PROFITS & PROGRESS

THROUGH LEAST-COST PLANNING

DAVID MOSKOVITZ
Energy and Regulatory Consultant
Hollywood Boulevard
Alna, Maine 04535
207-586-5838

Foreword by
John Rowe; President
New England Electric System

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National Association of
Regulatory Utility Commissioners
Room 1102 ICC Building; P.O. Box 684
Washington, D.C. 20044

Telephone No. (202) 898-2200

FOREWORD

By John Rowe
President & Chief Executive Officer
New England Electric System

In "Sir Gawain and the Loathly Lady," high king and chevalier must save no less than the peace of the kingdom and the pleasures of matrimony. While properly daunted by threats of at least greenhouse magnitude, they succeed, through painfully coming to understand that every woman wants her own way. In this white paper, NARUC transcends several sorts of chauvinism and applies similar wisdom to utility executives. That is none to soon, but wisdom is at least as remote on my side of the regulatory woods.

For most of our century, utility management has held to the faith that its product is fundamental to the social and economic well being of society, with positive externalities outweighing any possible negative ones. (This is provided, of course, that we can supply that product in our own way.) For several decades, a growing majority in NARUC has been building a new faith, now called least-cost planning, in which electric service is maintained (it is said) while growth in the consumption of electricity is radically curtailed through utility investment in customer energy efficiency. Meanwhile, the agnostic public (my customers - NARUC'S constituency) has voted for increased electricity supplies with its power switches and, increasingly, voted against such supplies with its ballots. No one is getting his or her own way.

Such discontent is hardly shocking. Public policies are not clear and the incentives to both consumers and producers are not consistent with the apparent trend of those policies (surprised anyone?). While environmental concerns jab at the consciences of commissioners, constrained electricity rates encourage the consumers to use more electricity. The utility is told to sell less of its chosen product and to provide a service it claims no unique ability to deliver. It must do this without being offered additional profit and often without being assured of cost recovery. Slowly, lashed by the misused slogan "duty to serve," utilities respond, but the overall results are credible to no one.

NARUC's 1988 policy statement - "a utility's least-cost plan for consumers should be its most profitable course of conduct" - provided fundamental recognition that the system of financial rewards must be made consistent with today's public policy objectives. This white paper provides a framework for achieving that consistency. Indeed, the words at the beginning of Section 2 should become a common creed for every commissioner and utility executive. Of course, I would quibble with details of this white paper, such as the suggestion that symmetrical treatment is an incentive instead of a minimum right, and the hint that suppressing utility profits is more important than the cost or quality of electric service. There is no time to quibble, however. The policies of the states my companies serve and the interests of those companies require that the theme of this report be implemented.

Successful proposals to implement the NARUC resolution should have the following hallmarks:

> <u>They should be experimental.</u> They should address most of the issues raised in this report, but should not purport to do so for all of the time.
>
> <u>They should be modest.</u> Success should provide retail companies with enough additional earnings to overcome the existing disincentives to the pursuit of energy efficiency.
>
> <u>They should be direct.</u> Utility managers must see immediate rewards.
>
> <u>They should be powerful.</u> Conservation, which for now appears the least-cost component of energy supply plans, must be the most profitable component.

I have had the privilege of leading two utilities with outstanding reputations for conservation efforts. But, neither has exhausted the conservation potential which commissioners and environmental groups believe exists. Incentive measures which are genuinely attractive to utilities provide the necessary means to develop the real potential, whatever it may be. Such incentive measures are equally necessary to obtain public credibility for least-cost planning.

ACKNOWLEDGEMENTS

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TABLE OF CONTENTS

SUMMARY

In the broadest sense, this paper discusses issues relating to the earnings implications which flow from the pursuit of least-cost plans. More narrowly, however, the issues, discussion, and conclusions apply with equal force whenever a utility implements cost-effective demand-side measures, whether as part of a least-cost plan or not. To a lesser extent, the paper addresses how these issues relate to many supply-side options, particularly cogeneration and renewable resources.

Least-cost planning (LCP) is a process of examining all electricity-saving and electricity-producing options to select a mixture of options that minimizes total consumer cost, often including consideration of environmental concerns and other responsibilities.

Standing between LCP the idea, and LCP the practical reality, is the fact that the utility industry is responds rationally to its economic environment, a response which is strongly skewed against LCP. The same can be said of utility investment in energy efficiency; it is a clear public policy and regulatory goal, but it is not being pursued in an aggressive fashion. The reason is clear. Traditional regulation creates a strong economic disincentive to the utilities' implementation of least-cost plans or investment in energy efficiency programs. Indeed, the ratemaking process generally used in most states has the following unintended, but nevertheless perverse, incentives.

* Each KWH a utility sells, no matter how much it costs to produce or how little it sells for, adds to earnings.

* Each KWH saved or replaced with an energy efficiency measure, no matter how little the efficiency measure costs, reduces utility profits.

* The only direct financial aspect of regulation that encourages utilities to pursue cost effective conservation opportunities is the risk that if they fail to satisfy regulators costs may be disallowed.

* No matter how cost effective, purchases of power from cogeneration, renewable resources, or other non-utility sources add nothing to utility profits.

The incentives and disincentives created by traditional regulation flow from the interaction of accounting conventions, legal and procedural matters such as regulatory lag and retroactive ratemaking, and more recent additions to regulation such as fuel adjustment clauses. Whatever the cause, the incentives embedded in the current system of regulation present a serious obstacle to the successful implementation of least-cost planning (LCP).

In a Resolution approved in July, 1989, NARUC concluded that regulatory reform was

needed to remove the disincentives to LCP and to make the successful implementation of a utility's least cost-plan its most profitable course of action. (See appendix C for the text of the Resolution.) It follows, therefore, that the single, overarching standard against which proposed incentive plans should be measured lies in the answer to this question:

> Viewed from the perspective of the utility, what course of action would be consistent with a profit-maximizing strategy?

Identifying a profit-maximizing strategy is the most important test of any incentive proposal, but other considerations are also quite important and should be given serious attention while developing or selecting the best plan for each state. These considerations, in general order of importance, are as follows:

Decoupling profits from sales;
Cost minimization;
Administrative simplicity;
Fuel switching;
Balance;
Predictability;
Environmental costs;
Non-participant impacts;
Skimming the cream;
Avoiding gaming; and
Distribution of incentives.

Incentive proposals have been grouped into three general categories based on the approach taken. The categories are:

Rate-of-Return Adjustments,
Shared Savings, and
Bounty.

For each of the approaches, sets of performance criteria are available to address one or more special concerns. All possible modifications to each approach have not been described. For the most part, regulators may mix and match different components of incentive plans until a desirable group of features is found.

To produce a reasonable profit-maximizing strategy, it will be necessary to decouple profits from sales. Under current regulation, increased sales always mean increased profits. As long as every incremental KWH sold adds to profits, the strong likelihood remains that a profit-maximizing strategy will lead to more sales and less DSM, even if DSM programs are profitable.

Because the ability of an incentive plan to decouple profits from sales is critical to a plan's success, a fourth and separate category of decoupling options is discussed. These decoupling options can be combined with any of the incentive plans to produce an overall package of regulatory reforms.

Conclusion

The following table presents a summary of the conclusions reached in this section. Listed across the top of the table are different assumptions of how state regulation might be structured. For example, the first column, "W/O Decoupling, W/O DSM Cost Recovery," describes a state which has not adopted revenue reconciliation mechanisms such as California's Electric Revenue Adjustment Mechanism (ERAM), or any of the other decoupling options, and which has no separate mechanism for recovery of DSM program costs. This means that the incentive plan selected must be capable of decoupling profits from sales while giving reasonable treatment to DSM program costs. Next, proceeding down the rows summarizes the capabilities of alternative incentive plans to produce a desirable result given the assumed status of regulation. A "yes" (Y) response means the incentive approach is a good candidate and attention should turn to the various ways to implement the general approach. A "no" (N) response means the approach is not a good candidate and a "maybe" (M) response means the capability of the approach to perform well depends on other matters.

This White Paper provides commissioners and commission staff with the background and framework needed to move forward with needed regulatory reforms. The remainder of the effort will be pursued with individual utilities in each state.

Clearly, the complexities and variations in regulation and the many factors in addition to regulation that influence utility decision-making and behavior cannot be distilled into one simple conclusion such as "fix the incentives." It would be as naive as it is tempting to say that all that is necessary is to fix the incentives and least-cost planning and energy efficiency will abound. Indeed, the disincentives are so potent that it would be even more naive to believe that least-cost planning or any significant investment in energy efficiency would be a reality without regulatory reform.

A debate, however, about the need for regulatory reform is a debate about the wrong question. Rather, the financial incentives of the existing system should be understood and compared with regulatory and legislative goals. Then, the debate should be about the gains and purposes served, and the beneficiaries of retaining the current system.

SUMMARY

ALTERNATIVE INCENTIVE PLANS

Features of State Regulation	W/O Decoupling W/O DSM Cost Recovery	W/Decoupling W/O DSM Cost Recovery	W/O Decoupling W/DSM Cost Recovery	With Decoupling W/DSM Cost Recovery
Rate-of-Return Overall	Y	Y	Y	Y
Rate-of-Return DSM	N	N	N	Y
Rate-of-Return Bills	Y	Y	Y	Y
Shared Savings Resource	N	M (See Note 2)	M (See Note 2)	Y
Shared Savings Bill	M (See Note 2)	Y	M	Y
Bounty	M (See Note 2)	Y	Y	Y

NOTES:

Y - Yes, the approach can produce the right incentives.

N - No, the approach cannot produce the right incentives.

M - Maybe. Under some conditions the approach can be made to produce reasonable incentives.

(Note 1: This approach can address all costs only if average fuel costs exceed marginal fuel costs, which is rarely the case. Otherwise, the approach is sufficient only for low-cost measures.)

(Note 2: This approach is capable only for very low-cost DSM measures and very low-cost revenues.)

All cases assume the use of actual rather than estimated savings.

SECTION 1 -- THE PROBLEM

1.0 OVERVIEW

In the global race for energy efficiency the United States ranks 9th out of the 10 industrialized OECD nations.[1] We use twice as much energy to produce a dollar of GNP as Japan, West Germany, or Sweden. Only about half of the differences in energy use can be explained by factors that do not relate to energy efficiency. Responsible estimates show that cost-effective technologies available today can cut the nation's energy use by 20% (EPRI)[2] to 75% (Lovins)[3] without lifestyle changes or lower GNP growth.

Adopting cost effective energy efficiency as the nation's investment strategy would reduce the United States' annual energy bill by $27 to $120 billion. A savings of this magnitude would produce a substantial improvement in the global competitiveness of U.S. business and industry, our trade deficit, and our dependence on foreign oil.

In the coming decade, when energy policy will be increasingly driven by national and global environmental responsibilities, increased energy efficiency will result in direct and immediate benefit to the environment. Electric utilities now account for 20% of the gases linked to the atmospheric greenhouse effect, 70% of the nation's sulphur dioxide and 33% of the nitric oxide emissions that cause acid rain, and 50% of all nuclear waste.[4] Increasing the efficiency of our energy use, particularly electricity, can produce substantial environmental and health benefits at a fraction of the cost of adding pollution-control equipment or other mitigating approaches.

A growing number of policy makers and utility regulators are pursuing "least-cost planning" (LCP) in the battle against environmental and efficiency problems. LCP is a process of examining all electricity-saving and electricity-producing options to select a mixture of options that minimizes total consumer cost and that includes consideration of environmental concerns and other spheres of responsibility.

While least-cost planning principles have come a long way and have been adopted by a

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[1] *"Building on Success! The Age of Energy Efficiency," Worldwatch Paper No. 82, March, 1988.*

[2] *"Impact of Demand-Side Management on Future Customer Electricity Demand," Electric Power Research Institute (EPRI), EPRI EM-4815-SR, October, 1986.*

[3] *"The Great Demand-Side Bidding Debate Rages On." by Amory Lovins, Electricity Journal, Vol. 2, No. 2, March, 1989.*

[4] *"Acid Rain: Science and Control Issues," Environmental & Energy Study Institute, Washington, D.C., July, 1989; "Breathing Easier: Taking Action on Climate Change, Air Pollution, and Energy Insecurity," World Resources, Inc., Washington, D.C., 1989.*

majority of states, the most vexing problem remains.[5] Specifically, how do regulators translate talk and ideas into action? Restated, how do we ensure that electric utilities fully embrace and implement least-cost planning in their own planning and investment decisions?

The impediment between LCP the idea, and LCP the practical reality, is the fact that the utility industry is responding rationally to its economic environment. Traditional state rate-setting regulation provides a strong economic disincentive to the utilities' implementation of least-cost plans or investment in energy efficiency programs. In particular, the demand-side elements of least-cost plans remain slighted. Indeed, the ratemaking process generally used in most states has the following unintended, but nevertheless perverse incentives.[6]

INCENTIVES INHERENT IN TRADITIONAL REGULATION

1) Each KWH a utility sells, no matter how much it costs to produce or how little it sells for, adds to earnings.

2) Each KWH saved or replaced with an energy efficiency measure, no matter how little it costs, reduces utility profits.

3) The only direct financial aspect of regulation that encourages utilities to pursue cost-effective conservation is the risk that dissatisfied regulators may disallow costs.

4) Purchases of power from cogeneration, renewable resources, or other non-utility sources add nothing to utility profits, no matter how cost-effective they are.

These incentives are inconsistent with otherwise efficient investment by utilities in conservation or many supply-side options. While none were the conscious creation of the rate setting process as it evolved over the last century, these incentives are real and powerful, much so that little progress toward implementing large scale efficiency programs can be expected in an environment controlled by such powerfully opposing economic forces.

Regulators rightly insist upon the implementation of least-cost planning, but regulators also rule over a process which rewards utilities financially when they sell more power. Least-cost

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[5]*According to EPRI Report # RP 2982-02, 43 States are either employing least-cost planning or are in the process of implementing a least-cost process.*

[6]*Throughout this paper, the terms "earnings" and "profits" are used interchangeably. Except where the context is clearly to the contrary, adding or subtracting from earnings or profits refers to the incremental change in earnings or profits, not the absolute level of either. It matters not whether earnings or profits are 8% or 16%, or whether earnings or profits are above or below an allowed rate-of-return. In all instances, the paper focuses on the incremental increase or decrease in earnings (or profits) that flows from a specified course of conduct.*

planning is likely to find little real success until ways are found to eliminate these mixed messages and align the financial interest of the utility industry with the goals of least-cost planning.

