase of this proceeding, each of these parties strongly supported applying the same shareholder incentive treatment to the bidding pilots that would be applied to the utility-sponsored programs that were being replaced. (See D.92-03-038, mimeo., pp. 10-11; D.92-09-080, mimeo., pp. 13-14.)

Our decisions made it very clear that future adjustments to the shared-savings mechanisms would apply equally to the pilots, and that the utility should negotiate contract terms and provisions that reasonably allocate the risks and benefits among affected parties, including ratepayers. Because winning bidders must "beat" the utility's projected cost-effectiveness performance to begin with, we do not believe that applying the shared-savings mechanism to winning bidders introduces any more risks of shareholder losses than the utility-sponsored program it replaces. (See D.92-09-080, mimeo., pp. 23-24; 87-92.) We believe that the risk of pursuing DSM programs in general is adequately balanced by the increased upside potential of earning on successful programs, whether implemented directly by the utility or via contractual arrangements with winning bidders.

e. <u>Interest on Earnings or Penalties</u>

Because shareholder earnings and penalties will be paid over time, parties raised the issue of how interest should be calculated to account for the time value of money. For example, if a program is implemented in year one, and earnings associated with that program are spread over ten years, how much higher should the payments to utilities be in year ten than if earnings were authorized and paid in year two? Conversely, if it turns out that the program is not cost-effective, and penalty payments are due to ratepayers in year ten, what interest should shareholders pay ratepayers to compensate them for the time value of money? Panel 1 proposes that the utility's equity cost of capital be used in these calculations. SoCal, DRA and TURN propose that the commercial paper rate be used. (Exh. 340A, p. 4.) SESCO recommends that the weighted cost of capital, including equity and debt, represents the time value of money. (SESCO Opening Brief, p. 11.)

Panel 1 and SESCO base their proposal on the argument that the cost of capital best reflects the long-term opportunity cost of shareholders. As TURN points out, however, money has an opportunity cost only if you would be able to earn on it in an alternative investment, that is, if you have it in hand to invest elsewhere. (Exh. 340A, p.4.) The position put forward by Panel 1 and SESCO presumes that shareholders should have their earnings on hand immediately upon program implementation, or at least after program costs and program participation have been verified. Our shift to ex post measurement, coupled with the incentive features adopted today, have clearly changed that presumption. Instead, the utility is paid incentives contingent upon actual performance, similar to "pay for performance" provisions in power contracts. Under such contracts, the producer receives its payment (and incurs associated profits or losses) as those monies are earned. There is no interest paid to the producer just because those payments may be stretched out over a lengthy period after project installation.

In many respects, the DSM incentive mechanism, coupled with our ex post measurement protocols, mimics such a contract: utilities earn only after savings are verified (or "produced"), in payments that extend over a 7-10 year measurement (or "contract") period. At the same time, however, these payments differ from most pay-for-performance contracts in that there can be differences in timing between performance and earnings payments due to the timing of earnings claims and the true-up requirements. Similarly, ratepayers may be entitled to repayments earlier than the claim in which penalties are assessed.

For example, at the end of the measurement period it may be determined that the utility should have earned $10 million distributed in four equal installments of $2.5 million, based on performance. However, actual earnings may have been recovered as follows: $4 million for the first claim (based on a forecast of $16 million in lifecycle per unit savings), $3.5 million for the second claim, $3.75 million for the third claim and -$1.25 million for the fourth claim (i.e., the utility had to pay back some of the earnings received in previous claims).

Because of these discontinuities, we believe that it is reasonable to calculate some interest on earnings and penalty accruals under the shared-savings incentive mechanism we adopt today. However, for the reasons stated above, we reject the notion that the cost of capital (average or equity) is the appropriate value. Instead, we adopt the 90-day commercial paper rate, which is used for the DSM balancing accounts and for shareholder incentives currently collected over a three-year period.[42]

As DRA points out, before interest (or earnings) can be properly calculated, there needs to be a consistent accounting scheme to track the various kinds of costs and benefits associated with DSM programs from the time of the target earnings filing through each of the earnings claims for that program year. (Exh. 341, pp. 66-67.) These details should be worked out in the context of developing and adopting the reporting requirements of the measurement protocols. To this end, we direct CACD to conduct workshops, as needed, for the purpose of continuing the ongoing work on refining these reporting requirements.

f. Retroactive Tax Treatment

In its direct testimony, Panel 1 explains that the tax deductibility of DSM expenditures has recently been

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[42] Under the current incentive mechanisms, some utilities have elected to recover their DSM shareholder earnings over three years, instead of one, for rate stabilization reasons. In these cases, the 90-day commercial paper rate is used to escalate the authorized incentive levels until they are collected in rates.

questioned by local Internal Revenue Service (IRS) auditors.[43] (Exh. 345, pp. 16-18.) The ramifications of this potential tax consequence have not been fully evaluated, and the outcome of the tax issue will not be resolved in the time frame of this phase of the proceeding. While parties generally agree that this change in tax treatment would impact tax levels and associated revenue requirements, they do not agree on whether or how it would affect the utilities' evaluation of the cost-effectiveness of DSM programs, for either funding or earnings claim purposes. (See RT at 3887-3888, 4606.)

In the event that current tax practices change, Panel 1 recommends that any effects these changes may have on earnings calculations be applied to prospective program years, and not to programs that have already been implemented. We believe that this is a reasonable approach in light of the uncertainty regarding the tax treatment of DSM expenditures. However, should the IRS ruling remain in effect, we will need to clarify how it should apply to the earnings claims for future programs. We will do so in the first AEAP following the IRS' final determination on this issue.

B. <u>Performance Adder Incentive Mechanisms</u>

Performance adder mechanisms have been in place since experimental DSM incentive mechanisms were first adopted in D.90-08-068. They generally apply to programs which are funded primarily for equity reasons, or in which the link between programs and savings is difficult to measure. In the past, these

[43] SCE is currently under audit and the IRS auditors have disallowed the deductibility of SCE's DSM program expenditures in prior years for tax purposes. SCE is contesting the audit.

have included direct assistance programs, which serve low-income customers, energy management services programs, which provide customers with information and audit services, and new construction programs, which are designed to promote the development of higher efficiency standards. Unlike shared-savings mechanisms, performance adder mechanisms do not base earnings on verified net benefits. Instead, earnings are generally calculated by multiplying the amount of recorded program expenditures by some percentage, usually a fixed five percent. Performance adder mechanisms can also include variable earnings rates, where the rates increase as a function of achieving higher levels of performance or standards.

Like shared-savings mechanisms, however, performance adder mechanisms include a MPS below which the utility is ineligible for earnings. These standards are generally based on units of accomplishment, such as the number of audits or installations. Current performance adder mechanisms do not include a penalty for performance below that minimum.

In the past, there have been some variations across utilities as to which types of incentive mechanisms apply to specific programs. (See Exh. 340.) Fixed-rate performance adder mechanisms have been applied to energy management services programs and direct assistance programs, while variable earnings rates have been applied to some utilities' new construction programs.

Parties generally agree that performance adder mechanisms should continue, and that they should apply to each program on an individual basis. Therefore, in order to qualify for earnings, each eligible program must achieve a pre-specified minimum performance standard. In addition, parties agree that penalties should not be included in the structure of the performance adder incentives. However, the parties disagree on what programs should be subject to performance adder treatment and how to construct the mechanisms themselves. We discuss these differences below. As reported by the parties, the proposals for different incentive structures result in very similar levels of recommended target earnings for performance adder programs.[44]

1. <u>Program Eligibility</u>

All key parties agree that non-mandatory direct assistance and energy management services programs should be eligible for performance adder treatment.[45] As discussed in Section A.5.d above, only SoCal recommends that new construction programs should also receive variable performance adder, rather than shared-savings treatment. WECC also suggests that other programs whose savings cannot be estimated reasonably, e.g., market transformation programs, may also be considered.

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[44] See Exh. 337, pp. A-5 - A-8. Clarifications were provided to CACD by respondents.

[45] After the workshops in March, 1994, SESCO presented testimony dissenting on this position, even though the workshops did not address performance adder mechanisms, and parties had no opportunity to respond to SESCO's recommendations in rebuttal. (See Exh. 388.) In accordance with the ALJ's ruling on the scope of SESCO's testimony, we do not address SESCO's specific recommendations and arguments regarding direct assistance programs in this decision. We note, however, that our resolution of the incentive treatment for direct assistance does address SESCO's concerns over the lack of incentives to reduce program costs under current performance adder mechanisms.

2. Incentive Structure for Energy Management Services

Energy management services programs consist of programs intended to provide information on the relative costs and benefits of installing measures or adopting practices which can reduce the customer's energy bill.

DRA, TURN, and SoCal believe that the performance adder mechanism for energy management services should be modeled after current mechanisms. Specifically, the performance earnings basis would be equal to verified program expenditures, and pre-tax earnings would be calculated as five percent of those expenditures. As in current practice, goals would be set according to forecast expenditures; earnings are paid on verified expenditures. DRA recommends a MPS of 75% of the forecasted number of audits or other service units for these programs. TURN concurs with DRA. SoCal recommends that the MPS should be equal to two-thirds of the forecasted service units. Under both proposals, the MPS would apply to the first earnings claim only. (See Exhibit 340.)

Panel 1 argues that the current performance adder treatment should be restructured to encourage improved productivity, i.e., to increase energy savings and reduce program costs. To this end, Panel 1 recommends that earnings be linked to improvements in the level of benefits per dollar spent, relative to the previous year. Under Panel 1's proposal, the utility would not be eligible for any earnings unless each program exceeded 70% of forecasted first-year energy savings, as verified in the first earnings claim. Above that level, earnings under current performance adder treatment (i.e, 5% of verified program expenditures) would be adjusted in two ways:

First, these earnings would be adjusted by the ratio of verified to estimated first-year energy savings. Estimated first-year energy savings would be based on an estimate of unit accomplishments (number of audits, surveys, etc.) multiplied by an estimate of first-year savings per unit. These estimates would be based on the most recent load impact studies, or average accomplishments from programs in the prior two years if recent studies are not available. (Exh. 345, pp. 43, 45.) Verified savings would be calculated by multiplying actual units of accomplishment, as verified in the first earnings claim, by the ex ante estimate of first-year savings per unit. The incentive mechanism does not rely on either an ex ante estimate or ex post verification of savings persistence. (RT at 4373-4377.)

Second, earnings would be adjusted by a factor based on the ability of the utility to reduce average costs relative to the previous year, up to a maximum of plus or minus 20 percent. This performance factor is calculated by dividing the current year's average cost of savings ($ per kWh or therm saved) by the average cost of the same program from the previous year. Current year costs would also be verified in the first earnings claim. If the relative program cost ratio exceeds 1.2, the performance factor is 0.8, if the relative program cost ratio falls below 0.8, the performance factor is 1.2. The performance factors are linear within that range. (Exh. 345, pp. 45, 49; RT at 4389.)

The performance factor would rachet so that a utility's earnings would be increased only in those years in which performance improved relative to the previous year. Earnings would be reduced in any year in which the utility was not able to sustain the previous year's level of performance. Consistent with the earnings distribution schedule adopted in D.93-05-063, the resulting earnings from this mechanism would be recovered over four earnings claims. (Exh. 354, p. 48.)

3. **Incentive Structure for <u>Direct Assistance</u>**

Direct assistance programs are intended to provide assistance to low-income or other target customer groups. Direct assistance consists primarily of full subsidies of the conservation measures. The primary purpose of the program is to serve an equity objective in assisting customers who are highly unlikely or unable to participate in other residential programs.

Direct assistance programs consist of both mandatory and non-mandatory DSM activities. The mandatory programs promote weatherization measures, and are not eligible for shareholder incentives.[46] The non-mandatory measures may include such measures as appliance replacement and energy education and are eligible for incentive treatment.

DRA, TURN, and WECC recommend that the incentive structure for non-mandatory direct assistance remain similar to current practice, where the performance earnings basis consists of verified program costs and pre-tax earnings are five percent of those expenditures. Similar to SoCal's and SDG&E's current mechanisms, DRA recommends that the MPS be linked to program accomplishments in the mandatory direct assistance program. Specifically, earnings would accrue for non-mandatory measures

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[46] See PU Code § 2790.

only after 75% of the goal for mandatory weatherization is achieved. TURN supports this approach. (See Exh. 340, p. 15.) Panel 1 recommends that its proposed performance adder mechanism be applied to direct assistance programs, but is silent on the linkage issue.

SoCal proposes that earnings on the non-mandatory program be linked to mandatory achievements and recommends a tiered approach, in which earnings accrue as follows:

Mandatory Goal	Non-mandatory Incentive Rate*
0 - 69.99%	0
70 - 74.99%	5%
75 - 79.99%	6%
80 - 84.99%	7%
85 - 89.99%	8%
90 - 94.99%	9%
95 - 100.00%+	10%

*Percent of program expenditures, pre-tax rate

As reported by SoCal, this approach would not significantly increase the earnings potential from direct assistance programs, relative to either the current, fixed rate approach, or Panel 1's performance adder approach.[47]

4. **Discussion**

Since 1990, we have experimented with incentive mechanisms designed to encourage the utility to offer DSM

[47] See Exh. 337, pp. A-5 - A-8. As clarified in conversations between CACD and SoCal, SoCal forecast target earnings for direct assistance programs at 5%, the mid-point of the tier range. Target earnings would increase if higher points on the tier were used for forecast purposes.

information and assistance equitably and without discrimination. As a result, utilities have been encouraged to maintain and expand non-mandatory direct assistance and energy management services programs by authorizing funding for these programs and by rewarding them in modest amounts for their efforts. All parties agree that these programs should continue to receive incentive treatment because they serve important policy goals, consistent with our current rules. (See Rule 11.)

We agree with DRA and others that these types of programs are appropriately afforded performance adder, rather than shared-savings treatment. (Exh. 336, p. 34.) These programs are not required to pass cost-effectiveness tests, result in savings which are not readily measurable, and are justified in terms of other, non-resource planning objectives. (See Rule 11.) As discussed in Section A.5.d above, we find that new construction programs should be subject to shared-savings incentives, since they are required under our Rules to provide resource benefits, and those benefits can be readily measured. We have previously ruled that it is premature to determine whether market transformation programs should be eligible for incentive treatment. (D.93-09-089, mimeo., pp. 43-44.) We may consider CEC's suggestions on how to link incentives under performance adder mechanisms to additional objectives in a future AEAP, after CADMAC members have had more opportunity to consider and develop these concepts. (Exh. 361, pp. 31-36, RT at 4457-4458.) Therefore, we will apply performance adder treatment only to nonmandatory direct assistance and energy management services programs.

Our adopted performance adder rates and minimum performance standards will apply to each of the following individual programs, as proposed by Panel 1 (RT 4378-4379): residential energy management services, nonresidential energy management services, and non-mandatory direct assistance programs. These requirements will be applicable to all direct assistance programs in the aggregate, including any direct assistance programs which are bid out, either to community-based organizations or in the DSM bidding pilots.

With regard to incentive structure, we must decide whether earnings should continue to be based on program expenditures, or whether they should be linked to a more explicit measure of performance. We agree with DRA and others that the Panel 1 proposal increases the complexity with which earnings are calculated under performance adder mechanisms. (Exh. 343, p. 60, Exh. 341, p. 57, RT at 5174.) Given the relatively low level of earnings involved, it is tempting to continue the very simple, straightforward linkage to program costs, as several parties propose.

Nonetheless, we reject the simplicity of the status quo because of its serious shortcomings. Under the current approach, earnings decrease if the utility achieves the same level of accomplishments at an actual cost that is less than forecasted program costs. Hence, the utility has no incentive to reduce per unit costs through cost minimization. Nor does the utility have any direct incentive to increase the level of accomplishments (and associated savings) relative to costs. Once the utility has achieved the MPS, utility earnings do not increase when (for example) a greater number of audits are conducted at the same level of program costs. Instead, earnings increase only if verified expenditures increase. This is not an incentive structure that we wish to continue.

In contrast, under the Panel 1 approach, the utility earns more if it achieves the same level of savings at a reduced cost, or produces a higher level of savings at the same cost. Moreover, the utility is motivated to beat that new level of performance by either reducing costs further or increasing program accomplishments for the same (or less) amount of expenditures. Otherwise, the utility will not be able to increase its earnings rate for subsequent program years.

Attachment 4 provides numerical examples to illustrate these incentives: The Base Case assumes that forecast expenditures for a hypothetical Commercial Energy Management Services program are $7,200,000. The estimated savings related to the energy audits are 36,000,000 kWh per year, based on ex ante estimates. The utility forecasts that 12,000 audits will be performed. The unit incentive is $0.01 per kWh and the estimated unit savings are 3,000 kWh per audit. In the base case, if targets are achieved and there is no cost minimization relative to the previous year, the utility will earn $360,000.

As Case 1 demonstrates, if the utility spends less on the program ($7,000,000), but achieves the estimated level of savings (36,000,000 kWh per year), and costs are minimized relative to the previous year, the utility's earnings will increase to $414,000. However, in Case 2, we can see that if the utility spends less than forecast ($7,000,000), but the savings decrease (30,000,000 kWh per year) and costs are not minimized, earnings decrease to $255,000.

