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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF SOUTH CAROLINA

Docket No. 91-606-E

In re: Petition of	)
South Carolina Electric	)
and Gas for a Certificate	)
of Public Convenience and	)
Necessity for a Coal-Fired	)
Plant near Cope, South	)
Carolina	)

Plunkett:
no offset on incentive, ...
for customer savings

DIRECT TESTIMONY OF
PAUL L. CHERNICK

ON BEHALF OF THE
SOUTH CAROLINA DEPARTMENT OF CONSUMER AFFAIRS

Resource Insight, Inc.
January 20, 1992

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I. INTRODUCTION AND SUMMARY

A. Witness Identification and Qualifications

Q: State your name, position, and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts. Resource Insight, Inc. was formed in August 1990 as the combination of my previous firm, PLC, Inc., with Komanoff Energy Associates.

Q: Summarize your qualifications.

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and in my current position at Resource Insight. I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached as Exhibit __PLC-1 to this testimony.

Q: On whose behalf are you testifying in this proceeding?

A: My testimony is being sponsored by the South Carolina Department of Consumer Affairs.

B. Purpose and Summary of Testimony

Q: What is the purpose of your testimony?

A: My testimony addresses whether the Cope project proposed by South Carolina Electric and Gas Company ("SCE&G" or "the Company") is necessary to meet the future needs of South Carolina ratepayers. My testimony focuses on whether SCE&G has adequately developed, considered, and integrated alternatives to the Cope project into its long-range resource planning. Specifically, my testimony considers if the need for new supply resources could be deferred or displaced by additional demand-side resources not included in the Company's integrated resource planning.

Q: Please summarize your conclusions.

A: SCE&G has considered only a narrow set of options in selecting the source of supply proposed at this time. The Company has neglected a wide range of resource alternatives it could choose from, failing to consider reasonable options available to meet its service obligation reliably and efficiently at least cost. This failure to prepare, compare, and pursue a full range of options actively renders its application deficient.

One consequence of this deficiency is that SCE&G is unable to establish that the Cope project is the least-cost option for meeting future demand for electric service. Specifically, SCE&G has not established that its resource plan includes all economical demand-side resources available in its service territory. On the contrary, the experience of other utilities and the Company's own analyses strongly indicate that SCE&G could obtain much more energy and capacity from cost-effective demand-side options than currently contained in its resource plan. Thus, the Company has not established that a combination of demand-side resources and alternative supply options could not meet the same need as Cope at a lower overall cost than building and operating the Cope project. Nor has it established that the acquisition of additional demand-side resources could not economically delay the need for Cope generation.

Q: Summarize the major deficiencies you find in SCE&G's demand-side resource planning.

A: Several deficiencies in SCE&G's demand-side planning undermine the Company's ability to acquire all cost-effective DSM. These deficiencies include the following:

- SCE&G's economic screening of demand-side options is biased and inconsistent. The Company relies primarily on the restrictive and discriminatory no-losers test to assess the cost-effectiveness and suitability of available demand-side resources. Moreover, SCE&G understates the benefits of demand-side resources in part by failing to incorporate specific estimates of avoided reserves, transmission and distribution (T&D) costs, losses, and the environmental costs of supply displaced by DSM.

- SCE&G is not comprehensively assessing, targeting, and pursuing energy-efficiency resources. SCE&G's piecemeal pursuit of savings will unnecessarily raise costs and reduce savings achieved from demand-side resources.

- SCE&G neglects large and inexpensive but transitory opportunities to save electricity in all customer classes. By failing to act to capture these valuable opportunities, SCE&G loses them. Such lost-opportunity resources arise when new buildings and facilities are constructed, when existing facilities are renovated or rehabilitated, and when customers replace existing equipment at the end of its economic life. To make matters worse, SCE&G's partial treatment of individual customers through piecemeal programs will actually create lost opportunities.

- SCE&G's programs are too weak to overcome the pervasive market barriers that obstruct customer investment in cost-effective efficiency measures. Incentives are not high enough and programs do not address many barriers.

Q: What do you conclude regarding additional demand-side savings available for acquisition by SCE&G?

A: To assess SCE&G's future need for capacity, I project the levels of DSM that could be reasonably expected if SCE&G developed comprehensive programs with the same intensity as those developed by collaboratives in other states. By 1996, SCE&G should be able to acquire peak demand savings from DSM of 273 MW (inclusive of standby generator and interruptible savings), or 148 MW more than the approximately 125 MW the Company projects in its 1991 Integrated Resource Plan (IRP).[1] SCE&G's intensified acquisition of demand-side resources could produce even larger increases in energy savings from DSM. By 1996, SCE&G's DSM programs could generate energy savings of 745 GWh/yr, more than a six-fold increase over the level contained in SCE&G's 1991 IRP (including savings from earlier programs). If we assume that Cope operates at an 75% capacity factor, then the additional savings attainable are equivalent to the output of 95 MW or 25% of Cope capacity.[2]

If SCE&G were to acquire these additional peak savings, then its capacity requirements would decrease by the equivalent of the 178 MW of Cope. Thus, the Cope project could be scaled back to 200 MW. More importantly, the magnitude of additional energy savings attainable might allow for the 385 MW baseload facility to be deferred or replaced by a combination of additional DSM and lower-cost combustion turbine or short-term purchases. Alternatively, these savings might allow the Company to construct a phased combined cycle

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[1] I have rounded estimates to the nearest MW and GWh to facilitate reproduction of my results. The projections are not intended to be significant to this level.

[2] Assuming an 75% capacity factor, Cope will generate 2,529 GWh per year. Thus, the additional energy savings I project are equivalent to 25% of the plant's output.

plant with initial installation of a combustion turbine and addition of a heat recovery steam generator at that time when it becomes cost-effective.[3]

Q: Have you determined the least-cost expansion schedule based on these additional savings?

A: No, I have not performed an integrated resource plan for SCE&G based on my estimates of additional available demand-side savings.

Q: Are you recommending that the Commission direct SCE&G to acquire additional savings equivalent to the levels you have estimated as attainable by the Company?

