FINANCIAL INCENTIVES FOR DSM PROGRAMS: A REVIEW AND ANALYSIS OF THREE MECHANISMS

Michael W. Reid and John H. Chamberlin
Barakat & Chamberlin, Inc.

Throughout the United States, the attention of electric utilities, regulators, and industry analysts has been drawn to the financial implications of electric utility demand-side management (DSM) programs. A consensus has emerged that traditional regulatory mechanisms do not reward electric utilities for pursuing "least-cost" options; moreover, implementation of DSM programs may be counter to utilities' financial interest. It is now widely believed that DSM will be unable to fulfill its potential in the absence of mechanisms to correct this imbalance.

Recently several utilities have developed proposals to create financial incentives for DSM. These proposals, some of which have been implemented after review and modification by regulatory authorities, are aimed at both offsetting the financial penalties of DSM programs and providing a "positive incentive" or reward for successful DSM implementation. While their intents are similar, specific approaches differ considerably.

This paper reviews recent efforts to provide incentives for utilities to undertake DSM. We first present our views of the need for, and appropriateness of, financial incentives. We then analyze specific incentive schemes that have been proposed (and, in two cases, adopted) for three different utilities in the Northeast. The mechanisms are analyzed for their ability to meet three objectives:

- Provide for full and timely recovery of all DSM program costs.
- Adjust for DSM-induced revenue losses.
- Counterbalance risk and loss of financial opportunity by providing a bonus, or "pure incentive," above cost.

INTRODUCTION

Throughout the United States, utilities, regulatory commissions, and intervenors are discussing the use of financial incentives to encourage balanced consideration of resource options and alignment of the profit motive with the goals of least-cost utility planning. To date, discussions on incentives have focused largely on mechanisms that would foster greater development of DSM resources. While a guiding principle of least-cost planning is that *all* resources should be given balanced consideration, the incentives debate has been concentrated on DSM because of:

- The depth of *unexploited DSM resources* that are cost-effective compared to supply-side utility resources.
- The significant *disincentives*--financial and otherwise--that surround utilities' efforts to invest in DSM.

This paper reviews recent efforts to provide incentives for utilities to undertake DSM. We first present our views of the need for, and appropriateness of, incentives. We then analyze specific incentive schemes that have been proposed (and, in two cases, adopted) for three different utilities in the Northeast.

WHY ARE DSM INCENTIVES SOUGHT?

An oft-repeated reaction to the concept of DSM incentives is, "Why give utilities an incentive to do something they should be doing anyway?" Implicit in this question is the assumption that DSM incentives represent a reward, or bonus, above and beyond the costs of doing DSM. While there is a reward component to most incentive proposals, we believe the major need for incentives is to overcome the *disincentives* inherent in traditional regulation that affect utilities' interest in, and motivation for, DSM programs. To a large degree, the disincentives are financial; that is, pursuit of DSM operates at cross purposes with utilities' financial interest, and thus imposes costs that must be compensated for. Disincentives also arise due to perceptions that DSM will increase utilities' exposure to risk. The principal disincentives are discussed below.

Failure to Recover All Program Costs

In many instances utilities' expenditures on DSM have not been recaptured in rates. This is most prevalent in states that base their ratemaking on historic test years. While growth in DSM outlays is sought by both regulators and intervenors, cost recovery in historic test year states is limited to the amount expended in a prior year. Even in states that use future test years, the problem can occur if program expenditures are greater than anticipated (for example, if participation exceeds forecasted levels).

The timing of cost recovery can create a more subtle disincentive for DSM. In many instances recovery of DSM expenditures is deferred significantly until after their incurrence, but no adjustment is made for the loss of interest (carrying charges) in the intervening period. While often not seen as a "real cost," the loss of carrying charges must be considered a cost from the standpoint of financial motivation.

Loss of Revenues

In the absence of special adjustment procedures, such as California's ERAM (Electric Revenue Adjustment Mechanism), DSM programs that reduce kilowatt-hour sales work at cross purposes with utilities' financial interests. This phenomenon is often referred to as the "lost revenues" problem. The practical effect, in many instances, is that the utility under-recovers its allowed fixed costs--costs that were authorized for collection by the regulatory commission in the prior rate case.