Case 3 demonstrates that if the utility spends more than forecast, but savings are equal to forecast and costs are minimized, earnings will increase to $374,000. However, if expenditures increase, savings are equal to forecast and costs are not minimized, earnings will decrease to $324,000. (See Case 4.)

In Panel 1's proposal, then, earnings are a function of both savings and cost minimization. We recognize that direct assistance and energy management services programs are not designed to defer or avoid more costly supply-side additions, and that they may never pass the TRC test of cost-effectiveness. Nonetheless, as long as these services are being provided, we believe that the utility should be motivated to reduce the cost and increase the amount of kilowatt-hour savings generated by these programs. Only the Panel 1 proposal provides this incentive. Both DRA and SoCal have agreed that Panel 1's proposal is conceptually superior to the current approach. (RT at 5169, 5174; Exh. 344, p.10.) We agree. Moreover, given the fact that utilities are already required to conduct extensive measurement of performance adder programs under our adopted protocols, Panel 1's proposal would provide this improvement without significantly increasing the measurement burden. (RT at 4371-4372; Exh. 345, p. 43.)

DRA has expressed concerns regarding implementation issues, more specifically, the specifications of our adopted measurement protocols for estimating first-year savings. (RT at 5172-5174.) We share the concern that the Panel 1 approach introduces per-unit savings estimates in an area where, by definition, the Commission has acknowledged that these programs do not lend themselves well to measurement and are not principally designed to produce resource savings. However, as indicated on the record, many of the estimating techniques that apply to shared-savings programs may be applicable to specific measures covered by these programs. In fact, several utilities have completed measurement studies for these performance adder programs using the adopted protocols. Moreover, PG&E is currently using a performance adder approach that requires estimates of per unit savings. (RT at 4360-4366.)

We believe that further specification of estimating techniques and protocols for performance adder programs can effectively be addressed by the CADMAC. As Panel 1 notes, the CADMAC is in the process of evaluating several issues related to the measurement studies required by D.93-05-063. (Exh. 345, p. 44.) We encourage the CADMAC to continue this evaluation in light of today's decision. Parties may present their recommendations in the next AEAP. (See Protocols adopted in D.93-05-063, p. B-6.)

While we adopt Panel 1's proposal for establishing the performance earnings basis and earnings rates, we believe that a higher minimum threshold of performance should be required before any earnings accrue from these programs. Current mechanisms for PG&E, SDG&E, and SCE requires a MPS of at least 75% for all energy management services programs. SoCal's MPS for these programs is 67%. We will apply the MPS to residential and nonresidential energy management services programs separately, but will adopt DRA's proposal for a MPS of 75%, which is generally consistent with current mechanisms. Although nonresidential energy management services programs are grouped together in a portfolio approach for earnings purposes, we expect the utilities to make every effort to serve each market sector, as they have in the past.

We also believe that the performance adder mechanism for non-mandatory direct assistance should be linked to achievements in the mandatory program. The primary goal for the non-mandatory program, as stated above, is to assist customers who may be unable to participate in other residential DSM programs. The goal of the mandatory direct assistance program is to reduce hardship as well as improve energy efficiency, as stated in PU Code § 2790. The weatherization goals of the mandatory program are dominant. More efficient appliances and other non-mandatory measures are important and lead to increased energy savings and reduced demand for the utilities, as well as lower bills for the participants. However, it is essential that our low-income ratepayers be afforded the building envelope efficiencies and amenities provided by basic weatherization measures. A clear linkage to the mandatory programs will help achieve the goals of both the mandatory and non-mandatory direct assistance programs. We have consistently reaffirmed that direct assistance programs achieve important policy goals. (See R.91-08-003, p. 21 and Policy Rule 11.) It makes sense, then, to reward the utilities for superior performance related to mandatory programs. Earnings will accrue on non-mandatory direct assistance programs only after a MPS of 75% is achieved on the mandatory programs, as proposed by DRA.

All parties agree that energy savings from either residential or nonresidential Energy Management Services programs which lead to energy efficiency rebates should be counted towards shared-savings goals, and not included in the calculation of earnings under the performance adder mechanism. Utilities currently track these installations explicitly. (RT at 4369-4371, 4379, 4381-4382, 4498-4499.) Panel 1 has proposed to include in its shared-savings calculations the energy savings which result from installations verified by post-audit visits, but does not specify whether such installations are part of the rebate program. (Exh. 345, p. 41.) We clarify that these energy savings should contribute to the shared-savings calculations only if the installations are verified by post-audit visits and the measures (prescriptive or customized) are rebated by the respective utilities.[48]

Table 9 presents the estimated impact of our determinations on target earnings, based on estimated 1994 program costs and benefits.

C. Funding Flexibility

Current policy for SDG&E, PG&E, and SoCal allows for unlimited movement of funds between programs given the same shareholder incentive treatment. All parties support applying this policy to SCE, and continuing it for the other three

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[48] SDG&E's current practice is to include under shared-savings treatment all savings resulting from measures installed based on utility representatives' recommendations, whether or not in connection with an audit or rebate. According to SDG&E, such installations are tracked separately and would not be double counted. In its comments on the ALJ's proposed decision, SDG&E recommends that this practice continue. We reject this proposal because it has the potential for verification and measurement problems.

TABLE 9

ADOPTED PERFORMANCE ADDER MECHANISM
TARGET EARNINGS
(Pre-tax $ million, 1994)

	PG&E	SCE	SDG&E	SOCAL	STATEWIDE TOTAL:
Res EMS	0.55	0.3	0.08	0.08	1.01
Nonres EMS					
Com	0.34	0.5	0	0.12	.96
Ind	0.15	0.3	0	0.03	.48
Ag	0.08	0.1	0	0	.18
Subtotal	0.57	0.9	0	0.15	1.62
Non mandatory DA	0.89	0.44	0.08	0.59	2.00
TOTAL	2.01	1.64	0.16	0.82	4.63

NOTE: Target earnings based on utilities' forecast for 1994 program year.

EMS = energy management services program
DA = direct assistance

Source: Exhibit 337; breakdown by program clarified by respondents.

utilities.[49] However, if the portfolio approach is adopted, SCE recommends that shifting program portfolios (i.e., residential and nonresidential shared savings programs) not be allowed.

Current policy also allows SDG&E, PG&E, and SoCal to spend 130% of authorized amounts for the sum of shared-savings programs. The utilities, CEC, and DRA recommend that this policy continue and also be extended to SCE. NRDC proposes that spending flexibility for shared-savings programs be increased to 150% of authorized levels. TURN recommends that the utilities be restricted in spending to authorized levels.

Neither NRDC nor TURN provides compelling reasons for changing these policies, or for not extending them equally to SCE. Restricting funding to 100% of authorizations, as TURN recommends, would impede the utility's ability to respond to unexpected market opportunities that can produce net benefits in excess of forecasted amounts. It would also place an unnecessary burden on the regulatory process. Given the performance features of our adopted shared-savings incentive mechanisms, we believe that the fund shifting and spending flexibility recently adopted for PG&E, SoCal, and SDG&E will only enhance the potential "win-win" situations resulting from utility DSM activities. At the same time, we are not convinced that an increase in this flexibility, as NRDC proposes, is necessary for utilities to

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[49] Funding flexibility for SCE was most recently addressed in SCE's 1992 general rate case. In that proceeding, SCE was required to request approval for any fund shifting across programs in excess of $2.5 million via advice letter filing. SCE was not given any flexibility to spend above authorized levels. In more recent general rate case proceedings for PG&E, SDG&E, and SoCal, the Commission authorized considerably more funding flexibility.

respond effectively to such opportunities. The 130% limit has only been reached by PG&E once over the last four years. (RT at 5330.) We prefer to maintain current levels of spending flexibility, and apply them equally to SCE.

However, we will restrict fund shifting between the residential and nonresidential portfolios under the shared-savings mechanism, in order to ensure that there is no incentive for utilities to concentrate their resources in programs for commercial customers at the expense of residential customers. Should there be a compelling reason for shifting funds from residential to nonresidential portfolios, the utility may file an application explaining those reasons for our review and consideration. If a utility wishes to shift funds from the nonresidential to the residential portfolio, the utility may seek authority by filing an advice letter.

We will also make one exception to the restriction against fund shifting between programs given different incentive treatment. Utilities will be allowed to shift funds as needed from the nonmandatory portion of direct assistance programs (performance adder treatment) into the mandatory portion (nonearning category). However, funds cannot be shifted in the other direction. (See RT at 4503-4506.) This will give utilities the flexibility to increase activities in mandatory areas without the need for an advice letter filing.

Attachment 3 outlines the fund shifting and spending policies adopted by today's decision.

DRA also recommends that penalties be established in this proceeding for circumstances in which a utility uses dollar authorized for DSM to implement non-DSM activities. (Exh. 341,

p. 63.) We prefer to address the issue of penalties in the appropriate earnings claim proceeding, if and when this type of fund shifting is evident. We have clearly stated that inappropriate use of DSM funds will not be tolerated. (See D.93-12-044.)

D. Consideration of Measurement Costs in Funding and Earnings Claims Proceedings

The costs associated with measuring DSM savings are not currently considered in DSM funding decisions, nor are they included in cost components used in current shared-savings mechanisms.[50] In D.93-05-063, we identified this phase of the proceeding as the forum for considering the treatment of measurement costs for program funding and earnings claims purposes.

Panel 1 members and SoCal recommend that measurement costs not be included in funding or incentive cost-effectiveness calculations at this time. They argue that doing so would prematurely eliminate low-TRC programs, because current measurement funding levels are not representative of long-term measurement costs. They contend that these costs are expected to decline in the future, as practitioners gain more experience.

[50] Current shared-savings mechanisms are similar to DRA's proposal in that they use the estimate of program costs (multiplied by a target earnings rate) to derive the target earnings level. Measurement costs are not currently included in those estimates and, because we do not adopt that approach for the future, they would not come into play in establishing the target earnings level under our adopted mechanism. However, forecasted measurement costs could be considered in establishing the MPS and in calculating actual performance earnings basis. Moreover, these costs could be considered in the calculation of whether or not a specific program passes the TRC test under the adopted TRC trigger.

Therefore, Panel 1 and SoCal recommend that the current practice be continued and revisited in the 1997 AEAP. (PG&E Opening Brief, pp. 48-49; Exh. 360, p. 48; Exh. 343, p. 65; Exh 344, pp. 14-15.)

DRA recommends that measurement costs be included in cost-effectiveness calculations for funding purposes, but not in the costs related to incentive mechanisms. DRA believes that the decision to include or exclude measurement costs now has a more important impact on funding decisions precisely because there has been a decline in the TRC cost-effectiveness of many programs. Moreover, DRA argues that an accurate identification of program-specific measurement costs has been made easier by the adopted measurement protocols and the improved definitions and reporting requirements for measurement activities.

DRA recommends that, beginning in 1995, the load impact and process elements of measurement budgets should be included as a cost when applying cost-effectiveness policy rules. However, DRA would not include measurement costs in any cost terms used in a shareholder incentive mechanism. DRA argues that doing so could sacrifice measurement objectives because it would introduce a profit dimension to forecasting and recording measurement costs. TURN supports DRA's recommendations, but would also extend them to incentive mechanisms. (Exh. 341, pp. 67-71; Exh. 340A, p. 13.) However, no party would apply these requirements to direct assistance or energy management services programs.

As a general principle, we believe that measurement costs should be included in evaluating the cost-effectiveness of DSM programs designed to defer or avoid supply-side alternatives because, as we stated in D.93-05-063, these represent a true cost of acquiring DSM resources. (D.93-05-063, mimeo., pp. 64-65.) However, we are reluctant to do so at the program or program element level until there are more specific protocols for allocating measurement costs. To do so would add unnecessary complexity and controversy in DSM funding proceedings. We also agree with SoCal and others that measurement costs over the next few years will reflect a learning curve; therefore, to consider those costs on a program-specific basis might prematurely terminate certain programs.[51] For similar reasons, we believe that it would be counterproductive to require that measurement costs be included in the program-specific TRC trigger until it is clear that these allocation issues can be resolved and more experience with ex post measurement is gained.

In the meantime, we reject the notion that DSM measurement costs should be completely ignored in funding or earnings claim proceedings for programs that are subject to shared-savings treatment. While consideration of these costs may not currently be practical or advisable at the program-specific level, we see no reason why certain thresholds cannot be established at a more aggregated level. It is not unreasonable to expect that overall DSM activities will be cost-effective enough to absorb current levels of measurement costs. To this end, we adopt the following requirements, beginning with the 1995 program year. First, as an additional condition for funding, the

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[51] We note that the gaming concern DRA raises in its testimony is specific to current mechanisms and the DRA proposal, which derive target earnings levels from program costs. We have not adopted that approach in today's decision. (See Exh. 341, p. 71.)

utility must demonstrate that DSM programs subject to shared-savings treatment are in aggregate cost-effective from both a UC and TRC perspective when estimated measurement and evaluation costs are included. In today's order, we adopt language modifications to Rule 6 to reflect these requirements. We do not extend these requirements to direct assistance or energy management service programs, since these activities are not required to pass cost-effectiveness tests as a condition for funding.

Second, for earnings claims purposes, we will also add the requirement that the performance earnings basis for each program year (both portfolios combined) must be adjusted to reflect the aggregate measurement and evaluation costs associated with that program year. For example, assume that at the first earnings claim for the 1995 program year, a utility's performance earnings basis is $30 million for its residential portfolio and $60 million for the nonresidential portfolio. Also assume that the utility has exceeded its MPS for each portfolio. Each of these determinations are made without considering measurement costs either in the forecast of target performance, or the calculation of actual performance.[52] Under our adopted incentive mechanism, the utility would earn $6,750,000 (.30 x $90 million

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[52] The determination of whether the portfolio meets the MPS or falls into the deadband would not be affected by measurement costs, either in establishing the MPS or in evaluating whether or not actual performance falls beyond the deadband range. However, measurement costs would affect the performance earnings basis beyond the MPS and deadband range, as described below.

divided by 4) in the first earnings claim, before measurement costs were considered.

Further assume that measurement costs for programs implemented in the 1995 year (through the first earnings claim) are $1 million in aggregate (i.e., both portfolios combined). The performance earnings basis of the combined portfolios would be reduced from $90 to $89 million, and earnings in the first claim would decrease from $6,750,000 to $6,675,000. In other words, shareholders would share measurement costs at the same 30% rate they share other program costs and benefits, whenever the portfolios yield positive net benefits in the aggregate. Similar calculations would be made at each earnings claim. Should one or the other portfolio fall into the penalty range, then the measurement costs associated with that portfolio would be refunded to ratepayers in full, consistent with the cost-effectiveness guarantee.

DRA recommends that only certain elements of the utility's measurement, forecasting and regulatory reporting budgets be considered in cost-effectiveness evaluations. We do not have a sufficient record in this proceeding to make a final determination on this issue. Within 90 days from the effective date of this order, CACD should conduct workshops and submit a workshop report on which measurement budget categories should be included in the requirements described above, and an appropriate method for including them. CACD's report should be filed in the Commission Docket Office and served on all appearances and the state service list in this proceeding.

E. Energy Policy Act of 1992

Section 111(a)(8) of the federal Energy Policy Act of 1992 (Act) requires state commissions to consider the following standard:

> "The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for construction of new generation, transmission, and distribution equipment."

Section 115(b)(4) of the Act provides a similar standard for gas utilities. Section 111(b) requires state commissions to consider whether implementing these standards would produce anticompetitive results.

In D.93-09-078, we identified this phase of the proceeding as the forum for considering these standards. Per the federal requirements, we must state our reasons for not adopting them, should we deviate from these standards as a result of our specific design of shareholder incentive mechanisms. (D.93-09-078, mimeo., pp. 41-42.)

The comparison of profitability required by the federal standards is similar to our interim rule on supply-side comparability, discussed in Section A.5.c above. We have learned in this proceeding that such comparisons are difficult to make, given the differing performance, earnings and investment characteristics of demand and supply-side resources. In addition, as we discuss in Section A.5.c, the specific risk/reward features of the DSM incentive mechanism should be considered in establishing DSM earnings opportunity.

Taking all of these considerations into account, we have adopted an earnings rate that is within the range of earnings opportunity afforded to comparable supply-side investments. We conclude that our adopted shared-savings mechanism is consistent with the federal standard, but based on a broader set of factors than the profitability guideline articulated in that standard. We believe that it is appropriate to consider a broader set of factors, given the complexity and diversity in our ratemaking treatment of both supply- and demand-side resources.

In its reply brief, SESCO argues that, because energy service companies do not have access to ratepayer funds, any shareholder incentive that allows utilities to earn more money for less performance than energy service companies would violate Section 111(b) of the Act. SESCO asserts that both the Panel 1 and DRA proposed shared-savings mechanisms would allow this to occur. (SESCO Reply Brief, pp. 11-13.)

