LBL--31882

DE93 001578

Sharing the Savings to Promote Energy Efficiency

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April, 1992

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The work described in this paper was funded by the Assistant Secretary for Conservation and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

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Contents

Page

Abstract ix

Introduction 1

Origin of the Shared-Savings Concept for Utility DSM Activities 2

Shared-Savings Defined for Utility Demand-Side Programs 3

Comparing Utility Shared-Savings Incentives 4
- Utility Earnings Calculation 7
- Determination of Load Reductions 9
- Determination of Avoided Costs 10
- Determining Program Costs 11
- Program Cost Recovery 12
- Incentive Recovery 12
- Performance Thresholds 13
- DSM Program Spending and Shareholder Earning Caps 16
- Program Eligibility 17
- Treatment of Lost Revenues 18

Evaluating Shared-Savings Incentives 19
- The Role of Collaboratives in the Design of Shared-savings Incentives 20
- Initial Results from Utility Shared-Savings Incentive Mechanisms 21

Summary 24

Acknowledgements 27

References 29

List of Tables

Table	Title	Page
1	Comparison of Utility Revenues, Sales, and Number of Customers	5
2	Comparison of Utility Shared-Savings Incentive Program Features	6
3	Calculation of Maximizing and Efficiency Incentives (1990 M$) Narragansett Electric Company	8
4	Minimum Performance Thresholds (% of Participation Targets) Pacific Gas and Electric - 1991 Program	15
5	Matching DSM Programs with Shareholder Incentives Pacific Gas and Electric	18
6	Comparison of Utility Shared-Savings and Overall DSM Program Performance (1990 M$)	22

List of Figures

Figure	Title	Page
1	PG&E Shared-Savings Incentive	14

ABSTRACT

Shared-savings incentives offer a new way for regulated utilities to improve earnings by encouraging customer energy efficiency. Benefits of cost-effective energy efficiency measures can be shared explicitly among customers participating in an utility demand-side management (DSM) program, all utility ratepayers, and the utility itself. For participating customers, electricity bills are lowered directly; for ratepayers, the costs of providing electric services are reduced; and for utility shareholders, they are allowed to retain a fraction of the net benefits as additional earnings.

In this study, we define the basic elements of shared-savings arrangements for utility demand-side resources. Next, we compare and contrast specific details of the arrangements approved for three different utilities: Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and two operating subsidiaries of the New England Electric System (NEES). Our analysis suggests that the percentage share of net benefits on which utilities are allowed to earn is a relatively poor indicator of the incentive mechanism's overall affect on utility earnings. Earnings opportunities and potential are also significantly influenced by particular incentive features. These include the definition and measurement of load reductions, program costs, and program benefits; program cost recovery and the timing of incentive recovery; performance thresholds; program spending and earnings caps; program eligibility criteria; treatment of lost revenues; and for NEES, a complementary, non-shared-savings incentive.

We conclude that the "collaborative" processes used to develop incentives for each utility proved extremely useful in allowing parties to negotiate trade-offs inherent between various program design features. In 1991, the net impact of DSM incentives resulted in PG&E, SDG&E, and NEES earning simple returns of 11%, 60% and 12% respectively, on their 1991 DSM program expenditures. The SDG&E earnings are significantly higher due to a pre-existing, non-shared saving incentive.

INTRODUCTION

Shared-savings incentives offer a new way for regulated utilities to improve earnings by encouraging customer energy efficiency. The basic idea is that the benefits of cost-effective energy efficiency measures can be shared explicitly among the customer participating in the utility program, all utility ratepayers, and the utility. For the participating customer, electricity bills are lowered directly. For utility ratepayers, the costs of providing electric service are reduced compared to the utility doing nothing to improve customer energy efficiency. For the utility, a fraction of the net savings to all ratepayers is retained as earnings.[1]

Business activities eligible for shared-savings remain under the jurisdiction of traditional state regulatory agencies, but the methods used to calculate earnings differ fundamentally from both those used in traditional ratemaking and those used by other regulatory incentive mechanisms for Demand-Side Management (DSM). First, eligible utility demand-side activities must have positive net resource value, which is different from traditional regulatory tests used to determine the prudence and usefulness of utility supply-side investments. Second, since the utility's earnings are a fraction of this net resource value, the relationship between the earnings from shared-savings and the traditional fixed rate of return earned on rate base may be only coincidental. Third, unlike other financial incentives to utilities for DSM, the earnings from shared-savings accrue in direct proportion to the net societal benefit of the demand-side activity, so that shared-savings may be able to harmonize the utilities' incentive to increase earnings with the societal goal of a least-cost energy system.

However, departures from traditional ways of regulating utilities have risks that utilities and their commissions must evaluate, including:

- uncertainty about the cost and performance of demand-side resources;
- uncertainty about the value of these resources as avoided supply-side resources;
- utility perceptions of the certainty of earnings from demand-side activities relative to other earning opportunities; and conversely,
- commissions' certainty about the amount and timing of utility DSM outlays and earnings.

It generally seems appropriate to distinguish among the risks that utilities and their commissions can and cannot control. For example, fuel-adjustment clauses have the primary effect of shifting risks associated with fuel price volatility onto the ratepayer. The rationale is that fuel price volatility is beyond the utility's control. In the case of shared-savings, however, no one yet knows the magnitude of these risks and, consequently, the appropriateness of existing rewards.

[1] Shared-savings incentives to reward utility DSM activities were first proposed in Wellinghoff (1988).

This report reviews progress in striking the balance between risk and reward for shared-saving incentives for utility demand-side programs.[2] We begin with a brief description of the origin of the shared-savings concept with energy service companies because this background highlights the role of state utility commissions in adjudicating the risks and rewards of delivering energy services. After defining the basic elements of shared-savings arrangements for utility demand-side resources, we review recent experience in New England for two operating subsidiaries of the New England Electric System (NEES), and in California for the Pacific Gas and Electric Company (PG&E) and the San Diego Gas and Electric Company (SDG&E), comparing and contrasting specific details of the arrangements approved for each utility. We comment on the collaborative processes that led to the development of the incentives because they were instrumental for reaching consensus on the principle of providing positive earning opportunities to utilities for their demand-side activities and because they played a major role in the design of programs eligible for these earnings. Early financial results from the programs are then presented.

ORIGIN OF THE SHARED-SAVINGS CONCEPT FOR UTILITY DSM ACTIVITIES

In the late 1970's, well-documented social and institutional barriers hindering the deployment of cost-effective demand-side resources (Blumstein et. al. 1980), created market opportunities for a new type of business dedicated to providing energy services, rather than energy forms, *per se* (Sant 1980). Energy service companies (ESCos) acted as third-party developers, financiers, and in some cases operators of energy-efficiency investments on behalf of building owners or industrial firms that were unable or unwilling to pursue efficiency opportunities on their own. In return, ESCos retained a portion of the utility bill savings that resulted from their energy saving services. The agreements between ESCos and building owners came to be known as shared-savings agreements because the ESCos' earnings were directly related to the amount of energy they were able to save for a client.