This problem may be mitigated somewhat by use of a forward-looking test year (which adjusts test year sales for anticipated DSM impacts) and by more frequent rate cases (which bring actual and test year sales into closer alignment). Even with such policies, however, utilities' motivation may be in the direction of less DSM (and greater sales), because every kWh not sold due to DSM reduces the contribution to fixed costs and earnings. Even if unanticipated sales growth puts the utility above its test year sales amount, every conserved kWh cuts into earnings.

Loss of Financial Opportunity

The third financial disincentive to DSM is the potential loss of opportunity for the utility to grow. Financial theory dictates that growth in a utility's size *per se* is not of intrinsic value: what matters is the rate of return on capital. But this theoretical view is not necessarily shared by utility executives and shareholders: growth in sales, rate base, earnings, and other statistics are often viewed as indicators of financial strength.

DSM works counter to a utility's growth interest in two ways. First, unless DSM expenditures are included in rate base (as is allowed in some states), choosing DSM resources over supply-side options substitutes an expense item for a capital item. In a worst-case scenario, the possible result is what might be called "the incredible shrinking utility": the utility's rate base declines due to amortization of old supply-side investments, which are not replaced (in rate base) by demand-side investments. Second, sales that are lost as the result of DSM are *permanently* lost (assuming persistence of DSM benefits). The result is that future fixed costs will be spread over a smaller sales volume, possibly leading to higher rates and possibly adverse impacts on the utility's competitive position.

Proponents of ERAM-type adjustment mechanisms claim they eliminate the incentive for utilities to increase sales. We believe this to be true only in the short-run--i.e., between rate cases. ERAM recaptures for ratepayers any over-recovery of fixed costs resulting from sales above the test-year amount. Nonetheless, a utility that increases sales will enter its next rate case with a greater sales base over which to spread fixed costs (assuming the increases are not transient). This may be desirable for competitive reasons, since it may allow lower average rates; it is doubly desirable if shareholders and managers value growth in areas other than profits (sales, rate base, number of employees, etc.) for its own sake. Therefore, even under ERAM utilities may view long-run sales growth as in their financial interest, and DSM as at odds with that interest.

Risks of DSM

In addition to the direct financial impacts described above, there are a variety of considerations that affect utilities' perceptions of the risk of DSM and therefore set up additional disincentives that must be overcome. Conservation advocates have often asserted that conservation programs are *less risky* than supply-side options for a variety of reasons: modularity (the ability to obtain DSM in small units), short lead time, lack of environmental risks, and so forth. The fact remains, however, that utilities seldom *perceive* DSM as a low-risk proposition. Several risks enter into utilities' views toward DSM:

Regulatory risk. A retrospective review of today's DSM programs may conclude they were done imprudently or were not "used and useful" and should therefore not be accorded full cost recovery. (Alternatively, regulators could extract a penalty in some other way, such as a reduction in the allowed return on equity.) This risk is heightened by the knowledge that turnover among regulators is high, and that decisions by today's regulators concerning DSM programs will not be binding on their successors.

Impact risk. Underlying the incorporation of DSM into a utility's integrated resource plan are assumptions concerning the expected energy and demand impacts, generally developed on a per-participant basis. The quality of the data used to generate impact assumptions varies greatly depending on the technologies employed and the quality of end-use data available. Further complicating impact estimation is the need to account for coincidence with system peak demand and the extent of free-ridership (the prevalence of customers whose DSM-related actions cannot be attributed to the program). The quality of information available for estimating impacts is steadily increasing, thanks to growth in DSM evaluation activities. Nonetheless, there is still some risk that actual impacts will be less than expected, which implies two further risks: (1) possible need to spend additional dollars on supply- or demand-side measures to make up the shortfall; (2) greater likelihood of adverse actions by regulators, as described above ("regulatory risk").

Market acceptance risk. Even where the technologies used in DSM programs and the expected impacts per customer are well-understood, there often remains substantial uncertainty about DSM program acceptance. Customer response to even the most prevalent types of programs (such as high-efficiency appliance rebates) cannot be predicted by today's models with adequate confidence. As with impact risk, possible outcomes of low market acceptance include the need for additional outlays to make up the difference, and greater exposure to regulatory risk.