Finally, while the debate over which cost effectiveness test to apply to conservation investments may continue in a few states, the absurdity of the incentives inherent in the current regulatory process persists, and the need for reform is largely unaffected by who wins. Even if a commission selects the most restrictive definition of cost effectiveness, the fact remains that without regulatory reform, cost-effective conservation is unprofitable and every KWH sold adds to profits. Taking action to align the incentives should not be delayed.

1.1 THE DETAILS

What is it about the traditional rate setting process that produces all the wrong incentives?

1.10 Profits are not Fixed

First, as regulated monopolies, utilities are entitled to have their prices for electricity set at a level that will allow recovery of all prudently-incurred operating expenses and fixed costs. These fixed costs include such things as taxes, interest, and a reasonable rate of return, or profit on their rate base (calculated as their capital investment in power plants and other hardware, minus depreciation).

Actual profit levels earned by utilities are not etched in stone. Instead, state public utility commissions examine utilities' historical and forecast expenses in rate cases and set the price of electricity at levels expected to earn the utility a specified rate of return. However, once the price is set, i.e., between rate cases, the utility has an incentive to sell more electricity whenever its marginal revenue from a sale exceeds its marginal cost to produce and distribute the power. Because a utility is virtually always "between rate cases," and because fuel clauses and utility accounting practices assure that marginal revenue exceeds marginal cost, a utility can always improve its earnings by selling more power.[7]

If profits rise too high, regulators can step in and lower the price that the utility can charge for electricity, but only after time-consuming hearings in which the utility will generally oppose any

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[7] *The result flows directly from the facts that prices are fixed and that fuel clauses are reconciled. The problem is unaffected by the procedure or assumptions used to fix prices; e.g., historic vs. future test year, or the level of sales or conservation used to set rates. The only aspects of regulation that make a difference are provisions that are reconciled, trued-up, or subject to deferred accounting and recovery. Even without fuel adjustment clauses, whenever prices are higher than the marginal fuel cost to produce power, the incentive to sell remains, albeit as a lesser incentive.*

change.[8] Even when rates are lowered, the utility is not required to give refunds or credits to customers to make up for past excess profits. Thus, a utility can keep all the profit it can make.[9]

1.11 The "Fuel Adjustment Clause"

In its understandable quest to maximize profits, a utility's most powerful incentive for selling more electricity is hidden in its regulatory fuel adjustment clause. Some 40 to 50 percent of the price of electricity is determined by the cost of fuel.[10] This cost is subject to considerable volatility, especially for oil and gas. To insulate utility shareholders from the impact of fluctuating fuel prices on earnings, nearly all states allow utilities to adjust customer prices periodically so that changing fuel costs do not affect profits.[11]

1.12 No Reason to Conserve Fuel

The "fuel adjustment" protection operates whether a utility's total fuel bill increases because of rising prices, or because more fuel is used to satisfy an increased demand for electricity. A utility that spends more than it has projected on fuel can raise the price of all electricity to spread the excess cost among its customers. If, however, it spends less than projected, the utility must pass on the savings to consumers through lower rates. Thus, the utility has little (or no) direct economic incentive to conserve fuel or to purchase the lowest cost fuel.[12]

Utilities even make money when they sell power for what initially appears to be less than it costs to produce. For example, to meet increased demand during peak periods, a utility may crank up a relatively inefficient diesel generator that consumes 10 cents worth of fuel to produce one kilowatt-hour (KWH) of electricity. The regulated price of power might be seven cents per KWH, which represents five cents in fixed costs and two cents allotted for the utility's "average" fuel costs. But the utility can recover the extra eight cents in fuel costs later (that is, the generator's ten-cent fuel cost minus the two-cent average fuel cost) by invoking the fuel adjustment clause to raise rates.[13]

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[8] *Shortening the time to complete rate cases or increasing the frequency of rate cases is not a solution because utilities will still always be "between rate cases."*

[9] *To be sure, the system also provides an incentive to reduce some types of costs. This aspect of the current regulatory system should not be lost when searching for new regulatory mechanisms.*

[10] *In 1987, the national average price of electricity was about 6.5 cents/KWH.*

[11] *Annual Report on Utility & Carrier Regulation, 1986 Edition, National Association of Regulatory Utility Commissioners (NARUC), Washington, D.C., Table 12, pp.415-416, supplemented by telephone conversations.*

[12] *As always, the risk that regulators will detect and punish wasteful practices will be present.*

[13] *In effect, the utility charges customers 15 cents for the KWH, 7 cents now and 8 cents later through the true-up provisions of the fuel clause.*

Meanwhile, the five-cent non-fuel, or base part of its rate remains in place.[14]

1.13 Recovery of Fixed Cost

As a general matter, in the short term, incremental sales of power to an existing customer add no costs other than the fuel needed to produce the power.[15] But, the combination of price-setting and accounting practices means that each KWH sold includes a piece of non-fuel cost-recovery even when there are no additional non-fuel costs.[16] This means each KWH sold adds to earnings.

The incremental contribution to the bottom line occurs whether the sale takes place before or after the utility has reached its projected level of sales. A nickel made on the sale of the first KWH is the same as a nickel made on the sale of the millionth or billionth KWH.[17]

Similarly, the incremental effect on profits remains undisturbed by a utility's achieved rate of return. Stated most simply, an incremental five cents is five cents whether it comes when the utility is earning an 8%, 12%, or 16% rate of return. While much of this discussion has described the effect of sales on profits, the effect of not selling power is the same. Each KWH not sold, or

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[14] *There are at least two reasons perhaps not to eliminate a fuel adjustment clause entirely, and adopt declining block rates with the tail block rate equal to or less than the utility's marginal fuel cost as a solution to the problem. First, there may be sound reasons for retaining some aspects of fuel clauses. For example, without fuel clauses, for utilities dependent on oil or gas, volatile fuel prices would be the primary determinant of profits. If utilities have no significant control over fuel prices, little could be gained by exposing them to this risk. Second, setting tail block rates at or below the cost of fuel would give customers the wrong price signal and would therefore seriously undermine the goals of LCP. For LCP to work, customer prices for incremental consumption should reflect the full cost of new resources.*

[15] *This is not typically the case for sales to new customers. New customers require new meters, poles, wire, and additional customer accounting costs. Consideration of incremental capacity costs is more complicated but generally does not affect the conclusions reached here. First, in many states, purchased capacity, or at least some types of purchased capacity such as purchases from qualifying facilities, are included as part of the fuel adjustment mechanisms. Second, recovery of the cost of new utility construction (including carrying costs) is generally deferred. This, together with the substantial control utilities have in most states over when to file a rate case, tends to reduce or eliminate these costs as an element in an analysis of incentives. Finally, shortages of generator capacity rarely occur, and when they do, they persist for a short period of time. More often than not utilities have more than the minimum amount of capacity needed to maintain reliability.*

[16] *Even when the marginal sales price is equal to or less than the marginal fuel cost, utility accounting continues to treat a part of the sales price as a contribution to non-fuel cost.*

[17] *A common misconception is that the disincentive to conserve exists only if the utility has sold less electricity than was assumed when prices were set. The incremental effect on earnings of sales or conservation is the same regardless of the level of sales.*

conserved, has a negative effect on earnings.[18]

[18] *The financial impact of an investment in energy efficiency is very large, about twice that of ordinary operating expenses such as plant maintenance or tree trimming. The table in Section 3.101 shows that a $1.6 million investment in DSM reduces earnings by $4.0 million. In comparison, increasing tree trimming spending by $1.6 million would decrease that year's earnings by $1.6 million.*

SECTION 2 --SELECTING AND IMPLEMENTING REGULATORY REFORMS

Perfection is the Enemy of the Good

A regulatory reform plan and its implementation should be compared to the existing regulatory system. For example, under the current regulatory system, utilities operate under financial incentives which encourage all opportunities, whether efficient or inefficient, to sell electricity. Regulators considering a regulatory reform proposal which may discourage utilities from promoting load growth should not ask if the plan is ideal, but whether such an incentive structure is better or worse than the existing incentive structure inherent in the current system.

Similarly, no regulatory system can eliminate the possibility that utilities might engage in actions which, when undetected by regulators, unjustly enrich the utility. The decision to implement an incentive plan which does not eliminate this possibility should be based on whether the motivation to engage in imprudent behavior is great, or whether such behavior would be more difficult to detect in the new plan than it is under the existing system.

There are many solutions available to state regulators to correct the incentive structure of regulation. This section presents a common framework of the most important considerations against which to test and evaluate each current and future alternative solution.[19] Additional considerations are discussed in Appendix A.

2.0 FIRST PRINCIPLES

Incentives and disincentives embedded in the current system of regulation present a serious obstacle to the successful implementation of LCP. NARUC concluded that regulatory reform was needed to remove the disincentives to LCP and to make a utility's least cost-plan its most profitable course of action.[20] It follows, therefore, that the single overarching standard against which proposed incentive plans should be measured is whether the new financial incentives will encourage the utility to implement successfully a least-cost plan.[21]

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[19] Throughout this section aspects of particular incentive plans are used to help explain the concepts. A more complete discussion of the available options are described and analyzed in Section 3 and Appendix A.

[20] See NARUC Resolution, Appendix C.

[21] Even though the goal is to create a regulatory structure which is completely compatible with least-cost planning, decisions to proceed with particular proposals should be based on relative improvements to the existing system of regulation. Every proposal, no matter how well conceived, will have its weaknesses and peculiarities. Nevertheless, the plan should be judged in relation to other proposals and the extraordinarily bad incentives in the existing system of regulation. While the ultimate goal is to have a plan which is completely consistent with least-cost planning, as a practical matter, states should pursue

2.00 Profit Maximizing Strategy

The test for an effective incentive proposal lies in the answer to this question:

> Viewed from the perspective of the utility, what course of action would be consistent with a profit-maximizing strategy?

The utility's most profitable course of conduct should be to implement successfully a least-cost plan. Commissioners should seek an incentive plan which satisfies this most important criterion. If the utility's most profitable course of conduct is to pursue programs that do not reflect a cost-minimizing plan while still promoting sales which are not cost-effective, the incentive plan fails to meet the primary criterion.

Be Creative

Consider as many alternative approaches as possible. As the discussion in Section 3 shows, many different approaches have already been identified and there will be more. Regulators will devise new, creative, and more effective plans if they focus on the particular needs and priorities of their state and do not limit themselves to conventional solutions to the problem.

Often the analyses, discussion, and design of specific incentive proposals begin with quantifying the negative impact DSM programs have on the utility's earnings. The analysis generally separates the adverse earnings impact into three parts: lost revenues, DSM program cost-recovery, and incentive components.

Next, separate incentive plans are designed to address each of the three elements.[22] This approach is not necessarily wrong, but it tends to limit the breadth of plans available for consideration and creates the risk that plans taking a different approach will be rejected solely because the plan does not fit a particular mold. To avoid these limitations, do not allow the framework, or specific deficiencies, of the current regulatory system to impose artificial constraints on the design or selection of incentive plans.

An example of a plan which approaches the problem in an entirely different manner will illustrate how regulation might be changed to produce reasonable incentives using relatively simple solutions. Consider a state which, like most, has a reconciled fuel adjustment clause, full recovery

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proposals which significantly improve the status quo.

[22] *It is generally believed that the job is done and the incentives are right when lost revenues have been restored and the utility is made whole for its efforts in the DSM programs and a bonus is provided. In fact, this may or may not be true depending upon how a program is structured.*

of all direct DSM program costs, and which has relatively high marginal fuel or production costs.[23] Assume that "Utility X" has a marginal revenue or marginal price of five cents per KWH and a marginal fuel cost of six cents per kilowatt-hour.[24] At first blush, a marginal KWH sold produces a net loss of one cent and "Utility X" would have no incentive to pursue this sale. On closer examination, however, the existence of the reconciled fuel clause means the entire six-cent marginal fuel cost will be returned to the utility. Because the utility is held harmless from the increased fuel cost, the sale that looked like a loss is, in fact, a profitable sale.

If, on the other hand, "Utility X" pursues conservation, even zero-cost conservation, it will experience a net loss of earnings. The KWH saved means a five-cent revenue loss to "Utility X" which is not offset by any cost reduction because the six-cent fuel cost saving is passed on entirely to customers. "Utility X" realizes a net loss. Thus, the utility has an incentive to pursue a five-cent sale rather than zero-cost conservation, even though the KWH sold "cost" six cents to produce.

Consider how the incentives shift if the fuel clause reconciliation process is changed slightly and fuel costs continue to be reconciled for changes in fuel prices, but not fuel quantity.[25] In this case, the incremental six-cent fuel cost is borne by the utility if it sells another KWH, and it is a cost savings to the utility if it conserves a KWH. Under these conditions, an incremental sale produces a one-cent loss, and zero-cost conservation produces a profit. With this simple change to just one aspect of the fuel adjustment clause, the sale of the marginal kilowatt-hour would not be a profit-maximizing strategy. Instead, the new profit-maximizing strategy for "Utility X" would be to pursue energy conservation over increased sales.[26]

Notice that in this example of an "incentive plan" no elements of the plan restore lost revenues or which provide a separate DSM incentive. Yet, the utility's incentives are tied to the successful

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[23] *The term "reconciled" is used in this paper in a number of areas, most generally relating to fuel clauses. A fully reconciled fuel adjustment clause means utilities recover dollar for dollar all fuel expenses including interest on fuel costs. Several states use partial reconciliation which can take many different forms. In some states, interest costs are not allowed; in others, a portion of the difference between projected and actual fuel cost is left at the utility's risk, to provide an incentive to the utility to minimize fuel costs. For example, in New York a utility recovers only 80% of the difference between projected and actual fuel cost. The manner and extent of reconciliation is a very important consideration in evaluating incentive plans.*

[24] *The five-cent price might be two cents of non-fuel base revenue and three cents of average fuel.*

[25] *If the utility's fuel bill increases because fuel prices increase, it continues to be protected by the reconciliation, or true-up, provisions of the fuel adjustment clause. If, however, the total fuel cost rises because sales increased, the utility must bear the extra cost. Likewise, the utility keeps any reduction in fuel cost caused by lower sales resulting from successful DSM efforts.*

[26] *Recall that "Utility X," like most utilities, recovers its DSM program costs separately so the six-cent fuel cost saving is not offset by the cost of conservation. In addition, recall that for this utility the marginal fuel cost exceeds its marginal revenue. This condition is very rare given today's relatively low fossil fuel costs.*

implementation of DSM programs.[27]

In summary, like good people, good incentive plans can take a wide variety of shapes, sizes, and personalities. Regulators, utilities, and others should remain tolerant and receptive to different approaches.

2.01 Unlimited Scope

Ideally, an incentive plan will encompass all aspects of LCP. Trying to simplify the task of finding the right incentive plan by limiting the scope of the undertaking is probably a mistake.