A: No. Although they may be appropriate goals, my estimates are illustrative of the magnitude of savings available if SCE&G developed comprehensive acquisition strategies comparable to those adopted by other leading U.S. utilities. The true extent of achievable demand-side savings can only be determined as part of an extensive effort to develop DSM opportunities in SCE&G's service area.

Although the actual magnitude of savings is difficult to determine at this time, SCE&G acknowledges that additional substantive savings are achievable beyond that incorporated in the IRP. The Company estimates that maximum achievable savings in 1996 from the limited portfolio of programs included in the IRP would exceed its current estimate of

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[3]The Company's low load growth sensitivity analysis indicated that a combined cycle unit would be the least-cost option for 1996. Integrated Resource Plan, August 1991, p. VI-6.

savings from these programs by almost 115 MW.[4] Including savings from programs currently under consideration would raise this figure to almost 170 MW. While attainable savings may not reach maximum achievable levels (due to customer acceptance or other market barriers), it is clear that DSM investment strategies that are more comprehensive and aggressive than currently employed by SCE&G can significantly enhance savings attainable from customer end-use efficiency.

Q: Based on these findings and conclusions, what are your recommendations with regard to Commission action on SCE&G's petition for a Certificate of Public Convenience and Necessity?

A: I recommend that the Commission reject the Company's proposal to build Cope until the utility demonstrates, consistent with the IRP procedures adopted in Order No. 91-1002: (1) that it has undertaken to implement all economic energy efficiency and load management that could displace new power plants and (2) that Cope is still the least cost supply option available to meet any remaining requirements. Regardless of the Commission's ultimate decision on SCE&G's application in this proceeding, it should direct the Company to improve its planning and acquisition of demand-side resources before it commits to the construction of Cope. These reforms should include immediate and vigorous actions to: (1) acquire all cost-effective demand-side resources throughout its service

[4]See response to Consumer Advocate interrogatory 2-35.

area with comprehensive energy-efficiency programs; (2) provide adequate incentives and appropriate program designs to overcome market barriers; and (3) pursue "lost-opportunity" efficiency resources, which arise when customers construct new facilities or renovate and when they add or replace appliances and equipment.

The Commission should advise the Company that until and unless it makes these reforms, its resource planning cannot be considered in compliance with Order No. 91-1002 and therefore neither adequately integrated nor truly least-cost. Without effective integrated least-cost planning, SCE&G cannot establish that resource additions are prudent or likely to be used and useful in providing future service to ratepayers. SCE&G will be at risk for investments and operating costs, including fuel, incurred due to the inadequacies in its conservation programs.[5]

Q: How have you organized the remainder of your testimony?

A: Section II examines the least-cost planning obligations SCE&G must satisfy for the Commission to approve its application under South Carolina statute and for its planning process to be in compliance with Commission Order No. 91-1002. In this section I also present the economic rationale for utility investment in demand-side resources, and the program strategies adopted by leading U.S. utilities to acquire DSM

[5]This is true for Clean Air Act compliance costs, as well as traditional supply costs.

savings comprehensively. In Section III, I delineate the Company's failure to pursue cost-effective demand-side resources systematically. I trace this failure to SCE&G's inadequate planning and design of demand-side programs. Section IV presents details of the improvements and expansion in demand-side resource acquisition that SCE&G should be directed to undertake, based on the activities of leading U.S. utilities. Using the plans of such utilities as a guide, I project the amount of DSM SCE&G should reasonably be expected to acquire. Finally, I present my conclusions and recommendations in Section V.

II. JUSTIFYING CERTIFICATION OF THE COPE UNIT UNDER INTEGRATED RESOURCE PLANNING

A. SCE&G's Application and Requirements of South Carolina Statutes and Commission Order No. 91-1002

Q: Please summarize SCE&G's proposal.

A: SCE&G has applied for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the construction of a 385 MW pulverized coal generating facility at a site located near Cope, S.C. The Company anticipates that the Cope project will be completed in 1996.

Q: What statutory requirements have you reviewed in consideration of this request for a Certificate of Public Convenience and Necessity?

A: I have reviewed the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. § 58-33-10 et seq. According to Section 58-33-160 (1)(d) of that Act, the Commission may not grant a Certificate of Public Convenience and Necessity for a facility unless it determines that "... the facilities will serve the interests of system economy and reliability." Subsection (c) requires consideration of the various alternatives and justification by the applicant of its choice(s).

In Order No. 91-1002, the Commission adopted IRP Procedures for developing integrated resource plans that incorporate resource options that "serve the interests of system economy and reliability." According to these Procedures:

> The IRP must demonstrate that each utility is pursuing those resource options available for less than the avoided costs of new supply-side alternatives. Demand-side options will be included in the IRP to the extent they are cost-effective and are consistent with the Commission objective statement for the IRP.[6]

Q: Has SCE&G met these requirements?

A: No. SCE&G has omitted a wide range of conservation resources from its resource plan and has failed to make a reasonable showing that no other cost-effective DSM alternatives to Cope exist. Although the Company is targeting a small amount of energy-saving efficiency resources, load management resources targeted to peak demand savings dominate its DSM portfolio. As a result, the Company is missing opportunities to acquire DSM savings that can mitigate or delay the need for a baseload plant such as that proposed for Cope.

By failing to explore viable alternatives, SCE&G provides the Commission with little foundation upon which to review its plans as submitted. This severely restricts the Commission's ability to fulfill its responsibilities under South Carolina statutes. It may also result in the Company's ratepayers paying for unnecessary amounts of expensive generating resources. The utility's failure to develop and exhaust the potential for least-cost demand-side resources provides the grounds for outright rejection of SCE&G's application. At a minimum, failure by SCE&G to comply with Order 91-1002 and

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[6]Commission Order No. 91-0002 in Docket No. 87-223-E (November 6, 1991), Appendix A, p. 10.

develop and incorporate least-cost options should lead the Commission to place strict conditions on any approval it grants the Company.

The Commission must not allow SCE&G to dismiss prospects for more comprehensive and flexible lower-cost options that may replace or delay the capacity SCE&G has proposed. As discussed below, SCE&G could possibly scale back its current expansion plans by aggressively promoting direct investment in its customers' energy efficiency.