Competitive risk. Increasingly, states are adopting the Total Resource Cost (TRC) test as the principal benefit-cost criterion for DSM program selection. A consequence of this decision rule is that utilities are being directed to implement programs that pass TRC but fail the Rate Impact Measure (RIM) test (also known as the non-participants or no-losers test). Such programs increase average rates. Therefore, even if all the direct financial risks identified above are "cured" through incentive adjustments, utilities may still be concerned that DSM-related rate increases will be harmful in competitive markets, possibly driving away incremental customers or sales, with consequent loss of contributions to margin. This problem may be exacerbated by "pure incentives" or bonuses, which exert additional upward pressure on rates.

Balance sheet risk. Unless DSM expenditures are given immediate recovery, they result in the creation of "regulatory assets" or "IOUs" that are probably less secure (from shareholders' and bondholders' perspectives) than traditional supply-side assets. Further, such assets are not bondable property, i.e., they cannot be pledged as collateral to support a debt issue. If DSM programs become sufficiently large, there is risk of an increase in the cost of capital.

ELEMENTS OF A DESIRABLE INCENTIVES APPROACH

It follows from the preceding discussion that incentive mechanisms should address each of the major areas of disincentive. Specifically, they should:

- Provide for full and timely recovery of all program costs.
- Adjust for DSM-induced revenue losses.
- Counterbalance risk and loss of financial opportunity by providing a bonus, or "pure incentive," *above* cost.

It is unlikely that any single regulatory change can serve all of these objectives. Thus, the challenge becomes one of crafting packages of mechanisms that are comprehensive in scope.

Given the complexities of test year definitions, fuel and purchased power adjustment clauses, statutory restrictions on the components of rate base, and so forth, it is unlikely that any one mechanism or package of mechanisms will be applicable without modifications across different states. Superior incentive proposals will be developed with state-specific regulatory practices in mind. It is also important, we believe, to tailor the approach at the utility-specific level. Different utilities may respond in different ways to the same incentive due to differences in structure, rate level, extent of competition, balance sheet characteristics, and management's perceptions.

INCENTIVE PROPOSALS: THREE VARIANTS

Orange and Rockland Utilities (O&R)

An incentive mechanism was established for O&R by the New York Public Service Commission (NY PSC) in an opinion and order issued in September 1989 (New York Public Service Commission 1989). The selected mechanism was based, in part, on an O&R proposal filed in early 1989 (Orange and Rockland 1989a). The description presented here is based on the PSC's order and O&R's compliance filing that followed the order (Orange and Rockland 1989b).

Cost Recovery. O&R will submit annually to the PSC a one-year projection of month-by-month program costs for its DSM programs. It will recover these costs through its fuel adjustment clause. All DSM costs not already accounted for in O&R's base rates, whether capital- or expense-type items, would be recovered in this manner. Monthly variances (positive or negative) in actual versus projected amounts will be tracked and will accrue interest. The cumulative variances will be added to or subtracted from the projected DSM costs for the next year.

Lost Revenues. With its projections of program costs, O&R will include an estimate of its fixed costs that will not be recovered due to DSM. The lost revenue per kWh is estimated by service class as the average rate net of fuel costs, minus an adjustment for variable operations and maintenance expenses. The projected amount will be recovered through the fuel clause. Following the 12-month period of program operation, O&R will estimate actual lost revenues based on program evaluation, and will reconcile under- or over-collections of lost revenues through the fuel clause over the next 12-month period.

Bonus. O&R originally proposed that it be given a bonus based on the level of supply-side investment that would be needed to provide the capacity needs met through DSM. O&R would estimate the cost of constructing a power plant with capacity equal to that provided by the DSM programs (using PSC-approved estimates of avoided cost). It would then estimate the return that it would have earned on such a plant, assuming it were depreciated over a ten-year period (comparable to the life assumed for DSM measures). O&R further requested that the allowed return on this "pseudo-investment" be set at 200 basis points higher than the company's ordinary return on equity. The bonus would be limited to a 1% increase in the company's overall ROE, plus 50% of any excess over that amount.