Limitations can take several different forms. For example, regulatory reform efforts could be targeted only at DSM instead of both demand- and supply-side aspects of LCP.[28] Limiting efforts to making conservation profitable and not trying to remove the incentive to sell more power is another example.[29]

Limiting the scope of the undertaking will narrow the range of options available, and may needlessly eliminate approaches that fit well with ratemaking or accounting practices unique to the state.[30] Moreover, these types of constraints would make it more difficult to get achieve optimum overall incentives, even when successfully addressing the narrow issues. The existing "incentives" are that:

1) all sales, whether cost-effective or not, add to earnings; and
2) all conservation, whether cost-effective or not, is unprofitable[31]

If a plan is limited to making DSM desirable, both sales and conservation would be profitable. While incentives limited to DSM represent a clear improvement, they stop short of producing a strategy that makes pursuing a least-cost plan the most advantageous course of action.

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[27] *The effectiveness of this approach depends on the relationship of marginal fuel cost to the price of electricity. If the price of power exceeds the marginal fuel cost, this approach is only partially effective.*

[28] *Environmental externalities, risk, and diversity are examples of matters which are generally not incorporated into any incentive plans nor are these matters which are reflected in the economic incentives embodied in existing regulation.*

[29] *To date, most proposals tend to be limited to making DSM programs profitable and do not address the incentives to increase sales or any aspect of supply-side options. This should come as no surprise because the existing incentives for DSM are most skewed.*

[30] *For example, an option which changes portions of the fuel adjustment clause would affect both DSM programs and sales incentives. States that narrow the scope of incentive plans to only DSM incentives will needlessly foreclose the use of this type of approach.*

[31] *The aim is to make only cost-effective selections, whether demand-side or supply-side, the profitable choice.*

2.02 Measurement

Incentives resulting from LCP will be greatly influenced by how, what, and when to measure. Consequently, measurement issues should not be viewed as a mere technical issue when policy makers discuss the merits of different incentive options. Many incentive plans, especially those limited to the demand side, require measurement of both capacity and energy savings. Plans that explicitly restore DSM-related lost revenues also generally require a measure of DSM-induced revenue loss.[32]

A combination of engineering and economic judgments instead of actual measurement of capacity and energy savings may be adequate for the purposes of program design. By contrast, regulatory incentive proposals not measuring actual achievements may result in the wrong underlying incentives.[33]

For example, consider the substantially different incentives produced by an electric water heater insulation program under two incentive plans where the only difference is how and when program savings are measured. The first plan has KWH savings based on extrapolating test data, engineering estimates, or measurements made at other times (or in other states). The second plan is the same in all respects except that program savings are based on random, statistically valid, on-site measurements of utility-installed measures.

Suppose, under the first plan, an agreement is reached that an electric water heater insulation blanket will yield 600 kilowatt-hours per year in energy savings. Under this plan, the utility will be allowed to recover direct and indirect program costs, 600 KWH's worth of lost revenues, and an incentive based on any rational approach.[34]

What happens when the utility actually achieves 700 kilowatt hours in savings through better quality-control or other efforts under its control? It loses money!

In contrast, what happens when the utility selects poor quality contractors and has inadequate quality-control efforts? Actual savings drop to 500 or 400 KWH per year, and utility profits

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[32] *California's ERAM is a time-tested approach which does not require the identification of DSM-induced lost revenues. Actual and projected (allowed) revenues are reconciled regardless of the cause of any discrepancy. Thus, the only measurement required is of actual revenues which is simple and verifiable.*

The plan described in Footnote 23, which consisted of changing the fuel clause, is an example of another approach that does not require the measurement of lost revenues. In that plan the fuel cost savings kept by the utility more than offset lost base revenues.

[33] *Cost/benefit analyses of measurement should not be forgotten.*

[34] *For the purpose of this example, the exact nature of the incentive element is not important. The analysis is the same whether it is a shared savings approach or a fixed payment for each KWH saved.*

increase!

Profits increase because the utility still recovers lost revenue based on an assumed 600 KWH savings when in fact not all of these revenues were lost. In addition, the incentive portion is unaffected by the lower actual savings.

Solely as a consequence of a measurement decision, the utility's profit maximizing strategy would be to select measures which would test well under the measurement criteria imposed, but perform poorly.

Under the second plan, where actual measurements of achieved results are used, what happens if the utility is able to achieve 700 KWH in savings? Profits go up. As it should be, earnings go down if the savings are less than 600 KWH. The profit-maximizing strategy is to get more savings rather than fewer.

2.03 Framework for Analysis

To simplify the evaluation process, start with a list of questions that describe important considerations. Consider:

What happens to profits if the utility sells another KWH?

What happens to earnings if sales are reduced by one KWH through conservation programs that cost $0.01 per KWH?, $0.02?, $0.10?

What happens to profits if a utility invests in load control and shifts a KW from on-peak to off-peak?

What happens if the utility pursues a power marketing strategy?

What happens if the utility selects the more costly of two supply-side options; or the more costly of two demand-side options; or a supply-side option which is more costly than a demand-side option?

Starting with just one proposed incentive plan, test the incremental effect on earnings of the alternative courses of action suggested by the questions.[35] The combination of the answers to the questions will unveil the utility's profit-maximizing strategy for that particular incentive plan. When the functioning of one incentive plan is understood, perform the same analysis using another

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[35] *When answering the questions, be very aware of all of the specific ratemaking and accounting practices used in the state. Of special importance are 1) the exact workings of fuel and purchased power clauses and associated reconciliation provisions, 2) any other ratemaking provisions allowing deferred expense accounting, including deferred accounting for conservation cost; and 3) rate design and revenue accounting provisions which affect the level of base revenue contributions of marginal sales of power to each customer class and for each rate period for time-of-use rates.*

incentive plan.

The analysis should not start with a particular course of action, i.e. conservation program "X", and then compare that program's effect on profits under alternative incentive plans. This approach asks the wrong question, and it is unlikely to lead to a useful answer. Knowing that conservation program "X" is more profitable under Plan "A" than it is under Plan "B" or under the existing system of regulation says nothing about the profitability of sales or conservation under Plan "A".

Thus, to evaluate the desirability of a plan, begin with a proposed incentive plan and, regardless of any other plan, test it against a wide range of conduct, and identify the profit-maximizing strategies. If those strategies are consistent with a desired course of conduct, consider it to be a good candidate while you proceed to review other proposed plans.

2.1 PROBLEMS, BENEFITS, AND GOALS

Identifying a profit-maximizing strategy is the most important test of any incentive proposal.

The next set of considerations are also quite important and should be given serious attention while developing or selecting the best plan for each state. The considerations are discussed in general order of importance:[36]

Decoupling profits from sales;
Cost minimization;
Administrative simplicity;
Fuel switching; and
Balance.

A final group of considerations which are of slightly less importance are discussed in Appendix A. These considerations are as follows:

Predictability;
Environmental costs;
Non-participant impacts;
Skimming the cream;
Avoiding gamesmanship; and
Distribution of incentives.

2.11 Decoupling Profits from Sales

Under current regulation increased sales always mean increased profits. As long as every

[36] *To be sure, there are many, often conflicting, forces which influence utility behavior. Changing the financial incentives is only one, albeit the most important, area that requires attention by regulators.*

incremental KWH sold adds to profits, a strong likelihood remains that a profit maximizing strategy will lead to more sales and less DSM, even if DSM programs are profitable.[37] Thus, incentive plans should be evaluated to see how effectively sales are decoupled from profits.[38]

Decoupling can take either of two forms. First, decoupling may merely eliminate the incentive to increase sales. This approach generally holds the utility harmless from fluctuating sales levels and provides no financial incentive or disincentive to increase or decrease sales. There are several different approaches to accomplish this first type of decoupling. The most widely known is California's Electric Revenue Adjustment Mechanism (ERAM), and it is discussed in Section 3.41.[39]

There are also other, very different, approaches which can accomplish very similar results. For example, fuel revenue accounting changes implemented in Maine set the non-fuel revenues from marginal sales equal to, or near, zero. The result is that incremental sales do not add to profits. This practice has been accomplished by changing accounting rules that generate no changes in retail prices.

Interestingly, plans which incorporate recovery of only lost revenues specifically attributed to efficiency programs do not decouple profits from sales. At most, this approach links conservation to profits the same way sales are already linked to profits. The disincentive towards energy efficiency is removed, but the overall incentive to sell power remains intact. Sales are always profitable regardless of the cost of producing the power.[40]

The second form of decoupling is with the use of plans which provide incentives when sales are decreased by cost-effective DSM measures and disincentives when sales increase. For example, plans which increase a utility's rate of return if customer bills decrease, and decrease rate of return when customer bills increase can decouple profits from sales even though there is no lost revenue adjustment. Because only a few incentive plans decouple profits from sales in this fashion, it is necessary to combine most incentive plans with separate decoupling options to produce the most

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[37] *Even where a plan succeeds in making a KWH conserved more profitable than a KWH sold, perceived risks and unfamiliarity with DSM programs will tend to bias a profit-maximizing strategy toward sales.*

[38] *This does not mean that all sales of electricity should be discouraged for its own sake. Sales, however, should not be profitable regardless of the cost of electricity or the cost of alternatives, including energy efficiency.*

[39] *See also Cavanagh. "Responsible Power Marketing in an Increasingly Competitive Era." Yale Journal on Regulation, New Haven: 1988. Vol. 5,No. 331.*

[40] *Oddly, consumer advocates often favor this approach because it is more limited in scope than an ERAM type approach. In fact, this approach presents the worst choice for consumers. First, this approach does not decouple profits from sales, and second it is an adjustment that always works in one direction, providing more revenue to the utility. In contrast, ERAM does decouple and it refunds money to consumers if sales increase.*

desirable overall incentives.

2.12 Cost Minimization

Will the proposed program encourage the utility to deliver conservation programs at the lowest cost to consumers?

Consider two incentive plans, both of which measure actual achieved conservation results. The first pays the utility a predetermined, fixed amount for each KWH saved. The fixed payment will be less than the utility's avoided cost and will therefore help assure that only cost-effective efficiency is purchased. The payment covers direct program cost and an incentive for the utility. The second plan pays the utility 110% of its actual program costs for each KWH actually saved.

To maximize profits under the first plan, the utility will try to reduce its cost of saving KWHs to maximize the difference between the fixed payment it receives and its out-of-pocket costs. To maximize profits under the second plan, the utility would get as much conservation as it could, regardless of the cost.

Generally, plans should be designed to encourage utilities to obtain DSM savings at the lowest possible cost.

2.13 Administrative Simplicity

Achieving significant reform of a regulatory system that has been in place for nearly a century will require substantial public and political support. Gaining the needed support will be difficult if the proposed plan is too complex or obscure.

Incentive plans should be simple and efficient to administer, or the cost of regulation may outweigh the benefit. The cost of regulation includes items such as the cost to the regulatory commission of administering the system, the cost to the utility of collecting and reporting any additional information, and the cost to all parties of participating in any new regulatory proceedings that may be needed.

In practice, this principle means avoiding incentive plans that rely on complex formulas or unverifiable measurements. For this reason, commissioners may want to avoid approaches which require separate proceedings in favor of plans which can be implemented within the framework of existing regulations.

2.14 Balance

Incentive proposals should have a reasonable risk/reward relationship. Once measurement criteria are set, superior performance should yield higher earnings, and similarly, inferior performance should yield lower earnings. The plan should not provide utilities with unreasonable opportunities to profit at the unnecessary expense of ratepayers, nor should the plan deprive the utilities of a reasonable opportunity to earn a fair return.[41]

To gain public acceptance and increase the likelihood that an incentive plan will produce the desired result, an incentive plan should operate symmetrically, i.e. rewarding superior and punishing inferior performance. Incentive plans which only reward utilities for good performance and has no effect when performance is poor will be criticized as being unfair and ineffective.

[41] *While this discussion may seem self-evident, there are plans discussed in Section 3 that run afoul of this consideration.*

SECTION 3 -- ALTERNATIVE APPROACHES

3.0 GENERAL

This section describes and evaluates alternative approaches to changing the incentives inherent in the current regulatory system. Incentive proposals have been grouped into three general categories based on the approach taken. The categories follow:

Rate-of-Return Adjustments
Shared Savings
Bounty

For each of these approaches, different performance criteria are available to address one or more special concern. All the possible modifications to each approach will not be covered here. Regulators, for the most part, can mix and match different components of incentive plans until they find a desirable group of features.[42]

Although the ability of an incentive plan to decouple profits from sales is critical to a plan's success in changing investment and other decisions, many of the plans fail to accomplish the desired decoupling. Therefore a separate category of decoupling options follows the discussion of the three categories of plans. These decoupling options can be used with any of the incentive plans to produce an overall package of regulatory reforms.

Three questions should be asked when structuring an incentive plan:

One: Will the incentive plan make available enough additional earnings to offset the existing disincentives and which alternative course of action will maximize earnings?[43]

Two: Does the incentive plan decouple profits from sales or must it be combined with a decoupling option?

Three: What behavioral changes does the plan encourage:
-energy savings or spending?
-cream-skimming, fuel switching, cost-minimization?
-can the plan accommodate considerations of environmental externalities?

The first two questions and the most important elements of the third question are discussed in this section. Secondary considerations and factors that are common to all plans are discussed in

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[42] *Specific proposals that have been the subject of publications or regulatory decisions are described only in general terms, with citations to more specific materials.*

[43] *Net revenues from a plan equal the incremental revenue minus direct and indirect costs, e.g. lost revenues and DSM program costs.*

Appendix A.

Throughout Section 3, simple quantitative calculations are used to illustrate the different plans' potential to produce enough incremental earnings to offset the disincentives of the current system. To simplify the discussion, the following uniform assumptions are made:

Illustrative Utility Statistics[44]

1) average price	$.07
2) average fuel cost	$.02
3) average non-fuel cost	$.05
4) marginal fuel cost	$.03
5) conservation cost	$.02[45]
6) rate base (total)	1 billion
7) allowed rate of return	12% overall
8) cost of equity	14%
9) cost of debt	10%
10) capital structure	50/50
11) annual sales	8 billion KWH
12) annual revenues	$560 million

Except as noted in the discussion, the state is also assumed to have a fully reconciled fuel adjustment clause.[46] As the following table shows, the incentives are improved by the elimination of fuel adjustment clauses, but the overall direction of the incentives is unchanged.