We conclude that SESCO's assertions of anticompetitive impacts are without merit. SESCO has participated minimally in this phase of the proceeding and has presented no witnesses to lend factual support to these assertions.[53] Moreover, the implication of SESCO's argument is that all utility-sponsored DSM must be put out to bid before incentives can be paid, or else utility DSM programs are anticompetitive. We rejected a similar

[53] Nor did SESCO choose to argue this point in its opening brief, so that other parties would have an opportunity respond in their reply briefs.

position put forth by Transphase Inc. in our decision authorizing DSM bidding pilots for SoCal, SDG&E, and SCE. (D.92-09-080, mimeo., pp. 36-47.) The ability of energy service companies to cost-effectively augment or replace utility DSM activities is currently being tested in our bidding pilots, consistent with Legislative requirements. Our evaluation of the DSM bidding pilots will assess how best to structure the relationship between utilities and third parties in a competitive bidding environment. This phase of the proceeding is not the forum for determining that relationship.

The incentive mechanisms adopted today do not represent new policies or standards for regulating utility involvement in DSM markets. Rather, they are the result of several years of experimentation with different regulatory approaches for ensuring that ratepayer dollars are well spent. We do not believe that today's decision alters the utility's role in the DSM market or its interface with private energy service providers. As required by D.92-09-080, we will continue to monitor this interface in our DSM funding proceedings. (Ibid. pp. 44-45.)

IV. Next Steps

Today's decision describes several follow-up activities that need to take place for consideration in future Commission rulings or AEAPs. Within 90 days from the effective date of today's order, CACD is directed to conduct workshops and submit a workshop report on (1) modifications to current program definitions that reclassify thermal energy storage as a measure under various program categories and (2) recommendations on which measurement budget categories should be included in cost-effectiveness evaluations, as directed by today's decision. CACD's workshop report should summarize the consensus and nonconsensus proposals of the parties and present CACD's specific recommendations for Commission consideration. CACD's report should be served on all appearances and the state service list in this proceeding. We will either consider the CACD's recommendations on an ex parte basis, after receiving further comments from interested parties, or address them in the 1995 AEAP, whichever comes sooner. (See Sections III.A.5.d. and III.D.)

Within 120 days, CACD is directed to conduct workshops and submit a workshop report on the reporting format and data requirements for utility filings on lost opportunities, as described in Section III.A.5.b.(3). CACD's report should summarize the consensus and nonconsensus proposals of the parties and present CACD's specific recommendations for Commission consideration. CACD's workshop report and recommendations should be served on all appearances and the state service list in this proceeding. We will consider CACD's recommendation on an ex parte basis, after receiving further comments from interested parties. Utilities will begin reporting their strategies and accomplishments in capturing lost opportunities on an annual basis, beginning with the 1995 AEAP.

The 1995 AEAP will also be the forum for considering parties' proposals on (1) how to report cost-effectiveness forecasts and results at the DSM program component, measure and element level and (2) how to treat various benefit and cost components in the calculation of net benefits or benefit-cost ratios, as described in Section III.A.5.b.(1). CACD is directed to hold workshops on this issue and, within 180 days from the effective date of today's order, file a workshop report describing the consensus and nonconsensus positions of parties on these issues. CACD's workshop report should be served on all appearances and the state service list in this proceeding and in the 1995 AEAP. In addition, as described in Section III.A.5.e., CACD should also conduct workshops, as needed, to refine the reporting requirements necessary to track DSM program costs and benefits (including interest calculations) for our consideration in future earnings claim proceedings.

As described in Section III.B.4, the CADMAC should continue its evaluation of measurement protocols for performance adder mechanisms, in light of today's decision. Parties may present their recommendations in the 1995 AEAP. We will also clarify how the IRS ruling on DSM expensing (should it remain in effect) applies to future program years in the first AEAP following a final IRS determination on this issue. (See Section III.A.5.f.)

The 1996 AEAP will be the forum for addressing measurement protocols for fuel substitution measures (for combined utilities) and load management programs. (See Section III.A.5.d.) The CADMAC should address these issues as part of its filing in that proceeding. We expect the joint subcommittee established in response to D.93-11-017 to continue its effort to resolve coordination issues between SoCal and SCE. We will consider extending incentives to the fuel substitution programs of those single-fuel utilities if and when coordination issues can be resolved. As we discussed in D.93-05-063, the appropriateness of continuing CADMAC activities will also be examined in the 1996 AEAP. (Ordering Paragraph 3.)

The 1997 AEAP is the forum for our comprehensive reassessment of the ex post measurement and evaluation protocols we adopted in D.93-05-063. (Ordering Paragraph 3.) We also intend to reevaluate the incentive mechanisms adopted by today's order in 1997, either in the 1997 AEAP or in another procedural forum identified by the Commission. Per our directives in D.93-09-078, CACD will submit the first of its triennial reports evaluating ratepayer risks, costs and benefits associated with shareholder incentives in time for this review. (See D.93-09-078, Ordering Paragraph 3.) As we stated in today's decision, we may consider expanding the TRC trigger to the program element or measure level as part of that review. (See Section III.A.5.b.(1).) We may also consider revisiting the issue of portfolio versus program-specific application of the incentive mechanisms, should we find that lost opportunities have been ignored by the utilities to the detriment of ratepayers. (See Section III.A.5.b.(3).)

In this phase of the proceeding, several parties request that the AEAP become the forum for evaluating DSM forecast filings, which have traditionally been submitted as Advice Letters on October 1 preceding the program year. We considered and rejected a similar request in the measurement and evaluation phase of this proceeding. As we stated in D.93-05-063, the need for an annual proceeding to update utility forecast filings would depend on the specific mechanism adopted in this phase. (See D.93-05-063, mimeo., p. 55.) We see no reason to change current procedures in light of the fact that today's decision significantly reduces the reliance of DSM shareholder earnings on the forecasts filed each year. We will continue to require that utilities file their projected program costs, benefits, and performance targets on October 1 of each year. This filing will be used to establish the minimum performance standards for shared-savings mechanism. These filings should also include the information necessary to calculate the unit incentive and relative program cost ratio required by the performance adder mechanism we adopt today. Respondents may augment their October 1, 1994 filings to provide this information by February 1, 1995. We encourage respondents to meet informally with DRA and other interested parties to discuss the specific information to be prepared for this filing.

All parties to this proceeding recommended that earnings be calculated on forecasts of avoided costs, consistent with the most recent Commission-adopted resource plan for each utility. (See Exh. 336, p. 30, Joint Table 6.) However, the implementation details and implications of this approach were not adequately addressed in this phase of the proceeding. For example, does the use of forecasts mean that the energy savings produced by a gas weatherization measure in year 5 (as verified by persistence studies) will be valued at the gas price projected when that measure was originally installed? Or will that gas price be updated to reflect current prices? We will also need to identify the specific forum, by utility, for obtaining avoided costs to use in DSM earnings calculations. Interested parties should address these issues in their 1995 AEAP testimony.

Finally, we recognize that future decisions on electric industry restructuring and regulatory reform may require an earlier review of the incentive approach we adopt today. As we stated in D.93-09-078:

> "As discussed throughout this order, the decisions we reach today are predicated on two major assumptions: First, that utilities will continue to procure DSM services on behalf of ratepayers and second, that our current regulatory framework remains intact. Future events may affect these assumptions, and thereby necessitate a reevaluation of shareholder incentives as a regulatory tool. For example, the role of private entities in DSM may increase to the point where regulated utility involvement in the demand side is no longer required. As a result of our industry restructuring proceedings, our current regulatory framework may be altered in a manner that sufficiently removes regulatory disincentives to DSM, or that fundamentally changes the role of utilities in generation and energy efficiency markets. We will need to reassess today's decision as changed circumstances warrant." (D.93-09-078, mimeo., p. 41.)

Therefore, we leave open the possibility of reevaluating our approach to DSM incentives in general, and the specific incentive mechanisms adopted today, at an earlier date. Any party to this proceeding or R.94-04-031/I.94-04-032 may petition to modify D.93-09-078 or this decision to schedule an earlier review under the following circumstances:

1. After the effective date of today's order, the Commission issues a final decision that establishes guidelines or proceeds with implementation steps to fundamentally change the industry structure or regulatory framework, and

2. These changes fundamentally alter the role of utilities in DSM markets or the regulatory disincentives to DSM.

Petitions to reexamine DSM shareholder incentives prior to 1997 should be filed at the Commission Docket Office and served on all appearances and the state service list in this proceeding and R.94-04-031/I.94-04-032. Any petition must clearly describe what aspects of the Commission decision on industry restructuring or regulatory reform have changed the role of utilities in DSM markets or the regulatory disincentives to DSM, why and how the existing incentive framework for DSM needs to be altered. The ALJ assigned to this proceeding may issue a ruling establishing a schedule for reply comments in addition to the protests permitted under Rule 8.1 et seq. of the Commission's Rules of Practice and Procedure. After reviewing those protests and comments, the Commission will rule on whether an earlier review is warranted.

V. Response to Comments on ALJ's Proposed Decision

Pursuant to PU Code § 311 and to our Rules of Practice and Procedure (California Code of Regulations, Title 20, Rules 77 to 77.5), the proposed decision of ALJ Gottstein was issued before today's decision. PG&E, SCE, SDG&E, SoCal, DRA, CEC, NRDC, SESCO, and Occidental Analytical Group filed timely comments on the proposed decision. Reply comments were filed by SCE, PG&E, SoCal, and SESCO.

We have made a number of modifications and clarifications in response to these comments. We have also corrected typographical errors and augmented certain sections to address the specific comments of parties on issues addressed in the proposed decision. Although many pages have changes, we have made no substantive modifications to the analysis or disposition of issues in the proposed decision, with the exception of increasing the shared-savings earnings rate to 30% and allowing utilities to file an advice letter, rather than an application to request funding shifts from nonresidential to residential portfolios. We emphasize, however, that today's determinations are made with the explicit proviso that they may need to be revisited before the 1997 DSM review, depending on the outcome of our electric utility restructuring proceeding.

Findings of Fact

1. In D.93-09-078, we determined that there are disincentives to DSM created by both regulation and the private profit-making nature of the utility, and that shareholder incentives are necessary under the current regulatory framework to overcome them.

2. The ex post measurement protocols adopted in D.93-05-063 made all shareholder earnings claims contingent upon the results of measurement studies performed over a 7 to 10-year period after program implementation.

3. Under the adopted ex post measurement protocols, recovery of shareholder earnings changed from being authorized one year after program implementation to being authorized in four equal installments over a 7 to 10-year period.

4. WECC's proposal to establish earnings by taking 25% of the recorded earnings basis at each claim is inconsistent with our ruling in D.94-05-063.

5. A DSM mechanism that motivates utilities to acquire resource benefits at the lowest possible costs is consistent with our least-cost resource procurement goals.

6. Under DRA's approach of establishing target earnings levels and performance earnings rates, shareholder earnings are unaffected by changes in resource benefits or program costs, as long as the utility forecasts that change accurately.

7. Under DRA's approach, earnings do not change if resource benefits or customer incentives are very different across programs, or from one program year to another, as long as the utility forecasts incremental measure costs accurately.

8. Under DRA's approach, earnings will increase with higher incremental measure costs, and vice versa.

9. Under approaches that establish the performance earnings rate independent of forecasted program costs or benefits, utility earnings increase as either resource benefits increase or costs decrease (and vice versa).

10. 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.

11. Under DRA's approach, the earnings rates for marginally cost-effective programs is well over 80% in some cases.

12. DRA's approach to varying performance earnings rates as a means to prevent creamskimming is inconsistent with our policy determinations in D.92-02-075.

13. In many cases, DRA's approach to establishing performance earnings rates produces disproportionately high penalties, relative to the net losses incurred.

14. For a typical program, DRA's penalty rates can range from 1.1% to 2646%, depending on the level of program performance at any given point in time.

15. WECC's proposed approach produces variations in average penalty rates that are similar to DRA's proposal.

16. The penalty rates under the DRA approach would be lower for less cost-effective programs than for those that perform better.

17. Both penalty and earnings rates under the DRA approach vary significantly across utilities, even for the same program.

18. In order to evaluate where to invest additional DSM funds to produce the most net benefits under the DRA approach, one must know the percent of actual performance earnings basis relative to the forecast for every DSM program, at that particular point in time. One will also need to compare the corresponding marginal earnings rates, which also vary by program.

19. When the performance earnings rate is established independent of program costs or benefits, that rate is consistent across programs or portfolios, and varies predictably. Under this approach, 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).

20. 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.

21. A utility can benefit under the DRA mechanism by underforecasting resource benefits or overestimating the level of program incentives needed to obtain a given level of savings.

22. Declining earnings rates or caps cannot distinguish between a runaway program and a program that is simply successful beyond expectations.

23. There is no evidence of any runaway programs occurring in the past or, if there was one, that its benefits could not be easily absorbed into the long-run DSM resource planning goals.

24. Establishing performance rates independent from forecasted DSM costs and benefits will eliminate major incentives for underforecasting performance, and thereby minimize the potential for windfall profits.

25. DSM funding limits continue to place an effective cap on runaway programs or windfall profits, should they manifest themselves in the future.

26. Declining earnings rates or caps will discourage the utility from continuing to pursue all cost-effective DSM.

27. Declining earnings rates or caps would award proportionately less earnings (or none at all) for providing ratepayers with greater levels of net benefits.

28. Our DSM rules establish the TRC test as the primary indicator of DSM program cost-effectiveness. Under our rules, the UC test is used to encourage the utility to minimize program costs as it strives to maximize resource benefits.

29. TURN's and SESCO's proposal to consider only one of these tests is inconsistent with recent policy determinations.

30. Weighting the UC and TRC cost components in the performance earnings basis provides a workable means for addressing the dual-cost nature of DSM in an incentive context.

31. Under a weighted average approach, it is possible for a program to fail the TRC test of cost-effectiveness on an ex post basis and still yield a positive performance earnings basis.

32. Encouraging utility managers to maintain or improve program TRC cost-effectiveness throughout the implementation period is a logical corollary to our rules that all programs must pass the TRC (and UC) tests of cost-effectiveness on a prospective basis to be eligible for funding.

33. PG&E, SDG&E, and SoCal currently include savings from both fuel sources in the calculation of net benefits, consistent with the Standard Practice Manual methodology for the TRC test.

34. Allowing a single-fuel utility to market technologies associated with the other fuel would place ratepayers in the position of funding interutility competition for increased market share.

35. Some utilities include environmental benefits, avoided transmission and distribution costs in their calculations of resource benefits, and others do not.

36. The DSM goals established in the state's least-cost planning forums represent a floor amount of cost-effective energy efficiency that each utility can and should pursue over a 10 to 15-year period.

37. Meeting resource planning goals requires utilities to provide a level of total program load impacts over entire sectors over a number of years.

38. A shortfall in one program in one year can be compensated for by other programs or other years that exceed their goals.

39. Utilities have been given considerable flexibility to change the design, mix or level of DSM activities from one year to the next.

40. Under TURN's proposal, even the smallest variation in lifetime program savings (e.g., 1%) would result in penalties.

41. 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 greater than 3.0 before the utility could be confident of getting any earnings.

42. The MPS requirements of the DRA, WECC, and SoCal proposals would strongly motivate utilities to underestimate DSM savings potential in establishing the MPS or to overstate measurement results.

43. Under the TURN proposal, a utility would incur a penalty of $1 million for producing $9 million in net benefits, if the preimplementation forecast of net benefits was $10 million.

44. 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.

45. Under the DRA mechanisms, 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.

46. DRA's approach to accountability can result in disproportionately high penalties relative to the actual net losses incurred. 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.

47. Under the TURN and DRA approaches to accountability, two utilities (or a single utility in consecutive years) can implement a program which promotes identical measures, incurs identical costs, provides identical benefits and yet receive very different earnings, depending on the utility's relative ability to accurately forecast those benefits.

48. Under the DRA and SoCal approach, 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 just below the 75% MPS threshold, even if there are sizeable net benefits achieved.

49. Under other proposals, earnings in each claim are reduced in direct proportion to changes in actual achievements, and in some cases previously paid out earnings would have to be returned to ratepayers. However, these proposals do not create an "all or nothing" outcome in later earnings claims, as long as the program or portfolio remains cost-effective.

50. PU Code § 746(b) requires that earnings accrue only after the utility has met a minimum threshold of performance.

51. Current application of PU Code § 746(b) links performance to factors that the utility can influence, e.g., through effective program design, cost controls or marketing strategies.

52. Under current incentive mechanisms, the MPS ranges from 50% to 75% of forecasted performance and applies on a program-specific basis.

53. 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 for superior performance.

54. Based on historical data, 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.

55. When the MPS is applied on a portfolio (as opposed to a program-specific) level, the utility can quickly respond to changing market conditions, and maximize ratepayer benefits in the process.

56. When the MPS is applied on a program-specific basis, the utility may be forced to pursue a less cost-effective program just to meet a program-specific minimum performance target.

57. 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.

58. From a least-cost procurement perspective, the aggregate results of utility efforts to procure resource value are what count the most.

59. Rule 3 of our DSM rules states that the utility should only pursue the most cost-effective programs first, if doing so does not create lost opportunities in the process.

60. With the exception of new construction, current program categories do not distinguish between lost market opportunities and other types of DSM activities.

61. A program-specific application of the MPS would neither inhibit a utility from ignoring lost opportunities nor encourage

marketing efforts to capture those opportunities, relative to a portfolio approach.