B. To demonstrate that a proposed resource is least-cost, SCE&G must show that it has exhausted the wide range of viable cost-effective demand-side alternatives

Q: What must SCE&G establish to substantiate the need for Cope?

A: SCE&G must show that Cope is part of the least-cost plan for reliably meeting future demand.

Q: How do the principles of integrated least-cost planning relate to the Commission's assessment of the need for Cope?

A: The objective of least-cost planning is to minimize the <u>total</u> system costs of providing adequate and reliable service. <u>Integrated</u> planning extends the range of options beyond supply to include demand-side resources. A facility for which a utility seeks a Certificate of Public Convenience and Necessity forms a major part of the utility's long-range plan. Thus, the specific proposal and the plan of which it is a component are inextricably linked.

The requirement to minimize total costs of electricity services means that a particular project is needed only if it costs less than available, viable alternatives. This principle carries two important implications. First, it places an obligation on utilities to explore fully and develop adequately all reasonable options as viable alternatives to the facilities for which they seek a Certificate of Public Convenience and Necessity. Without such an obligation, a utility could simply neglect otherwise reasonable alternatives by failing to develop them sufficiently for full consideration. For example, the Company could present the Commission with a *fait accompli* by examining only its preferred option and failing to explore, develop, and analyze other competing supply technologies.

The second implication of least-cost planning for the Commission's consideration of the Company's application is that the Company must consider as resource alternatives combinations of smaller sources. Otherwise, a utility could sidestep a true evaluation of a variety of alternatives by opting to meet all its long-range resource requirements with a single large facility.

Q: Why should the Commission's consideration of resource alternatives extend to demand-side resources?

A. As recognized in the IRP Procedures adopted in Order No. 91-1002, the objective of utility resource planning should be the minimization of the long-run costs of providing adequate and reliable energy services to customers. The minimization of total costs requires that utilities choose the demand or supply resources with the lowest costs first, and then draw on progressively more expensive options until demand is satisfied.[7]

Least-cost planning therefore requires the utility to pursue cost-effective demand-side savings that would otherwise not be exploited. These efficiency gains are worth pursuing to the point that any further savings would cost more than supply, counting all costs incurred by either the utility, its customers, or other parties.

Q: Does least-cost planning obligate utilities to pursue only the most cost-effective DSM?

A: No. Least-cost planning requires utilities to pursue the most cost-effective resource plan. This goal implies that SCE&G should pursue all cost-effective DSM -- that is, all DSM available for less than the cost of supply it would avoid. Stopping short of this goal would obligate the utility to make up for the foregone savings with more expensive supply.

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[7]Uncertainty and risk complicate this task. Future demand is unknown. This makes some resources riskier than others. In general, larger resources with longer lead times carry greater risks for the system. Once utilities gain the capability to deploy efficiency resources, they can acquire them in small increments over short lead times. Some efficiency resources, such as programs to raise new buildings' efficiency, coincide with demand growth. More efficient loads generally are more stable loads, implying lower load uncertainty.

Q: What role should the rate impact measure (RIM) or no-losers test have in determining the cost-effectiveness of a demand-side resource?

A: The no-losers test has no role in the economic screening of demand-side programs or the technologies incorporated in such programs. Use of the RIM will lead to the rejection of economical DSM. The IRP Procedures prevent such a rejection by requiring that cost-effective options not be dismissed simply because they fail the RIM.

Q: How does use of the no-losers test lead utilities such as SCE&G to reject cost-effective DSM?

A: DSM is cost-effective if its total benefits exceed its total costs, i.e., if it passes the total resource cost (TRC) test.[8] Under this test, costs include outlays for energy-efficiency measures themselves (including any continuing operating costs), plus utility program delivery costs. Benefits include the avoided costs of utility supply, plus any non-electric savings, such as for natural gas, water, labor, and equipment replacement. A DSM measure or program satisfies the total resource test if its benefits exceed its costs because it will lower the total costs of providing energy services.

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[8]DSM is cost-effective if it is less expensive than system avoided cost, including avoided generation capacity, energy, T&D, losses, and environmental costs. DSM can be cost-effective, even if it is more expensive per kWh than Cope, since the DSM resource avoids a more expensive mix of energy, T&D capacity, losses, and environmental effects.

The RIM test adds another component to the comparison. The RIM adds to the true costs of DSM the revenue shifts associated with the sales reductions that accompany energy conservation. The RIM also ignores costs and benefits incurred directly by customers.

Depending on the relationship between avoided costs and retail rates, the no-losers test can completely rule out DSM, no matter how low its acquisition costs. For example, if retail rates exceed avoided costs, the "cost" of sales losses will exceed the benefit of avoided costs. In that case, DSM must have <u>negative</u> acquisition costs to pass the no-losers test. The RIM will frequently reject demand-side resources that would lower <u>total</u> system costs.

Q: Should environmental externalities of generation be included in the total resource cost of supply avoided by DSM?

A: Yes. As required by the IRP Procedures:

> Environmental costs are to be considered on a monetized basis where sufficient data is available. Those environmental costs that cannot be monetized must be addressed on a qualitative basis within the planning process.[9]

Q: Should sufficient data be available for monetizing environmental costs?

A: The fact that several commissions and utilities around the country have adopted monetized values for externalities is strong indication that such externalities can be reasonably quantified. Externality values have been adopted by New York,

[9] <u>Id.</u>, Appendix A, p. 6.

Massachusetts, Nevada, California, and New Jersey regulators, as well as by the Bonneville Power Administration.

C. Need for utility investment in demand-side resources

Q. Why should utilities intervene in customer energy-use choices?

A. Customers typically require efficiency investments to pay for themselves in two years or less, while utilities routinely accept supply investments with payback periods extending beyond twelve years. In Appendix 1 to this testimony, I show that this "payback gap" has the same effect as an exceedingly high markup by customers to the societal costs of demand-side resources. The pervasive market barriers underlying the payback gap lead utility customers to reject substitutes for supply which, if scrutinized under utility investment criteria, would appear highly cost-effective.