[44] *These assumptions are generally consistent with national averages shown in Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1987.*

[45] *Each $1.00 of program cost is assumed to save ten KWH per year for five years. Total savings over the five-year life are 50 KWH, producing a simple average cost of $.02 per KWH. Thus, a $.10 investment in year one will produce one KWH of savings each year for five years.*

[46] *Whether direct program costs are recovered through expensing, ratebasing, or amortization makes no significant difference.*

Incremental Earnings Impacts[47]

	w/fuel clause	w/o fuel clause
Incremental KWH sold	$.05[48]	($.04)[49]
Incremental KWH saved w/DSM program cost recovery	($.05)[50]	($.04)[51]
Incremental KWH saved w/o DSM program cost recovery	($.07)[52]	($.06)[53]
Incremental KWH saved w/rate base treatment	($.0488)[54]	($.0388)[55]

Without a fuel clause the magnitude and direction of the short-term incentives depend on the relationship of retail rates to marginal fuel costs. If retail rates exceed marginal fuel costs, which is the case in most jurisdictions, incremental sales are profitable. With a fuel clause, incremental sales are profitable regardless of the relationship of retail prices to marginal fuel costs.

3.1 RATE-OF-RETURN ADJUSTMENTS

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[47] *This is a simplified illustration of the earnings impacts of DSM programs under typical rate-setting procedures with and without a fully reconciled fuel clause, and with or without separate recovery of program costs.*

[48] *The entire non-fuel component is realized because fuel cost is fully recovered from customers.*

[49] *Utility receives $.07 from retail sale, less the full $.03 marginal fuel cost.*

[50] *The entire non-fuel component is lost. The $.03 marginal fuel cost savings is realized by customers.*

[51] *The utility loses the $.07 retail rate but save $.03 in fuel costs, thereby realizing a net loss of $.04.*

[52] *Same as note 43 except the utility also incurs $.02 cost for DSM program.*

[53] *Same as note 44 except the utility also incurs $.02 cost for DSM program.*

[54] *Same as note 43 except the utility receives return: 12% on the $.10 of rate base associated with one KWH saved. This further assumes no lag in the DSM investment and cost recovery.*

[55] *Same as note 44 except the utility receives return on the $.10 of rate base associated with one KWH saved.*

The most common approach to providing incentives for LCP or energy efficiency investment is to adjust the utility's allowed rate of return (either on equity or total return) in relation to a specified accomplishment, such as achieving a target level of conservation, a reduction in customer bills, a specified level of DSM spending or some other indicator of performance.

In some cases, the adjusted rate of return is applied to the total investment (rate base), and in others, only toward the investment in demand-side measures. These two approaches are discussed separately, followed by a discussion of the use of return adjustments based on customer bills.

3.10 Rate-of-Return Adjustment--Total Rate Base

3.100 General Description

This subsection addresses incentive plans that operate by adjusting the utility's allowed rate of return on its total investment. Within this category there are several variations which establish different performance criteria (or benchmarks) for judging whether and how much to change the utility's rate of return.

Performance criteria discussed thus far tend to fall into two groups. First, adjustments to the rate of return are compared to the utility's ability to achieve a specified level of capacity (or energy) savings. Second, rate-of-return adjustments are measured in relation to changes in customer bills.

Programs which relate rate of return to capacity or energy savings targets can be measured in a number of ways. The particular approach selected will determine the incentive characteristics of the plan. Table 1 summarizes the nature of the underlying incentives for four different performance measurements.[56]

Each of these performance criteria, one based on estimated savings and the others representing different ways to measure achieved savings, produces different incentives. The four performance criteria shown across the top of Table 1 are as follows:

(1) Estimated Savings - DSM savings are based on engineering estimates, experience from other areas, or otherwise agreed-upon levels established in advance. The primary difference between estimated and actual savings is the former does not reflect the savings achieved by a utility's programs.

(2) Actual Savings - DSM program results are measured directly by techniques such as after-the-fact metering of statistically valid samples of installations. In some situations actual savings may include engineering estimates. In general, "actual savings" are the product of careful program evaluation and reflect the savings achieved by the actual DSM accomplishments of a utility.

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[56] *These are not the only four performance criteria which could be used.*

(3) Load vs.Forecast - DSM results can be measured indirectly on an aggregate basis by comparing the utility's actual load against its load forecast. The comparison determines which goals were consistent with DSM and other LCP efforts.[57] The differences between the actual load growth and the adjusted forecast would be used as a measure of overall DSM program performance.

(4) Efficiency Measure - Aggregate program performance can also be judged in terms of measures of efficiency, either BTU per dollar GNP, KWH per dollar GNP, KWH per customer, or other similar scales. The difference between actual and adjusted forecast efficiency is the yardstick.

TABLE 1
RATE OF RETURN ADJUSTMENTS
(Total Investment)

PERFORMANCE CRITERIA	(1) Estimated Savings	(2) Actual Savings	(3) Load vs. Forecast Difference	(4) Efficiency Measure BTU/$GNP KWH
DSM INCENTIVES	Perverse	Good	Good	Good
DECOUPLING	No	No	Yes	Yes
SCOPE	DSM Only	DSM Only	DSM Only	DSM and partial supply-side with certain efficiency measures
COST MINIMIZATION	No - Unless payment includes program cost recovery	No - Unless payment includes program cost recovery	No - Unless payment includes program cost recovery	No - Unless payment includes program cost recovery
ADMINISTRATIVE SIMPLICITY/COST	Low cost	Low incremental cost if good program evaluation	Medium to low	Medium to low

3.101 Incentive Potential

Adjusting the rate of return on a utility's overall investment may produce enough incremental revenue to offset the disincentives in the current ratemaking process. Applying the typical utility

[57] Before making the comparison, the projected load would have to be adjusted for differences in weather, economic conditions, and other relevant factors which are outside the utility's control.

data to a modest utility DSM program produces the following results:[58]

Annual DSM Savings (1% of sales)	8 million KWH
DSM Cost (8 million KWH x $.02)	$1.6 million
Lost Revenue (8 million KWH x $.05)	$4.0 million
	============
Total	$5.6 million
Incremental Earnings Each 1% change in Rate of Return (Overall Return) (1% x $1 billion)	$10 million
Required Change in Rate of Return to Produce $5.6 million of Earnings	.56%

These figures show that relatively small changes to a utility's allowed rate of return can produce enough revenue to offset DSM program costs and lost revenue. Any change in return over the amount shown in the table will provide a positive incentive.

Finally, combining this type of approach with other DSM program cost recovery, lost revenue adjustments, or decoupling approaches means the required change in the rate of return will be smaller than the table suggests. The required change in rate of return would also be smaller in a state without a fuel adjustment clause.

3.102 DSM Incentive

Will the performance criteria provide incentives that operate in the right direction?

As discussed in Section 2, approaches which rely on engineering estimates, agreed-upon program benefits, or other estimated savings (Table 1, Column 1) tend to produce perverse

[58] *This represents about 0.3% of the utility's total revenues, and is slightly less than the relative level of DSM spending for California utilities. It is about 10% of the relative spending of several New England utilities.*

incentives. Under these plans, the utilities' financial rewards are negatively affected by achieved results and positively affected by the number of installations.

Financially, the best course of action for a utility under this scheme would be to implement a large DSM program which produces few results. For example, the company might install a large number of devices which, because of inaccurate estimates, free-rider effects, or low quality materials, produce lower efficiency improvements.

The previous table shows that it requires a .56% (56 basis point) change in the utility's allowed rate of return to compensate for all direct and indirect DSM costs. This change produced $5.6 million in increased earnings which exactly offset DSM program costs and lost revenues. The following table illustrates the incentives produced by a plan which uses estimated savings. The table uses with the $5.6 million incentive payment from the previous table, and shows what would happen when actual DSM savings are 50% higher and, alternatively, 50% lower, than estimated.

DSM SAVINGS

Original Increase in Earnings	$5.6 million
Incremental Earnings with 50% less savings (8 million KWH x 50% x $.05)	$2.0 million
Incremental Earnings with 50% more savings (8 million KWH x 50% x $.05)	($2.0) million

In sharp contrast, each of the three performance criteria in Table 1 which rely on actual measurements will produce incentives which are proportional to performance. If achieved results increase (either because of the number or quality of installations), whether measured by metering, load reductions, or efficiency improvements, the rate-of-return adjustment also increases.

3.103 Decoupling

Are any of the variations of rate-of-return adjustments capable of decoupling profits from sales without relying on a separate decoupling option?

To be fully effective, an incentive plan should decouple profits from sales. As shown in Table 1, the first two performance criteria (which rely on either actual or estimated DSM impacts) do not decouple. In both approaches, increased sales produce increased earnings and have no impact on the apparent success of implementing DSM programs.[59]

The two remaining approaches (actual/forecast load, and actual/forecast efficiency) will accomplish decoupling. In both performance criteria, increased sales reduce the utility's measured results, which means lower profits or negative incentives.

3.104 Scope

Do any of the performance criteria allow the plan to extend to matters beyond DSM programs?

As summarized in Table 1, the first three approaches do not extend beyond demand-side programs. The fourth approach which measures energy efficiency can, however, be used to incorporate at least some efficiency opportunities on the supply side. For example, measures such as BTUs of utility fuel input per customer would capture changes in power plant efficiencies, i.e., heat rates. Because of the operation of fuel adjustment clauses, utilities currently have little or no incentive to pursue these opportunities.

In fact, with reconciled fuel adjustment clauses, utilities are held harmless from increased fuel costs resulting from plant inefficiency. Meanwhile, the deferral of maintenance costs, which causes deteriorating plant efficiency, improves short-term earnings. A plan that creates supply-side efficiency incentives would be an improvement.[60]

3.105 Administrative Simplicity

Do any of the performance criteria pose unreasonably high administrative costs?

The administrative costs of the estimated or measured program performance criteria would be relatively high if savings estimates are made on a program-by-program basis. The incremental costs, however, would be relatively low if the information is already developed for program evaluation or other purposes.

Measuring savings on an aggregate basis may impose fewer procedural and administrative costs on utilities and regulators than disaggregated program-by-program evaluations, assuming that regulators are unable to devote staff resources to program evaluation. An incentive plan that is

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[59] *Depending on the precise method of measuring achieved results, it might not be in the utility's financial interest to pursue programs that increase the load of customers who participate in DSM programs. For example, if demand-side program benefits are measured by comparing consumption of participants vs. non-participants, it would not be in the utility's interest to pursue a load-building program that might be favored by participants in DSM programs. Such a program would tend to increase consumption of the participating customers and thereby reduce the measured savings of a DSM program. This conclusion, however, is very sensitive to the precise method of measurement selected.*

[60] *Incentive plans based on revenue per customer (i.e., customer bills) would go one step further and incorporate fuel and purchase power procurement activities, much of which is now insulated by fuel adjustment clauses.*

based on aggregate performance would place the burden on utilities to use more detailed program evaluations to decide which programs to expand, contract, or modify to achieve the best overall results.

The administrative regulatory costs associated with the remaining performance criteria, load/forecast and efficiency measures, may be lower than these for either of the first two approaches, if the data and necessary adjustments are already subject to regulatory proceedings.

3.106 Cost Minimization

Do any of the performance criteria create the desirable incentive to minimize the cost of delivering supply or demand-side options?

Most rate-of-return plans, either proposed or in effect, incorporate separate mechanisms to recover direct DSM program costs. These DSM cost recovery mechanisms generally rely on regulatory oversight and the accompanying risk of disallowance to assure that program costs are reasonable. If this is the case, none of the four performance criteria in Table 1 (with the possible exception of the fourth-- Efficiency Measure) provide any incentive to minimize the cost of efficiency improvements.

On the other hand, if the rate-of-return adjustment and the resulting payment to the utility includes program cost-recovery, a substantial incentive to minimize the cost of delivering energy efficiency exists. In this case, the utility's financial reward would increase if its cost to achieve any particular result were lower. The utility would be better off if it reached or surpassed a performance goal and at the lowest possible cost.[61]

3.11 Rate-of-Return Adjustment -- On DSM Investment

3.110 General Description

This approach assumes that a state permits or requires ratebasing of DSM investments. In other respects this approach is very similar to the rate-of-return adjustment on total investment, except that the increased rate-of-return is applied only to investments in conservation or load management activities.

The performance criteria shown across the top of Table 2 are the same criteria used in the discussion of return adjustments to total investment. The criteria are as follows:

(1) Estimated Savings - DSM impact on an estimated basis.
(2) Actual Savings - DSM impact on an actual basis.
(3) Load vs.Forecast - DSM impact as measured by actual demand for electricity

[61] *See Appendix A Section A.2 for a discussion of ways to minimize or eliminate the cream-skimming incentive.*

vs. the adjusted load forecast.

(4) Efficiency Measure - DSM impact based on an efficiency measure.

TABLE 2

RATE-OF-RETURN ADJUSTMENTS
(On DSM Investment Only)

PERFORMANCE CRITERIA	**(1) Estimated Savings**	**(2) Actual Savings**	**(3) Load vs. Forecast Difference**	**(4) Efficiency Measure BTU/$GNP KWH/Customer**
DSM INCENTIVES	Perverse	Good direction but inadequate	Good direction but inadequate	Good direction but inadequate
DECOUPLING	No	No	No-Inadequate revenues	No-Inadequate revenues
SCOPE	DSM Only	DSM Only	DSM Only	DSM and partial supply-side with certain efficiency measures
COST MINIMIZATION	Perverse	Perverse	Perverse	Perverse except with certain measures
ADMINISTRATIVE SIMPLICITY/COST	Low cost	Low incremental cost if good program evaluation is done	Medium to low	Medium to low

3.111 Incentive Potential

The potential of this approach to produce revenues necessary to offset existing disincentives is very limited. The following table shows that the level of DSM investments is so low in relation to the magnitude of the existing disincentives that plausible adjustments to the rate of return have no practical effect.

DSM COSTS AND RETURN[62]

Lost Revenue	$.05/KWH
Incremental Investment in DSM	$.10/KWH

[62] *Direct DSM program costs are fully recovered through annual amortization or depreciation charges and, therefore, not shown on this table.*

Incremental Return at:	
12%	$0.012/KWH
14%	$0.014/KWH
20%	$0.02/KWH
Required Overall Return on DSM Investment to Produce $.05	50%
Required Equity Return on DSM Investment to Produce $.05	100%

This table shows that the incremental earnings produced by typical ratebasing incentive plans are a tiny fraction of what would be required to change the overall financial incentives. Consequently, this approach is only useful when combined with other cost recovery and decoupling options.

3.112 DSM Incentives

DSM incentives are, once again, perverse if based upon estimated determination of DSM impacts.

The incentives are generally positive for the remaining performance criteria (actual measurements, changes in load growth, or changes in efficiency). Utility earnings increase as actual performance improves; however, because utility earnings would be directly proportional to the amount of DSM investment, cost minimization would be discouraged.