The actual bonus adopted by the PSC differs significantly from O&R's proposal. The major weakness of O&R's proposal, from the PSC's standpoint, was that the costs of the DSM programs would not figure in the incentive; thus, O&R would not have a direct incentive to control costs. For this reason, the PSC substituted a "shared savings" approach, under which O&R will be granted 20% of the "net resource savings" attributable in each year to DSM. Net resource savings for any one year are calculated as (1) the value of the energy and capacity savings attributable to DSM; plus (2) an adjustment of 1.4 cents per kWh for avoided environmental impacts; minus (3) the company's DSM program costs. For purposes of this calculation only, DSM program costs will be amortized over a ten-year period, i.e., one-tenth of the original expenditure will be subtracted from the energy, capacity, and environmental savings each year. Not included in the calculation of net savings are DSM costs borne directly by customers who participate in the programs.

The bonus will only be collected *after* actual results are available from the company's evaluation activities. Collection will occur over a one-year period through the fuel adjustment clause. The incentive will be capped at an amount equal to an additional 0.75% return on equity.

In its compliance filing, O&R projected that its 1990 DSM expenditures would total $4.3 million and yield first-year avoided-cost benefits of $658,000. Allocating one-tenth of the program costs to the first year, the net benefits would be approximately $225,000, of which O&R would capture 20%, or $45,000. Additional bonus amounts attributable to the first-year program would be collected in each of the nine succeeding years. Presumably, there would be a "cascading" effect in later years, as additional bonuses (from additional expenditures made in 1991, 1992, etc.) take effect.

Massachusetts Electric Company (Mass. Electric)

Mass. Electric, a retail subsidiary of the New England Electric System (NEES), filed an incentive proposal for its 1990 DSM programs in September 1989 (Sergel 1989). In March 1990 the Massachusetts Department of Public Utilities (DPU) adopted an incentive plan for Mass. Electric that differs significantly from the company's proposal in the way the bonus component is computed (Massachusetts Department of Public Utilities 1990). The proposal and the plan as adopted are described below.

Cost Recovery. Mass. Electric proposed to recover DSM program costs as they occur. A separate fund would be created on the company's books to track DSM costs. Revenues for the fund would be collected through an allowance in base rates. Actual DSM expenditures would be charged against the fund monthly. Any difference between the amounts collected and expended would be reconciled, with interest, at the end of the year. If actual costs differed significantly from the projected amounts, the utility could petition for interim adjustments.

The DPU's decision did not alter Mass. Electric's cost recovery scheme. The DPU noted, however, its goal of eventually requiring that cost recovery be linked to actual performance. This would be consistent with the DPU's "preapproved contract" approach for supply-side resources, which envisions that cost recovery of supply-side resources will be governed by a predetermined price per unit of capacity and/or energy output. To this end, the DPU directed Mass. Electric to include a performance-based cost-recovery mechanism when it files for approval of its 1992 DSM programs.

Lost Revenues. Mass. Electric did not request an explicit adjustment for lost revenues due to DSM. Because Mass. Electric purchases all of its power at a wholesale rate from an affiliated company, fixed costs comprise a smaller portion of its cost of service than is typical for stand-alone utilities, so lost revenue is not seen as a major problem. Mass. Electric did suggest, however, that its "maximizing incentive" (described below) would provide "a concrete reimbursement of lost revenues to the extent they exist" (Sergel 1989). The DPU's decision did not address the lost revenues issue.

Bonus. Mass. Electric proposed a two-part bonus scheme tied to estimated avoided costs. It is most readily understood by referring to the 1990 values cited in the company's filing. What Mass. Electric called the "maximizing incentive" would be set at 5% of the present value of the DSM programs (as measured by avoided costs), net of participants' costs. For its 1990 DSM programs Mass. Electric estimated a present value benefit of $97.6 million (net of customer costs), yielding the "maximizing" bonus of $4.9 million. The second part of the bonus, the "efficiency incentive," would be calculated on a shared savings basis. The projected 1990 program costs of $37.0 million would be subtracted from $92.7 million (the program value less the maximizing incentive), and the utility would be allowed to capture 10% of the result, or $5.6 million. Mass. Electric calculated that the combined bonus amount of $10.5 million (efficiency incentive plus maximizing incentive) would yield an increase of about 2% in return on equity if the DSM programs met 100% of goals.[1]

Mass. Electric proposed to collect the maximizing incentive during the program year as measures are installed, based upon predetermined estimates of per-measure impacts, lifetimes, and free-ridership that were included in its proposal. For example, Mass. Electric estimated that each compact fluorescent lamp installed in the small commercial/industrial customer segment would provide 0.045 kW demand reduction and 143 annual kWh energy reduction; 5% of the participants would be free-riders; and that the benefits would last for three years. Based on these values and its avoided costs, Mass. Electric would calculate the present value of each unit installed. As customers enter the program and compact fluorescent lamps are installed, Mass. Electric would be able to claim credit for the value of the lamps and collect 5% of this amount from the fund as the maximizing incentive.