Q. Are short-payback requirements confined to a few, relatively unsophisticated customers?

A. Not according to extensive research. As discussed in the handbook on least-cost utility planning prepared for the National Association of Regulatory Utility Commissioners:

> According to extensive surveys of customer choices, consumers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years. Moreover, this behavior is not limited to residential customers. Commercial and industrial customers implicitly require as short or even shorter payback requirements, sometimes as little as a month. This phenomenon is not only independent of the customer sector, but

also is found irrespective of the particular end uses and technologies involved.[10]

Q. Why do customers act as if they attach high markups to efficiency investments?

A. Limited access to capital, institutional impediments, split incentives, risk perception, inconvenience, and information costs compound the costs and dilute the benefits of energy efficiency improvements. These factors interact to form even stronger barriers. Utilities can accelerate investment in cost-effective demand-side measures with comprehensive programs that reduce or eliminate these barriers.

Q. How can utilities substitute demand-side measures such as energy efficiency improvements for utility supply?

A. Customer demand for energy services such as lighting, space conditioning, and industrial shaft power can be met in a multitude of ways, involving varying combinations of electricity, capital, fuel, and labor. It is often possible to reduce the sum of these costs without compromising the level and quality of service by substituting capital behind the meter for capital behind the busbar. For example, if it costs less to save a kilowatt-hour (kWh) with a more efficient motor than to produce it with generating capacity, total costs will be lower if efficiency is chosen over production.

Q. Are such trade-offs between efficiency and consumption made automatically in the marketplace in response to price signals?

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[10] Least-Cost Utility Planning: A Handbook for Public Utility Commissioners, Vol. 2, December 1988, p. II-9.

A. To some extent. With some simplifying assumptions, microeconomic theory predicts that pricing electricity at marginal cost will automatically lead to optimal resource allocation.

In reality, customers routinely decline efficiency investments which, if evaluated with a utility's economic yardstick, would appear to be extremely attractive resources. Based on utility price signals -- which often exceed estimates of long-run marginal costs -- typical customers require efficiency investments lasting as long as 30 years or more to pay for themselves within two years. By contrast, utilities routinely accept long-lived supply options with apparent payback periods of 12 years or longer. By forgoing low-cost efficiency investments, consumers compel utilities to expand supply at higher cost.

This disparity between individuals' and utilities' investment horizons constitutes a "payback gap" that leads to over-investment in electricity supply. Utilities can bridge the payback gap, thereby avoiding more expensive supply investments, by investing directly to supplement price signals.[11]

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[11]The 17-fold markup in the example in Appendix 1 means that an electric rate of 6 cents/kWh would not motivate a customer to spend 6 cents per conserved kWh. Rather, the customer would only invest in efficiency that to a utility would cost about 1/3 cent/kWh. Equivalently, a utility would have to set prices seventeen times higher than marginal cost to stimulate the customer response that is optimal.

Q. Why does the payback gap imply that utilities need to invest in customer efficiency improvements?

A. Market barriers force customers to apply more exacting investment criteria to efficiency choices than utilities apply to supply options. Without utility intervention, the payback gap will lead customers to under-invest in efficiency and utilities to over-invest in supply. As the NARUC least-cost planning handbook states:

> Demand-side resources are opportunities to increase the efficiency of energy service delivery that are not being fully taken advantage of in the market. To make use of demand-side resources requires special programs, which try to mobilize cost-effective savings in electricity and peak demand. Without such programs, these savings would not have occurred or would not have materialized without significant delay, and in any case could not have been <u>relied upon</u>, forcing utilities to construct expensive back-up capacity and causing higher rates. [emphasis in original][12]

Explicitly acknowledging the payback gap leads to two conclusions about the potential for demand-side resources and strategies needed to realize it:

- Utility price signals are much weaker as a tool for stimulating investment changes than most analyses assume.

- A vast amount of economical efficiency potential remains for utilities to tap as demand-side resources.

Q. Please summarize how market barriers weaken price signals and leave a large potential for cost-effective utility investment in demand-side resources.

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[12] <u>Id</u>. at II.1.

A. The NARUC handbook sums up this relationship as follows:

> The short-payback requirements for efficiency investments usually result from different combinations of these factors [market barriers]. But the multitude of dynamics involved explains why the payback gap is not just found for particular end uses or particular customer groups, but is so universal. It also explains why consumer investment[s] in efficiency and load management are not governed solely or even mainly by an economically efficient response to prevailing prices. For these reasons, the redesign of utility rates alone, or any other strategy limited to the correction of prices only, is insufficient to mobilize the bulk of demand-side resources. Direct intervention is needed to strengthen market mechanisms and remove institutional and market barriers.[13]

These market barriers are discussed in more detail in Appendix 1.

D. The need for comprehensive strategies in planning and acquiring demand-side resources

Q: What types of strategies are essential to least-cost demand-side planning?

A: Comprehensive strategies that achieve all cost-effective efficiency improvements for each customer involved in a utility DSM program. In addition, utility programs should be comprehensive in addressing all customers and all market segments.

The Vermont Public Service Board defines DSM comprehensiveness in the following terms:

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[13] Id. at II.15.

> Utility demand-side investments should be comprehensive in terms of the customer audiences they target, the end-uses and technologies they treat, and the technical and financial assistance they provide. Comprehensive strategies for reducing or eliminating market obstacles to least-cost efficiency savings typically include the following elements: (1) aggressive, individualized marketing to secure customer interest and participation; (2) flexible financial incentives to shoulder part or all of the direct customer costs of the measures; (3) technical assistance and quality control to guide equipment selection, installation, and operation; and (4) careful integration with the market infrastructure, including trade allies, equipment suppliers, building codes and lenders. Together, these steps lower the customer's efficiency markup by squarely addressing the factors that contribute to it.[14]

Q: Why is a comprehensive approach to demand-side resource acquisition a prerequisite for integrated least-cost resource planning?

A: This imperative is rooted in the least-cost planning objective of pursuing all achievable savings available for less than utility avoided costs. In effect, SCE&G should invest on the conservation supply curve for each customer's facility until the next kWh and/or kW of savings exceeds avoided costs. Only a comprehensive approach that pursues efficiency savings sector by sector and customer by customer, not measure by measure, will allow SCE&G to achieve the optimum amount of least-cost efficiency resources.