3.113 Decoupling

Neither the first nor the second performance criteria achieve decoupling. Theoretically, the third and fourth criteria can decouple profits from sales. Under both of these variations (change in load growth and change in efficiency), increased sales would tend to reduce the utility's incentive payment. The increased sales, however, would produce far more earnings than would be lost through a lower incentive payment.

Thus, because the earnings potential of these criteria is so small, as a practical matter decoupling would not likely be accomplished.

3.114 Scope

As was the case with rate-of-return adjustments applied to total investment, none of the first three performance criteria is capable of extending efficiency opportunities to the supply side. Depending on the particular efficiency measure selected, the fourth criterion may capture some supply-side efficiency improvements.

3.115 Administrative Simplicity

The conclusions discussed at Section 3.105 is equally applicable here.

3.116 Cost Minimization

Because this approach would relate the level of the incentive payment to the level of DSM investment, the utility's financial interest would be best served by pursuing the more costly DSM opportunities. The incentive to minimize DSM costs would be the same as the incentive to minimize the cost of any investment, i.e., the risk of detection by regulators and the possible disallowance of costs.

3.12 Rate-of-Return Adjustment -- Customer Bills

3.120 General Description

This approach adjusts a utility's rate of return (on total investment) in relation to performance criteria which focus on customer bills. In part, this approach is being treated separately to illustrate some of the different measurement approaches available and the effect of the choices on the resulting incentives.

There are at least four different ways to specify performance criteria, each of which produces a different set of overall incentives.[63] The performance criteria shown in Table 3 are as follows:

(1) Forecast vs.Actual - This performance criterion compares actual average customer bills (by customer class) to prior forecasts of customer bills. The forecast would be consistent with the average bills after implementing a reasonable LCP, and adjusted for factors which are outside of the utility's control, such as economic and weather conditions.

(2) Internal Index - The next criterion is similar to a comparison of average bills for participants with those of non-participants. A statistically valid sample of utility customers would be selected and their future participation in DSM programs monitored. Customers in the sample group who elect to participate in programs during the next year (or two) would be dropped from the sample or control group.

[63] Throughout this discussion, "average customer bills" refers to average bills for a customer class. Thus, average residential bills would be equal to total residential revenue divided by total number of customers.

The control group would provide an "internal index" against which all other average customer bills would be compared. The utility would be rewarded or punished based on differences between the average bills of customers in the internal index and bills of customers overall.

(3) External Index - This performance criterion begins with average customer bills for a targeted utility and average customer bills for a group, or index, of other utilities, which in the aggregate have the same fuel mix, weather, and economic conditions as the targeted utility. The targeted utility's allowed rate of return would be adjusted up or down depending on relative changes in the average customer bills for the targeted utility compared to the average customer bills of the index. Thus, if customer bills for the targeted utility increase over a relevant time period by 10%, while bills increase by 12% for the index, the utility would have outperformed the index group and would have a higher rate of return based on the two percentage point differential.[64]

(4) Before/After - The final performance criterion focuses on the difference in customer bills prior to and following participation in the program. The difference in bills would be adjusted for variations in weather conditions and other factors which would have substantially affected bills but are unrelated to the utility's DSM program.

[64] *For a more complete discussion of this approach see Moskovitz and Parker, "How to Change the Focus of Regulation so as to Reconcile the Private Interest With the Public Goals of Least-cost-Planning" (Presented to NARUC's Sixth Biennial Regulatory Information Conference, September,1988).*

TABLE 3

RATE-OF-RETURN ADJUSTMENTS
(Customer Bills)

PERFORMANCE CRITERIA	**(1) Forecast vs. Actual**	**(2) Internal Index**	**(3) External Index**	**(4) Before vs. After**
DSM INCENTIVE	Good	Good	Good	Good
DECOUPLING	Yes	No-But can offset lost revenues	Yes	Partial
SCOPE	Full coverage except for forecast adjustment	DSM Only	Full coverage	Full coverage except for adjustments
COST MINIMIZATION	Yes	No-Unless payment includes cost recovery	Medium	Partial
ADMINISTRATIVE SIMPLICITY/COST	Medium	Medium	Medium	Medium

<u>3.121 Incentive Potential</u>

Because these plans all operate by adjusting a utility's rate of return on overall investment, the incentive potential is the same as rate-of-return adjustments on total rate base. (See Section 3.1)

<u>3.122 DSM Incentive</u>

Because all of the approaches are designed to capture actual savings, they each produce reasonable incentives to pursue DSM activities . In each case more, or lower-cost, DSM will produce greater incentive payments.

<u>3.123 Decoupling</u>

In both the first (target/actual) and third (external index) criteria, sales promotion to existing customers would negatively impact the utility's measured performance, but would not affect the yardstick against which that performance is compared.[65] Thus, increased sales produce lower or negative incentives. This condition means the first and third criteria can decouple profits from sales.

For the internal index and before/after criteria, increased sales would affect both the yardstick and the utility's measured performance, and there would be no net effect on the incentive measure.[66] These criteria are therefore, not capable of decoupling profits from sales.

3.124 Scope

The first (forecast/actual), third (external index), and fourth (before/after) criteria would credit a utility's performance with all actions which reduce average bills in relation to the yardstick. Because bills are reduced by cost-effective demand-side measures and cost effective supply-side measures (or any cost-cutting opportunities the utility may have), these approaches can provide a wide range of desirable incentives. For example, forecasted average bills would include an assumption about the cost of new power acquisitions which would become the yardstick against which actual performance is measured. Utility power acquisition that is less costly than forecast will increase the utility's incentive payment.[67]

Supply-side decisions affect the yardstick in the second approach (internal index) to the same extent they affect the utility's measured performance. Therefore, this variation is limited to DSM programs.

3.125 Administrative Simplicity

All the criteria are reasonably easy to administer. The first (actual vs. forecast) and fourth (before/after) may involve more substantial regulatory proceedings to determine the scope and impact of any required adjustments. The second (internal index) and third (external index) would require less effort after the system is established, but more effort initially to create a reasonable index.

3.126 Cost Minimization

Approaches which include the cost of DSM programs in average bills, but which are not

[65] *The addition of new low-use customers would decrease average bills and the addition of new high-use customers would increase bills. As utilities have relatively little influence over their number of customers, the best a utility could realistically do is encourage all new customers to be as efficient as possible.*

[66] *In the fourth approach (before/after), there may be a partial decoupling, but only to the extent that the increased sales affect the group of participating customers.*

[67] *With respect to the first (forecast/actual) and fourth (before/after) approaches, the scope of the program is limited only by those matters taken into account to adjust the forecasted bills. Thus, if forecasted bills are adjusted to reflect actual purchases from qualified facilities, this element would be eliminated from the scope of the incentive plan.*

included in the yardstick, would provide incentives to minimize the cost of the programs. Thus, the first (forecast/actual) and third (external index) criteria would automatically provide an incentive to establish DSM programs at the lowest possible cost. In fact, with both criteria, if the cost of DSM programs exceeds the utility's avoided cost, average customer bills would increase and the utility would be penalized or at least receive no reward.

In the ordinary case, the second criterion (internal index) would not provide an incentive to minimize cost because the cost of DSM programs is borne by both participants and non-participants alike. Because the cost would be included in the average bills of the control group and all other customers, there would be no apparent change in bills and, therefore, no incentive to minimize the cost of DSM programs.

The fourth criterion (before/after) would provide a partial incentive to minimize cost because bills measured before a DSM program would not reflect the program cost, while the bills measured after program implementation would ordinarily reflect DSM program costs. The incentive is limited, however, because bill calculation will reflect only those costs which have been allocated to the participating customer class.[68]

3.2 SHARED SAVINGS

3.20 General Description

In the broadest sense, all incentive plans may be considered shared savings plans. Different approaches (e.g., rate-of- return adjustments, bounty, etc.) use different mechanisms to identify and split available savings, but no approach produces payments to utilities which exceed total savings. This section, however, considers only those incentive plans which explicitly identify a savings and propose a sharing mechanism to compensate utilities for all, or part, of the direct and indirect costs incurred from an energy efficiency improvement.[69]

Table 4 summarizes the incentives associated with the following four variations of shared savings plans:

(1) Resource Savings - Estimated - Shared savings proposals can be divided into two categories, depending on the savings being shared. This approach identifies a net resource savings as the difference between avoided cost and the cost of an energy

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[68] *The incentive would not be limited if the before/after calculation was adjusted solely for the purpose of determining the level of an incentive payment by allocating all DSM program costs to participating customers.*

[69] *For examples of this approach see Wellinghoff, "The Forgotten Factor in Least-Cost Utility Planning: Cost Recovery," P.U.F., March 31, 1988; and "Inquiry of a Ratemaking Methodology for Encouraging Demand-Side Resource Options, Finding and Conclusions," Docket No. 89-651, Nevada Public Service Commission, July 6, 1989.*

efficiency improvement.[70] The net savings is then split between the utility and the consumer. To distinguish this approach from others, it will be referred to as "shared resource savings." In this first performance criterion, the DSM savings are estimated.

(2) Resource Savings - Actual - The second variation is the same as the first except DSM savings are based on actual measurements.

(3) Bill Savings - This approach is similar to the model of third-party energy service companies that identify reductions in customer bills after an energy efficiency improvement. The savings are then split between the efficiency provider and the customer. The provider's share normally covers the installed cost of the efficiency improvement. This approach will be referred to as "shared bill savings."

(4) Unbundled Energy Services - Finally, proposed approaches exist, which in various ways, unbundle energy-supply and energy-savings services. These approaches "buy" or "sell" cost-effective energy conservation services from or to customers. In one variation, the utility (or contractor) installs a demand-side measure and charges the customer for the saved KWHs. The charge for KWHs is equal to the utility's retail rate. For example, the utility may either sell extra KWHs to power an uninsulated electric water heater or sell fewer KWHs plus the energy service of insulating the water heater. If the water heater insulation blanket saves 600 KWHs per year, the

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[70] *Some approaches define this difference in more detail than others. For example, the Nevada Notice of Inquiry provides:*

> *"Net System Benefits are the reduction in revenue requirements resulting from the implementation of demand-side programs. Such benefits are described by the Utility Cost Test contained in Chapter 5 of the California Standard Practice Manual... After removing the present value (discount and summation) terms and alternate fuel terms (which would apply to another utility) the formula becomes:*
>
> *NSB = [UAC] - [UC + INC + UIC]*
> *[Net System Benefits] [Benefits] [Costs]*
>
> *A sharing fraction g would be determined to allocate the savings between the utility and its customers such that the demand-side incentive (DSI) would be:*
>
> *DSI = g(NSB), where: 0 < g > 1*
>
> *The sharing fraction would be set at the sole discretion of the Commission at the time of its preapproval of capitalizing the applicable demand-side program(s). At a rate case proceeding, the net system benefits accrued since the previous rate case would be allocated."*

utility charges the customer the full retail rate for the saved energy.[71]

Another, and very similar, approach exists which incorporates demand-side bidding procedures into a qualifying facility and supply-side action. In this approach the retail customers or a third-party energy service company could bid to deliver demand-side measures on the same basis as a supply-side proposal, but the bidder would pay the utility for saved KW and KWH at the full retail rate.[72]

Appendix B includes a discussion of the comparison of unbundled bidding plans to shared bill plans. The discussion concludes that unbundled energy plans are essentially shared bill savings plans in which most savings are retained by the utility.

TABLE 4
SHARED SAVINGS

PERFORMANCE CRITERIA	**(1) Resource Savings Estimated**	**(2) Resource Savings Actual**	**(3) Bill Savings****	**(4) Unbundled Energy Services**
DSM INCENTIVE	Perverse and inadequate	Good, but inadequate	Good	Good
DECOUPLING	No	No	Depends on measurement (see Table 3)	No-But offsets lost revenues
SCOPE	DSM and possibly new supply	DSM and possibly new supply	DSM	DSM only
COST MINIMIZATION	No-Unless payment includes cost recovery	No-Unless payment includes cost recovery	Maybe, See Table 3	Yes
ADMINISTRATIVE SIMPLICITY/COST	Low cost	Low cost if data is already produced for program evaluation, otherwise Medium	Low market penetration, Medium cost	Difficult to under-stand, Medium cost

**The measurement variations in Table 3 apply with equal force to shared bill savings.

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[71] *Whittaker. "Conservation and Unregulated Utility Profits: Redefining the Conservation Market," Public Utilities Fortnightly, July 7, 1988; and Katz. "Proper Utility Incentives: Everybody Wins," presented at Western Conference of Public Utility Commissioners, June, 1989.*

[72] *See Cicchetti and Hogan. "Including Unbundled Demand-Side Options in Electric Utility Bidding Programs," Public Utilities Fortnightly, June 8, 1989.*

3.21 Incentive Potential

Some, but not all, of the shared savings plans can produce enough incremental earnings to offset existing financial disincentives. For example, in shared resource plans, the savings (Savings = Avoided Cost - DSM Cost) available to be shared approaches zero as the DSM cost approaches full avoided cost. This is why incentive plans which incorporate shared resource concepts are combined with other cost recovery and decoupling approaches.[73]

The savings available from a bill savings plan can be large enough to offset lost revenues and DSM costs. For example, using the typical utility data shown in Section 3.0, the bill savings to the participating customers would be $.07 per KWH. This savings would be adequate, albeit barely, to compensate the utility for a $.05 non-fuel revenue loss, plus the $.02 cost of conservation. In addition, a further $.01 net savings associated with fuel costs (the difference between the $.02 average and $.03 marginal fuel cost) would result which, under ordinary circumstances, would be shared by all customers.[74]

3.22 DSM Incentives

Table 4 summarizes the incentive structure of various shared savings approaches. Like other incentive plans, shared savings plans which rely upon estimated savings produce the wrong incentives. Under this variation, superior results will yield lower earnings and vice versa.

Either the shared resource or bill savings approach can yield reasonable incentives if the savings to be shared are based on actual achievements.[75]

3.23 Decoupling

The extent of decoupling depends on the specific performance criteria. For example, if bill savings are identified using either before/after or participant/non-participant comparisons, the incentive to increase sales is largely unaffected, and decoupling is not achieved. On the other hand, measuring shared bill savings by the target/actual or external index approaches can decouple profits from sales.[76]

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[73] *For example, the preferred approach in Nevada correctly combines a shared resource savings approach with DSM cost recovery and a mechanism to restore lost revenues. Likewise, New York has recently approved temporary incentive plans for Niagara Mohawk and Orange and Rockland, which combine a shared revenue approach with DSM cost recovery and lost revenue recovery.*

[74] *The $.01 fuel savings is not available for use in a shared savings plan because it is shared by all customers.*

[75] *By the nature of the plan, bill sharing approaches tend to be ex post or actual measurements.*

[76] *Measuring on this basis is more amenable to plans that focus on average bills for large groups of customers, as opposed to plans that are limited to customer specific bill savings. See Geller, "Use of Financial Incentives to Encourage LCUP and Energy Efficiency," June 1988, for a fuller discussion of the*

Shared resource savings approaches do not result in decoupling. Consequently, this approach will produce the desired incentives only if it is combined with other plans which decouple profits from sales.