The efficiency incentive would be collected only after the close of the program year, at which point actual program costs would be known. Mass. Electric would collect the efficiency incentive in installments over the following year.

The DPU's decision made several major alterations to Mass. Electric's bonus mechanism. The bonus amounts will be based on actual program results, rather than on predetermined per-unit impacts. The proposed total bonus level was cut in half, so that if Mass. Electric achieves 100% of its program goals, the bonus would amount to $5.25 million, or a 1% increase in the utility's ROE. A threshold of 50% of program goals was established, so that Mass. Electric must meet half of its kW and kWh goals before any bonus is earned. Once the threshold is passed, Mass. Electric will earn the bonus on a specified per-kW and per-kWh basis: $8.32 per kW-year and $.00308 per kWh. If Mass. Electric surpasses 100% of goals, it will still earn the bonus on all kW and kWh above the goals. The bonus will be collected only after the utility has submitted its report on the first program year showing actual per-unit savings, as determined by program evaluation activities. The specific mechanism for the collection of the bonus was not specified by the DPU.

Philadelphia Electric Company (PECO)

In early 1990 PECO submitted a broad outline of an incentive mechanism to the Pennsylvania Public Utility Commission in response to a Commission staff paper and questionnaire on incentives (Philadelphia Electric Company 1990). Unlike the O&R and Mass. Electric plans described above, PECO's incentive approach has not been developed to the level of a formal filing.

Cost Recovery. PECO proposes a split cost recovery approach for DSM expenditures. Expense-type items would be recovered as incurred through the fuel

1 *Due to the structure of the holding company of which it is a part, the ROE for Mass. Electric alone may be a misleading figure. If the same incentive mechanism were adopted for all the retail companies under its parent, the system-wide increase in ROE would be 0.6%.*

adjustment clause. Actual expenditures would be reconciled with recovered amounts annually. Capital-type items would receive deferred accounting treatment, with an accrual of interest, until the next rate case, at which point they would be folded into rate base and recovered, with a return, over a specified amortization period.

Lost Revenues. PECO would seek preapproval of the expected reduction in fixed costs per program participant. It would collect these amounts through the fuel adjustment clause based upon a projected schedule of participants. At year-end, reconciliation would occur based on the actual number of participants. No retrospective changes would be made in the preapproved values of lost fixed costs per participant.

Bonus. PECO would receive a "shared savings" bonus based on the difference between the present value of the DSM programs (as measured by avoided costs) and the actual program costs. The percentage of savings to be retained by PECO was not specified. The present value of the avoided costs per participant would be preapproved by the commission. The bonus would be collected through the fuel adjustment clause during the program year. At year-end, reconciliation would occur based on the actual number of participants and actual program costs; the preapproved avoided costs would not be adjusted retrospectively.

HOW WELL DO THE PROPOSALS MEET THE OBJECTIVES?

In this section we consider how well each of the three incentive mechanisms meet the objectives outlined previously.

Full and Timely Recovery of All Program Costs

In general, each of the incentive mechanisms will address the partial cost recovery problem. Both O&R and Mass. Electric will recover program costs as they are incurred; unexpected cost increases will be recoverable in the next year through a reconciliation procedure.

PECO proposes to follow a similar treatment for some of its expenditures but to ratebase those that go toward capital items.[2] Its proposal to accrue a return on these capital items before they enter rate base would address another potential area of under-recovery. On the other hand, ratebasing could expose the company to additional risks, including possible denial of full cost recovery at some future date and "balance sheet risk" as described earlier. There might be offsetting advantages to ratebasing DSM, however, such as mitigation of short-term upward pressure on rates.