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[14]Vermont Public Service Board, Decision in Docket 5270, Investigation into Least-Cost Investments, Energy Efficiency, Conservation and Management of Demand for Energy, p. III-44.

Q: How does the strategy you recommend differ from other approaches a utility might take to demand-side investments?

A: Buying efficiency savings is a markedly different proposition from selling or marketing conservation measures. The latter tends to concentrate on individual technologies. It often leads utilities to fragmented and passive efforts to convince customers to adopt individual measures that marketing research indicates they are most likely to want and accept. Another frequent but misguided objective is to seek savings from customers as inexpensively as possible. Such a strategy will neglect savings costing more than the cheapest conservation (say, 4 cents/kWh rather than 2 cents/kWh), but which are available at less than utility avoided costs (say, 6 cents/kWh.) Both alternatives, while intuitively attractive at face value, could well lead utilities to acquire more supply than least-cost planning criteria would justify.

Q: What are the practical implications of this "efficiency-buying" approach to utility demand-side investments?

A: Treating each customer as a reservoir of exploitable electricity resources leads to some important principles about the way to design and implement programs. Most importantly, successfully capturing economical energy efficiency opportunities requires that utility programs be comprehensively targeted. This means that utilities should generally address the entire efficiency potential of the customer, not just one end-use or measure. Otherwise, utilities would have to re-visit their customers many times over to tap all available, cost-effective efficiency savings. In the end, less of the efficiency resource would be recovered at higher costs than if the utility extracted all the efficiency potential one customer at a time.[15]

Addressing technologies and end-uses comprehensively among customers avoids two common mistakes in utility efficiency programs:

- "cream-skimming", neglecting measures that would be cost-effective at the time other measures are installed but which would be more expensive or impractical later; and
- failing to account for interactions between technologies and end-uses.

Q: Why are comprehensive strategies needed to overcome market barriers to customer efficiency investment?

A: While individual customers may decline particular cost-effective efficiency measures for one reason or another, a multiplicity of barriers is likely to impede any class's exploitation of economically feasible efficiency potential. Short of customizing a different program for every customer, utilities need to design programs that address the full array of obstacles preventing least-cost customer efficiency investments.

[15] A clear analogy exists to the development of oil and gas resources or mining. The resource is limited, and careless extraction of one part of the resource can interfere with development of the rest of the potential.

Q: Is it realistic to expect utilities to assume the responsibility for exploiting all customer efficiency opportunities, attempting to complete them in unified programs?

A: Yes. Treating efficiency potential thoroughly does not necessarily mean installing all measures in one visit. In fact, many successful programs start with a thorough site analysis and the installation of a few straightforward measures. The utility then follows up with a detailed investment plan for achieving the full potential. For example, when an existing chiller needs replacing, the utility may offer a rebate for a downsized, higher-efficiency chiller in conjunction with a comprehensive relamping project.

Nor is it essential that one program cover all end-uses for a particular customer group. Comprehensiveness should be judged by how completely a utility's full portfolio of programs covers relevant end-uses, options, and sectors. For example, utilities may use several programs to cover residential efficiency potential. They target weatherization retrofits, new construction, and appliance replacement separately because of the different structure and timing of the decisions involved.[16] Such an approach is comprehensive if the two programs are linked where appropriate.

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[16]Appliance programs are often structured differently for appliances selected by ratepayers (e.g., refrigerators) and those selected primarily by contractors (e.g., water heaters, HVAC.)

E. Need to target lost-opportunity resources explicitly

Q: What do you mean by lost-opportunity resources?

A: The Northwest Power Planning Council defines lost-opportunity resources as those "which, because of physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop these resources or to hold them for future use."[17] On the demand-side, lost-opportunity resource programs pursue efficiency savings that otherwise might be lost because of economic or physical barriers to their later acquisition.[18]

Q: Are lost-opportunity resources important?

A: Yes. Acquiring all cost-effective lost-opportunity resources should be a utility's top demand-side priority for at least five reasons. First, the situations that create the potential for lost-opportunity resources are the leading source of load growth, and thus actually create requirements for new resources. Load growth is driven largely by customer decisions to add new or expand existing facilities, where a "facility" may be any building, appliance, or equipment. Second, lost-opportunity resources often represent extremely cost-effective savings, since only incremental costs are incurred to achieve higher efficiency levels. Third, acquisition of lost-opportunity resources cannot be postponed.

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[17]Northwest Power Planning Council, 1986 Northwest Conservation and Electric Power Plan, Vol. 1, p. Glossary-3.

[18]"Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," at 7.

Fourth, market barriers to customer investment in lost-opportunity resources are among the most pervasive and powerful. Fifth, lost-opportunity resources are the most flexible demand-side resources available to utilities. They tend to correlate with demand growth since rapid growth tends to correspond to construction booms and facility expansion. Unlike any other option available to utilities, the acquisition of lost-opportunity resources will parallel the utility's resource needs.[19]

Q: Where are lost-opportunity resources usually found?

A: One-time opportunities to save energy through improved energy efficiency arise in three market sectors:

- during the design and construction of new building space;
- when existing space undergoes remodeling or renovation; and
- when existing equipment either fails unexpectedly or is approaching the end of its anticipated useful life.[20]

As observed by Gordon, et al.:

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[19]The Vermont Public Service Board recognized that "a utility committed to pursuing all efficiency opportunities that would otherwise be lost will automatically synchronize its new resource acquisitions with swings in resource need." Decision in Docket 5270, Investigation into Least-Cost Investments, Energy Efficiency, Conservation and Management of Demand for Energy, April 16, 1990, p. III-110.

[20]A fourth category of lost-opportunity measure, addressed earlier, arises in retrofit situations. Often there are measures that would be cost-effective to install in conjunction with other measures, but that would not be economical to pursue in a subsequent visit or through a separate program. Frederick W. Gordon, et al., "Lost Opportunities for Conservation in the Pacific Northwest," undated, at 2.

> If these opportunities are not pursued at a specific time, they will be much more expensive, much less effective, or impossible to pursue later. ... [lost opportunities] have a unique importance because they cannot be postponed.[21]

Q: What distinguishes a lost-opportunity measure from a discretionary DSM opportunity?