3.24 Scope

The shared resource savings approaches proposed have focused only on demand-side measures. There is no reason, however, why supply-side resource saving cannot be measured and shared in a similar fashion.

The efficiency of supply-side decisions is ultimately reflected in customer bills. Therefore, depending on the precise performance criteria selected (see Table 3), bill sharing plans can capture efficiency gains for both demand- and supply-side resources.

3.25 Administrative Simplicity

Resource savings approaches require the measurement of avoided costs, as well as the cost and quantity of capacity and energy saved by efficiency programs. As a general matter, commissions and utilities already calculate avoided costs for other purposes and therefore will not need to undertake complicated administrative requirements. Deriving program-by-program savings estimates will require significant effort unless the data is already gathered for DSM program evaluation or other purposes.[77]

Different measurement issues are raised for a shared bill approach. The principal information required to conduct a shared bill plan is readily available customer billing information. Additionally, methods of identifying changes in customer bills such as before/after or participant/nonparticipant comparisons must be developed.

The unbundled approaches involve measurement issues similar to those of shared bill plans. However, unbundled plans raise serious questions of public understanding and customer acceptance. For example, it is unlikely that any but the most sophisticated customers will accept plans which require the participating customer to continue paying for saved KWHs.

3.26 Cost Minimization

Some variations of shared savings approaches can provide incentives for utilities to maximize net savings and to obtain efficiency or other resources at the lowest possible cost.

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target/actual
approach. Also, see Section 3.12 for additional discussion of the difference between the various bill savings measurement approaches.

[77] *While a shared resource savings approach could be administered on a program-by-program basis, the same result would occur if measured on an aggregate basis. Measuring aggregate program impacts may pose fewer problems than attempting to disaggregate to the program level.*

Shared resource savings approaches which include DSM program cost-recovery as part of the utility's share of the savings will provide an incentive to achieve savings at the lowest possible cost. If DSM program costs are recovered through separate ratemaking procedures, the plan itself will not provide a financial incentive to be cost effective and other procedures must be used.[78]

Shared bill savings approaches ordinarily include DSM program cost recovery as part of the utility's or ESCO's savings share. Therefore, these approaches provide a financial incentive to minimize the cost of DSM programs.[79]

3.27 Non-Participant Impacts

The ability of different incentive approaches to create incentives to minimize non-participant impacts is discussed in Appendix A. It is also noted here because two of the shared savings approaches, shared bill savings and unbundled energy services, are designed to eliminate non-participant impacts. In the ordinary form of both of these variations, all of the DSM program's direct and indirect costs are borne by the participating customers and there are, consequently, no non-participant impacts.

3.3 BOUNTY

3.30 General Description

Bounty approaches provides payment, i.e. a bounty, to utilities in return for specified achievements. For example, a utility might be paid a bounty of "x" cents for each KWH saved, or "y" dollars for each block of power saved.[80]

Table 5 summarizes the incentives produced by five different performance criteria for bounty plans. Any of the criteria can be implemented based on bounty per KWH, KW, or a combination of the two. The performance criteria are as follows:

(1) Estimated Savings - In the first criterion, DSM impacts are based on estimated savings determined prior to program implementation. A bounty, or payment, is made to the utility for each KW or KWH of estimated savings.

[78] *The incentives to deliver lowest-cost DSM programs will be determined by the characteristics of the separate cost-recovery mechanism, not the shared savings plan.*

[79] *The specific incentives, however, depend on the way bill savings are measured. The conclusions contained in the discussion of "Rate-of-Return Adjustment - Customer Bills," apply with equal force here.*

[80] *The payment is always less than avoided cost; thus, this approach can also be considered a shared savings plan.*

(2) Actual Savings - The next criterion measures DSM program impacts after the fact to identify actual results.

(3) Single Price - This criterion is a particular variation of (2) in which the bounty is a single fixed payment for each KWH saved. Thus, if a bounty is established at $.02 per KWH saved, $.02 would be paid whether the KWH were saved by a lighting program, an insulation program, or a motor replacement program.

(4) Multiple Price - This criterion is another variation of (2), but different prices are set for different programs. The bounty amount depends upon the type and cost of the program and its on-peak/off-peak resource-savings characteristics.

(5) Load vs.Forecast - The last criterion shown in Table 5 pays the utility based on achieved savings measured by comparing actual power demands to previously forecast demands adjusted for major variables such as weather and economic conditions (target/actual).

TABLE 5

BOUNTY

PERFORMANCE CRITERIA	**(1) Estimated Savings**	**(2) Actual Savings**	**(3) Single Price**	**(4) Multiple Price**	**(5) Load vs. Fore-Cast**
DSM INCENTIVE	Perverse	Good, but insufficient	Good, but insufficient	Good, but insufficient	Good, but insufficient
DECOUPLING	No	No	No	No	Yes
SCOPE	DSM and possibly supply	DSM and possibly supply	DSM and possibly supply	DSM and possibly supply	DSM only
COST MINIMIZATION	No-Unless bounty includes program cost recovery	No-Unless bounty includes program cost recovery	Yes-But risk of cream skimming	Yes	No-Unless bounty include program cost recovery
ADMINISTRATIVE SIMPLICITY/COST	Low cost	Medium cost	Medium cost	High cost	Medium cost

3.31 Incentive Potential

Bounty payments are ordinarily limited to full avoided cost and, therefore, can compensate utilities for only direct DSM costs which, at the extreme, are equal to avoided costs. Consequently, bounty plans must be combined with other cost recovery and decoupling options to be fully effective.

3.32 DSM Incentives

As was the case for all of the other incentive criteria, basing the incentive payment on estimated results produces perverse incentives. Alternatively, the incentives are reasonably good for bounty programs when performance criteria based on actual program achievements are measured on a program-by-program or aggregate basis.

The principal difference between the single price and multiple price variations in bounty plans (both assumed to be measured with actual figures) is that the single price plan will provide the greatest incentives to obtain the lowest cost efficiency opportunities.

In the multiple price plan, bounty prices would be set lower for low cost savings and higher for high cost efficiency opportunities. Generally, the different bounties would be priced to produce the same level of incentives to pursue cost effective DSM opportunities, regardless of the cost of the opportunity.[81]

For the fifth criterion (target/actual), the utility would have an incentive to achieve the greatest possible savings.

3.33 Decoupling

In each of the first four variations (estimated, actual, single price, multiple price), increased sales, regardless of the cause, have no effect on the apparent success in meeting a performance measure. Therefore, none of these criteria decouple profits from sales.

The fifth criterion (target/actual) can at least partially decouple because increased sales lead to a higher level of actual load, which reduces the bounty paid to the utility. This characteristic can be used to decouple profits completely from sales, but only if the level of the bounty is adequate.[82]

3.34 Scope

While bounty plans have been implemented or discussed only in conjunction with demand-side programs, there is no theoretical reason why these criteria cannot be applied to supply-side resources. A bounty can be offered for each MW of cost effective capacity, each MW of a renewable resource, or each MW of an environmentally benign source.

3.35 Administrative Simplicity

Administrative costs are the highest with the fourth criteria (multiple prices), due to the need to track separate program savings and incentive payments.

3.37 Cost Minimization

The bounty criteria provides the impetus to minimize delivered efficiency improvement costs only if the bounty payments include compensation for DSM program expenditures.

3.4 DECOUPLING

[81] *This discussion of the distinction between single- and multiple-price bounty plans assumes that the bounty payment includes the utility's program cost recovery. If a utility's program cost are recovered in another fashion, then the single price approach will provide an equal incentive, regardless of the direct program cost.*

[82] *The extent of decoupling depends on the difference between the added earnings from increased sales and the earnings reduction due to lower measured load reductions.*

3.40 General Description

Breaking the link between profits and sales is an important step towards correcting the current regulatory system's incentives.

Some variations of the three general incentive plan categories involve performance measures that tie incentive payments to sales levels. In these instances, the utility is not explicitly made whole.[83] Instead, higher sales lead to a smaller or even negative incentive and lower sales lead to greater incentive. Decoupling profits from sales is accomplished when the incremental earnings from increased sales is equal to or less than the incremental reduction in earnings produced by the incentive plan. Many of the plans discussed and described in the tables, however, cannot decouple profits from sales. Nevertheless, these plans can be used if combined with separate regulatory reforms which decouple. Indeed, any of the plans described, even those capable of decoupling, can be combined with separate decoupling approaches. In that case, the need for the incentive plan would be significantly reduced.

3.41 Electric Revenue Adjustment Mechanism (ERAM)

In 1978, the California Public Utilities Commission adopted the Electric Revenue Adjustment Mechanism (ERAM). At the time of a rate case, the California Commission, using a future test year approach, established the utility's non-fuel revenue requirement. ERAM uses the revenue limit established in the rate case and, on a going-forward basis, tracks non-fuel revenue as it is received by the utility from customers. To the extent that actual annual non-fuel revenue collected by the utility deviates from the allowed revenue, the company either surcharges or refunds ratepayers.[84]

If sales and, therefore, revenues are lower than expected, the revenue shortfall is returned to the utility though a rate adjustment. If sales and, therefore, revenues are higher than expected, the utility must return the over-collection to customers. These adjustments are made regardless of the cause of the revenue difference.[85] Since 1978, ERAM has produced ratepayer refunds about as often as it has produced utility surcharges.

The important difference between ERAM and approaches which restore DSM-induced lost revenue is the different treatment of revenue from increased sales. This is the ERAM element that removes the profits from increased sales.

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[83] *California's ERAM is an example of an effective decoupling approach which does operate as a make-whole mechanism.*

[84] *Because revenues are fixed and not earnings or profits, the incentive to cut costs and thereby increase the level of earnings remains unchanged.*

[85] *Besides conservation, the major factors that affect sales and revenue levels are weather and economic conditions. While making utility revenues indifferent to sales, ERAM also makes utilities indifferent to weather and general economic conditions. Because neither weather nor economic conditions are within the utilities' control, little is lost by removing the risks from utilities.*

Finally, because ERAM operates on an overall revenue level, measurement of energy efficiency is not required. The only measurement requirements, namely revenues, are straightforward and easily verifiable.

3.42 ERAM on a Per-Customer Basis

Because ERAM fixes revenue requirements for a future period, it requires a forecast of all rate case components that will influence the utilities' future revenue requirements. This means ERAM, as implemented in California, fits well only with states using a future test year approach to rate-making or an historic test year supplemented with attrition analysis.[86]

A variation on the California ERAM exists, which can be implemented in states using either historic or future test year. At the time of a rate case, revenue requirement is divided by the corresponding number of customers (by customer class). This produces a revenue-per-customer limit which would then operate like ERAM. While new rates are in effect, the utility tracks non-fuel revenues received from customers, as well as the number of customers. Rates are adjusted annually so the utility retains only the allowed non-fuel revenue per customer.

The theory behind setting rates on an historic test year basis is that the test year establishes a constant relationship between costs, investments, and revenues. Increased revenues, realized in the period during which rates are to be in effect, are supposed to offset higher costs incurred after the test year and no more. In fact, in the short term, increased sales to existing customers do not produce increased non-fuel related costs.

Using a revenue-per-customer approach is a practical way to reconcile the realities of utility economics with the theoretical basis of historic test year ratemaking. This approach allows utilities to retain incremental revenues associated with higher sales due to changes in the number of customers. Because new customers often mean new non-fuel related costs, including poles, wire, meters and capacity, this modification tends to reduce earnings erosion that would occur if a strict revenue cap were imposed. Meanwhile, increased revenue (net of fuel costs) that results from increased sales to existing customers would be returned to customers instead of increasing utility earnings.

3.43 Fuel Revenue Accounting

An approach implemented in Maine in 1986 can be used to decouple profits from sales in states with a reconciled fuel adjustment clause.

Most states with a reconciled fuel adjustment clause either explicitly or implicitly allocate

[86] *An attrition analysis also requires forecasted sales and expense levels and is, therefore, amenable to a California ERAM approach.*

average fuel cost to each KWH sold. Thus, a $.07 commercial rate and a $.05 industrial rate each include $.02 of average fuel cost. This means that the non-fuel contribution to earnings is $.05 for the commercial rate and $.03 for the industrial rate (rate minus average fuel cost).

Similarly, for a utility with time-of-use or seasonal rates, the higher on-peak rates make a greater contribution to profits. For example, a utility may have a $.10 per KWH on-peak rate and a $.05 per KWH off-peak rate. In most states, both prices include an average fuel cost of $.02. This means the non-fuel component of the on-peak rate is $.08 and only $.03 for the off-peak rate. On-peak sales, therefore, add substantially more to earnings than off-peak sales, and a utility able to shift load from off-peak to on-peak periods realizes higher, not lower, profits.[87] This is exactly the opposite of what regulators would like to have happen. Of course, the more likely response to these incentives is that the utility would not actively encourage or assist customers in shifting on-peak load to off-peak periods.

These issues, along with decoupling profits from sales, can be addressed by changing the accounting treatment of fuel and non-fuel revenues.[88] Rather than account for all fuel revenues on a flat average per KWH basis, a greater proportion of on-peak (or tail-block) prices can be treated as fuel revenue, leaving a smaller portion of on-peak (or tail-block) rates to contribute to earnings.[89]

The following table illustrates the changes in accounting using the previous example of a utility with time-of-use prices.

	ON-PEAK	OFF-PEAK
BEFORE		
Fuel (cents/KWH)	$.02	$.02
Non-Fuel (cents/KWH)	$.08	$.03
Price (cents/KWH)	$.10	$.05
AFTER		
Fuel (cents/KWH)	$.08	$.01
Non-Fuel (cents/KWH)	$.02	$.04
Price (cents/KWH)	$.10	$.05

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[87] *Boston Edison recently implemented time-of-use rates which resulted in customers shifting load from on-peak to off-peak periods. The difference between on-peak and off-peak contribution to earnings meant Boston Edison experienced a significant drop in its earnings.*

[88] *Changing the accounting treatment does not require any change to actual retail prices. The accounting changes are invisible at the customer level but very visible to the utility.*

[89] *A utility's price structure might charge $.05 per KWH for the first 300 KWH's and $.06 per KWH for all additional KWHs. The $.06 portion of the price structure is called the tail-block.*

This table points out three important features of fuel revenue accounting:

* Prices are unchanged by the accounting change. Rate design questions do not arise from such an approach.