The experience of the ESCo industry during the past ten years is currently relevant for two reasons. First, the ESCo industry has tapped only a limited amount of the available, cost-effective, demand-side resource. The existence of these un-tapped resources has induced commissions to provide incentives to utilities to acquire these resources. Second, one of the most important reasons ESCos have been unable to fully tap demand-side resources is that measuring energy savings is a formidable task, a major challenge for commissions and utilities when designing equitable shared-savings incentives.

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[2] This report is based on Chapter 6 from *Regulatory Incentives for Demand-Side Management*, edited by Nadel, Reed, and Wolcott, American Council for and Energy Economy, 1992. Frequent references are made to other chapters in this book.

What is new for utility shared-savings is that the regulator, in effect, acts as an independent arbiter of energy savings. That is, the measurement dispute is no longer strictly an issue between an ESCo, or any energy service provider, and the client. Energy savings will become a central topic for the utility and its regulator because the regulator must allocate the risk of demand-side resource performance and value between the utility and its ratepayers. In this capacity, commissions must make the same type of determination that they make in determining the value of supply-side resource investments (Wiel 1990). The important difference is that because energy savings can never be observed directly, these will always be an element of controversy. As we shall see, there is no standard to allocate this performance risk; no one has yet developed a precise prescription.

SHARED-SAVINGS DEFINED FOR UTILITY DEMAND-SIDE PROGRAMS

The basis for most utility shared-savings programs can be characterized using this simple formula:

$$NRV = (LR \times AC) - PC$$

where:

NRV	=	net resource value ($)
LR	=	load reductions (Kw or Kwh)
AC	=	utility avoided supply costs ($/kW or $/kWh)
PC	=	energy efficiency program costs ($), including utility administration, rebates, and customer contribution[3]

When a utility invests in a cost-effective demand-side program, the program has a positive net resource value. In shared-savings, this positive value is shared between the utility and its ratepayers. The utility's share is typically specified as a fixed percent of the net resource value (i.e., 10%, 13.5%, and 15% for NEES, SDG&E, and PG&E, respectively).[4]

As a result of this direct link between the net resource value of a demand-side investment and a utility's earnings, shared-savings incentives reward successful utility acquisition of cost-effective demand-side resources, rather than utility spending on DSM programs.[5] In this

[3] There are subtle, but important, differences in the definition of program costs between various utility shared-savings incentives.

[4] In the case of NEES, in addition to 10% of net resource value, they also receive 5% of gross resource value.

[5] Spending levels are the basis for some DSM incentive mechanisms such as ratebasing; see "Ratebasing" by M. Reid (Nadel, Reid and Wolcott 1992).

respect, shared-savings differ fundamentally from most other types of incentive mechanisms because an explicit determination of net benefits, including energy savings, must be made.

Despite the simplicity of the concept, there are a variety of ways the terms in the equation can be defined, the incentive to the utility calculated, and qualifying utility performance measured.

COMPARING UTILITY SHARED-SAVINGS INCENTIVES

Shared-savings incentives have been approved in 13 states (Nadel, Reid, and Wolcott 1992). However, shared-savings are a new earnings opportunity for utilities; the first shared-savings incentive was approved in 1989. Existing incentives are probably best regarded as experiments in progress. In other words, we fully expect that features of the incentives will undoubtedly change, perhaps dramatically, as commissions and utilities gain experience.

In this section, the shared-savings incentives approved for two of the operating subsidiaries of the New England Electric System, Narragansett Electric (NE) in Rhode Island, and Granite State Electric (GSE) in New Hampshire are described.[6] The shared-savings incentive approved for Narragansett Electric was the first of its kind in the United States. The shared-savings incentives approved for the Pacific Gas and Electric Company and the San Diego Gas and Electric Company, both in California, are also reviewed (Schultz and Eto 1990). Where relevant selected features of the shared-savings incentives that have been approved for New York State utilities are discussed, although our descriptions are not intended to be comprehensive (Gallagher 1991).

This review of shared-savings incentives is organized around the following ten program features:

- Earnings Calculation
- Determination of Load Reductions
- Determination of Avoided Costs
- Determining Program Costs
- Program Cost Recovery
- Incentive Recovery
- Performance Thresholds
- DSM Program Spending and Shareholder Earning Caps
- Program Eligibility
- Treatment of Lost Revenues

[6] The largest operating subsidiary of NEES is Massachusetts Electric (ME), which has a bonus type incentive for its DSM activities. Due to ME's size relative to NE and GSE, certain aspects of its DSM activities are mentioned, which are directly relevant for the incentives earned by NE and GSE.

Table 1
Comparison of Utility Revenues, Sales, and Number of Customers

			NEES	
	PG&E	*SDG&E*	*NE*	*GSE*
Electric Revenue (B$)	5.9	1.2	0.4	0.04
Sales (BkWh)	68.2	13.4	4.5	0.60
Customers (M)	4.1	1.1	0.3	0.03
Avg. Revenue (¢/kWh)	8.7	8.6	7.8	7.4

Source: Energy Information Administration 1991

Before discussing specific incentive mechanisms, we make two general observations. The relative size of a utility and its energy efficiency programs, and associated regulatory staff have a tremendous influence on the formulation of DSM incentive mechanisms. These differences are alluded to in Table 1, which compares utilities by electricity revenue, sales, customers, and average revenue in 1988 per kilowatt hour. Particular features of the California shared-savings incentives are described in greater detail, due to the size of these efforts. The viability of California-style shared-savings incentives in states with smaller utilities and commission staff is clearly a legitimate concern.

Second, even though we discuss program features separately, these features are interdependent, and thus it is extremely important to evaluate program features in aggregate to understand their net impact and how they counter-balance one another. Our findings are summarized in Table 2.

Table 2
Summary of Utility Shared-Savings Incentive Program Features

	New England Electric Service			
	Narragansett Electric Rhode Island	*Granite State Electric New Hampshire*	*Pacific Gas & Electric California*	*San Diego Gas & Electric California*
Utility Earnings	10% of NRV plus 5% of avoided cost benefit (see Table 3 for sample calculation)		15% of NRV (see below for definition of program costs)	13.5% of NRV
Load Reductions	Participation based on utility records; per participant savings based on engineering estimates that are updated for future year programs using detailed program evaluations of current year programs			
Avoided Costs	Determined by NEES system planners annually for life of current year program		Set annually (for life of current year program) in pre-existing proceedings to determine long-run marginal costs	
Program Cost	Includes both utility and customer costs. Utility cost based on company records; customer contribution estimated		Includes only utility costs, based on company records	Identical to NE
Program Cost Recovery	Expensed annually			
Incentive Recovery	Lifecycle program benefits fully recovered in year following program start		Life-cycle program benefits recovered over 3 years from program start	
Performance Threshold	No earnings on first 50% of estimated overall savings, but no penalty	Earnings on all savings, provided 50% threshold is exceeded; no penalties	Program-by-program participation targets trigger receipt of incentives or, for sub-par performance, penalties (see Table 4)	
Spending and Earnings Caps	None, differences in overall expenditures of greater than 10% must be reported quarterly		Spending cap of +30% of authorized budget Earnings cap of +10% of pre-program estimate	
Program Eligibility	All demand-side activities treated as a package		Only demand-side activities explicitly designed to displace supply resources eligible; other demand-side activities subject to non-shared savings incentives (see Table 5).	
Treatment of Lost Revenues	Annual Federal Energy Regulatory Commission (FERC) rate case for generating subsidiary, New England Power System, reconciles revenues due to differences between forecast and actual sales		Electricity Revenue Adjustment Mechanism (ERAM) maintains balancing account to reconcile differences between forecast and actual base rate revenues on an annual basis. Fuel adjustment clauses treat impacts on variable cost fluctuations	