A: The two dominant factors that determine if a conservation measure is a lost opportunity measure are: (1) the feasibility or cost premium of installing it later, and (2) the service life of the building or equipment involved.[22] Efficiency is inexpensive during construction, renovation, or replacement, when higher levels can be attained through design changes and incremental investments. Once these opportunities lapse, efficiency improvements often require existing equipment to be discarded and work to be redone in a retrofit decision. In the case of new equipment such as appliances, all efficiency potential may be lost until the end of its useful life.[23]

Q: How rapidly are these opportunities lost?

A: These opportunities represent rapidly vanishing resources because builders, businesses, and consumers are making essentially irreversible choices on a daily basis. The window of opportunity for influencing these decisions is

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[21] Gordon, op. cit., p. 2.

[22] Id.

[23] Id. at 9.

quite short. For new commercial construction, this window may be a matter of weeks or months; for appliances, a utility's opportunity to acquire cost-effective savings may be limited to hours or at most days. The consequences of these decisions can last anywhere from a decade to a century.

Q: Are lost opportunities discussed in the Commission's IRP Procedures?

A: Yes. The Commission recognizes the vital importance of capturing lost opportunities. Requirement B.22 states, in part:

> Utility DSM plans shall give attention to capturing lost opportunity resources. They include those cost effective energy efficiency savings that can only be realized during a narrow time period, such as new construction, renovation, and in routine replacement of existing equipment.

Q. Have other utilities or regulators recognized the imperatives of lost-opportunities?

A. Yes. The Northwest Power Planning Council first urged Bonneville Power Administration and the region's utilities and regulators to pursue lost opportunities in its 1983 Plan. Its 1986 plan reaffirmed this recommendation in spite of a large capacity surplus.[24] In Vermont, the Public Service Board and the utilities it regulates are making lost-opportunity resources a top priority.[25] The Idaho Public Utilities Commission recently ordered utilities under its

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[24]1986 Northwest Plan, <u>op. cit.</u>, at 9-28 through 9-30.

[25]Vermont PSB Docket 5270, Vol. III, at 58-59, 92-102.

jurisdiction to submit a "Lost Opportunities Plan."[26] The Wisconsin PSC also declared that utilities should not let such valuable yet transitory efficiency opportunities escape:

> The importance of improving the energy efficiency of commercial buildings as soon as possible must be emphasized. These buildings represent long-term investments (up to 70 years) which will significantly affect the use of energy once they are constructed. Retrofitting to achieve energy efficiency, as experience has shown, is usually expensive, if possible at all. Therefore the commission is not willing to allow these 'lost opportunities' for energy efficiency to continue unabated.[27]

Northeast Utilities has adopted this same perspective in its demand-side programs, which it developed under an unprecedented collaborative design process spearheaded by the Conservation Law Foundation. Utilities in Massachusetts and Vermont have oriented their demand-side strategies toward lost-opportunity resources.

Q: What incentives will maximize SCE&G savings from lost-opportunity resources?

A: Because of the brief window of opportunity typical of lost-opportunity resources and because of the permanence and magnitude of their savings, it is essential that utilities pay essentially the full incremental cost of lost-opportunity measures. As noted in Section II.F., this imperative has been recognized in many collaboratively-designed DSM programs.

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[26] See Order No. 22299, Case No. U-1500-165, January 27, 1989.

[27] Wisconsin Public Service Commission, Fifth Advance Plan Order, Docket 05-EP-5, pp. 33-34.

Q: Can you cite an example of a utility that has found on its own that incentives of 100% of incremental costs are effective?

A: Yes. Puget Sound Power and Light offers a prime example of a utility that has learned this lesson from its own experience. In its new commercial building program, program incentives were set initially at 50-80 percent of incremental measure costs. Puget decided to change its policy and now offers incentives equal to full incremental cost, up to a maximum of avoided costs, for this program. Following is the rationale behind this change, as explained to Portland Energy Investment Corp.:

> We were getting about 50-60 percent of the people that we were talking to. But we were not even talking to the speculative building market. When it came down to accepting and installing the measures, cost was the deciding factor for owners: even among participants, owners were not installing all the measures that should have gone into the building because of measure costs. The comprehensiveness of the energy savings was being compromised. We believe that we can get an additional 20-30 percent of the people to participate with full-incremental cost incentives.
>
> We believe that without full incentives, in the long run, we would have lost as much as 80 percent of penetration into buildings. It is easier to attract owner-occupied buildings, where the owner has a stake in the savings, and full-incremental cost incentives would encourage the owner to become more aggressive on energy conservation. In the speculative building's market, we felt that we could lose as much as 100 percent of the market without full-incremental cost incentives.[28]

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[28]Personal communication between Mac Jourabchi, PECI, and John Plunkett, Resource Insight, Inc., March 21, 1991.

Puget's conclusions support my contention that incentives covering full incremental costs are needed to capture both sources of lost-opportunities: harder-to-reach customers who would not participate otherwise, and comprehensive measures that even participants would not otherwise install.

F. Potential scale of DSM acquisitions of leading utilities

Q: What do you find from your examination of DSM plans by utilities with comprehensive program designs?

A: I find that such utilities are forecasting large amounts of electricity savings, compared to their current loads and projected demand growth. These sizable savings are associated with major financial commitments by sponsoring utilities. While aggregate DSM expenditures represent a significant share of total utility revenues, the savings these utilities are buying compare favorably to new utility supply, on the basis of direct costs, and especially when the costs of environmental externalities are included in the costs of such supply. Finally, the program plans of these leading utilities aim at achieving all cost-effective DSM savings from utility customers over time. Included in their program designs are such critical elements as financial incentives covering all or most of the costs of efficiency measures; hassle-free service delivery; and intense and focused marketing.

Q: Which utilities do you rely on here?

A: I am referring to the plans of 7 utilities in the Northeastern U.S., primarily in New England, with DSM programs designed in collaboration with non-utility parties. The utilities examined here include Boston Edison (BECO), Commonwealth Electric (CommElec), Eastern Utilities (EUA), New England Electric Service (NEES), Western Massachusetts Electric (WMECO), New York State Electric and Gas (NYSEG), and United Illuminating (UI).

Q: Why have you restricted your examination to these utilities in particular?