* Shifting consumption from on-peak to off-peak previously cost the utility $.05 in lower earnings. After the accounting change, utility earnings would increase by $.02.

* Increased on-peak sales used to be very profitable. After the change, increased on-peak sales may not be profitable at all.[90]

The same approach can be used for rates without time-of-use or block features. For these rates, new "accounting blocks" can be created that accomplish the same result. For example, a flat $.07 per KWH residential rate can be turned into a two-block rate schedule. The first 300 KWH would be billed to customers at $.07 per KWH but accounted for as $.05 non-fuel revenue and $.02 of fuel revenue. Sales in excess of 300 KWH would also be billed to customers at $.07 per KWH but accounted for as $.02 non-fuel and $.05 fuel.

These changes are illustrated in the following table:

	FIRST 300 KWH	EXCESS SALES
BEFORE		
Fuel (cents/KWH)	$.02	$.02
Non-Fuel (cents/KWH)	$.05	$.05
Price (cents/KWH)	$.07	$.07
AFTER		
Fuel (cents/KWH)	$.02	$.05
Non-Fuel (cents/KWH)	$.05	$.02
Price (cents/KWH)	$.07	$.07

Making these changes in the accounting treatment of fuel substantially reduces and possibly eliminates the non-fuel contribution of the marginal KWHs sold. Decoupling is accomplished when incremental sales add only that revenue needed to offset incremental costs.[91] Meanwhile, in all other

[90] *If the $.08 fuel revenue attributed to the on-peak KWH sales exceeds the actual marginal fuel costs, the difference would be returned to customers because of the fuel clause reconciliation provisions. This reimbursement to customers would further reduce the on-peak contribution to earnings below the apparent $.02 level.*

[91] *In addition to decoupling of profits from sales, this approach tends to level utility earnings over the course of a year, thereby reducing earnings volatility and reducing earnings sensitivity to weather and other uncontrolled factors.*

respects the fuel clause mechanism remains intact. During each fuel clause period, an effort is made to match fuel costs with fuel revenues, and any differences are made up in subsequent periods.

3.44 Fuel Clause Reform

Another approach for states with fully reconciled fuel adjustment clauses is to eliminate or reduce the extent or scope of reconciliation. Abolishing the reconciliation features of a fuel adjustment clause would mean that incremental revenues from increased sales would be at least partially offset by incremental fuel costs. Conversely, saving a KWH would produce cost savings equal to the marginal cost of fuel. This cost savings would at least partially offset the revenue lost by foregoing a sales opportunity. Incremental sales would continue to add to earnings, but only to the extent that the marginal price of electricity exceeds the marginal fuel cost of producing the electricity.[92]

A milder reform to accomplish a similar result would be to continue the reconciliation provisions of fuel clauses, but limit the scope of reconciliation to changes in fuel prices. For example, fuel clauses might initially be established based on projected fuel prices expressed as dollar per barrel, dollar per ton, etc. Reconciliation, or true-up, provisions would then be limited to adjustments which reflect the difference between the assumed fuel prices and actual prices. Fuel quantities, a function of plant performance and sales levels, would not be reconciled. An incremental KWH sold would increase fuel quantity without regard to what may have happened to fuel prices. Similarly, saving a KWH would reduce fuel quantity and save the utility the marginal cost of fuel used to produce the KWH.

The effect of this change on the DSM incentives would be the same as eliminating the reconciliation features entirely. This approach, however, would continue to insulate utility earnings from the volatility of fuel prices.

The attributes of these four decoupling approaches are summarized in Table 6.

TABLE 6

DECOUPLING

	ERAM	ERAM CUSTOMER	FUEL ACCOUNTING	FUEL REFORM

[92] *Currently, retail prices almost always exceed the utilities' marginal fuel cost.*

EXTENT OF DECOUPLING	Complete	Complete	Partial to Complete	Partial
LIMITATIONS	Requires future test year	Future or historic test year	Requires reconciled fuel clause	Limited ability to correct incentives

Conclusion

Table 7 presents a summary of the conclusions reached in this Section. Listed across the top of the Table are different assumptions of how state regulation of incentive plans might be structured. For example, the first column, "W/O Decoupling, W/O DSM Cost Recovery," describes a state which has not adopted ERAM or any of the other decoupling options and which has no separate DSM program cost-recovery mechanism. This means that the incentive plan selected must be capable of decoupling profits from sales and also give reasonable treatment to DSM program costs. Next, the table summarizes the capabilities of alternative incentive plans to produce a desirable result given the assumed regulatory status. A "yes" (Y) response means the incentive approach is a good candidate and attention should turn to the various ways that the general approach can be implemented. A "no" (N) response means the approach is not a good candidate and a "maybe" (M) response means the performance of the approach depends on other factors.

TABLE 7

SUMMARY
ALTERNATIVE INCENTIVE PLANS

	W/O Decoupling W/O DSM Cost Recovery	**W/Decoupling W/O DSM Cost Recovery**	**W/O Decoupling W/DSM Cost Recovery**	**With Decoupling W/DSM Cost Recovery**
Rate-of-Return Overall	Y	Y	Y	Y
Rate-of-Return DSM	N	N	N	Y
Rate-of-Return Bills	Y	Y	Y	Y
Shared Savings Resource	N	M (See Note 2)	M (See Note 2)	Y
Shared Savings Bill	M (See Note 1)	Y	M	Y
Bounty	M (See Note 1)	Y	Y	Y

Y - Yes, the approach is capable of producing the right incentives.

N - No, the approach is not capable of producing the right incentives.

M - Maybe. Under some conditions the approach can be made to produce reasonable incentives.

(Note 1: This approach can address all costs only if average fuel costs exceed marginal fuel costs, which is rarely the case. Otherwise, they are sufficient only for low-cost measures.)

(Note 2: This approach is possible only for very low-cost DSM measures and very low-cost revenues.)

All cases assume the use of actual rather than estimated savings.

APPENDIX A

There are a number of factors slightly less important than the factors discussed in Sections 2 or 3 but which should nevertheless be considered when designing or selecting an incentive plan. These items include consideration of fuel-switching, environmental externalities, minimization of non-participant impact, cream-skimming, and predictability.

A.0 Fuel Switching

Will the plan reward programs that achieve cost effective fuel switching by customers?

Instances exist in which large electricity and overall energy efficiency savings are feasible through fuel switching programs.[93] In some instances, switching may occur from electricity to natural gas, while in others, electricity is exchanged for a renewable fuel, for example, solar or wood. In either case, alternative incentive plan evaluations should consider how electric utility profits change as a result of customer fuel switching. Under the current system, electric utilities discourage fuel switching, no matter how cost effective, because it always means lower profits.[94]

All of the incentive plans described in Section 3 can accommodate fuel switching programs. However, some plans require a conscious decision to treat fuel switching programs like all other efficiency programs while others automatically reflect fuel switching electricity savings. For example, rate-of-return adjustments to either estimated or actual DSM savings would capture the savings of cost-effective fuel switching, but only if the fuel-switching programs are specifically treated as eligible DSM programs for which savings are estimated or measured. In contrast, rate-of-return adjustments based on load/forecast comparisons would automatically reward fuel-switching efforts.

A.1 Environmental Costs

Many states which have adopted LCP also attempt to incorporate environmental externalities in the planning and decision making process. Traditional utility planning has always included consideration of a utility's directly incurred environmental control costs. Thus, the cost of building and operating a sulfur dioxide scrubber is reflected in the cost of a new coal-fired power plant. Even a scrubbed coal plant, however, emits pollution whose environmental damage is not borne by the utility or reflected in its prices. In increasing numbers, states attempt to take these externalized costs and reflect them in the LCP decision process.[95]

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[93] *The availability of fuel switching as an element of a least cost plan varies from state to state. States with combined gas and electric utilities are more likely to look favorably on fuel switching as an option.*

[94] *The impact will be different for combined gas and electric utilities.*

[95] *External benefits from new power supplies, such as construction jobs, tax revenue, and backing-out foreign oil, are often given weight in investment decisions. External costs should be given as much consideration as external benefits.*

None of the general approaches to incentive plans expressly consider environmental externalities. Nevertheless, once a state has decided how to incorporate environmental concerns in its decision-making process, reflecting that decision in any of the alternative plans is not a difficult task.

To illustrate, a state might decide that its consumers and society overall would be served by imposing a 20% economic penalty for fossil fuel sources of generation when making its resource decisions. In other words, a state might decide that ratepayers and society would be better off paying 20% more for electricity, but saving the costs that higher levels of pollution would cause. Incorporating this type of decision into an incentive plan means that the utility's correct decision to select a 20% more expensive but cleaner option should not jeopardize its efforts to achieve the same earnings level it would have without the clean option selection. Thus, special attention should be paid to any incentive plan that measures performance against a standard without the same 20% environmental concern cost premium.

For example, consider a plan that focuses on the utility's relative ability to control customers' bills, as compared to an index of other companies. Adding 20% to the cost of the utility's new resource acquisitions (demand- or supply-side) would make the utility appear to be less efficient than the utility index group (assuming the other utilities have not had a similar policy imposed on their resource decisions). To make the bill comparison fair, 20% of the cost of all of the target utility's added demand-and supply-side resources should be subtracted from the utility's average bills before comparing its performance to the index.

A.2 Non-Participant Impacts

Is the proposed program designed to minimize nonparticipant impacts? Depending on the utility's average and marginal costs and the state specific mechanisms for DSM cost recovery, DSM programs may have an adverse impact on average prices, thereby raising prices and bills for customers who do not participate in DSM programs.[96]

As a general matter, the non-participant impact of even very large DSM programs is small, much smaller than the impact of supply-side options.[97] However, with the exception of the shared bill savings, unbundled approaches, and some of the customer bill approaches, incentive plans generally do not provide financial incentives to minimize non-participant impacts. Nevertheless, incentive plans can be structured to encourage utilities to design DSM programs in ways that minimize non-participant impacts. Generally, however, there are three steps to be taken which may address this concern.

First, a number of the variations of alternative plans provide an incentive to minimize the

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[96] *Rates for participating customers increase as well, but the DSM program causes their bills to decrease.*

[97] *For a more complete discussion of this and related issues see Cavanagh, "Responsible Power Marketing in an Increasingly Competitive Era," 5 Yale Journal on Regulation 331, 1988.*

cost of energy efficiency programs. Minimizing the cost of energy efficiency will tend to minimize non-participant impacts.

Second, plans can be designed to provide incentives for utilities to obtain as much contribution as possible from participating customers. The greater the customer contribution toward energy efficiency, the lower any non-participant impacts. For example, rate-of-return adjustments based on average customer bills can exclude from the bill calculation any direct participant contribution. The greater the participant contribution, the larger the apparent bill savings and the larger the incentive. This approach, however, tends to undermine the level of participation in energy efficiency programs and, thus, may be counterproductive.

Finally, non-participant impacts may also be addressed by assuring that energy efficiency programs are widely available to all customers and all customer classes. Wide program availability will tend to minimize the number of non-participating customers.

A.3 Skimming the Cream

Will the proposed incentive plan encourage the utility to engage in cream-skimming programs, and, if so, how much of a concern is that practice?

Skimming the cream in this context means designing and carrying out only the lowest-cost measures while leaving behind other cost-effective opportunities for energy efficiency. The most common example occurs in new construction where cost-effective measures left out at the time of construction are prohibitively expensive to fix later.

In another example, commercial lighting retrofits might cost two cents per KWH saved, while heating and cooling improvements might cost four cents if done on the same trip, but six cents if done separately. An incentive program that paid the utility five cents for each saved KWH might cause the utility to improve the lighting and earn three cents while foregoing the four cent cooling improvement that would have netted only one cent. An incentive plan that paid the utility three cents for lighting and five cents for heating and cooling would net the utility the same one cent for both projects.[98]

The most important reason to avoid cream-skimming is that cost effective opportunities will be permanently lost and consumers will pay more than necessary for energy services.[99]

Of course, in comparison to existing regulations, a plan which suffered only from the potential for cream-skimming would be a vast improvement over the current system. Nevertheless, one should be aware of the possible problem and the available solutions, including solutions outside

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[98] *In this case one might still encounter another type of cream-skimming where the utility pursues only the easiest lighting and heating opportunities.*

[99] *In all cases, the DSM opportunities at risk are cost effective, but the payback on the less cost-effective measures is below the hurdle rate for the investing entity.*

of an incentive plan itself. Cream-skimming potential is generally the greatest with plans which provide strong incentives to utilities to minimize the cost of energy efficiency.

In general, there are three ways to lessen the potential for cream-skimming. First, some level of regulatory oversight of program design can be retained to assure that cream-skimming programs are not implemented. This is the current approach, and this level of regulatory oversight could continue even with significant reforms of financial incentives associated with DSM program implementation.[100]

Second, any of the incentive plans may be implemented in a more disaggregated fashion. For example, bounty plans can be established to create different bounty levels for different types of programs. Lower bounties for relatively inexpensive conservation measures, and higher bounties for more expensive programs, would tend to minimize any financial incentive to pursue cream-skimming opportunities.

Third, plans which allow utilities to recover actual program costs separately from incentive plans tend to remove cream-skimming incentives. This approach, however, also removes the incentive to minimize program costs.

A.4 Predictability

While regulators will always maintain a wide range of discretion in rate-setting proceedings, incentive proposals that clearly lay out guidelines and expectations are likely to motivate utility managers more than alternatives that rely heavily upon the exercise of commission discretion.[101] Regardless of how responsible, consistent, and objective regulators are, suspicion will always exist between regulatory commissions and utilities.[102] Consequently, incentive proposals which rely upon the discretion of commissioners may not achieve full potential in motivating utility managers, even if the commission discretion is always exercised in a responsible manner.

Predictability does not mean that the utility should know in advance, or be guaranteed a particular level of earnings. Rather, the utility must know that a specific accomplishment will produce a particular and predetermined effect. The greater and more immediate the cause and effect, the more likely it is that the regulatory incentives will have a positive influence on utility managers. Similarly, incentives that reward promptly, rather than in the distant future, will be most effective.

Any of the incentive plans described in Section 3 can provide the needed level of predictability by assuring that the rules are clearly articulated prior to implementing the incentive plan. For example, in the rate-of-return adjustment criteria, it would be important to state in advance

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[100] *In addition, experience with collaborative design efforts in New England suggests utilities and energy efficiency advocates can work together to design conservation programs in which cream-skimming potential is minimized.*

[101] *An extreme example of a plan that relies on commission discretion consists of a general promise by regulators that a utility will be treated generously if it successfully pursues any LCP.*

[102] *Even where there is no distrust the relatively short tenure of most commissioners -- about 4 years in the U.S. -- adds to the lack of predictability of approaches that rely on commission discretion.*

how much the rate of return would be adjusted for a particular level of results.