Adjustment for DSM-induced Revenue Losses

Both the O&R and PECO mechanisms would provide dollar-for-dollar compensation for DSM-induced shortfalls in fixed cost coverage. Because its purchase of all power at wholesale rates reduces the significance of lost revenues, Mass. Electric neither requested nor received an explicit adjustment, stating instead that the bonus would provide sufficient offset to cover lost revenues. To the extent that revenue loss due to DSM does occur, the Mass. Electric mechanism provide a less straightforward response to the problem.

Bonus to Counterbalance Risk and Loss of Financial Opportunity

All three mechanisms provide for a bonus, or true incentive, above program costs and lost revenues. While computed in different ways, each strives to offset some of the risk and loss of financial opportunity associated with major DSM programs.

How well each mechanism serves this purpose depends on the uncertainty surrounding the actual bonus that will eventually be earned. Uncertainty is a function of both the timing of the bonus and uncertainty about its magnitude. Of the three proposals, only O&R stretches the bonus out over an extended period (ten years). This consideration, we believe, increases the regulatory risk that the bonus will not be earned in full--and therefore diminishes its value.

2 *PECO has not indicated whether it will seek to capitalize incentive payments that support customers' purchases of long-lived equipment, or whether capitalization would be limited to direct equipment expenditures by PECO.*

In all cases the magnitude of the bonus is uncertain because it depends, in part, on the success of the programs in recruiting participants. The O&R and Mass. Electric bonuses additionally depend on post-installation measurements of actual program impact. In contrast, the PECO plan, as well as Mass. Electric's original proposal, would remove this element of uncertainty by relying on predetermined per-customer or per-measure impacts to compute the bonus.

All of the mechanisms give the utilities an incentive to "do a good job" with their DSM programs in terms of signing up customers. The issue becomes, How important is it to tie bonuses to actual measured results? Surely the notion of paying for *actual*, rather than predicted, performance, has strong intuitive appeal. Further, one might argue that under the PECO approach the company would have no incentive to ensure that the measures are installed well--or (to carry the argument to the extreme) that the company would benefit by intentionally doing a *poor* job.

We believe the importance of using measured results is overrated, particularly in situations where the DSM programs are being approved for a limited time frame and ongoing evaluation efforts are planned. Under the PECO plan, for example, the company would come before the commission *annually* to seek approval of next year's programs and their assumed per-customer impacts. The commission would look to the most recent evaluation results to help it gauge the credibility of the company's impact estimates. Any short-term "gaming" of the system by failing to implement measures well would likely be revealed by evaluation, and would carry a severe risk of loss of credibility with the commission.[3]

Reliance solely on measured results poses two disadvantages. One is that it delays receipt of the bonus until the results are in. The second, and more serious, disadvantage is that it makes the bonus less certain. Other things being equal, we would expect that this reduction in certainty increases the size of the bonus needed to overcome utilities' hesitancy to pursue DSM.

While reliance on preapproved impacts brings the risk that ratepayers will pay bonuses for savings that were not achieved, we believe the potential cost is small, given frequent opportunities to revisit the assumed impacts.

Basis for the Bonus. O&R's original proposal would have based the bonus on avoided costs (specifically, on the size of the investment displaced by DSM). The O&R mechanism as approved by the PSC substitutes a shared savings incentive, which relies on both the avoided costs and DSM program costs. The NY PSC rejected this formulation in favor of a shared savings approach, which relies on both the avoided costs and DSM program costs:

> Under the company's proposal, DSM program costs would simply be recovered, and would not affect the calculation of the incentive itself. The company could conceivably find it profitable to pursue demand reductions without regard to costs. Under [a shared savings] proposal, in contrast, the amount of the incentive payment would be directly tied to the cost-effectiveness of the DSM measures chosen. For this reason, a percentage of savings mechanism is superior (New York Public Service Commission 1989).

The PECO proposal also adopted the shared savings approach. Mass. Electric's original proposal used a combination of avoided costs alone (for the maximizing incentive) and shared savings (for the efficiency incentive). This approach was altered by the Massachusetts DPU, however, due to the DPU's reluctance to institutionalize avoided costs:

> The Department cannot at this time support using avoided energy and capacity costs to calculate value. ...[A]voided energy and capacity costs may not accurately represent value. Instead, such costs are a complex mixture of marginal and embedded costs, which at best represent only the next best alternative. As the Department has made clear its intent to eliminate the need to use

[3] *An approach similar to PECO's (preapproval of impacts, coupled with an evaluation plan) was recently endorsed by a coalition of utilities, regulators, and intervenors in California (California Collaborative Process 1990).*

administratively-determined avoided cost for the resource selection and resource pricing process...the Department is interested in minimizing the reliance on such calculations (Massachusetts Department of Public Utilities 1990).