A: Unlike many other utilities in the U.S., these companies' plans follow the least-cost planning objectives of utility demand-side planning and acquisition discussed earlier. Accordingly, their program plans best represent the savings, expenditures, and program characteristics associated with truly comprehensive DSM plans.[29]

1. Program savings and spending

Q: How much electricity are these collaboratively-designed DSM plans expected to save?

A: Exhibit __PLC-2 provides various measures of aggregate electricity savings for these collaborative DSM plans. To facilitate comparison with SCE&G, I have expressed the savings

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[29]Both the plans and the procurement mechanisms of many of these utilities can still be improved. Nonetheless, their plans illustrate the range of savings available to utilities that are seriously interested in DSM.

as percentages of peak load and energy sales and as percentages of growth in demand and energy. Total DSM savings as a fraction of cumulative growth in peak demand ranges from a low of 32% for BECO to a high of 81% for EUA. Energy savings range from 31% of cumulative sales growth for NYSEG to 63% for EUA. Obviously, the longer the program's duration, the higher the fraction of total electricity demand it will achieve. Thus, Exhibit __PLC-2 shows that UI's 20-year program plan generates total peak savings amounting to 20% of its projected peak demand. BECO's 5-year program achieves a 4% reduction in peak load.[30] In terms of energy savings, these collaborative programs generate between 4% and 16% of total sales.

Exhibit __PLC-3 provides expected savings figures for 1991.

Q: How much are utilities with collaboratively-designed programs planning to spend on them?

A: In general, spending ranges between 3% and 6% of total electric revenue, as seen in Exhibit __PLC-4. Expenditures in the early years of long-range DSM plans are as low as 2.2% for NYSEG ($25.4 million) to as high as 5.3% for NEES ($85 million). Over time, average DSM expenditures range from 3.5% for BECO (which exclude expenditures on load-control programs ~~which~~ that save no energy) to 6.7% for NYSEG.

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[30]The differences are thus due more to the planning horizon than to ultimate targets.

Q: How much are these savings expected to cost?

A: Exhibit __PLC-5 provides aggregate cost estimates of expected electricity savings for several collaborative utilities. Using total program expenditures, this exhibit indicates that the gross cost of conserved electric energy ranges from 1.8 cents/kWh (for Com/Electric's non-residential programs) to 6.2 cents/kWh (for NEES' 1991 conservation portfolio).

Q: Explain how you calculated these figures.

A: First, I amortized DSM budgets over an estimated average measure life of 15 years to arrive at annualized DSM expenditure over the years of program savings. To compute the gross cost of conserved energy, I divided this amortized cost over the maximum annual energy savings.

2. Program strategies

Q: What is the overriding objective of these program designs?

A: All of the collaborative program designs seek to achieve the maximum level of cost-effective savings possible by maximizing the level of cost-effective customer participation and by maximizing the cost-effective savings by program participants.

Q: What approaches are common to the collaborative program designs?

A: These plans share several essential characteristics. They are comprehensive in terms of measures targeted, customers treated, and strategies employed. Moreover, they offer much higher financial incentives to customers than has been the norm among typical utility DSM programs.

Q: Are such comprehensive approaches necessary for achieving high participation?

A: Yes, according to a growing body of research. This imperative is reflected in a recent study of utility experience with non-residential conservation programs. According to Nadel:

> Comprehensive programs can achieve very high participation rates (several program have reached 70% of targeted customers) and very high savings (one pilot program achieved 22-23% savings). In general, the highest participation rates and highest savings (as a percent of pre-program electricity use of participating customers) are achieved by comprehensive programs which combine regular personal contacts with eligible customers, comprehensive technical assistance, and financial incentives which pay the majority of the costs of measure installation.[31]

Nadel and Tress incorporate this finding into the strategies they develop for achieving statewide targets set by the New York PSC and State Energy Office. As they conclude:

> In order to obtain savings of this magnitude, a comprehensive array of conservation programs must be pursued aggressively, including programs directed at all major sectors, end-uses, and market types (e.g., retrofit, replacement, and new construction). Furthermore ... in order to obtain these savings [sic] will require a transition from traditional program approaches (e.g., audits

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[31]Nadel, S., Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs For Commercial and Industrial Customers, Final Report prepared for the New York State Energy Research and Development Authority. April 1990, pp. 174, 183.

and modest rebates) towards new program approaches (e.g., high rebates and direct installation services.)[32]

a. **Customer financial incentives**

Q: How are customer incentive levels determined in these programs?

A: In general, incentives are set as high as necessary to maximize participation by eligible customers and ensure that participating customers maximize the penetration of cost-effective measures. This is because experience by utilities leads to the inescapable conclusion that, for most customer segments, maximum cost-effective savings will only be realized if utilities pay for the full incremental costs of efficiency measures. This finding is one of the major lessons learned from utility experience to date. With some exceptions, these utilities pay the full incremental cost of cost-effective efficiency measures.

Exhibit __PLC-6 summarizes the customer incentives offered by these collaborative programs. Notice that in most lost-opportunity situations, utilities pay the full incremental costs of measures. This is true for new construction and non-residential equipment replacement and building remodeling. This exhibit also shows that these

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[32]Nadel, S. and Tress, H., The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs, Final Report prepared for the New York State Energy Research and Development Authority and the New York State Energy Office. November 1990, p. 9.

leading utilities are paying the full costs of measures in direct installation programs that are targeted at hard-to-reach customers, such as low-income residential and small commercial customers.

NEES had developed substantial experience with programs with various incentive structures to tap the efficiency potential of market segments <u>prior</u> to the collaborative design process.[33] Yet, nearly all NEES programs now cover 100% of measure costs.[34] The one notable exception to this rule is in the large commercial/industrial retrofit program, where the Company will "buy down" investments so their customers have a payback period of between 12 and 18 months.[35]

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[33]For example, NEES had run side-by-side comparisons between custom rebate programs and demand-side bidding systems. It found that the custom rebate package was more cost-effective, achieved higher participation, and obtained greater electric savings than performance contractors. Hicks, E.G., "Third Party Contracting Vs. Custom Programs for Commercial/Industrial Customers", <u>Energy Program Evaluation: Conservation and Resource Management</u>, Chicago, August 1989, pp. 41-45. NEES had also previously run programs offering 100% financing for selected measures. For example, the Enterprize Zone program paid all lighting efficiency costs for small C/I customers and achieved 60% participation among targeted customers. Nadel and Ticknor, "Electricity Savings form a Small C&L Lighting Retrofit Program: Approaches and Results," <u>Energy Program Evaluation: Conservation and Resource Management</u>. Chicago; August 1989, pp. 107-112.