With respect to measurement related issues, establishing measurement criteria in advance is all that is required. For example, a plan could require program savings to be measured by randomly testing and sub-metering a sample of 2% of the installations per year. Indeed, going further and specifying that each installation will be assumed to save "x" KWH is counterproductive.

A.5 Avoid Gaming

Any regulatory system, including traditional utility regulation, is subject to efforts by parties to engage in short-term "gaming." Simple manipulations, like the timing of rate case filings, or the timing of certain maintenance expenses (such as plant maintenance or tree trimming) which can be deferred or accelerated, can all have a significant effect on the utility's bottom line. Care should be taken when selecting and designing regulatory proposals so that the opportunity for gaming is no greater than it is already.

One way to lessen the incentive for manipulation is to assure that the implemented plan will remain in effect long enough to make such gaming risky. In addition, short term gaming temptations would be minimized by allowing the capitalization and amortization of DSM program costs in a way that bears some relationship to program benefits. A recent study by the Alliance to Save Energy includes an excellent discussion of this issue.[103]

A.6 Distribution of Incentives

The effectiveness of economic incentives is a function of where the incentives are directed within the utility company, i.e., shareholders, managers, employees, etc. The implementation of regulatory incentives which serve to benefit only distant stockholders will not be as effective as regulatory incentives which are at least in part directed toward utility executives and managers responsible for the successful (or unsuccessful) implementation of the least-cost plan.

Many utilities already have incentive compensation plans in effect. These plans may not be consistent with LCP incentive plans. For example, a compensation plan that weds the salary of a plant manager to heat rate may be compatible with LCP while a compensation plan tied to sales levels would not.[104]

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[103] *"Ratebasing of Conservation Program Costs", The Alliance to Save Energy, Discussion Paper, Washington, D.C., November, 1987.*

[104] *Central Maine Power Company has instituted a management compensation plan which rewards top managers based on CMP's rates relative to other New England utilities and the level of the company's earnings per share. By selecting relative rates instead of bills, managers' salaries go up if there is little or no conservation and salaries go down if the company succeeds in implementing substantial amounts of cost-effective efficiency. The same is true for earnings per share. Earnings will go up if sales increase.*

APPENDIX B

OTHER CONSIDERATIONS

A number of other considerations and questions frequently arise in discussions concerning the implementation of regulatory incentives. The most frequent subjects are discussed briefly below.

B.0 Effects of External Causes

One criticism of some proposals is that they fail to hold utilities harmless from factors outside the utility's control.[105] Generally, it makes little sense to have regulatory incentives in place when there is no ability on the part of the utility manager to respond to the incentive. Therefore, regulatory incentive plans should attempt to hold utilities harmless from factors truly outside their control. This policy must be considered with an appreciation of the extent to which existing regulation accomplishes this goal. For example, while weather is outside a utility's control, profits are subject to sales fluctuations caused by weather under current regulations.

Unless utility profitability is somewhat insulated from the influence of outside factors, the earning fluctuations occasioned by some factors (i.e., price of fuel) may be so large in relation to the desired regulatory incentives that the incentives become ineffective. For example, consider a plan that allows a utility's rate of return to rise or fall up to 100 basis points based on DSM program performance, but also removes all financial protection from changes in fuel prices. Once the 100 basis point cap is reached, the incentive plan is ineffective. Thus, if utility managers reasonably expect that the cap will always be hit due to changing fuel prices, the incentive plan will be much less effective than intended.[106] This is not to say that utilities should be insulated from all of the risks that bear on competitive firms.

Again, this factor should also be considered in the context of existing regulations. Under the present system, for example, utilities are not held harmless from the effects of weather and economic conditions.[107] Both these factors can have a very significant effect on utility earnings, and the fact that incentive plans also do not hold utilities harmless from changes in weather and economic conditions, therefore should not be a sufficient reason for dismissal.

B.1 Role of Unregulated DSM Subsidiaries

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[105] The entire notion of holding utilities harmless from factors outside their control is a subject in itself, and is unique to regulated industries. In the context of regulatory reform, critics often point out that particular proposals result in benefit or harm that flow from plant performance, fuel prices, economic conditions, etc. While regulators are generally sympathetic to some or all of these concerns, it is worth noting that competitive businesses are subject to the same considerations and are not held harmless. To be sure, these differences in the risk profiles of various industries can and should be reflected in allowed rates of return.

[106] For the purpose of this discussion it is assumed that fuel price changes are outside the utility's control.

[107] Indeed, the strong economy and hot weather of recent years has had a positive effect on utility earnings.

Some utilities already have unregulated energy service subsidiaries, and others may be in the process of seeking similar approvals. The operation of unregulated DSM subsidiaries may prove to be a useful adjunct, but the creation of such subsidiaries is no substitute for regulatory reform.

With an unregulated subsidiary, but without regulatory reform, a situation would exist where the successful operation of the unregulated subsidiary has an adverse impact on the parent utility's earnings. The question would remain whether a profit maximizing-strategy for the overall entity (the combined business of the utility and its unregulated subsidiaries) would be best served by the successful or unsuccessful operation of the unregulated subsidiary.

B.2 Distribution Utilities

Distribution companies generally purchase power from other utilities under rates or contracts approved by the Federal Energy Regulatory Commission (FERC).

In addition to factors which affect the financial incentives for other utilities (fuel clauses, rate structures, etc.) the terms of wholesale rates or contracts influence the distribution companies' incentives.

These terms are very similar to those contained in rates or contract charges between utilities and large industrial companies. In particular, the distribution company will incur a monthly demand charge and an energy charge for all power. The distribution company's costs of purchased power (capacity and energy) are ordinarily passed on to its retail customers through purchased power clauses which operate similar to a utility's fuel adjustment clause. Meanwhile, each KWH sold by the distribution company to its retail customers includes an additional component which recovers all other fixed costs. Because increased sales (to existing customers) do not increase fixed costs, each KWH has the same type of impact on revenues as it does for other utilities, albeit at a lower level.

B.3 Multi-State Utilities

Designing incentive plans for a utility that is part of a multi-state holding company presents additional considerations.

Most importantly, correcting the incentives for the state-regulated retail utility will not affect the incentives for the parent company or for the combined company. If planning and investment decisions are controlled or substantially influenced by an entity other than a state-regulated utility, and the correct incentives do not extend beyond the state-regulated utility, any improved incentives will have little effect. To have a meaningful effect on utility behavior and investment decisions will require the Federal Energy Regulatory Commission to reform federal regulatory mechanisms. Thus far the FERC has shown no interest in LCP or any related regulatory reforms.

B.4 Combined Gas and Electric Utilities

While this entire discussion has focused on electric utilities, the incentives are essentially the same for gas utilities. Therefore, the only complication for a combined gas and electric utility relate to fuel-switching. There appears to be no general rule concerning which fuel would be more profitable to the combined entity. Thus, if this is an area of concern, a utility-specific analysis is necessary.

B.5 Unbundled Energy Services

In an ordinary shared savings approach, an energy service company[108] (ESCO) enters into a contract with a customer. The ESCO installs an energy efficiency improvement at its expense and the customer pays for it over time by paying the ESCO a share of the savings in the customer's electric bill. The customer retains the remaining savings.

Assuming a reasonably competitive market and arms-length negotiation between the ESCO and the customer, the ESCO's share of the savings compensates the ESCO for all of its costs, including a reasonable rate of return. Thus, in the context of a competitive demand-side bidding process, the ESCO's bid price to the utility will be the same as its share of the savings (adjusted for any differences in the transaction costs).

In the ordinary shared savings model, the total benefit available to be shared by the customer and the ESCO is the difference between the retail rate and the cost of conservation. The unbundled energy service proposals are structured differently.[109] The ESCO (for this first example, the ESCO is the utility) buys and installs the device and charges the customer the full retail rate for all the saved energy. Any difference between the price and the cost of the efficiency improvement is retained by the utility. Thus, in the simplest form the unbundled energy service is like a shared savings plan in which the ESCO (in this case, the utility) keeps 100% of the savings.

The unbundled bidding version adds a little complexity because it can more easily occur in a three-party transaction involving utility, customer, and a separate ESCO.[110]

First, the two-party case: This case is similar to the unbundled example described above except that the utility makes a cash payment equal to the bid price instead of buying and selling the efficiency measure, and the efficiency measure is installed by the customer. Meanwhile, the customer continues to pay the full retail rate for all saved KWHs.

Thus, if the bid price is equal to the cost of the efficiency improvement, this is also a shared

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[108] *The ESCO may be a utility.*

[109] *Whittaker, "Conservation and Unregulated Utility Profits: Redefining the Conservation Market",* <u>*Public Utilities Fortnightly*</u>*, July 7, 1988; see also Katz, "Proper Utility Incentives: Everybody Wins", Western Conference of Public Utility Commissioners, June, 1989.*

[110] *Cicchetti and Hogan, "Including Unbundled Demand-Side Options in Electric Utility Bidding Programs",* <u>*Public Utilities Fortnightly*</u>*, June 8, 1989.*

savings plan where the utility retains 100% of the savings. If the bid price exceeds the cost of the efficiency improvement, the arrangement looks more like an ordinary shared savings plan.[111] From the perspective of the customer, the only situation in which this type of arrangement is superior to an ordinary shared savings plan is when the customer prefers cash to hardware. In return for this difference, the customer must participate in the bid process.

The three-party case (ESCO, utility, and customer) is more complex. These arrangements can take at least two forms. In the first, the ESCO buys and installs an energy efficiency device, the customer continues to pay the same retail bills (pays the retail price for each saved KWH), and the utility pays the ESCO the bid price.[112]

Fig. 1

This form illustrates several important matters. First, without a payment from the ESCO to the customer, this will appear to the customer to be a shared savings plan in which 100% of the savings goes to others. Because shared savings plans have very low market penetration without a substantial payback to the customer, this approach is unlikely to produce significant results.

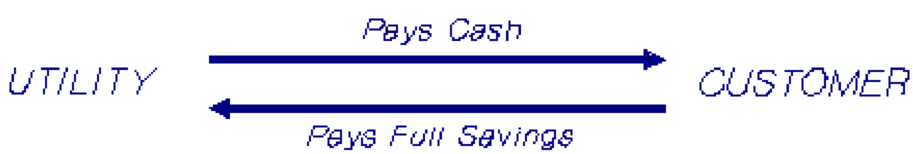

Fig. 2

[111] *If the purpose of bidding is to use competition to reduce the price of efficiency improvements, the bid price will equal the efficiency improvement's cost.*

[112] *A portion of the bid price may have to be returned to the customer to entice him to participate.*

Second, because the bid price cannot exceed avoided cost, any payment made by the ESCO to the customer will reduce the maximum investment the ESCO can make in efficiency equipment.

In the second form, the ESCO (the bidder) pays the utility the retail rate for bid KWHs and receives the bid price from the utility. The ESCO buys and installs an energy efficiency device and may or may not charge the customer for the service provided.

The left portion of the diagram points out that the utility payment for energy efficiency is

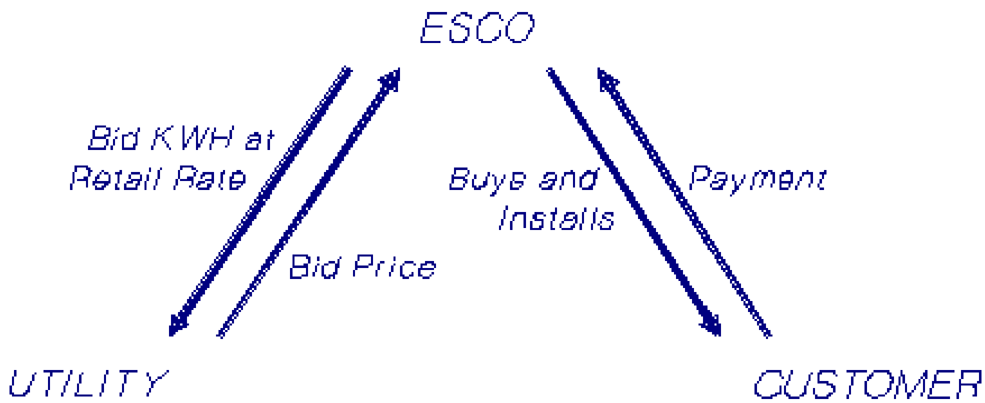

Fig. 4

Fig. 3

limited to the difference between average and marginal cost. Assuming the left portion of the diagram produces no net payment, what remains is the ordinary ESCO/customer shared savings plan. If average cost exceeds marginal cost, which is the case in many parts of the country, the net utility payment is negative. To offset this impact, the ESCO would require a correspondingly higher share of the savings from the customer, reducing further the likelihood that a contract between the ESCO and the customer will be executed.

APPENDIX C

Resolution in Support of Incentives for Electric Utility Least-Cost Planning

WHEREAS, National and International economic and environmental conditions, long-term energy trends, regulatory policy, and technological innovations have intensified global interest in the environmentally benign sources and uses of energy; and

WHEREAS, The business strategy of many electric utilities has extended to advance efficiency of electricity end-use and to manage electric demand; and

WHEREAS, Long-range planning has demonstrated that utility acquisition of end-use efficiency, renewable resources, and cogeneration are often more responsible economically and environmentally than traditional generation expansion; and

WHEREAS, Improvements in end-use efficiency generally reduce incremental energy sales; and

WHEREAS, The ratemaking formulas used by most state commissions cause reductions in utility earnings and otherwise may discourage utilities from helping their customers to improve end-use efficiency; and

WHEREAS, Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society; and

WHEREAS, Improvements in the energy efficiency of our society would result in lower utility bills, reduced carbon dioxide emissions, reduced acid rain, reduced oil imports leading to improved energy security and a lower trade deficit, and lower business costs leading to improved international competitiveness; and

WHEREAS, Impediments to least-cost strategies frustrate efforts to provide low-cost energy services for consumers and to protect the environment; and

WHEREAS, Ratemaking practices should align utilities pursuit of profits with least-cost planning; and

WHEREAS, Ratemaking practices exist which align utility practices with least-cost planning; now, therefore, be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC) assembled in its 1989 Summer Committee Meeting in San Francisco, urges its member state commissions to:

1) consider the loss of earnings potential connected with the use of demand-side resources; and

2) adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and

3) otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action.

Sponsored by the Committee on Energy Conservation
Adopted July 27, 1989