62. A program-specific application of the MPS to new construction would subject the utility to all-or-nothing fluctuations in earnings, based on factors that are particularly difficult to forecast with any accuracy.

63. The utility does not benefit in the longer term by ignoring lost opportunities under an incentive structure that pays earnings in direct proportion to the net benefits generated.

64. Compared to a program-specific approach, the portfolio approach creates less disincentive to ignore lost opportunities that produce relatively low net benefits in the short-run.

65. Programs receiving shared-savings treatment are not designed to address the equitable allocation of program activities to low-income customers; rather the direct assistance programs are designed for this purpose.

66. Concerns over potential inequities between the residential and nonresidential classes can be effectively addressed by establishing two separate portfolios, and applying the MPS separately to each.

67. Applying a portfolio approach only when net benefits are negative, as WECC and SoCal propose, selectively ignores the reducing effect that portfolio aggregation can have on the earnings side.

68. Under previous shared-savings mechanisms, all risk of losses (e.g., negative net benefits) beyond the first earnings claims have been borne by ratepayers.

69. Only the Panel 1 proposal would require shareholders to consistently compensate ratepayers for 100% of losses up to the total amount of DSM program costs recovered in rates.

70. In D.93-05-063, we accounted for differences between gas-only and combined or electric-only utilities by adopting less stringent ex post measurement protocols for SoCal.

71. The cost-effectiveness differential between gas-only and other utilities is diminished when both gas and electric savings associated with each measure are included in earnings calculations.

72. The advantages that a combined utility has in averaging gas and electric measure performance are reduced by our recent rules that require cost-effectiveness testing at the program element or measure level for funding purposes.

73. The cost-effectiveness guarantee proposed by Panel 1 provides a warranty to all ratepayers that each utility's residential and nonresidential portfolios will be cost-effective.

74. Manufacturer's warranties are currently relied on to provide protection from operational defects, including inaccurate efficiency ratings.

75. Due to the wide variation in savings per installation due to customer operation variation, neither manufacturers nor utilities currently warrant the savings or economic performance of the equipment for individual program participants.

76. 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, as described in this decision.

77. In D.93-09-078, we confirmed our expectations that regulatory and financial biases exist against DSM, and that shareholder incentives are an effective way to address them.

78. In the past, supply-side comparability was considered in the context of the utility's authorized rate of return, which was used to establish the upper limit to target DSM earnings.

79. Under the comparable shareholder value approach, historical levels of DSM earnings per share are used to establish the level of target earnings.

80. The comparable shareholder value approach does not account for the fact that the risk and reward profiles of DSM and alternative incentives can change considerably over time.

81. Under this approach, target earnings levels in the future may ratchet upwards or downwards whenever historical performance (and associated earnings) are significantly different from historical targets.

82. Because plants are amortized over their useful life, using the authorized rate of return to establish target earnings levels or the shared-savings rate significantly underestimates what the utility actually earns on utility-constructed plants.

83. The effective earnings rate associated with supply-side resources deferred or avoided by DSM investments can be calculated either by (1) taking the present value of revenue requirements streams associated with a rate-based plant, or (2) applying the investment deferral methodology used in avoided cost calculations.

84. The effective earnings rate associated with supply-side resources deferred or avoided by DSM investments ranges from approximately 26% to 52%.

85. Target earnings levels increase to a range of $77 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 comparable earnings. If earnings were based on equivalent performance, rather than costs, this starting point would be even higher.

86. Over the 1990-1992 period, PG&E's DSM expenditures provided earnings of 0.26 to 0.29 cents/kWh in comparison to $1.10 to $1.29 on the supply-side. 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.

87. The 1990-1994 historical average of target DSM shared-savings earnings was approximately $38 million.

88. The proposals for target earnings in this proceeding range from $29.5 million to $88.7 million.

89. Relative investment risk has several dimensions, including who funds the initial investment and who bears the risk of noncost-effective investments, and how shareholder earnings vary with project performance.

90. 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.

91. Even if a rate-based facility is removed from rate base, utilities have generally been able to recover the undepreciated investment costs, without a return.

92. Variations between forecasted and actual sales (throughput) do not affect earnings on electric or core gas facilities, since these sales are currently given full balancing account treatment.

93. Under traditional ratemaking treatment, electric utilities do not earn on purchases from independent power producers or other utilities, but neither do they make any initial capital investment or assume a significant degree of forecasting risk.

94. Ratemaking treatment for core gas procurement and electric generation and dispatch activities are changing such that greater performance risks are imposed on utility shareholders, with commensurately greater potential rewards.

95. The DSM incentive mechanism adopted today, coupled with our adopted ex post measurement protocols, imposes performance risks on the utility that are substantially greater than previous DSM incentive mechanisms.

96. 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.

97. TURN's and DRA's proposed target earnings levels represent a substantial discount below the level of earnings opportunity available from comparable avoided supply-side investments.

98. DRA's conclusions about the bias towards DSM alternatives are inconsistent with our findings and conclusions in D.93-09-078.

99. DRA's assessment of relative performance risks overstates the risks to ratepayers from DSM, and understates the risks to ratepayers from supply-side options.

100. TURN's comparison of DSM rewards with those of a power purchase agreement does not acknowledge the substantial difference in shareholder risks associated with these options.

101. A portfolio approach serves to decrease the absolute level of potential penalties, relative to a program-specific approach, whenever the penalty rate is higher than the earnings rate.

102. The probability of falling into the penalty range is reduced under a portfolio approach.

103. The evidence in this proceedings is not conclusive on how much a portfolio approach will reduce risks (both the probability and level of penalties), compared to a program-specific approach.

104. Under the adopted incentive mechanism, the upside potential is not limited by caps or declining earnings rates, as it has been in the past.

105. The downside risks resulting from the combined features of the incentive mechanism adopted today will be substantially less than if we applied those features to each individual program.

106. An earnings rate of 30% and corresponding target earnings level is within the range of estimated earnings opportunity from comparable supply-side investments.

107. Our DSM rules direct that incentive mechanisms should be based on a shared-savings approach for programs whose savings can be reasonably estimated.

108. Our DSM rules require that new construction programs produce net benefits to be eligible for ratepayer funding.

109. SoCal's proposed incentive treatment for new construction programs would fail to ensure that the program's contribution to higher efficiency standards also produces net benefits to ratepayers.

110. In D.93-11-017 we found that shareholder incentives are needed to motivate utilities to create cost-effective resource value in general, and did not distinguish among the types of DSM activities that can create that value.

111. Cost-effective resource value can be created in the process of shifting load or switching fuels, as well as via energy efficiency programs.

112. Under our funding rules and the shared-savings incentive mechanism adopted today, the utility would not be rewarded for increasing energy consumption via load shifting or fuel substitution.

113. Thermal energy storage is a technology that can serve various program objectives, depending on its design and application.

114. Appropriate ex post measurement protocols need to be developed before incentives can be extended to fuel substitution and load management programs.

115. SoCal's recommendation that utilities have the option to forgo shareholder incentive treatment would defeat the purpose of adopting performance-based incentives for DSM programs.

116. The position on interest accrual put forward by Panel 1 and SESCO presumes that shareholders should have their earnings in hand after the first earnings claim.

117. Under the ex post measurement protocols and the incentive mechanism adopted in today's order, the utility is paid contingent upon actual performance, similar in many respects to "pay for performance" provisions in power purchase contracts.

118. There can be some differences in timing between performance and earnings payments under the DSM incentive mechanism, due to the timing of the earnings claims and the true-up requirements.

119. The 90-day commercial paper rate is currently used for the DSM balancing accounts and for shareholder incentives that are not recovered in a single year.

120. Local IRS auditors have recently disallowed the tax deductibility of DSM expenditures, which is under appeal by Southern California Edison. A final IRS ruling on this issue is not expected to be made in the near future.

121. Direct assistance and energy management services programs are designed to offer DSM information and assistance equitably and without discrimination.

122. The current performance adder approach does not provide any incentive for the utility to reduce per unit costs through cost minimization, or to increase the level of accomplishments and associated savings relative to costs.

123. Under the Panel 1 performance adder proposal, the utility earns more if it achieves the same level of savings at a reduced cost, or produces a higher level of savings at the same cost.

124. Utilities are already required to conduct extensive measurement of performance adder programs under our adopted ex post protocols.

125. The Panel 1 approach for performance adder incentives would not require the forecasting or verification of savings persistence.

126. Many of the estimating techniques that apply to shared-savings programs may be applicable to specific measures covered by direct assistance and energy management services programs.

127. The mandatory direct assistance programs provide low-income ratepayers with building envelope efficiencies and amenities provided by basic weatherization measures. The nonmandatory program augments these savings with more efficient appliances and other nonmandatory measures.

128. A clear performance linkage between mandatory and nonmandatory direct assistance programs will help achieve the goals of both types of programs.

129. The spending and fund shifting flexibility recently adopted for PG&E, SoCal and SDG&E provides these utilities with needed flexibility to respond to changing market conditions in a manner that can produce additional net benefits in excess of forecasted amounts.

130. TURN's proposal to limit funding to 100% of authorized amounts for all utilities would impede the utility's ability to respond to changing market conditions and would place an unnecessary burden on the regulatory process.

131. The current 130% spending limit has not significantly inhibited utilities from responding effectively to market opportunities.

132. When coupled with the portfolio approach adopted in today's decision, the flexibility to shift funds from residential to nonresidential portfolios under the shared-savings mechanism

could cause utilities to concentrate on the commercial sector at the expense of residential customers.

133. Utilities do not currently have the flexibility to shift funds from the nonmandatory (performance adder) direct assistance program into the mandatory (expense category) program, even though performance is currently linked for SoCal and SDG&E.

134. Measurement costs represent a true cost of acquiring DSM resources.

135. Until we establish specific protocols for allocating measurement costs, including these costs for cost-effectiveness review at the program or program element level would only add unnecessary complexity and controversy in DSM funding and earnings claims proceedings.

136. Because of the learning curve involved in ex post measurement, considering measurement costs on a program-specific basis at this time could prematurely terminate certain programs.

137. It is feasible to establish cost-effectiveness requirements that include measurement costs on an aggregated basis for both funding and earnings claim purposes.

138. Because of the learning curve involved in ex post measurement, considering measurement costs on a program-specific basis at this time could prematurely terminate certain programs.

139. The record in this proceeding is not sufficient to make a final determination on what elements of the utility's measurement, forecasting and regulatory reporting budgets should be considered in cost-effectiveness evaluations.

140. The comparison of profitability required by Sections 111(a)(8) and 115(b)(4) of the Energy Policy Act of 1992 is difficult to make, given the differing performance, earnings and

investment characteristics of demand and supply-side resources and the associated ratemaking treatment.

141. Our adopted shared-savings mechanism is consistent with the federal standards set forth in the Energy Policy Act of 1992, but based on a broader set of factors than the profitability guideline articulated in that statute.

142. SESCO has presented no witnesses to lend factual support to its assertions of anticompetitive impacts from our adopted shared-savings incentive mechanism.

143. The implication of SESCO's arguments on anticompetitive impacts is that all utility-sponsored DSM must be put out to bid before incentives can be paid.

144. The ability of energy service companies to cost-effectively augment or replace utility DSM activities is currently being tested in our bidding pilots, consistent with Legislative requirements.

145. Today's decision does not alter the utility's role in the DSM market or its interface with private energy service providers.

Conclusions of Law

1. Least-cost procurement is best achieved by motivating utilities to maximize DSM benefits whenever and wherever opportunities to do so actually exist in the market.

2. It is reasonable to link earnings directly to net benefits by establishing performance earnings rates beyond the deadband range independent of forecasted program costs or benefits.

3. Once a minimum level of performance has been met, utilities should be able to increase earnings if and only if they

increase net benefits to ratepayers, and should receive less earnings for reduced benefits.

4. Beyond the deadband range, the relationship between earnings and net benefits should be proportional and consistent across programs and utilities.

5. The calculation of earnings or penalties in each claim should be fully trued-up by subtracting out the earnings (or penalties) recovered in previous claims.

6. It is reasonable to adopt fixed incentive rates beyond the deadband range, because they send a consistent signal to utilities to maximize ratepayer net benefits through DSM programs.

7. It is reasonable to adopt a weighted average approach for the TRC and UC cost components in establishing the basis for earnings and penalties under a shared-savings mechanism. The weighting should be 2/3 TRC and 1/3 UC to reflect our policy emphasis on total resource costs and benefits.

8. It is reasonable to adopt the ex post TRC trigger proposed by SDG&E, PG&E, NRDC, and CEC, and to apply the trigger to each program across all earnings claims, so that ratepayers are 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.

9. The electric savings associated with gas measures, or the gas savings associated with electric measures should be included in the calculation of earnings, as described in Section III.5.b.(1) of this decision.

10. Our requirement in D.93-11-017 that SCE and SoCal coordinate their energy efficiency programs should extend to the

calculation of energy savings under today's adopted incentive mechanisms, including the use of consistent sets of marginal costs.

11. Until SCE and SoCal can demonstrate that they have coordinated sufficiently to pursue energy efficiency in a fuel blind manner, it is premature to allow SoCal to market electric efficiency measures or to allow SCE to market gas technologies with ratepayer funds.

12. 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. Today's consideration of incentive mechanisms should not change the role or purpose of these planning forecasts.

13. It is reasonable to let the role of DSM in utility resource procurement establish itself independent of planning forecasts, by aligning shareholder and ratepayers interests in the procurement of least-cost resources.

14. The primary focus of least-cost resource procurement should be on actually acquiring the most net benefits for ratepayers, and not on forecasting.

15. It is 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.

16. Utility accountability under a DSM shared-savings incentive mechanism should be defined primarily in terms of realized rather than forecasted net benefits.

17. Consistent with PU Code § 746(b), it is reasonable to require that utilities meet a minimum threshold of performance before any earnings accrue to shareholders.

18. It is reasonable to continue the current practice of establishing a MPS for the first earnings claim only, with a deadband range that begins at 0% of forecasted performance.

19. An MPS at the higher range of proposals, i.e., 75% represents a reasonable threshold of minimum performance when the incentive mechanism is applied on a portfolio basis.

20. It is reasonable to apply the MPS on a portfolio basis, as described in this decision.

21. Utilities should design and implement their DSM programs to ensure that lost opportunities are not ignored in the process of maximizing net benefits.

22. Utilities should develop and report their strategies and accomplishments for capturing lost opportunities in each AEAP, as well as in proceedings where they apply for program funding.

23. In exchange for putting up the funds for utility investments in DSM, ratepayers should be fully protected against losses, up to the amount of program costs recovered in rates.

24. The threat of waning utility commitment to DSM does not justify limiting the downside risk to ratepayers by ignoring the results of savings persistence studies.

25. Earnings and penalties should be calculated across all earnings claims, as described in this decision.

26. It is premature to impose the warranty requirements offered by independent energy service companies on utility

programs, until the legal and other implications of these requirements are more fully explored.

27. The comparable shareholder value approach is an unreliable indicator of the level of target earnings needed to overcome DSM disincentives under present circumstances.

28. It is reasonable 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.

29. In designing the next generation of DSM incentives, it is reasonable to balance the imposition of greater risks on the utility with a greater opportunity to earn.

30. The TURN and DRA proposals for performance earnings rates and associated target earnings are not supported by the record.

31. It is reasonable to pick an earnings rate at the lower end of estimated earnings opportunity from comparable supply-side investments, given the significant risk-mitigating effects that portfolio diversification can have on shareholder exposure.

32. As described in this decision, a DSM incentive mechanism that provides utilities with an opportunity to share verified net benefits at a 30% rate beyond the deadband range, but guarantees ratepayers against 100% of losses, is reasonable and should be adopted.

33. It is reasonable to count on and expect net benefits from new construction programs when utilities prepare their target earnings filing.

34. New construction contract commitments entered into as of the effective date of this order should be subject to the shared-savings treatment adopted in today's decision. Installations of new construction measures resulting from agreements entered into prior to this decision should be subject to the earnings mechanism in place at the time those agreements were made.

35. Any load management program designed to increase the consumption of electricity and decrease the consumption of gas should be subject to the three-prong test consistent with our Rules for fuel-substitution programs.

36. Thermal energy storage should be reclassified as a technology or measure under retrofit, new construction or fuel substitution program categories, as discussed in this decision. In appropriate cases, TES may be classified as load management. The Commission should revisit the appropriate classification of thermal energy storage after CACD's workshop report is submitted.

37. It is reasonable to extend shared-savings incentives to fuel substitution programs for combined utilities, provided that the (1) programs pass the three-prong test adopted in our Rules and (2) appropriate measurement protocols have been adopted by this Commission.

38. It is reasonable to extend shared-savings incentives to load management programs that promote energy efficiency after appropriate measurement protocols have been considered and adopted by this Commission.

39. Because of timing differences between payments and performance under the shared-savings mechanism, it is reasonable

to calculate interest on earnings and penalty accruals at the 90-day commercial paper rate.

40. CACD should hold workshops, as needed, for the purpose of refining the reporting requirements necessary to track DSM program costs and benefits (including interest accruals) for our consideration in future earnings claim proceedings.

41. It is reasonable to apply any effects of tax deductibility changes related to the calculation of penalties or earnings on a prospective basis, and not retroactively to programs that have already been implemented.