Utility Earnings Calculation

The utility's share of the net resource value ranges between 10-15% among the four utility incentives. For comparison, in New York, incentive mechanisms award utilities between 5-20% of the resource benefits (Gallagher 1991). However, the actual financial benefits to the utility are complicated by various definitions and conventions associated with calculating the components of net resource value (particularly the definition of DSM resource costs) as well as the timing for the recovery of the incentive. It is also important to note the hybrid nature of the shared-savings incentives approved for the two NEES subsidiaries. The NE and GSE incentive programs involve, in addition to a share of the savings, a "maximizing incentive" that scales directly with the total value of avoided resource savings (i.e., before subtracting program costs). For these utilities, the net benefit of shared-savings programs is a combination of a share of the net resource savings and a further incentive to aggressively pursue all DSM opportunities.

A sample calculation of NE's incentive appears in Table 3. It only applies when the net resource benefits exceed a 50% threshold.[7] Note that evaluation and customer costs (lines 2 and 3 of Table 3) are subtracted from the total avoided utility supply costs prior to calculation of these thresholds. Finally, the maximizing incentive (line 10) is subtracted from the net benefit before the NE share is calculated. Table 3 illustrates that the maximizing incentive (line 10) approaches the size of the shared-savings incentive (line 11) and so is an integral part of the overall incentive to the utility.

One rationale for the maximizing incentive is that it provides an earnings opportunity to the utility for demand-side activities that do not always have significant net resource benefits, such as some residential programs. Without this type of incentive, a profit-maximizing utility with limited budgets and staff will tend to pursue only the most cost-effective demand-side activities, usually in the commercial sector. In California, the issue of "cream-skimming" and the importance of utility delivery of demand-side programs aimed at other goals besides net resource value is addressed through performance thresholds and program eligibility.

[7] The use of performance thresholds is described in a later section. For NE, incentives are earned on all savings beyond 50% of overall program goals. For GSE, incentives are earned on all savings, not just those in excess of 50%, but only when the threshold has been exceeded.

Table 3
Calculation of Maximizing and Efficiency Incentives (1990 M$)
Narragansett Electric Company

Line		*1990 M$*
1	Total Avoided Cost Benefits	42.3
2	Evaluation Costs	0.4
3	Customer Direct Costs	1.8
4	Total Adjusted Program Value	40.1
5	Base Value (50% of Program Goal)	13.7
6	Qualifying Value (in excess of 50% threshold)	26.4
7	Utility Program Costs (not including evaluation or customer costs)	14.3
8	Base Costs (50% of Program Goal)	4.9
9	Qualifying Cost (in excess of 50% threshold)	9.4
10	Maximizing Incentive (based on Qualifying Value)	1.3
11	Efficiency Incentive	1.6
12	Total Conservation Incentive	2.9

Notes:
Line 4 =(Line 1 - (Line 2 + Line 3))
Line 6 = (Line 4 - Line 5)
Line 8 = (Line 5 / Line 4) * Line 7)
Line 9 = ((Line 6 / Line 4) * Line 7)
Line 10: (5% * Line 6), but not less than zero
Line 11: (10% * (Line 6 - Line 9 - Line 10)), but not less than zero
Line 12: (Line 10 + Line 11)

Source: Hutchinson 1991

Determination of Load Reductions

Measuring load reductions (either kW or kWh) is an imperfect science. In principle, load reductions can only be measured after a program or measure has been installed for some time. A particularly problematic issue is how to properly account for effects that are not within the control of the utility but that affect load reductions, such as weather or occupant behavior. Another issue is "free riders" or load-reducing actions that customers would have undertaken anyway, even in the absence of the utility's program. In this discussion, only two specific issues related to the calculation of utility earnings from shared-savings programs are discussed: (1) the separation of load reductions into two components -- measuring participation in utility programs and measuring load reductions per participant; and (2) the evolution of measurements for load reduction per participant during subsequent program cycles.

The four utility shared-savings incentives distinguish between two components of load reductions: (1) technology or measure performance; and (2) marketing or utility program performance. The first refers to load reductions per program participant, for which the utilities are not held directly responsible. The second refers to program participation, for which the utilities *are* held responsible.

Due to the accelerated nature of utilities' earnings from the shared-savings incentives, estimates of load reductions per participant must be made before field measurements are available. Program participation, conversely, is determined from utility records. In other words, ratepayers bear the risk of a *measure's* demand-side performance on a per unit basis, while the utility bears the risk of the performance of its demand-side *program*. This risk often translates to the level of participation obtained by the utility for its programs. However, the utility's risks are relatively modest, since it influences the setting of program performance targets.

The estimates of a measure's performance, however, are not static. Because it is difficult to estimate a measure's performance, PG&E, SDG&E, and NEES (the parent of NE and GSE), are comprehensively evaluating utility demand-side programs.[8] The spending levels proposed by the utilities and management attention to program evaluation are expected to significantly advance the state-of-the-art in this area. The outcome of these evaluations will be used to update the estimates of each measure's performance for future program planning. However, the revised per participant/measure load reduction estimates can never retroactively reduce the savings

[8] NEES's program evaluation will focus on Massachusetts Electric's DSM activities in Massachusetts, which has a bonus-type incentive, based on measured evaluation results. Results from these evaluations will be used by both NE and GSE, after appropriate adjustments for conditions unique to each service territory.

figures per measure or participant that were used to develop incentive payments for the previous year's programs.[9]

A major contribution of the shared-savings incentives in California has been the rigorous discussion of measurement issues. For the first year of the programs, values were adopted for first-year load reductions, decay in savings over time, lifetimes, and free-rider fractions on a measure-by-measure basis. More importantly, acceptable techniques for evaluating and revising these variables over time were agreed on (CPUC 1990).

Determination of Avoided Costs

Load reductions are multiplied by utility avoided supply costs ($/kW and $/kWh) to obtain the total benefit of demand-side programs. The primary concern in establishing these costs for incentive determination purposes is ensuring that they are consistent with other utility uses of avoided costs. Without this consistency, the utility will have an incentive to manipulate these values to increase the apparent net resource value of the programs and consequently their earnings.

For the four utilities, treatment of avoided supply costs is similar to estimating energy savings per participant. To calculate net benefits from programs so that utility earnings can be quickly recovered, avoided supply costs are fixed for the programs' life. In NEES, these long-term values are determined annually by NEES's wholesale subsidiary, with review and approval by the Federal Energy Regulatory Commission (FERC). In California, they are established by an ongoing, pre-existing regulatory forum for resource planning.

Avoided supply costs are defined strictly in terms of direct costs avoided for these four utilities. In addition, other costs, external to the utility's direct costs, are avoided by reliance on demand-side rather than supply-side resources. One notable example of such external costs is the environmental damage caused by the construction and operation of supply-side resources (Ottinger et. al. 1990). In New York State, *dollar* estimates of these values are being included to determine the *avoided cost benefit* of demand-side resources eligible for shared-savings incentives (Gallagher 1991).