The Massachusetts DPU substituted a bonus method based on kW and kWh achieved. It designed this method to produce the same *result* as Mass. Electric's proposal, namely, achievement of a target increase in ROE if the programs are fully successful. (The DPU, however, set the target at 1% additional ROE rather than the 2% sought by Mass. Electric.)

Notwithstanding Massachusetts' concerns about avoided costs, we believe the shared savings approach is sound and has intuitive appeal to both utilities and regulators. It represents a reward for value received, and it gives the utility a continuing incentive to control costs. Further, it is readily understood by persons outside the utility/regulatory community and is thus likely to pass the "front page test." For these reasons, we expect that other states will likely make shared savings the basis for the bonus component.

In the final analysis, however, the mechanism for computing the bonus is less important than its size and the level of uncertainty surrounding its receipt. While we see advantages to the shared savings mechanism, we suspect that utility managers will view any mechanism primarily in terms of its potential contribution to ROE.

Dollar Value of the Bonus. Perhaps the key question is one that cannot be answered definitively at this point: How large must the bonus be to serve its purpose? An executive with a major investment banking firm has suggested that an increase of .15-.25% in total ROE arising from an incentive would be meaningful to utility investors (personal communication with Caren Byrd, Morgan Stanley & Company, September 1988). If its programs are fully successful, Mass. Electric's incentive plan will yield its parent the equivalent of an additional 0.3% ROE.[4] Another way to view the Mass. Electric plan is that it will provide a bonus of $5.25 million on outlays of $37.0 million, or roughly 14% above actual expenditures.

Whether these amounts ultimately prove adequate, inadequate, or excessive will not be evident for some time. One possible gauge is the effect that one utility's bonus arrangement has on other utilities' DSM plans. For instance, if the precedent established for one utility leads other utilities to approach the commission with proposals for bonuses of similar magnitude, and those companies are showing significantly expanded commitments to DSM, we might infer that the bonus is sufficiently attractive.

CONCLUSIONS

Each of the three incentive mechanisms reviewed here basically meets the goal of overcoming the disincentives that surround utility DSM programs. The most significant differences across the mechanisms are found in the bonus component, which serves to offset the perceived risks of DSM and provide a "pure incentive" above actual costs. Mechanisms that reduce the utility's uncertainty about the receipt of the bonus by providing it in a lump sum will likely prove more powerful motivators than those that spread the bonus out over a period of years. Use of preapproved per-unit or per-customer impact measurements reduces uncertainty and thus increases the apparent value of the bonus. Annual review of program plans and assumed impacts, supported by continuing evaluation activities, minimizes the risk that utilities will "game" the incentive system or receive excessive rewards.

---

4 *This estimate assumes an equivalent incentive is put in place for all the NEES retail companies. For Mass. Electric alone, the ROE increase is 1%.*

REFERENCES

California Collaborative Process. 1990. An Energy Efficiency Blueprint for California. Appendix A: Measurement Protocols for DSM Programs Eligible for Shareholder Incentives (January 1990).

Massachusetts Department of Public Utilities. 1990. DPU 89-194/195 (March 30, 1990).

New York Public Service Commission. 1989. Case 89-E-041, Opinion No. 89-29 (September 12, 1989).

Orange and Rockland Utilities, Inc. 1989a. Memorandum in Support of Least Cost Annual Power Supply (LCAPS) Petition (February 14, 1989).

Orange and Rockland Utilities, Inc. 1989b. Compliance Filing Re: Case 89-E-041, Opinion No. 89-29 (September 27, 1989).

Philadelphia Electric Company. 1990. Response to the Pennsylvania Public Utility Commission Regarding Approaches to Encourage Utility Investment in Demand-Side Resource Options (February 16, 1990).

Sergel, Richard P. 1989. Testimony on Behalf of Massachusetts Electric Company in DPU 89-195 (September 1989).