42. Should the current IRS ruling remain in effect, we should clarify how the ruling will apply to the earnings claims for future programs. We should do this in the first AEAP following the IRS final determination on this issue.

43. Incentive treatment should continue for non-mandatory direct assistance and energy management services programs because they serve important policy goals, as articulated in our DSM Rules. However, because they are not required to pass cost-effectiveness tests, or result in savings that are readily measurable, they should be subject to performance adder (rather than shared-savings) incentive treatment.

44. As long as direct assistance and energy management services are provided, the utility shold be motivated to reduce the cost and increase the amount of kilowatt-hour savings generated by these programs. The Panel 1 performance adder approach should be adopted because it provides this incentive.

45. It is reasonable to adopt a 75% MPS for all energy management services programs, applied separately to the residential and nonresidential programs. Utilities should make

every effort to service each market sector within those programs, as they have in the past.

46. It is reasonable to require that utilities earn 75% of their goals in mandatory direct assistance before any earnings accrue on nonmandatory programs.

47. Utilities should be rewarded for performance in non-mandatory programs only after they have achieved superior performance (i.e., 75% of forecasted achievement) related to mandatory programs.

48. Our adopted performance adder mechanism should apply to the following individual programs: residential energy management services, nonresidential energy management services, and non-mandatory direct assistance programs. These requirements should be applicable to all direct assistance programs in the aggregate, including any programs which are bid out, either to community-based organizations or in the DSM bidding pilots.

49. In light of today's decision, the CADMAC should continue to evaluate issues related to the measurement studies required for performance adder programs, and present its recommendations in the 1995 AEAP.

50. Energy savings from energy management services programs should contribute to the shared-savings calculations (as opposed to the performance adder calculations) only if the installations are verified by post-audit visits and the measures are rebated by the respective utilities.

51. It is reasonable to require Commission approval before the utility can shift funds under the shared-savings mechanism between the residential and nonresidential portfolios.

52. It is reasonable to require the utility to file an application requesting authority to shift funds from residential to nonresidential portfolios.

53. It is reasonable to allow the utility to request authority to shift funds from nonresidential to residential portfolios by filing an advice letter.

54. The issue of penalties for circumstances when a utility uses dollars authorized for DSM to implement non-DSM activities should be addressed in the appropriate earnings claim proceeding, if and when those circumstances arise.

55. It is reasonable to expect that DSM activities subject to shared-savings treatment will be cost-effective enough to absorb current levels of measurement costs directly linked to measuring the impacts of shared-savings programs on an aggregated basis.

56. Once measurement cost allocation issues have been resolved, and we have more experience with ex post measurement, it is reasonable to consider measurement costs on a more disaggregated basis, e.g., at the program or program element level.

57. Our DSM rules should be modified to require, as an additional condition for funding DSM programs in 1996 and beyond, a demonstration that DSM programs subject to shared-savings treatment are in aggregate cost-effective from both a UC and TRC perspective when estimated measurement and evaluation costs are included.

58. As described in this decision, the performance earnings basis for each program year (for both residential and nonresidential portfolios combined) should be adjusted to reflect

the aggregate measurement and evaluation costs associated with that program year. Should one or the other portfolio fall into the penalty range, then the measurement costs associated with that portfolio should be refunded to ratepayers in full, consistent with the cost-effectiveness guarantee adopted in today's decision.

59. In order to implement today's adopted policies on the treatment of measurement costs, CACD should conduct workshops on which measurement budget categories should be included in the cost-effectiveness evaluations, and an appropriate method for including them, as described in this decision.

60. Given the complexity and diversity in our ratemaking treatment of both supply- and demand-side resources, it is reasonable to consider a broader set of factors in establishing DSM earnings opportunity than those specifically set forth in Sections 111(a)(8) and 115(b)(4) of the Energy Policy Act of 1992.

61. Our evaluation of the DSM bidding pilots should assess how best to structure the relationship between utilities and third parties in a competitive bidding environment.

62. SESCO's assertions of anticompetitive impacts are without merit.

63. This order should be effective immediately, in order to proceed as expeditiously as possible on the completion of activities required for upcoming earnings claims proceedings, as described in this decision.

INTERIM ORDER

IT IS ORDERED that:

1. Beginning with program year 1995, Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southern California Gas Company (SoCal), referred to collectively as "respondents," shall implement the incentive mechanisms and other rules adopted in today's decision. Unless otherwise ordered by the Commission, the incentive mechanisms adopted by today's order will be in effect through the 1997 program year.

2. Respondents shall develop and report their strategies and accomplishments for capturing lost opportunities in each Annual Earnings Assessment Proceeding (AEAP), beginning with the 1995 AEAP, in addition to reporting this information in proceedings where they apply for program funding. As described in this decision, the Commission Advisory and Compliance Division (CACD) shall 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 workshop report at the Commission Docket Office and serve copies on all appearances and the state service list in this proceeding. The assigned Administrative Law Judge shall request further comments on CACD's report before making a final recommendation on reporting requirements to the Commission.

3. Within 90 days from the effective date of today's order, CACD is directed to conduct workshops and submit a workshop report on proposed modifications to current program definitions that reclassify thermal energy storage as a measure

or technology under retrofit, new construction or fuel substitution programs. Workshop participants should consider SCE's proposal to include thermal energy storage as a measure under load management in certain cases. CACD's workshop report shall be served on all appearances and the state service list in this proceeding. The assigned Administrative Law Judge shall request further comments on CACD's report before making a final recommendation on language changes to the Commission. As described in Section 5.e., CACD shall also conduct workshops, as needed, for the purpose of refining the reporting requirements necessary to track DSM program costs and benefits (including interest calculations) for Commission consideration in future AEAP proceedings.

4. As discussed in Section III.A.5.d of this decision, the CADMAC shall present its recommendations on measurement protocols for fuel substitution measures and load management programs in the 1996 AEAP. This Commission shall consider extending incentives to the fuel substitution programs of single-fuel utilities if and when SCE and SoCal can demonstrate that they have coordinated their efforts sufficiently to pursue energy efficiency in a fuel-blind manner.

5. This Commission shall consider how the Internal Revenue Service (IRS) ruling on DSM expensing, should it remain in effect, be applied to the earnings and penalty calculations for future program years in the first AEAP following a final IRS determination on this issue.

6. As described in Section III.B.4, the CADMAC shall continue its evaluation of measurement protocols for performance adder mechanisms, in light of today's decision. The CADMAC and

other parties may present their recommendations for protocol refinements or changes in the 1995 AEAP.

7. Consistent with today's decision, the DSM rules, program terms and definitions are modified as indicated in Attachment 6 to this order. Until further notice of this Commission, the DSM rules, program terms and definitions presented in Attachment 6 shall be used by respondents in the development and implementation of their DSM programs.

8. Within 90 days from the effective date of today's decision, CACD is directed to conduct workshops and file a workshop report on which measurement budget categories should be included in cost-effectiveness evaluations, and an appropriate method for including them, as directed by today's decision. CACD's workshop report shall be served on all appearances and the state service list in this proceeding for additional comment. CACD's recommendations shall be considered on an ex parte basis, or in the 1995 AEAP, whichever comes sooner.

9. Within 180 days from the effective date of this order, CACD shall file a workshop report describing the consensus and nonconsensus positions of the parties on the following issues: (1) how to report cost-effectiveness forecasts and results at the DSM program component, measure and element level and (2) how to treat various benefit and cost components in the calculation of net benefits or benefit-cost ratios, as described in Section III.A.5.b.(1). CACD's workshop report shall be filed at the Commission Docket Office and served on all appearances and the state service list in this proceeding and in the 1995 AEAP. The 1995 AEAP will be the forum for considering parties' proposals on these issues.

10. By February 1, 1995, respondents shall augment their 1995 program year DSM Advice Letter filings to include all forecast information necessary to implement the incentive mechanisms adopted by today's decision. This will include forecasts of target performance on a portfolio basis for the purpose of establishing minimum performance standards under the adopted shared-savings mechanism. It will also include the inputs necessary to calculate the unit incentive and relative program cost ratio for today's adopted performance adder mechanism.

11. As described in Section V, SCE, SDG&E, PG&E, SoCal, and other interested parties are directed to present testimony in the 1995 AEAP on implementation issues associated with the avoided cost valuation of DSM savings for earnings claim purposes.

12. Unless otherwise directed by Commission order, the incentive mechanisms adopted today shall be reevaluated in 1997, either in the 1997 AEAP or in another procedural forum identified by the Commission. Any party to this proceeding, Rulemaking 94-04-031 or Investigation 94-04-032 may petition for modification of this decision on D.93-09-078 to schedule an earlier review under the circumstances and procedures described in Section IV. of today's order. Such petitions to reexamine DSM shareholder incentives prior to 1997 shall be filed at the Commission Docket Office and served on all appearances and the

state service list in this proceeding, Rulemaking 94-04-031 and Investigation 94-04-032.

This order is effective today.

Dated October 26, 1994, at San Francisco, California.

DANIEL Wm. FESSLER
President
PATRICIA M. ECKERT
NORMAN D. SHUMWAY
P. GREGORY CONLON
JESSIE J. KNIGHT, JR.
Commissioners

ATTACHMENT 1

EFFECTS OF A PORTFOLIO APPROACH ON
POTENTIAL LEVEL OF EARNINGS AND PENALTIES: CASE EXAMPLES

The effect of a portfolio depends on the degree to which the shared-savings rate is linear, i.e., constant across all levels of performance (negative or positive). The more linear the mechanism, the less will be the effect and vice versa.

This attachment presents numerical examples to illustrate the potential effects of the portfolio approach. Table 1 summarizes these results. As indicated by Cases 1A and 1B, the portfolio approach will have no effect if it is unlikely that any individual program would fall within the deadband range and the shared-savings rate is equal for performance beyond the deadband. Of the proposals before us, only the TURN proposal would meet these conditions.[1]

However, if the shared-savings rate is not linear, then the portfolio approach will reduce the potential level of penalties and increase the potential level of earnings, relative to a program-specific application of the mechanism. These effects are illustrated by Cases 1C and 1D, using the Panel 1 earnings rate of 30% and penalty rate of 100%.

As illustrated by these cases, applying a portfolio approach to an incentive mechanism that has a higher penalty than earnings rate will equalize those rates when the sum of program performance is positive. When that sum is negative, the higher penalty rate will still apply to the portfolio.[2] Irrespective of these effects, however, a portfolio approach applied to a mechanism that has a higher penalty rate will result in a greater

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[1] This is because TURN's deadband is a single point--i.e., 100% of forecasted performance. Based on historical evidence, it appears highly unlikely that the performance of any one program would exactly match its target level for a particular program year. (See Exhs. 370-372.)

[2] For example, in Case 1C, the effective shared-savings rate on the portfolio is -100% (i.e., $5 in penalties for negative net benefits of $5). In Case 1D, the effective rate becomes 30% for the portfolio as a whole ($46.5 in earnings for $155 in net benefits).

downside potential, all other things being equal. (Compare the results of Case 1A with Case 1C).

The effects of a portfolio approach when one or more individual programs would fall within the deadband range is illustrated by Cases 2A through 2F. In general, a portfolio approach will decrease potential penalties and increase potential earnings under these circumstances, even if the penalty and earnings rates are identical beyond the deadband range. (See Cases 2A, 2D, 2C, and 2F.) In effect, the performance of programs in the deadband range serve to "pull up" the lower-performing programs when results are aggregated.

As SoCal points out, portfolio aggregation can reduce earnings in situations when negative performing programs pull the entire portfolio into the deadband range. Cases 2B and 2E illustrate this effect.[3] However, these examples and the ones provided by SoCal assume that the MPS is applied across all four earnings claims. Since the MPS will apply only to the first earnings claim, the probability of this result occuring may not be very high. Hence, in general, we conclude that a portfolio approach serves to decrease the level of potential penalties and increase the level of potential earnings, relative to a program-specific approach. All parties appear to agree on this overall effect. (RT at 3949-3952, 4262, 5292-5295.)

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[3] See also Exh. 382; Exh. 337A; RT at 4818-4965.

ATTACHMENT 1

TABLE 1
EFFECT OF PORTFOLIO APPROACH ON POTENTIAL LEVEL OF PENALTIES AND EARNINGS, RELATIVE TO PROGRAM-SPECIFIC APPROACH1/

	ALL INDIVIDUAL PROGRAMS FALL OUTSIDE DEADBAND	
	(1) SUM $PEB_r < 0$	(2) SUM $PEB_r > 0$
PENALTY = EARNINGS RATE BEYOND DEADBAND	NO EFFECT (CASE 1A)	NO EFFECT (CASE 1B)
PENALTY > EARNINGS RATE BEYOND DEADBAND	REDUCES PENALTIES (CASE 1C)	INCREASES EARNINGS (CASE 1D)

	INDIVIDUAL PROGRAMS FALL WITHIN AND OUTSIDE DEADBAND		
	(1)	(2) SUM $PEB_r > 0$	
		(a) SUM PEB_r < MPS	(b) SUM PEB_r > MPS
	SUM $PEB_r < 0$		
PENALTY = EARNINGS RATE BEYOND DEADBAND	REDUCES PENALTIES (CASE 2A)	REDUCES EARNINGS* (CASE 2B)	INCREASES EARNINGS (CASE 2C)
PENALTY > EARNINGS RATE BEYOND DEADBAND	REDUCES PENALTIES (CASE 2D)	REDUCES EARNINGS* (CASE 2E)	INCREASES EARNINGS (CASE 2F)

* Since the portfolio PEB_r does not meet the MPS, earnings are reduced to zero.

1/ See attached tables for numerical examples of each case.

CASE 1B

All Programs Fall Outside Deadband
Performance Earnings Rate is Linear
Sum PEB_r is Negative

	Program A	Program B	Program C	Program D	Sum of A - D	Portfolio
(1) PEB	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	-3	46.5	46.5

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

PEB_f = Forecasted Performance Earnings Basis (Net Benefits)

PEB_r = Realized Performance Earnings Basis (Net Benefits)

CASE 1A

All Programs Fall Outside Deadband
Performance Earnings Rate is Linear
Sum PEB_r is Negative

	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	-40	-50	-5	-5
(2) ÷ (1)	0.8	0.56	-0.6	-0.8		-0.02
EARNINGS	15	10.5	-12	-15	-1.5	-1.5

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

PEB_f = Forecasted Performance Earnings Basis (Net Benefits)

PEB_r = Realized Performance Earnings Basis (Net Benefits)

CASE 1C

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

	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	-40	-50	-5	-5
(2) ÷ (1)	0.8	0.56	-0.6	-0.8		0.02
EARNINGS	15	10.5	-40	-50	-64.5	-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)

CASE 2A

Programs Fall Within and Outside Deadband
Performance Earnings Rate is Linear
Sum PEB_r is Negative

	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	-40	-50	-5	-5
(2) ÷ (1)	0.8	0.56	-0.6	-0.8		0.02
EARNINGS	15	0	-12	-15	-12	-1.5

ASSUMPTIONS: MPS = 75%
PER = 30% for PEB_r above MPS
30% for negative PEB_r

PEB_f = Forecasted Performance Earnings Basis (Net Benefits)

PEB_r = Realized Performance Earnings Basis (Net Benefits)

CASE 2B

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

	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	0	24	-3	36	0

ASSUMPTIONS: MPS = 75%
PER = 30% for PEB_r above MPS
30% for negative PEB_r

PEB_f = Forecasted Performance Earnings Basis (Net Benefits)

PEB_r = Realized Performance Earnings Basis (Net Benefits)

CASE 2C

Programs Fall Within and Outside Deadband
Performance Earnings Rate is Linear
Sum PEB_r is Positive and Above MPS

	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	0	24	-3	36	46.5

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

PEB_f = Forecasted Performance Earnings Basis (Net Benefits)

PEB_r = Realized Performance Earnings Basis (Net Benefits)

CASE 2D

Programs Fall Within and Outside Deadband
Performance Earnings Rate is Nonlinear
Sum PEB_r is Negative

	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	-40	-50	-5	-5
(2) ÷ (1)	0.8	0.56	0.6	-0.8		0.02
EARNINGS	15	0	-40	-50	-75	-5

ASSUMPTIONS: MPS = 75%
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)

CASE 2E

Programs Fall Within and Outside Deadband
Performance Earnings Rate is Nonlinear
Sum PEB_r is Positive and Below MPS

	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	0	24	-10	29	0

ASSUMPTIONS: MPS = 75%
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)

CASE 2F

Programs Fall Within and Outside Deadband
Performance Earnings Rate is Nonlinear
Sum PEB_r is Positive and Above MPS

	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	0	24	-10	29	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)

(END OF ATTACHMENT 1)

ATTACHMENT 2

Shareholder Earnings Versus Performance for Gas Utility Supply-Side Resource Investments/Expenditures

Figure 1 - **TRADITIONAL INVESTMENTS** (Ratebased Transmission, Distribution & Storage Investments from a Core Market Perspective)