Another increasingly significant avoided cost is avoided transmission and distribution (T&D) facilities. The avoided costs used in the PG&E and NEES shared-savings incentives explicitly

[9] It is interesting to note that none of the shared-savings incentives allows the findings from the measure evaluations to update future year estimates for measures installed in prior years. This is partly due to the accelerated nature of incentive recovery. But more importantly, it is symbolic of the give and take involved in the negotiations that led to development of the incentives. In contrast, the non-shared-savings incentives to be earned by Massachusetts Electric will be based on after-the-fact measurement of load reductions.

include these costs. A general concern when avoided T&D costs are included is that the programs eligible for these incentives must be targeted to locations that, in fact, have avoidable T&D facilities (Rosenblum and Eto 1986).

Determining Program Costs

The societal cost of demand-side resources includes the utility's and the customer's expenses. If both are included and netted out from the benefits of avoided utility supply costs, the shared-savings formula is similar to the total resource cost test. If only the utility's costs are included, the formula becomes similar to the utility cost test.[10] Both approaches are used to determine shared-savings incentives.

Both NEES subsidiaries (NE and GSE) and SDG&E include customer and utility costs in calculating their shared-savings incentives. PG&E includes only utility costs. There are good reasons to support either choice. On the one hand, inclusion of customer costs is truer to the total resource cost standard. On the other hand, incremental customer costs (like energy savings) are difficult to measure, and, in any case, utility incentives to minimize its costs to deliver demand-side programs by reducing the incentives paid to participating customers are stronger if they are not combined with customer costs. Consideration of only utility costs will, however, tend to make the utility's "share" of the savings larger relative to a share based on the difference between avoided supply costs and the combination of utility and customer costs. In addition, when incentives are based only on utility costs, societal costs (utility costs plus customer costs) may increase since these costs are of minor concern to utility.

In a practical sense, the importance of these definitions depends on specific DSM program designs. For example, the DSM programs of the NEES subsidiaries usually pay most of the demand-side resource cost. The customer contribution is nearly zero. In this case, utility cost and total resource cost tests would yield essentially the same result.

When customer costs are included in the calculation of shared-savings incentives (NEES and SDG&E), determination of incremental customer costs is analogous to that for energy savings. In both cases, per unit estimates are agreed on in advance because it is difficult to measure actual incremental customer costs. In addition, information on customer costs is collected for updating the estimates that will be used in future year's programs. These estimates will not retroactively affect earnings from previous program years.

For PG&E, when customer costs are not included, each program must first pass the total resource cost test, as a threshold requirement, so customer costs are not ignored. As with the

[10] See CPUC/CEC (1987) or NARUC (1988) for a formal definition of these cost-benefit tests for demand-side resources.

incentives for NEES and SDG&E, the incremental customer costs used in the total resource cost test are estimates that will be updated for future programs.

Program Cost Recovery

One of the most important features of the four utility shared-savings programs involves timely recovery of program expenditures. Utilities' uncertainty about regulators' treatment of these costs has been cited as a major barrier to utility participation in demand-side markets (Chamberlin and Hanser 1991). All four utility programs provide immediate recovery of program costs as operating expenses in the year they are incurred. Expensing demand-side program costs has gone a long way toward increasing each utility's comfort with acquiring demand-side resources.

Incentive Recovery

The net resource benefits from demand-side activities accrue annually for the life of the measure. However, the shared-savings incentives earned by NEES, PG&E, and SDG&E are recovered in advance of the useful life of the measures. For both NEES subsidiaries, the utilities' share of the entire lifecycle benefits from a given year's activities are recovered in full by the end of the year after those activities are verified. For PG&E and SDG&E, benefits are also accelerated, but they are spread over the first three years following program delivery.

Utilities and commissions each have reasons to accelerate the shared-savings incentive. From the utilities' perspective, delayed earnings of shared-savings incentives increases the risk that the earnings will not be recovered because of, among other things, changing regulatory philosophies. Commissions, too, cite reasons for wishing to accelerate utility shared-savings earnings. First, accelerated earnings increase certainty about the total amount of ratepayer dollars to be paid. Second, accelerated earnings increase the visibility of the profits from demand-side activities to the utility and sends a signal to utility management. Third, accounting is simplified when multiple program elements, each with a different lifetime, do not need to be tracked separately.

Accelerated incentive recovery is similar to front-loading payments to Qualified Facilities (QFs) in power sales agreements with utilities. In California, front-loading became controversial because of a perceived oversupply of QF power in the mid-1980s and, as a result of falling real (net of inflation) oil prices, charges that QFs were being overpaid. In the present context, these concerns are largely addressed by; (1) the need for eligible programs to pass the total resource cost test; and (2) spending caps that, in California, limit the maximum level of activities on an annual basis or, in New England, trigger regulatory review when budgets are exceeded. Conversely, because incentive recovery is guaranteed, ratepayers have no recourse if subsequent evaluations reveal that performance has fallen short of expectations. For front-loaded QF

contracts, substantial penalties are levied for sub-standard performance. For California utility shared-savings incentives, as discussed below, penalties are in place for sub-par program participation, but not sub-par measure performance.

Performance Thresholds

Performance thresholds, a central feature of the California shared-savings incentives, serve as regulatory sticks by specifying explicit earnings penalties if utility DSM program participation goals are not met. Performance thresholds are also present in the NEES shared-savings incentives, but they are specified in a more aggregate manner.

Performance criteria assess penalties for sub-par utility performance. In California, they were developed in response to utility underspending of authorized conservation and load management budgets during the mid to late 1980s (Caldwell and Cavanagh 1989). The effect is that the shared-savings earnings can be substantially reduced or even become operating losses for the utility if performance fails to meet expectations.

The California performance criteria are defined on a program-by-program basis. Performance is measured by program participation, not by program energy savings. This effectively separates the risk of the conservation measure's performance from program participation. Measure performance is deemed to be beyond the control of the utility, while participation rates are regarded as subject to influence by utility managers. There are three steps. First, an annual target level for program participation is set by the utility. Second, a minimum performance threshold or fraction of the target level is negotiated. If participation fails to exceed this threshold, no incentives are earned. If participation exceeds the threshold, incentives are earned on the entire amount of net savings from the program. Third, a "deadband" is established below the minimum performance level. Figure 1 illustrates how PG&E's incentive mechanism for its 1990 resource programs is structured. Penalties accrue if participation falls below the deadband.

The target levels and performance thresholds are set for individual programs (see Table 4). Both the goals and minimum performance criteria reflect the utility's and commission's confidence in the probability of program success. Mature programs may have high goals and minimum performance thresholds, while goals for new or experimental programs may be defined more modestly. Since goals and thresholds are specified program-by-program, utility cream-skimming can be mitigated somewhat by establishing high goals and thresholds for less cost-effective (i.e., less profitable) programs, which might otherwise be neglected.

NEES's performance criteria are specified on an aggregate basis: incentives are only earned when energy savings exceed 50% of overall DSM program goals. This specification allows the utility considerable flexibility in two dimensions. First, the utility may reallocate efforts among

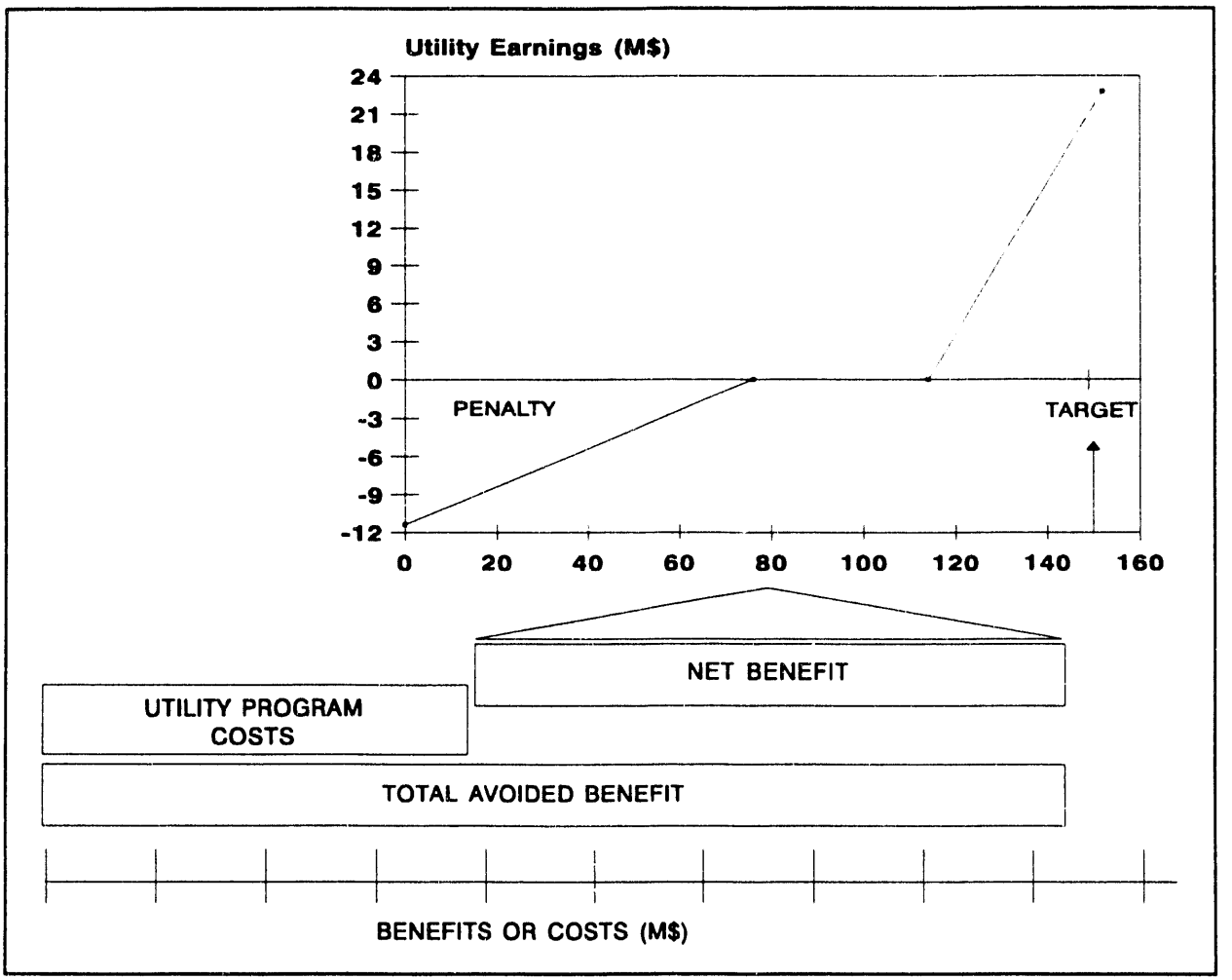

Figure 1
PG&E Shared Savings Incentive

individual programs throughout the year.[11] Second, threshold performance can be met through any combination of participation and savings per participant. In short, the specificity inherent in the California incentives is replaced in New England by a bottom-line orientation.

The specification of the NE performance criteria complicates calculation of net program benefits because the criteria act as earnings thresholds, (see, for example, Table 3). No incentives are earned on the first 50% of projected savings; incentives are only earned on savings *in excess* of

[11] A quarterly filing with the commissions is required when program spending differs from agreed rates by more than 10%. These filings may then become the basis for subsequent regulatory intervention although this has not happened in New England.

Table 4
Minimum Performance Thresholds (% of Participation Targets)
Pacific Gas & Electric - 1991 Program

	Minimum Performance Thresholds for Incentive Payments (% of participation goals)
Commercial, Industrial, Agricultural Energy Management Incentives	75%
Commercial New Construction	25%
Residential New Construction	30%
Residential Appliance Efficiency	75%
Commercial, Industrial, Agricultural Energy Management Services	70% 75% for commercial
Residential Energy Management Services	80%
Super Efficient Homes	70%

Note:
The thresholds represent percentages of participation goals that must be exceeded for the utility to earn incentives; if exceeded, the incentives are earned on the total benefits from the programs, not just those in excess of the thresholds. If participation is less than the threshold value, the utility earns no incentive. If participation is significantly below the threshold value, penalties are applied.

Source: Pacific Gas and Electric Company 1991

the 50% threshold. This means that the first 50% of program accomplishments, and utility expenditures, assuming these expenditures vary in direct proportion to savings, do not produce any incentive. Conversely, assuming the program target is reached, earning 10% on 50% of the savings means that only 5% has been earned on the entire program. For GSE, once the 50% threshold is reached, 10% is earned on all net savings, including the savings required to reach the 50% threshold.

DSM Program Spending and Shareholder Earning Caps

Spending caps limit the maximum a utility can spend beyond its authorized DSM program budget. Shareholder earning caps limit the maximum incentive a utility can earn. Both are discussed in this section because spending is often directly related to earnings. That is, since the incentives are based on prior estimates for savings per participant or measure installed, spending caps become, *de facto*, earnings caps.

DSM program spending caps may superficially seem contradictory; if energy efficiency is such a good idea, shouldn't program expansion be encouraged? But, unlimited expansion of demand-side programs may not be warranted for several reasons. Theoretically, the cost-effectiveness of demand-side programs can diminish with program size as avoided costs decrease and the difficulty (i.e., cost) of recruiting participants increases on a per unit basis. However, fixed avoided cost values are generally agreed on in advance for the purposes of calculating incentives, and thus, changes in per unit values due to quantity changes are usually not reflected in incentives' formulas. In addition, as spending increases, the amount of money that must be collected from ratepayers also increases, sometimes causing rate increases. Some utilities and commissions try to keep these rate increases to modest levels each year by limiting program expansion. Furthermore, administering greatly expanded programs may be difficult for the utility and its commission in the short run.[12] Finally, unlimited earnings from demand-side activities raise the more fundamental issue of what ought to be the appropriate basis for utility earnings. All three issues reflect the experimental nature of existing, shared-savings incentive mechanisms. Improved methods for dealing with mid-year adjustments in program spending and earnings will evolve as all parties deal with the programs.