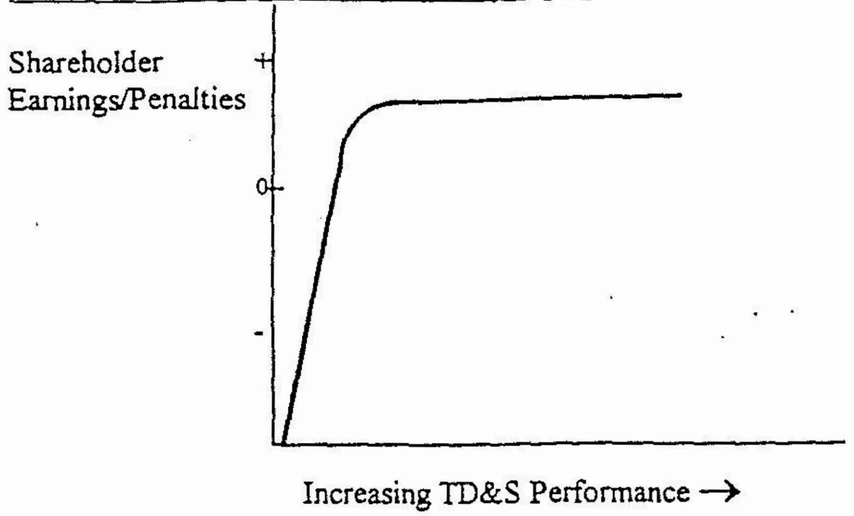


Figure 2 - **"TRADITIONAL" CORE GAS PURCHASES** (Core Gas Purchases Under Traditional Regulatory Framework for PG&E and SCG Affiliate Core Gas Purchases)

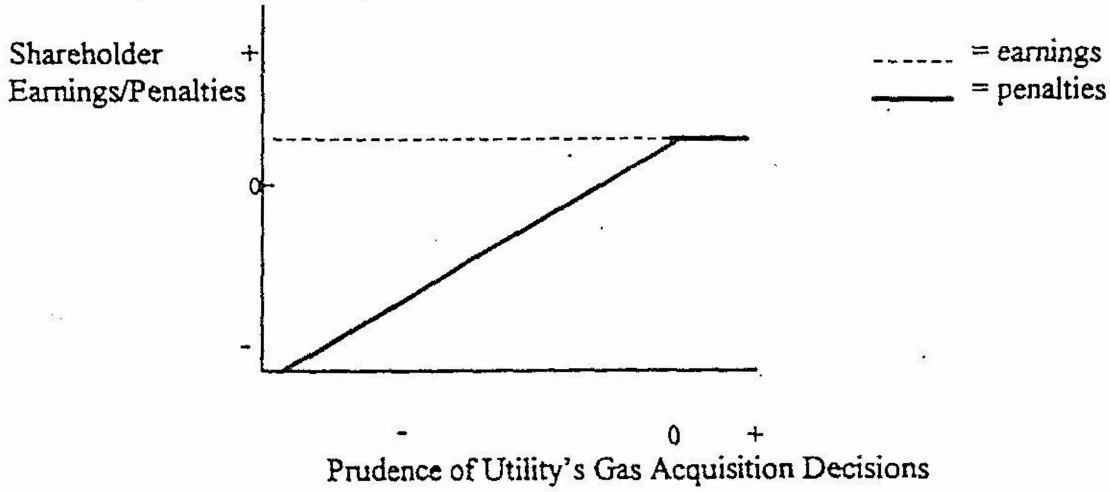
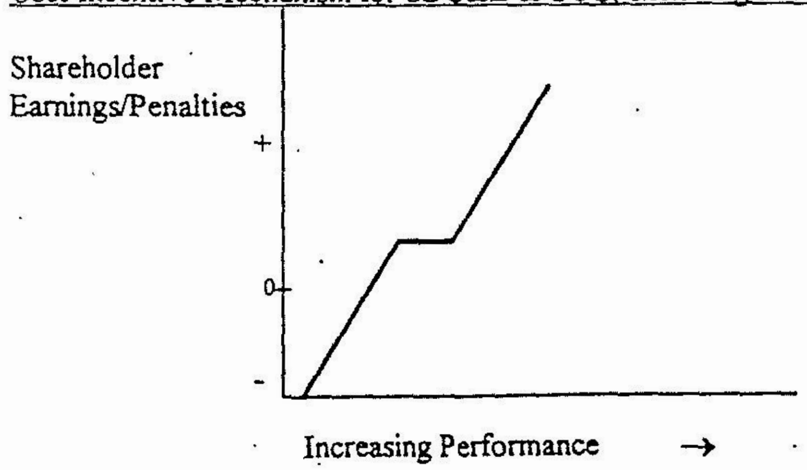


Figure 3 - **"NEW GENERATION" CORE GAS PURCHASES** (Core Gas Purchases Under Gas Cost Incentive Mechanism for SDG&E & SCG, excluding affiliate supplies)



Source: Exhibit 337, p. D-1-14

ATTACHMENT 3
ADOPTED RULES FOR FUND SHIFTING AND SPENDING
(for all utilities, beginning in 1995)

	CARRY-OVER, CARRY-FORWARD	BETWEEN PROGRAMS, WITHIN CATEGORY	IN/OUT OF CATEGORY	SPENDING CAP
I. SHARED SAVINGS PROGRAMS	YES	YES	NO 1/	130%
II. PERFORMANCE ADDER PROGRAMS	YES	YES	NO 2/	100%
III. EXPENSE ONLY				
A. Direct Assist. (mand)	YES	NA	NO	100%
B. Information	YES	YES	NO	100%
C. "Other" Energy Efficiency	YES	YES	NO	100%
D. Load Management	YES	YES	NO	100%
F. Fuel Substituion	YES	YES	NO	100%
G. Load Retention	YES	YES	NO	100%
H. MFRR	YES	YES	IN ONLY	100%
I. OTHER	YES	YES	NO	100%

"CARRYFORWARD, CARRYOVER" as defined in 1994 RRM.
"SPENDING CAP" refers to actual expenditures, over the funding cycle, relative to authorized amounts; spending caps apply to categories, not individual programs.
"YES" means that the utility has the discretionary authority to move funds, with no need for Advice Letter filing or application.
"NO" means that utility must file an application (or Advice Letter if funds moved out are being shifted to MFRR).
"IN ONLY" (for MFRR category) requires Advice Letter filing and approval.
TOTAL DSM funds retained in balancing account; monies unspent at end of funding cycle returned to ratepayers, with interest. Expenditures for all DSM activities subject to verification in the AEAP.

1/ "NO" applies to shifting in/out of shared-savings portfolios (residential, nonresidential) as well. However, shifts from the nonresidential to the residential portfolio requires an advice letter filing, rather than an application.

2/ Funds may be shifted from non-mandatory direct assistance to the mandatory program (but not in the other direction).

(END OF ATTACHMENT 3)

NUMERICAL EXAMPLES OF PANEL 1 PERFORMANCE ADDER PROPOSAL

Assumptions:

Forecast expenditures = $7,200,000
Estimated savings = 36,000,000 kWh per year
Estimated audits = 12,000
Unit incentive = $\frac{(5\% * \$7,200,000)}{36,000,000 \text{ kWh per year}}$
= $.01 per kWh
Estimated savings per audit = $\frac{36,000,000 \text{ kWh per year}}{12,000 \text{ audits}}$
= 3,000 kWh per audit

Base Case: Target is achieved

Verified expenditures = forecast ($7,200,000)
Actual savings = forecast (36,000,000)
Current year average cost per kWh saved (CYAC) = $\frac{\$7,200,000}{36,000,000 \text{ kWh}}$
= $0.20 per kWh saved
Previous year average cost per kWh saved (PYAC) = $0.20 per kWh saved
Relative program cost ratio (RPCR) = $\frac{\$0.20}{\$0.20}$
= 1.0
Performance Factor = 1.0 (from attached Figure 1)
Earnings = verified per-unit incentive * verified savings * perf. factor
= .01 * 36,000,000 * 1.0
= $360,000

ATTACHMENT 4
Page 2 of 4

NUMERICAL EXAMPLES OF PANEL 1 PERFORMANCE ADDER PROPOSAL

Case 1: Verified expenditures less than forecast ($7,000,000)
Verified savings = forecast (36,000,000)
Current costs less than previous year's

CYAC	= $.1944 per kWh saved
PYAC	= $.23 per kWh saved
RPCR	= 0.85
Performance factor	= 1.15
Earnings	= .01 * 36,000,000 * 1.15
	= $414,000

Case 2: Verified expenditures less than forecast ($7,000,000)
Verified savings less than forecast
Actual audits = 10,000 * 3000 = 30,000,000 kWh saved
Current costs greater than previous year's

CYAC	= $.23 per kWh saved
PYAC	= $.20 per kWh saved
RPCR	= 1.15
Performance factor	= 0.85
Earnings	= .01 * 30,000,000 * 0.85
	= $255,000

Case 3: Verified expenditures more than forecast ($8,000,000)
Verified savings = forecast (36,000,000)
Current costs less than previous year's

CYAC	= $.22 per kWh saved
PYAC	= $.23 per kWh saved
RPCR	= 0.96
Performance factor	= 1.04
Earnings	= .01 * 36,000,000 * 1.04
	= $374,400

NUMERICAL EXAMPLES OF PANEL 1 PERFORMANCE ADDER PROPOSAL

Case 4: Verified expenditures more than forecast ($8,000,000)
Verified savings = forecast (36,000,000)
Current costs more than previous year's

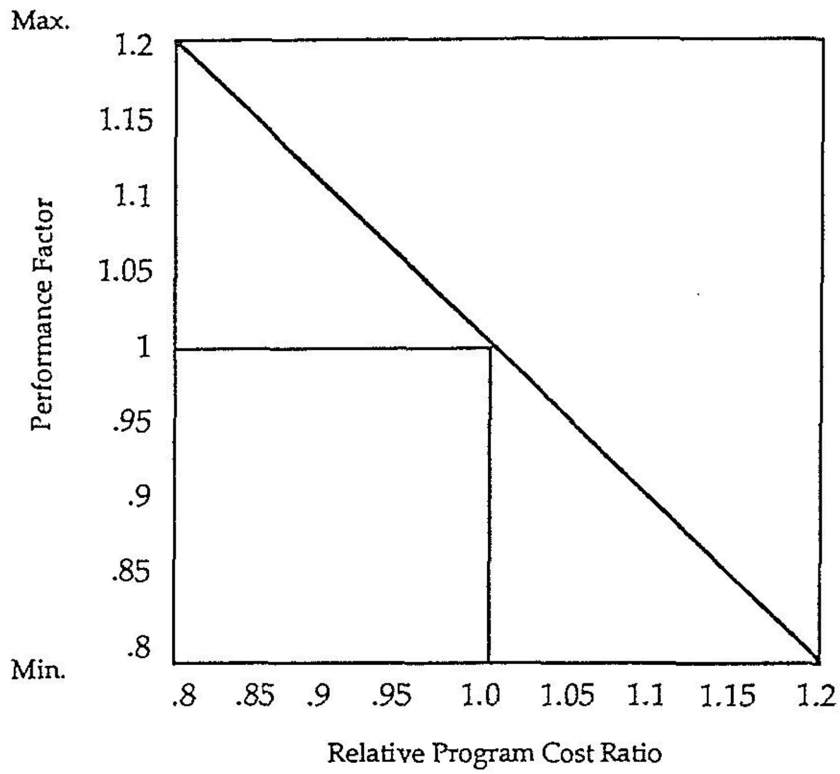
CYAC	=	$0.22 per kWh saved
PYAC	=	$0.20 per kWh saved
RPCR	=	1.1
Performance factor	=	0.90
Earnings	=	.01 * 36,000,000 * .90
	=	$324,000

Note: The unit incentive is re-calculated in each case, based on verified expenditures and savings.

ATTACHMENT 4
Page 4 of 4

FIGURE 1

Performance Factor Curve for Performance Adder Mechanism



$$\text{Relative Program Cost Ratio} = \frac{\text{Average Cost of Savings (kWh or therms) for Current Year}}{\text{Average Cost of Savings for Previous Year}}$$

Source: Exhibit 345

(END OF ATTACHMENT 4)

Table and Acronyms and Abbreviations

AEAP	Annual Earnings Assessment Proceeding
ALJ	Administrative Law Judge
CACD	Commission Advisory and Compliance Division
CADMAC	California DSM Measurement Advisory Committee
CEC	California Energy Commission
CPUC	California Public Utilities Commission
D.	Decision
DRA	Division of Ratepayer Advocates
DSM	demand-side management
ECAC	Energy Cost Adjustment Clause
Exh.	Exhibit
I.	Investigation
kW	kilowatt
kWh	kilowatt-hour
MPS	minimum performance standard
NRDC	Natural Resources Defense Council
Panel 1	the utilities, CEC, and NRDC collectively
PG&E	Pacific Gas and Electric Company
PHC	prehearing conference
PU	Public Utilities
R.	Rulemaking
Respondents	SCE, SDG&E, PG&E, and SoCal collectively

ATTACHMENT 5
Page 2

RT	Reporter's Transcript
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SESCO	SESCO, Inc.
SoCal	Southern California Gas Company
TER	target earnings rate
TRC	total resource cost
TURN	Toward Utility Ratemaking Normalization
UC	utility cost
WECC	Wisconsin Energy Conservation Corporation

(END OF ATTACHMENT 5)

ADOPTED RULES, TERMS AND DEFINITIONS FOR DEMAND-SIDE MANAGEMENT PROGRAMS[1]

I. Resource Planning and DSM Program Definitions

1. This 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.

2. Lost opportunities are those energy efficiency options which offer long-lived, cost-effective savings and which, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. In developing funding priorities for cost-effective DSM activities, the utilities should consider capturing lost opportunities as an additional ranking criterion for programs with Total Resource Cost benefit-cost ratios greater than 1.0. The utilities should submit a detailed account of strategies designed to capture lost opportunities with any request for shareholder incentive mechanisms and/or for increases in DSM program funding.

3. As defined by the Collaborative, "cream skimming" results in the pursuit of only the lowest cost conservation and load management measures, leaving behind other cost-effective opportunities. Cream skimming becomes a problem when lost opportunities are created in the process. Utilities should pursue the most cost-effective DSM resource programs first, if doing so does not create lost opportunities.

4. To ensure optimal funding of DSM activities requires consistent treatment of programs across utilities and across regulatory forums. Common terms and program definitions help ensure consistent treatment. The utilities should use the definitions included in the Appendix to these rules when characterizing any proposed program. The burden is on the utility to justify any departure from them. This OIR will remain open to accommodate future requests to modify the terms or definitions proposed herein or to add new terms or definitions.

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[1] This attachment reflects the DSM rules, terms, and definitions adopted in D.92-02-075 (as corrected in D.92-03-007), D.92-10-020, D.92-12-050, D.93-02-041, D.93-10-063, and D.93-11-017 and modified by today's order. Additions are highlighted; deletions are ~~struck out.~~

II. Cost-Effectiveness Indicators

5. The tests in the Standard Practice Manual (SPM) help assess the variety of effects associated with new or expanded DSM programs. The tests in the SPM will serve as the standard for determining DSM program cost-effectiveness until a methodology is established that allows for the side-by-side comparison of demand- and supply-side resources. The utilities should perform cost-effectiveness analyses for any proposed DSM program consistent with the indicators and methodologies included in the SPM. The utility should, to the extent practicable, perform each of the tests included in the SPM for any proposed DSM program.

6. This Commission relies on the Total Resource Cost Test (TRC) as the primary indicator of DSM program cost effectiveness. This reflects our view that utility DSM activities should focus on programs that serve as alternatives to supply-side resource options. Energy efficiency programs which promote energy efficiency serve as such alternatives because they reliably reduce a utility's fuel and/or capacity needs. Some load management programs and fuel-substitution programs may also serve as alternatives to supply-side resource options.

The TRC test measures the net effect of a DSM program on all ratepayers by combining the net benefits of the program to participants and to nonparticipants. Therefore, financial incentives or rebates to participants cancel out in the calculation of TRC net benefits (as do revenue losses). Because we are concerned over excessive rebates to participants and the overall revenue requirement impact of DSM programs, we will require that utility-sponsored DSM activities also pass the Utility Costs (UC) test of cost-effectiveness. The requirement that a utility-sponsored DSM activity pass both the TRC and the UC test is called the Dual-Test. Unless otherwise indicated in these Rules, utility DSM programs, program components and elements must pass the Dual-Test to be eligible for funding.[2]

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[2] Unless otherwise indicated in these Rules, all cost-effectiveness tests and program analysis should be conducted at the individual measure, program component and element level.

As an additional condition for funding beginning with the 1996 program year, the utility must demonstrate that DSM programs subject to shared-savings treatment are in aggregate cost-effective from both a TRC and UC perspective when estimated measurement and evaluation costs that are directly related to the measurement of savings from these programs are included.

7. To the extent practicable, nonprice factors should be considered along with price factors in utility resource procurement. Insofar as nonprice factors developed in the Biennial Resource Plan Update (Update) for supply-side resources affect DSM programs, the utility should include them in cost-effectiveness analyses consistent with their development in the Update. Non-price factors should be included in the Rate Impact Measure (RIM) test and both the UC and TRC test for cost-effectiveness evaluation using the Dual-Test.[3] Electric utilities should use the forum described in Decision 91-10-048 to publish information on transmission and distribution costs. This information should be used consistently across all resource options for the purpose of quantifying avoided transmission and/or distribution costs.