The California shared-savings incentives contain explicit limits on expanded DSM program spending. The limits are set at 30% beyond authorized program budgets. Shareholder earnings are limited to no more than 10% above anticipated levels. The NEES programs do not contain explicit limits on program spending or earnings, but changes in spending of more than 10% are reported quarterly and, as a result, may become the subject of regulatory review.

In New York State, the shared-savings incentives for some utilities put a cap on earnings by linking the size of the incentive that can be earned to that which could have been earned under traditional rate-of-return regulation (Gallagher 1991). In other words, an independent measure is used to limit earnings from shared-savings incentives, in this case, by linking the shared-savings incentive to profits achievable under traditional utility regulation. While in New York, this measure is based solely on the utility's program costs, the California Public Utilities

[12] Slower program growth rates will give the utility additional time to "fine-tune" its programs. These efforts can increase the cost effectiveness of programs by allowing utilities to modify aspects of their program designs (i.e., lower rebate levels and more effective recruitment strategies).

Commission (PUC) has proposed establishing similar limitations based on total program (i.e., including customer) costs (CPUC 1992).

Program Eligibility

The program eligibility criteria for DSM incentives vary considerably between the California utilities and NEES. Within the New England states where NEES's subsidiaries operate, it has been felt that only exemplary utility DSM programs should be eligible for incentives. Largely for this reason, GSE's DSM programs were the only utility programs in New Hampshire initially allowed to earn incentives. This philosophy also explains why NE is only allowed to earn incentives on savings in excess of a threshold. In California, all major utilities are eligible to earn incentives. Utilities are allowed to earn incentives on all eligible DSM programs, but, as described previously, the programs must first exceed minimum participation goals.

A second and more important area of difference is in the types of DSM programs eligible for incentives. All of NE's and GSE's demand-side activities are treated in aggregate when incentives are determined; i.e., the shared-savings incentive is based on the total impact of all demand-side activities. There are, however, two important subtleties. First, each activity taken separately must pass the total resource cost test. Second, many activities not directly related to the delivery of energy savings, such as measurement and evaluation, are included in calculating total program costs.

California, on the other hand, has adopted a much more disaggregated approach. Demand-side activities are first identified by demand-side categories and only those activities falling into certain categories are eligible to earn incentives. The categories distinguish between programs that are primarily oriented toward displacing supply resources and those that are primarily oriented toward other goals, such as equity or customer service. In addition, measurement and evaluation activities are explicitly separated from individual programs and are not eligible for incentives. This is also the case for NEES. Table 5 summarizes California's categorization of demand-side activities with examples of eligible programs and the type of available incentive.

California's approach recognizes that utilities have multiple reasons for intervening on the demand-side. Shared-savings, as an incentive for these activities, only make sense for activities with the primary objective of displacing supply resources. Other equally important demand-side activities should not be subject to the same incentive structure because the motivation for them is often legitimately quite different. These programs include those developed for equity considerations, such as certain residential programs. Similarly, demand-side activities with impacts that are difficult to measure, such as information or rate design programs, are probably also inappropriate for shared-savings incentives.

Table 5
Matching DSM Programs with Shareholder Incentives: Pacific Gas & Electric

Program Category	*Examples*	*Incentive Treatment*
Resource	Residential, Commercial, Industrial and Agricultural Rebates; Residential and Commercial New Construction	Shared Savings
Equity/Service	Direct Assistance; Residential, Commercial, Industrial and Agricultural Audits; Super-Efficient Homes Pilot Program	Performance-Based Earnings Adder
Other	Innovative Rate Design, Measurement and Evaluation; and General Administration	No Incentives

Source: PG&E 1991

For demand-side programs that are primarily equity or service oriented, performance-based earnings adders were adopted. These adders are essentially cost-plus or bonus-type incentives that are triggered by achieving some measurable level of performance, such as number of audits provided.[13]

Treatment of Lost Revenues

A potentially complicating issue when comparing the net benefit of shared-savings incentives among utilities is the relationship between the earnings from shared-savings and the sales revenue losses that are associated with utility demand-side interventions. Some say these losses should be netted out from any calculation of the benefits of a shared-savings incentive. In fact, the issue is probably more philosophical than practical.[14]

[13] For NE and GSE, incentives for less cost-effective programs provided implicitly through the use of the "maximizing incentive" previously described. This feature allows the utility to earn incentives despite the low net resource value of certain demand-side activities.

[14] The existence of "lost revenues" is really just a manifestation of the failure by traditional regulation to account for fluctuating sales volumes, whatever their cause.

California is well-known for the Electricity Revenue Adjustment Mechanism or ERAM, which establishes a balancing account to ensure that an approved revenue requirement is earned independent of sales volumes (Marnay and Comnes 1990). It is less well-known that New England Power, NEES's wholesale electric subsidiary which collects 70% of NEES's revenues, has in effect a revenue adjustment mechanism on file with FERC. FERC annually approves New England Power's wholesale rates using a future test year. The result is that because the rates are determined annually and because demand-side activities are accounted for explicitly in the future test year forecasts, there is little room for unanticipated, "lost" revenues. Discrepancies, to the extent that they persist for any reason, including weather, business cycle, and DSM, are effectively "trued-up" in the following year's filing.

Thus, for all four utilities, demand-side activities that reduce sales beyond levels predicted in the rate-setting process are addressed by either explicit or implicit balancing accounts which ensures that authorized revenue requirements will be earned. Uniform decoupling of revenues from sales for the four utilities facilitates comparisons among their shared-savings incentives, but it makes it difficult to transfer results to utilities in states where different ratemaking practices make "lost revenues" a more serious issue.

EVALUATING SHARED-SAVINGS INCENTIVES

In reviewing the calculation of utility earnings from shared-savings programs, it is apparent that the bottom line can only be determined by considering the combined impact of all incentive components. The utility's share of earnings can be increased either by; (1) providing an increased share (percentage) of the net resource benefits; (2) by bonuses earned in addition to a percentage of the net savings; (3) by using an avoided cost that includes externalities, or; (4), by excluding the customer's contribution from program costs. Conversely, earnings can be decreased by providing the utility with a lower share of the net resource benefits, by program thresholds below which no incentives are earned, or by the inclusion of programs whose cost-effectiveness may be low or indeterminate.

In this section, we attempt to assess these earnings trade-offs. Our discussion begins by describing the non-traditional regulatory settings from which the incentives arose because they provide important background information on the role of negotiations. Next, 1990 program results are used to assess quantitatively the profitability and significance of these utilities' demand-side activities.

The Role of Collaboratives in the Design of Shared-Savings Incentives

The shared-savings incentives for PG&E, SDG&E and NEES arose from "collaborative" negotiations that proceeded outside traditional regulatory forums. These negotiations were responsible for both the acceptance of the idea that it would be appropriate to reward utilities for their energy efficiency activities and for the specific incentive designs reviewed in the previous section. In particular, the informal setting of the collaborative process allowed for explicit bargaining and trading-off among various incentive design features. It is, therefore, misleading to evaluate the program design features reviewed in the last section in isolation. The combined effect of these features not only determines the financial bottom line; it also attempts to balance the risks and rewards inherent in the programs.