8. Resource value refers to the ability of a DSM program to reliably reduce utilities' fuel and/or capacity needs. For DSM programs designed to defer or avoid these requirements, the resource value associated with such programs should be consistent with the avoided costs of electric service adopted in the Update and, when completed, the avoided costs of natural gas service adopted in Investigation 86-06-005. These values should be used in applicable cost-effectiveness analyses and when calculating shareholder incentives. We will address the issue of consistency between resource planning determinations and DSM funding authorizations in this OIR/OII, after CACD's workshop report is submitted (see Sections IV.F and V.B of Decision 92-02-075.)

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[3] The RIM test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. The benefits calculated in the RIM test are the savings from avoided supply costs (to which non-price factors would apply). The costs for this test are the program costs incurred by the utility, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any period when load has been increased.

9. Insofar as a DSM program results in indirect costs, they should be considered. The speculative nature of any attempts to quantify indirect costs significantly reduces their applicability as an analytic tool at this time. These costs should therefore not be required in any of the cost-effectiveness tests included in the SPM. The issues related to indirect costs of DSM programs are technical in nature. The California DSM Measurement Advisory Committee represents the appropriate forum for developing the procedure and methods for collecting data related to indirect costs.

10. Shareholder incentives represent a true economic cost in the production of utility DSM programs and should be included as a direct cost in the TRC test, the Rate Impact Measure (RIM), the Utility Cost test (UC) and the Societal test.

11. The usefulness of the TRC test as a primary indicator of cost-effectiveness is limited for certain programs which do not necessarily focus on the timing or type of resource needs of the utility. Direct Assistance programs address equity concerns; as such, positive cost-effectiveness shall be an important, but not the sole, factor used to determine funding levels for these programs. Cost-efficiency is also important in the conduct of Direct Assistance programs. For Information Programs and Energy Management Services, the link between programs and savings is difficult to discern. Strict adherence to the TRC should not be required for these programs.

New Construction Programs should be designed, funded and implemented in a manner which effectively promotes the development of future, higher efficiency standards by the CEC, as well as the objectives of Public Utilities Code § 701.1. In conjunction with the CEC standards, utility New Construction Programs should provide resource benefits in the form of reduced demand to be met by the utility electric and gas systems. Utility New Construction programs should also be designed to minimize lost energy efficiency opportunities.

For each New Construction Program (residential and nonresidential), the TRC test should be the primary indicator of cost-effectiveness for the program as a whole. Each program as a whole must pass the TRC test; individual measures or program elements promoted by each program need not indicate TRC cost-effectiveness. However, fuel substitution activities in the new construction sector must be evaluated using the criteria established in Rule 13. The utilities' cost-effectiveness analyses should be accompanied by source-BTU and other information that will be useful for CEC standard-setting.

12. Bypass deferral and load building programs lack resource value, and the TRC does not apply to these programs. The TRC may or may not apply to other load retention programs (e.g., economic development activities), as these programs may or may not have resource value. Though the focus of utility DSM activities should be on energy efficiency the pursuit of load building, bypass deferral or other load retention programs may achieve additional policy goals.

In the long term, the need for load retention and load building activities should be ameliorated by resource planning efforts which minimize the possibility of causing major imbalances between the costs of providing service from existing facilities and utility assets and the costs of new resource additions. As a long-term strategy, utility interests in retaining customer loads and responding to competitive pressures from nonutility entities to provide customer services should focus primarily on programs which reduce customer bills and provide long-term rate benefits in the form of least-cost resource planning and acquisition. As a general practice, utility resource planning should be undertaken in a way that minimizes the need for load building programs.

Proponents of load building and load retention programs, including economic development activities, carry the burden of proof to quantify social and ratepayer benefits of these programs.[4] Requests for ratepayer funding for these programs should be backed by program-specific analysis, and programs should meet the guidelines outlined below.

The program proponent must demonstrate that ratepayer benefits associated with the program outweigh the short- and long-term resource acquisition costs associated with the program and identify the effect on core customer rates of programs that increase load in noncore markets. Expected program benefits should be identified in terms of rate effects, resource planning effects and other effects. The proponent must identify net

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[4] Proponents of fuel substitution programs with a predominantly load building or load retention character must, however, demonstrate that the program is source-fuel efficient and does not degrade the environment, pursuant to Rule 13.

program impacts by isolating the benefits that can be attributed to the program from those that may occur even in the absence of the program.

The proponent of any economic development activity must also demonstrate that those activities are designed to support and complement other federal, state or local efforts. For approval of each economic development activity, the utility will be required to demonstrate that it has reviewed the programs of federal, state, regional and local economic development agencies and, where appropriate, consulted with these entities to assure that each program element does not unnecessarily duplicate, and is complementary with programs being undertaken or planned by these entities to encourage economic development.

Utilities should design any load building or load retention program so as to avoid frustrating this Commission's goal of encouraging energy efficiency and energy conservation. Ratepayers should not fund load retention or load building programs that are primarily intended to actively solicit existing customers of other California utilities which have expressed no intent to relocate. Ratepayer funding for DSM programs should be limited to activities that directly relate to the utility's traditional responsibilities to provide safe, reliable, nondiscriminatory and reasonably-priced energy services within the utility's own service territory.

12a. <u>Bypass Deferral</u>

Bypass deferral programs involve negotiation of Special Contracts and provision of bypass deferral customer services authorized by this Commission. Non-DSM Special Contracts and DSM-funded bypass deferral activities should be evaluated using the RIM I test both with and without the incorporation of non-price factors identified in Rule 7, and must achieve a RIM I test value of 1.0 or greater in both cases.[5] In addition to RIM test evaluation, Special Contracts should be designed with

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[5] The RIM I test and RIM II test are differentiated by the fuels incorporated into the analysis. The RIM I test only includes estimates of the impacts a proposed program will have in terms of the primary fuel influenced by the program or provided by the utility. The RIM II test includes the impacts of the program on both fuels supplied by the California investor-owned utilities: electricity and natural gas.

consideration to evaluation and implementation guidelines set forth in prior Commission decisions, and should be subject to any such guidelines established by future Commission decisions which address these contracts. Special Contract treatment may be afforded to efforts to avoid gas-fired self-generation projects if these projects do not pass the TRC test and other criteria established for the evaluation of fuel-substitution programs, provided that they meet the evaluation criteria described above.

Costs in the form of rate discounts and conservation alternatives for bypass deferral should be accounted for and recovered as specified in Special Contract provisions. Costs associated with program administration and customer financial assistance should be sought and recovered outside of DSM budgets for non-core natural gas and as a bypass deferral program within DSM budgets for electric and core natural gas. Reporting of deferred load impacts should distinguish between load impacts deferred through Special Contracts and DSM-funded activities.

12b. <u>Other Load Retention Activities and Load Building</u>

Other load retention programs may involve activities targeted at specific customers and activities intended to influence communities and customers in general. Activities targeted at specific customers should be evaluated using the RIM II test both with and without the incorporation of non-price factors identified in Rule 7 and must achieve a RIM II test value of 1.0 or greater in both cases. Load building programs should also be evaluated with the RIM II test both with and without the incorporation of non-price factors identified in Rule 7, and must achieve a RIM II test value of 1.0 or greater in both cases.

13. Fuel substitution programs may offer resource value and environmental benefits. Fuel-substitution programs should reduce the need for supply without degrading environmental quality.

Fuel-substitution programs, whether applied to retrofit or new construction applications, must pass the following three-prong test to be considered further for funding:

1. The program must not increase source-BTU consumption. Proponents of fuel substitution programs should calculate the source-BTU impacts using the current CEC-established heat rate.

V. Shareholder Incentives

14. The Electric Revenue Adjustment Mechanism and Core Fixed Cost Account remove significant ratemaking disincentives for utilities to invest in demand-side management. To further ensure that demand-side management programs which result in, or promote, energy efficiency are not disadvantaged in utility resource procurement decisions, we initiated a pilot program of shareholder incentives in D.90-08-068. Shareholder incentives can help ensure that the utility is motivated to procure the least-cost resources by providing a comparable opportunity for earnings from prudent investments in both demand- and supply-side alternatives. We will examine the effectiveness of the specific incentive mechanisms adopted in D.90-08-068, the longer term role of shareholder incentives in resource procurement and revisit the issue of earnings comparability after CACD's report to the Legislature is submitted in late 1992.

15. The differences among utility shareholder incentive mechanisms approved in D.90-08-068 should eventually converge toward a more uniform, statewide approach. Pending CACD's report on shareholder incentives, it is appropriate to establish a limited number of guiding principles governing future shareholder incentives. These principles should apply to shareholder incentive mechanisms proposed after the final adoption of this rulemaking.

16. Shareholder incentive mechanisms should be designed to encourage energy efficiency and load management programs that promote energy efficiency. Load building and load retention programs should not be eligible for shareholder incentives. Fuel substitution programs should also be ineligible pending resolution of the technical issues associated with assessing the benefits to ratepayers of these programs.

17. Shareholder incentive mechanisms should balance risk and reward. Coupling rewards for good performance with penalties for poor performance represents a reasonable way of achieving that balance. Any proposed shareholder incentive mechanism should therefore include minimum performance requirements and accompanying penalty features. The utilities should focus minimum performance requirements on efforts to achieve cost-effective energy efficiency opportunities, and in particular, on those which represent potential lost opportunities.

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18. Shareholder earnings derived from a shared-savings approach to incentives reflect the value of the energy saved. Incentive mechanisms that determine earnings based solely on program expenditures are unrelated to that value. Thus, for programs whose savings can be reasonably estimated, a shared-savings approach is superior. Shareholder incentive mechanisms should be based on a shared-savings approach for programs whose savings can be reasonably estimated.

19. For program year 1995 and beyond, the shared-savings mechanism for all four respondents will have the following characteristics, as explained by our recent decisions in the shareholder incentive phase:

- o The shared-savings mechanism applies to two separate portfolios: one for residential and one for nonresidential DSM programs, including new construction activities. Calculations of earnings or penalties are based on the aggregated performance of programs within each portfolio.

- o Consistent with our adopted ex post measurement protocols, calculations of earnings or losses are based on the results of ex post studies conducted over a 7- to 10-year period after program implementation. Earnings (or penalties) are recovered in four equal installments over that measurement period.

- o To be eligible for any earnings, the utility must achieve a minimum performance standard (MPS) equal to 75% of target performance for each portfolio, as verified at the first earnings claim.

- o If portfolio performance achieves or exceeds the MPS, utility shareholders will earn 30% of net benefits (resource savings minus costs), as verified over all four earnings claims.

o The utility must reimburse ratepayers for any portfolio losses (i.e., negative net benefits) up to the total amount of DSM expenditures recovered in rates.

VI. Measurement, Evaluation, and Accounting

20. The stable development of DSM programs that deliver reliable energy savings for California's ratepayers depends on well-designed methods of program measurement and evaluation. Thoughtful measurement and evaluation practices are required to gauge utility performance, verify energy savings, and improve the design and success of future DSM programs. The utilities should make program measurement and evaluation a priority.

21. It is reasonable to base shareholder incentives on prespecified savings until we can implement a shift from prespecified savings estimates to ex post verification made after program implementation. Though prespecified savings estimates increase risks to ratepayers, the measurement protocols developed as part of the Blueprint help mitigate these risks. To implement the shift to ex post verification, we will conduct a consolidated measurement and evaluation (M&E) phase in this Rulemaking and Companion Investigation. This M&E phase will serve as the forum for addressing the following types of measurement-related issues:

o Pre-Implementation Measurement. The acceptable methods and procedures for estimating, prior to program implementation, the various program impact parameters for DSM programs. These include the load impacts (and its components), participation level, utility costs, total costs and useful lives of DSM measures.

o Post-Implementation Measurement. The acceptable methods and procedures for measuring DSM program impacts after program implementation. This includes developing guidelines for M&E activities beyond current activities.

o Incorporating the Results of Measurement Studies. Using the results of M&E activities to (1) refine pre- and post-implementation measurement protocols, (2) adjust forecasts of DSM program savings, and (3) adjust shareholder earnings under a shared-savings mechanism.

We intend to base payments of shareholder incentives on post-installation verified savings, for all shared-savings programs authorized as of January 1, 1994, using the protocols adopted in the M&E phase. Verification may be in the form of metered results, sample bill analysis, or other post-installation measurement methods that we deem appropriate. As part of the M&E phase, we will consider procedural options for refining and updating M&E protocols on an on-going basis.

22. It is important that forecasts of DSM savings be reliable in meeting California's energy needs. Rigorous measurement and evaluation enhances the reliability of these forecasts. The utility will include a comprehensive and aggressive measurement plan with any request for DSM funding which includes shareholder incentives. For programs authorized for 1992 and 1993, this plan should be consistent, at a minimum, with the protocols contained in Appendix A of the Collaborative Blueprint. For programs authorized for 1994 and beyond, this plan should be consisted with the protocols adopted in the M&E phase of these proceedings.

22a. The increased level and importance of the costs of measurement have increased the importance of the current regulatory practice of retaining separate funding authorization for Measurement, Forecasting, and Regulatory Reporting (MFRR) in utility DSM budgets, and for ensuring that these authorized funds remain available for the prudent use of the utilities to meet their DSM measurement and evaluation responsibilities. Funds authorized for MFRR should not be used to fund other types of DSM activities, and utilities should retain the flexibility to shift funds within this budget category and to carry forward and carryover authorized MFRR expenditures within a general rate case (GRC) authorization period. Movement of funds into MFRR from other DSM budget categories may be permitted on the basis of an Advice Letter filing.

For the next few years, however, we do not expect to authorize increased funding for MFRR activities beyond current authorized funding levels, escalated to account for inflation.

We direct that each utility's MFRR budget proposal be rigorously justified and reviewed in a zero-based budgeting context during a GRC proceeding occurring during this period.[6] The cost impact of the adopted ex post measurement protocols is not expected to pose a budgeting issue until later in the 1990s. At that point, the increased costs of ex post measurement may increase to the point were it will be necessary to either increase MFRR budgets or reduce some other MFRR activities.

Rather than determine at this point which of the various options is preferable, we direct the utilities and other parties to include a thorough review of MFRR activities and costs in the expected review of the ex post measurement protocols in the 1997 Annual Earnings Assessment Proceeding (AEAP). In the meantime, utilities should either (1) reduce total MFRR funding if and when cost-saving techniques can be established without jeopardizing the quality of MFRR activities; (2) maintain MFRR funding at current levels; or (3) augment funding for essential MFRR activities from funds not being expended in other budget categories (subject to Advice Letter approval). In any case, utilities should strive to coordinate the planning and implementation of the program measurement, load metering, and saturation survey activities in a manner which produces cost reductions, and diligently monitor costs in these MFRR areas in preparation for the likely need to prioritize MFRR activities later in this decade.

23. The utility should explicitly quantify the following for any proposed shareholder mechanism:

- o The rate effects of both the program incentive and programs costs to which the incentive will apply;
- o The program's net resource savings; and

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[6] SCE's last GRC was for test year 1992. PG&E, SDG&E, and SoCal have had more recent GRC's in which increases have been considered to account for the increased costs of moving toward ex post measurement. Therefore, for SCE only, we will consider commensurate increases in its upcoming test year 1995 GRC, provided that such increases can be justified by a zero-based budgeting analysis.

- o The timing of both rate effects and resource savings.

24. The DSM Advisory Committees provide an informal forum for parties to review utility programs and to work with the utility on any proposed changes to its programs. These activities can augment effective program implementation. The utilities should continue the Advisory Committees. For the Committees to be effective, the utilities should clearly define the role of the Committee and the input it seeks; provide the Committee with comprehensive information on program implementation activities; notify Committee members in a timely fashion of proposed program changes; provide adequate information supporting such changes; and coordinate Committee activities with current and anticipated regulatory proceedings and other review procedures. To this end, respondents should establish a single clearinghouse for all Advisory Committee noticing and scheduling, as described in Section IV.H of this order.

25. We intend to improve the consistency with which DSM programs are treated across utilities and across regulatory forums by initiating the consolidated M&E phase described in Rule 21 and by addressing generic policy and methodological issues in this Rulemaking and Companion Investigation. Determinations made in these proceedings should be used in any subsequent utility-specific proceedings. We may also consider further consolidation of DSM-related issues at a later stage of these proceedings, after our generic investigation on ratemaking (R.90-02-008/I.90-08-006) is completed.

VII. Bidding

26. Introducing competition into the utility's acquisition of demand-side resources offers great potential for achieving our goal of reliable, least cost, environmentally sensitive energy service.

27. The utilities will work with the Division of Strategic Planning (DSP) to develop and implement several DSM pilot bids. PG&E has volunteered to conduct a pilot bid based on a partnership approach. Public Utilities Code § 747 requires this Commission to test at least one DSM-only bid, an integrated resource bidding pilot, and a DSM bidding pilot for gas utilities. As one of their DSM-only bid pilots, respondents should test at least one replacement bid. CACD will perform an evaluation of the pilots, in consultation with the California

Energy Commission. This Commission will submit its report, with any recommendations, to the Legislature by January 1, 1993.