For example, all the incentives include minimum performance thresholds below which no earnings (and, in California, penalties) apply. This feature is designed partly to ensure a serious utility response to the incentives being offered. Concerns were expressed that, without these thresholds, no guarantees would ensure that utilities would aggressively pursue energy efficiency opportunities. In other words, the availability of financial incentives was predicated on a commitment by the utility to obtain significant savings.

In California, thresholds were also specified on a program-by-program basis to ensure that all customer groups would be able to participate in utility-sponsored energy efficiency activities. This feature, intended to limit utility cream-skimming in more lucrative energy efficiency markets, is a contrast to the bottom-line orientation of the NE and GSE shared-savings incentives whose thresholds are based on total program savings. In effect, the commissions and utilities must balance equity concerns against the need for flexibility with a relatively untested incentive. It is difficult to argue that one approach is superior to the other; in both cases, utility and commission staffing and priorities were different. Indeed, to the extent that in the future the balance is determined along with a host of other utility DSM policy issues, with or without a collaborative process, there may never be a conclusive answer.

Another example of the risk balancing reached through consensus in the collaborative is the decision to base first-year program savings per participant including, in California, energy and peak demand savings, free-rider fractions, and persistence, on estimates that are now assumed to remain unchanged for the lifetime of the measures installed in the first-year programs. In effect, this decision transfers all the risks of demand-side measure performance to the ratepayer. In return for immunity from the performance risk of their demand-side activities, however, the utilities agreed to initiate large-scale evaluations of their programs to measure these risks precisely.

The design of the shared-savings incentives was the result of collaborative negotiations among stakeholders. While one can argue that the same results could have emerged from traditional regulatory forums, it is doubtful they could have emerged as quickly as they did in New England

and California. In both cases, shared-savings incentives were established within one year after the initiation of discussions.

Initial Results from Utility Shared-Savings Incentive Mechanisms

Table 6 presents 1990 program results for PG&E, SDG&E, and NEES. For the shared-savings portions of the utilities' demand-side activities, details are presented relevant to calculating the incentive, including the expected avoided utility supply costs (life-cycle energy and capacity savings times avoided costs), and the utility and customer costs, which when subtracted from the avoided costs, yield the net resource value of the programs. The shared-savings and other incentives, where applicable, are reported. In addition to information specific to the utilities' shared-savings programs, summary information on aggregate demand-side activities and earnings is reported for PG&E, SDG&E, and NEES.

To evaluate the relative impact of shared-savings (and other DSM) incentives on utility operations, we use two crude ratios: (1) the percent of total utility operating revenue accounted for by demand-side programs in order to measure the role of demand-side activities in overall utility operations; and (2), the earnings resulting from incentives as a percent of utility demand-side program expenditures in order to gauge the profitability of demand-side activities. We also present an indicator that measures the cost premium associated with shared-savings incentives by expressing the utility shared-savings earnings as a percent of the utility and customer costs for the program. This ratio measures the added cost to society and ratepayers represented by the incentives to the utility. In other words, this ratio accounts for the way incentives, in effect, raise the cost of delivering energy efficiency.

We also present aggregate earnings information for the utilities' entire DSM program. These numbers, presented under the heading, "Total Incentive" in Table 6, include the utility shared-savings programs. The reasons for presenting aggregate results differ slightly for each utility.

Both PG&E and SDG&E sponsor demand-side activities that do not receive shared-savings incentives. Some of these activities, however, are eligible for other incentives. More important, the receipt of shared-savings incentives for some demand-side activities is probably, in some sense, conditional on the utility's offering of these other, non-shared-savings activities. In other words, for PG&E and SDG&E, the shared-savings incentives must be viewed as one component of a utility's overall DSM activities.

Table 6
Comparison of Utility Shared-Savings and Overall DSM Program Performance
(1990 M$)

	PG&E		*SDG&E*		*NE*	*GSE*	*NEES*
	SS[1]	*Total*[2]	*SS*[1]	*Total*[2]	*SS*[1]	*SS*[1]	*Total*[2]
Avoided Utility Supply Costs	115.4		21.7		42.3	4.4	
Utility DSM Program Expenditures	20.6	141.0	4.0	16.7	14.7	1.7	71.2
Estimated Customer Contribution	17.9		4.5		1.8	0.2	
Net Resource Value Total Resource Cost Test Utility Cost Test	94.8		13.1		25.8	2.5	
Shared Savings Incentive	14.2		1.8		1.6	0.2	
Other Incentives		1.6	0.2	8.0	1.3	0.2	5.0
Total Incentive	14.2	15.8	2.0	10.0	2.9	0.4	8.3
DSM Expenditures as a Percent of Utility Revenues	0.2	1.5	0.2	0.8	0.6	0.1	3.8
Total Incentive as a Percent of DSM Program Expenditures	69	11[3]	50	60	20	24	12
Total Incentive as a Percent of Utility Program Cost and Customer Contribution	37		24		18	21	

Notes:

1 SS = Shared Savings

2 Total = Total DSM Program, including components eligible for shared savings incentives

3 PG&E's return of 11% on all 1990 DSM activities may be misleading because PG&E's incentive earning programs only began in the second half of 1990. A more proper measure, if data had been available, would be to express the earnings (15.8 million) as a fraction of PG&E's spending on DSM in second half of 1990, which was less than the $141.4 million spent over the entire year. In this case, the percentage earnings would be significantly larger.

Sources: PG&E 1991; SDG&E 1991; Hutchinson 1991

Aggregate results for NEES are also appropriate because NEES has centralized program operations. Centralized planning, operation, and evaluation costs cannot be easily allocated to activities in individual service territories. For example, NEES's major program evaluation activities will take place in the Massachusetts Electric service territory. The costs will be borne by NEES and will consequently not show up on Massachusetts Electric's budget or on NE's or GSE's, yet these evaluation results will be used to determine savings and incentive earnings from future programs for all three operating companies.

The shared-savings components of California utility DSM programs are modest, accounting for no more than a quarter of total utility DSM activities.[15] However, for both PG&E and SDG&E, shared-savings programs were only in operation during the last half of 1990. They are approximately 50% of what they might have been if they had been operating for the entire year. Total DSM activities for the entire year, which include the shared-savings programs, account for measurable percentages of PG&E, SDG&E, and NEES operating revenue (1.5, 0.8, and 3.8%, respectively). NEES's DSM expenditures represent the largest percentage of operating revenue among the three utilities.

Shared-savings appear to be profitable for the utilities. The shared-savings components of the utilities' demand-side activities produce earnings of up to nearly 70% (PG&E) on expenditures for utility DSM programs that are eligible for shared-savings incentives.[16] In general, both PG&E and SDG&E shared-savings incentives are more profitable (69 and 50%, respectively) than those of NE or GSE (18 and 21%, respectively) from the standpoint of return on shared-savings DSM program expenditures. Part of the reason is that NE only earns incentives on program savings in excess of a 50% threshold. More important, PG&E and SDG&E are engaged in many DSM activities that are not eligible for shared-savings incentives, while all of NEES's DSM activities (except measurement and evaluation) are considered in calculating incentive payments. Conversely, NEES's DSM incentives also include a maximizing incentive, which is not based on the shared-savings concept. These additional incentive features complicate direct comparison of the shared-savings components of the utility's DSM activities and highlight the appropriateness of examining all incentives jointly in the context of the utility's total DSM activities.

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[15] As previously noted, all NEES's DSM programs are rewarded with incentives, so this distinction cannot be made for NE, GSE, or NEES.

[16] It is tempting, but not possible, to compare these returns to authorized utility returns on un-depreciated rate base, which are typically 11-13%. First, return on rate base is earned annually for the accounting life of the depreciating rate base; shared-savings incentives are earned on an accelerated basis either entirely in the first year (NEES) or over the first three years (PG&E and SDG&E) after the program has been established. Second, not all DSM program expenditures would be eligible for inclusion in rate base; only capital expenses are typically included in rate base. Third, and most important for PG&E and SDG&E, as mentioned previously, shared-savings program expenditures and incentives must be considered jointly with all of these utilities' DSM earnings.

When shared-savings and other DSM incentive earnings are compared to all DSM activities, the overall returns for PG&E and NEES are more modest, 11 and 14%, respectively.[17] On the other hand, SDG&E's overall DSM program earnings are quite remarkable. SDG&E's non-shared-savings incentives are so profitable that the overall return on expenditures for their program (60%) is higher than the return on the shared-savings DSM activities. In fact, the returns were even higher initially, due to the absence of earnings caps on the non-shared-savings portion of SDG&E's programs.[18] As a result of this apparent oversight, SDG&E, in its filing to the California Public Utilities Commission (CPUC) for its incentive, claimed $6.2 million less than it would have otherwise been entitled to under the original terms of the non-shared-savings incentive. Even with the reduced claim for incentive earning, SDG&E's DSM programs are the most profitable of the three utilities.

Incentives represent an added cost to society for delivering energy efficiency. The shared-savings incentives paid to PG&E raise the total cost (customer costs plus utility program costs) of the shared-savings incentive-eligible demand-side measures to society by nearly 40%. For SDG&E, NE, and GSE, the cost premiums are more modest, ranging from 18 to 24%.[19] In part, these cost premiums reflect the high cost effectiveness of the DSM activities; all the programs continue to pass the total resource cost test with the inclusion of the incentives. More importantly, they reflect the limited experience of both commissions and utilities in determining what is the appropriate level of incentive for utility delivery of customer energy efficiency programs. It is clear, however, that the incentives paid to these utilities have added measurably to the cost of delivering energy efficiency.

SUMMARY

Shared-savings can provide positive incentives to utilities for DSM. In the examples we reviewed in California (PG&E and SDG&E), New Hampshire (GSE), and Rhode Island (NE), the incentives are almost always positive since they are accompanied by guarantees on program cost recovery, and by pre-existing explicit or implicit de-coupling mechanisms that automatically remove the disincentives associated with reduced sales. In California, however, sub-par program

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[17] PG&E's return of 11% on all 1990 DSM activities may be misleading because PG&E's incentive earning programs only began in the second half of 1990. A better measure, if data had been available, would be to express the earnings ($15.8 million) as a fraction of PG&E's spending on DSM in the second half of 1990, which was less than the $141.4 million spent over the entire year. In this case, the percentage earnings would be significantly larger.

[18] These programs were approved prior to the California Collaborative.

[19] Recall that these cost premiums reflect only the added cost of measures eligible for shared-savings incentives. For both PG&E and SDG&E, significant portions of the utilities' DSM activities are not eligible for shared-savings incentives, although they may be eligible for other, non-shared-savings incentives.

performance, measured by program participation relative to a target value, can lead to earnings penalties.

Shared-savings are unique from other utility incentives for DSM in that they make the link between the net resource value of demand-side activities and utility earnings explicit. In this regard, shared-savings reward utility performance in acquiring cost-effective demand-side resources, rather than spending ratepayer dollars.

A potential disadvantage of basing utility incentives on net resource value is the need to measure this value, in particular, the load reductions resulting specifically from utility demand-side activities. For each of the utility shared-savings incentives examined, estimates of load reductions on a per measure basis are being used in conjunction with actual program participation levels. In effect, demand-side *measure* performance risks have been transferred to the ratepayer, while demand-side *program* participation risk remains with the utility. At the same time, significant utility resources are being devoted to measuring and evaluating programs to provide better estimates for future demand-side measure performance. A consequence of agreements to use measure performance estimates, as well as estimates of future avoided costs, is that net resource benefits are largely agreed on in advance and can be quickly recovered by the utilities.

As a result of these agreements, the shared-savings incentives for PG&E, SDG&E, GSE, and NE are very clear and understandable: if the utility can achieve pre-specified performance thresholds, then well-defined incentives will be earned. With the exception of knowing whether it will meet its program performance targets (specified as energy savings or program participation levels), the utility can predict exactly how much it will earn. Accelerated recovery of the incentives also simplifies administration by commissions and the utilities because incentive recovery is completed within a few year's time.

On the other hand, California's shared-savings incentives feature detailed program design elements that tend to complicate their administration. To address cream-skimming and to ensure utility participation in a variety of demand-side markets, California shared-savings incentives include program-by-program performance (i.e., participation) thresholds, below which penalties apply.

The shared-savings incentive for PG&E is based solely on utility costs, not utility and customer costs. While this tends to increase the net resource benefit for which PG&E is eligible to earn a percentage, it also provides a strong signal for the utility to minimize its own costs (reducing rate impacts) although not necessarily the customer's cost in acquiring demand-side resources. For example, partly as a result of this decision, PG&E rebates typically pay only a fraction of the incremental costs of an energy efficiency measure. In contrast, the NEES subsidiaries, whose shared-savings are based on total costs, typically pay almost 100% of the incremental cost of energy efficiency measures.

The DSM incentives available to GSE, NE, PG&E, and SDG&E also address broader policy considerations for demand-side resources. GSE's and NE's incentives include a "maximizing" incentive that provides additional incentives for demand-side measures with smaller net resource benefits, such as certain residential programs. PG&E's and SDG&E's incentives address these concerns through program-specific performance thresholds and penalties. They also distinguish between classes of demand-side activities and provide separate, non-shared-savings incentives for some of them.

Finally, the results from the utilities' 1990 DSM activities confirm the profitability of the incentives. As a percent of total DSM program expenditures, the incentives are providing measurable returns (PG&E - 11%; SDG&E - 60%; NEES - 12%). At the same time, incentives to utilities for their DSM activities also measurably increase society's cost of acquiring DSM.

ACKNOWLEDGEMENTS

The work described in this paper was funded by the Assistant Secretary for Conservation and Renewable Energy, Office of Utility Technologies, Office of Energy Management Division of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098. The authors would like to thank Mark Hutchinson, New England Electric System; Scott Logan and Ali Miremadi, Division of Ratepayer Advocates, California Public Utilities Commission; Steve Wiel, Nevada Public Service Commission; Chuck Goldman and Ed Kahn, Lawrence Berkeley Laboratory; and, finally, the editors of *Regulatory Incentive for Demand-Side Management*, Steve Nadel, Michael Reid and David Wolcott for their assistance and helpful comments.

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