28. The bid pilots should be designed to ensure that (1) the procurement process is fair, (2) contract terms equitably share risks, and (3) utility market power is mitigated. To the extent practicable, the bidding pilots should incorporate both price- and non-price factors for all DSM programs.

29. Each of the pilots, including PG&E's, will be addressed in the investigation opened in conjunction with this rulemaking.

30. Unless otherwise indicated, changes in Commission direction should be applicable to program changes made by the utility that do not require Commission approval, as well as to utility Advice Letter filings or to funding requests filed with or considered by the Commission after adoption of the rule. Utilities should not wait until the next formal filing to effectuate these changes. Rather, utilities should make program changes as soon as practicable after the effective date of the adopted rule, and inform their Advisory Committees of the program changes and implementation schedule.

DSM PROGRAM TERMS AND DEFINITIONS

Lost Opportunities

Efficiency measures which offer long-lived, cost-effective savings that are fleeting in nature. A lost opportunity occurs when a customer does not install an energy efficiency measure that is cost-effective at the time, but whose installation is unlikely to be cost-effective later.

Cream Skimming

Cream skimming results in the pursuit of a limited set of the most cost-effective measures, leaving behind other cost-effective opportunities. Cream skimming becomes a problem when lost opportunities are created in the process.

Resource Value

An estimate of the reliable energy (e.g., kWh, therms) and capacity (e.g., kW, Mcfd) reductions resulting from a DSM program. The calculation of resource value and associated benefits should be consistent with the avoided costs of electric service adopted in the Biennial Resource Plan Update and, when completed, the avoided costs of natural gas service adopted in Investigation 86-06-005.

Uneconomic Bypass

Customer power generation or supply at a cost less than utility retail tariffs, but above utility marginal cost to serve. Electric bypass deferrals may or may not include a corresponding opportunity cost due to the potential loss in natural gas sales. An opportunity cost is realized if the customer would have installed natural gas-fired generation equipment to produce electricity for the customer's use.

I. Conservation and Energy Efficiency Programs

Conservation programs are defined as programs which have the effect of reducing consumption of at least one fuel during the hours of operation of the equipment or building affected by the measure. Energy efficiency programs are defined as programs which reduce energy use for a comparable level of service.

Residential Conservation and Energy Efficiency

Residential Information Programs: Programs intended to provide customers with information regarding generic (not customer-specific) conservation opportunities. For these programs, the information is unsolicited by the customer. Programs which provide incentives in the form of unsolicited coupons for discounts on low cost measures are included.

Residential Energy Management Services: Programs intended to provide customer assistance in the form of information on the relative costs and benefits to the customer of installing measures or adopting practices which can reduce the customer's utility bills. The information is solicited by the customer and recommendations are based on the customer's recent billing history and/or customer-specific information regarding appliance and building characteristics.

Residential Weatherization Retrofit Incentives: Programs which provide financial incentives (rebates, low-interest loans) to install weatherization measures in existing buildings. Incentives are predominantly weatherization measures that affect the building shell. Incentive payments for other measures (nonbuilding shell) are included, usually when provided in connection with building shell materials.

<u>Residential New Construction</u>: Programs which provide financial incentives or significant technical assistance to builders of new residential structures, with the primary purpose of exceeding existing energy efficiency Title 24 standards. Program activities include fuel substitution activities when promoted as an integrated package of measures which promote electric and gas energy efficiency. If the building type is not subject to Title 24 standards, New Construction programs should offer financial incentives or technical assistance to exceed energy efficiency over currently acceptable standard practice for these facilities. New Construction programs include education and support activities for designers, architects, building officials, and other parties who may influence the supply of and demand for buildings that are more efficient than Title 24 requires (or current practice if Title 24 does not apply).

<u>Appliance Efficiency Incentives</u>: Programs which provide incentives to customers in existing residential structures. The incentives are intended to lead to the installation of a more efficient appliance than would have been installed in the absence of the program. Incentives are paid (to manufacturers, salespersons, or customers) for the replacement of an existing appliance or the installation of a new appliance in an existing residential building.

<u>Direct Assistance</u>: Programs which are intended to provide assistance to low income or other "target" customer groups. Assistance consists primarily of full subsidies of the conservation measures. The primary purpose of the program is to serve an equity objective in assisting customers who are highly unlikely or unable to participate in other residential programs.

<u>Master Meter</u>: Program intended to reduce energy usage in existing residential structures which have master meters by replacing the master meter with individual meters.

<u>Other Residential Conservation Programs</u>: Any residential conservation program or program activities not defined above.

Nonresidential Conservation and Energy Efficiency

<u>Nonresidential Information Programs</u>: Programs intended to provide customers with information regarding generic (not customer-specific) conservation opportunities. For these programs, the information is unsolicited by the customer. Programs which provide incentives in the form of unsolicited coupons for discounts on low cost measures are included.

<u>Commercial Energy Management Services</u>: Services to customers in commercial buildings which provide customer assistance in the form of information on the relative costs and benefits to the customer of installing measures or adopting practices which can reduce the customer's utility bills. The information is solicited by the customer and is based on the customer's recent billing history and/or customer-specific information regarding appliance and building characteristics.

<u>Industrial Energy Management Services</u>: Services to customers in industrial facilities which provide customer assistance in the form of information on the relative costs and benefits to the customer of installing measures or adopting practices which can reduce the customer's utility bills. The information is solicited by the customer and is based on the customer's recent billing history and/or customer-specific information regarding appliance and building characteristics.

<u>Agricultural Energy Management Services</u>: Services to customers in agricultural facilities which provide customer assistance in the form of information on the relative costs and benefits to the customer of installing measures or adopting practices which can reduce the customer's utility bills. The information is solicited by the customer and is based on the customer's recent billing history and/or customer-specific information regarding appliance and building characteristics.

<u>**Commercial Energy Efficiency Incentives**</u>: Programs which provide incentives to customers in existing commercial buildings. The incentives are intended to lead to the installation of a more efficient device(s) or systems utilizing the same energy source than would have been installed in the absence of the program.

<u>**Industrial Energy Efficiency Incentives**</u>: Programs which provide incentives to customers in existing industrial facilities. The incentives are intended to lead to the installation of a more efficient device(s) or systems utilizing the same energy source than would have been installed in the absence of the program.

<u>**Agricultural Energy Efficiency Incentives**</u>: Programs which provide incentives to customers in existing agricultural facilities. The incentives are intended to lead to the installation of a more efficient device(s) or systems utilizing the same energy source than would have been installed in the absence of the program.

<u>**Nonresidential New Construction**</u>: Programs which provide financial incentives or significant technical assistance to builders of new nonresidential structures, with the primary purpose of exceeding existing energy efficiency Title 24 standards. Program activities include fuel substitution activities when promoted as an integrated package of measures which promote electric and gas energy efficiency. If the building type is not subject to Title 24 standards, New Construction programs should offer financial incentives or technical assistance to exceed energy efficiency over currently acceptable standard practice for these facilities. New Construction programs include education and support activities for designers, architects, building officials, and other parties who may influence the supply of and demand for buildings that are more efficient than Title 24 requires (or current practice if Title 24 does not apply.)

<u>**Street Lighting Conversion**</u>: Programs designed to replace less efficient lighting equipment with more efficient lighting equipment in utility-owned street lights.

Other Nonresidential Conservation/Energy Efficiency Programs: Any nonresidential conservation program or program activities not defined above.

System Efficiency

Conservation Voltage Reduction: Programs which improve utility generation system efficiency by regulating the voltage levels of delivered electricity.

Other System Efficiency Programs: Any other program intended to improve the efficiency of utility-owned transmission or distribution facilities.

II. Load Management

Load management programs are defined as any program which reduces electric peak demand or has the primary effect of shifting electric demand from the hours of peak demand to non-peak time periods, with a neutral effect on or negligible increase in electricity use.

Residential Air Conditioner Cycling: Programs which involve the installation of cycling devices on residential air conditioning equipment. Air conditioning loads are interrupted ("cycled" or "shed") by the utility at times of peak load.

Residential Time-of-Use: Programs intended to reduce customer bills and shift hours of operation of appliances to off peak periods through the installation of a time-of-use meter and the availability of time-differentiated rates.

Pool Pump Timer: Programs which involve the promotion of shifting pool pump hours of operation from on-peak to off-peak periods.

Nonresidential Air Conditioner Cycling: Programs which involve the installation of cycling devices on air conditioning equipment in nonresidential buildings. Air conditioning loads are interrupted ("cycled" or "shed") by the utility at times of peak load.

Nonresidential Time-of-Use: Program intended to reduce customer bills and shift hours of operation of equipment from on-peak to off-peak periods through the installation of a time-of-use meter and the availability of time-differentiated rates. Mandatory TOU participation is not included.

Thermal Energy Storage:[7] Programs which provide financial incentives to customers or builders to install thermal storage equipment and materials capable of fully or partially storing thermal energy during nonpeak periods for use during peak demand periods.

Interruptible/Curtailable: Programs which provide financial incentives in the form of reduced billing charges to customers in exchange for the capability of utility-initiated interruption or curtailment of service. Terms of the reduced service agreement (frequency, duration, penalty clauses, incentive levels, cost of equipment) are agreed to by contract.

Other Load Management: Any other load management program not defined above.

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[7] Consistent with today's order, this program category will be reclassified as a measure or technology under retrofit, new construction or fuel substitution programs. (See Section 5.d.)

III. Fuel Substitution

Fuel Substitution programs are defined as programs which are intended to substitute energy using equipment of one energy source with a competing energy source.[8]

Electric Fuel Substitution: Programs which promote the customer's choice of electric service for an appliance, group of appliances, or building rather than the choice of service from a different fuel. These programs increase customers' electric usage and decrease usage of utility-supplied natural gas. Electric fuel substitution includes Bypass Deferral Special Contracts which cause the deferral or avoidance of the installation of gas-fired equipment which would have been used to produce electricity for the customer's use, and are negotiated and established pursuant to CPUC procedures. Contract provisions may include a discounted rate, conservation and/or load management incentives, or a combination of rate and conservation/load management incentives.

Gas Fuel Substitution: Programs which promote the customer's choice of natural gas service for an appliance, group of appliances, or building rather than the choice of service from a different energy source. These programs increase customer usage of natural gas and decrease usage of an alternative fuel.

[8] "Energy source" currently refers only to utility-supplied electricity and natural gas. As the analytical constraints become less restrictive for evaluating alternative fuels, this stipulation may be broadened accordingly.

IV. Load Retention and Load Building

Load retention consists of programs which provide a rate discount, incentive or substantial technical assistance and which defer or change a customer decision to terminate or reduce utility service, without resulting in the substitution of one utility-supplied fuel (electricity or gas) with another. Load retention activities fall within the following two general categories:

(1) **Bypass deferral** consists of programs which provide a rate discount, incentive or substantial technical assistance to a customer to defer or change a customer decision to terminate or substantially reduce utility service for utility-supplied fuels (electricity, natural gas, or electricity and natural gas) and replace this service with non-utility service or fuels. Administration costs for bypass deferral programs consist of costs of utility personnel to defer or prevent customers from obtaining non-utility service beyond those costs incurred in the form of providing rate and energy efficiency information as a part of Energy Management Services programs.

(2) **Other load retention** consists of programs other than bypass deferral which defer or change a customer's decision to terminate or reduce utility service for utility-supplied fuel without resulting in the substitution of one utility-supplied fuel (electricity or gas) with another. This category includes activities intended to promote economic development by reversing customer decisions to reduce corporate production or service output, or to relocate outside the state or service territory.

Load building programs are defined as programs which have the effect of increasing the annual sales/consumption of one or both utility-supplied fuels from stationary energy-using equipment without decreasing the consumption of either fuel. Economic development activities that have this effect are considered to be a load building program (e.g., programs intended to promote economic growth by attracting new customers to the state or service territory.)

V. Demand-Side Measurement, Forecasting, and Regulatory Reporting Category Descriptions

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List of Appearances

Respondents: David R. Clark, J. F. Walsh, Jeffrey M. Parrott, Attorneys at Law, and Y. A. Whiting, for San Diego Gas & Electric Company; Robert B. Keeler, Lisa Urick, Ivan J. Tether, Attorneys at Law, and Robert L. Ballew, for Southern California Gas Company; Robert B. McLennan and Ann D. Cummings, Attorneys at Law, for Pacific Gas and Electric Company; and Stephen E. Pickett, Frank J. Cooley, and Gene E. Rodriques, Attorneys at Law, for Southern California Edison Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barbara Barkovich, for Barkovich and Yap; Ralph Cavanagh, Attorney at Law, for Natural Resource Defense Counsel; Steven F. Greenwald and Andrea B. Colace, Attorneys at Law, for Skadden, Arps, Slate, Meagher & Flom; Norman J. Furuta and Sam DeFrawi, Attorneys at Law, for Federal Executive Agencies; Grueneich, Ellison & Schneider, by Dian M. Grueneich, Attorney at Law, for California Department of General Services and South Coast Air Quality Management District; James Hodges, for The East Los Angeles Community Union; Jonathan Blees, Attorney at Law, D. Stephen Williams, and Michael Messenger, for California Energy Commission; Lon W. House, for Assn. of California Water Agencies; Randolph Wu, Attorney at Law, and Wayne Lepire, for El Paso Natural Gas Company; Douglas K. Kerner, Attorney at Law, for Roberts & Kerner; Audrie Krause, K. Justin Reidhead, Michel Peter Florio, and Peter V. Allen, Attorneys at Law, and Eugene Coyle, for Toward Utility Rate Normalization (TURN); Martin A. Mattes and Diane I. Fellman, Attorneys at Law, for Graham & James; Daniel Meek and Richard Esteves, Attorneys at Law, for SESCO, Inc.; Andrew Brown, for Barakat & Chamberlin; David L. Modisette, for Edson & Modisette; Sara Steck Myers, Attorney at Law, and V. John White, for Coalition for Energy Efficiency and Renewable Technologies; Bronson, Bronson & Mc Kinnon, by Scott W. Pink, Attorney at Law, and Douglas A. Ames, for Transphase Systems, Inc.; John D. Quinley, for Cogeneration Service Bureau; John W. Witt, City Attorney, by Peter V. Allen and Deborah Berger, Deputy City Attorneys, for the City of San Diego; Andrew Brown and Jan Smutny-Jones, Attorney at Law, for Independent Energy Producers Association; Jackson, Tufts, Cole & Black, by William H. Booth, Joseph Faber and Allan Thompson, Attorneys at Law, for California Large Energy Consumers Association; James Adams, for Energy & Resource Associates; Robert I. Burt, for California Manufacturers Association; Adam Pan, for Sierra Energy and Risk

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Assessment; Richard Shaw, John Paternos, and Barbara Vauthier, for California-Nevada Community Action Association/ASCEP; Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Ronald Leibert, Attorneys at Law, for Industrial Users; Lee Riggan, for Association of Southern California Energy Programs (ASCEP); Thomas R. Sheets and John Walley, Attorneys at Law, for Southwest Gas Corporation; Terry E. Singer, W. H. Wellford, and Chris Willrich, for the National Association of Energy Service Companies; Abdullah Y. Ahmed, for Occidental Analytical Group; Joel Singer, Attorney at Law, for Awad & Singer; Richard Miller and Brad Davids, for Proven Alternatives; Frank J. Mazanec, for EUA/Onsite, L.P.; Larry Goldberg, for Energy & Resource Advocates; Richard Sweetser, for American Gas Cooling Center; Maurice Brubaker, Attorney at Law, for Drazen, Brubaker and Associates; Steve Harris and Nancy Vandenberg, for Enron/Transwestern Pipeline Co.; W. Marcus and J. Nahigian, for JBS Energy, Inc.; Cary G. Bullock, for Kenetech Energy Management, Inc.; Emilio E. Varanini, Attorney at Law, for Marron, Reid and Sheehy; Robert B. Weisenmiller, for Morse, Richard, Weisenmiller and Associates; George R. Edgar, for Wisconsin Energy Conservation Corporation; Thomas J. O'Rourke, Attorney at Law, for O'Rourke and Company; Michael Shames, for Utility Consumer Action Network; Michael D. Byars, for The Trane Company; Michael Shapiro, for State Senate; Steven Stoft, for University of California; Harry Frami, for California State Department of Corrections; Matthew B. Brady, Attorney at Law, for Knox, Lemmon, Brady, Anapolsky and Sheridan; Greg Blue, for Destec Energy, Inc.; Donald H. Maynor, Attorney at Law, for City of Anaheim and the Power Agency of California; Charles Goldman, for Lawrence Berkeley Laboratory; Patrick L. Splitt, for App-Tech. Inc.; Lynn Tran, for California Energy Commission; Robert I. Burt, Sr., for California Manufacturers Association; Danielle Albano, for Wright & Talisman; David R. Branchcomb, for Henwood Energy Services; Sandra Bodmer-Turner and Jon S. Castor, for themselves.

Division of Ratepayer Advocates: James Scarff, Attorney at Law, and Don Schultz.

Commission Advisory and Compliance Division: Randi Greenspan, Michelle Cooke, and Stephen Layman.

(END OF ATTACHMENT 7)