[34]See generally <u>Power by Design: A New Approach to Investing in Energy Efficiency</u>, submitted to the Massachusetts DPU by CLF on behalf of NEES, September 1989. NEES pays 100% of incremental costs in all residential programs, small C/I retrofits for customers under 100 kW, and all new construction across all sectors.

[35]For comprehensive retrofits -- i.e., where the customer commits to all cost-effective measures -- NEES will pay 100% of measure costs.

Likewise, Boston Edison uses full funding in order to acquire all cost-effective efficiency resources in most sectors. For example, BECo pays 100% of measure costs in direct installation programs and in new construction programs. One exception is 2/3 funding in residential lighting rebate programs (which supplement the direct installation program, similar to the approach in the residential lighting programs developed by Nadel and Tress). Another exception to the full-funding rule is in the non-institutional commercial/industrial retrofit program, where the utilities buy down efficiency investments to a one-year payback period. Finally, utilities buy down efficiency improvements in industrial processes to an 18-month payback in new industrial construction.

Q: Can you cite utility experience to support your conclusion that full utility funding is necessary to accomplish maximum cost-effective penetration?

A: There is little full-scale program experience that demonstrates maximum participation achievable from alternative utility investment levels. In the residential sector, only direct investment has proved to be effective in reaching high participation.[36] Most recently, NEES has obtained 50%

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[36]Nadel observes that in general, "when financial incentives are high, substantial participation and savings rates can be achieved" from comprehensive programs. Nadel, <u>Conservation Potential</u>, <u>op. cit.</u>, p. 6. This observation even applies to relatively low-cost investments. The Santa Monica Energy Fitness Program in 1984-85 achieved 33 percent participation by offering free installation of up to three efficiency measures. Michigan replicated the Santa Monica approach by offering free installation of up to six measures. Participation averaged 49 percent (ranging

participation in its Energy Fitness program offering direct installation to residential customers in Worcester, Mass. In the non-residential sectors, it is becoming increasingly clear that only fully-funded programs offering comprehensive assistance reach high customer participation and achieve high measure penetration. Programs offering only partial incentives without individualized marketing and close technical support do not succeed. In general, "rebate programs currently in operation have not been especially effective at promoting 'system' improvements, i.e., efficiency improvements involving the interaction of multiple pieces of equipment."[37]

Q: Is the customer incentive level the only factor influencing customer participation?

A: No. Many factors influence a customer's decision to install cost-effective efficiency measures. Although money may not be all that matters, it matters a lot. In fact, when non-financial factors such as marketing and technical assistance are held constant, raising the level of utility funding will increase participation. Nadel concludes:

> Data on the effect of different incentive levels are limited but show that providing

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between 36 and 59 percent). Kushler, et al., "Are High-Participation Residential Conservation Programs Still Feasible? The Santa Monica RCS Model Revisited", Energy Program Evaluation: Conservation and Resource Management. Chicago; August 1989, pp. 365-371. Note the coincidence between higher participation and the more comprehensive set of measures offered to participants.

[37]Nadel, Lessons Learned, op. cit., p. 184.

> free measures results in the highest participation rates. High incentives ... appear to promote greater participation than moderate incentives ... However, moderate incentives may not achieve higher participation than low incentives.[38]

Any ambiguity over the optimal incentive levels disappears once the question is posed in terms of least-cost planning objectives. As Nadel observed:

> If demand-side resources are to play a major role in meeting future electricity needs, then programs will need to reach a substantial proportion of targeted customers and will need to have a significant impact on the electricity consumption of the customers that are reached.[39]

Since the goal of least-cost planning is to maximize the penetration of all cost-effective measures:

> Obviously, to maximize market penetration intensive personal contact marketing and the offer of free measures must be combined. While this combination is the most expensive, it may be the best choice if very high levels of market penetration and energy savings are desired.[40]

As Berry concludes:

> Participation rates above 50% tend to occur only when all factors are favorable to producing them. That is, they are most likely to occur in highly convenient programs, offering free services and direct installation, which are not supply-constrained, and which are marketed by trusted

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[38]Nadel, op. cit., p. 186.

[39]Id., p. 181.

[40]Berry, L. The Market Penetration of Energy Efficiency Programs. Oak Ridge National Laboratory; April 1990, p. 40.

> sponsors through direct personal contact with customers.[41]
>
> The amount of participation is usually constrained more by the supply of services (i.e., the resources committed to programs) than by the demand for them. Thus, the maximum rates observed may be more relevant to choosing planning assumptions than the average rates. When there is strong enough motivation (and a sufficient commitment of resources) to acquire energy-efficiency resources, participation levels above 50% can probably be obtained for most program types and for most customer groups and communities.[42]

She adds:

> [M]arket penetration rates above 80% will not be achieved with a business-as-usual approach or with the level of resources typically devoted to programs. Free, direct installation programs that are heavily marketed may sometimes achieve this level of market penetration. Most utilities do not, however, offer such aggressive and expensive programs. .... A realistic view of the evidence suggests, however, that penetration rates above 80% will not occur without dramatic changes in typical approaches to the promotion of energy-efficiency programs.[43]

Q: Doesn't such an aggressive approach risk paying too much for DSM savings?

A: It is certainly possible that high penetration could be achieved in some customer segments, market types, or efficiency measures with less than full utility funding. SCE&G has not determined where this might be possible. The Company will not be able to determine the "optimal" incentive

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[41] Id. at 66.

[42] Id. at 66-67.

[43] Id.

until it finds what works at higher levels. Past utility experience supports the conclusion that setting incentives too low entails more risk than paying too much.

It is important to remember that increasing the fraction that utilities pay for measure costs will not raise the costs of the measures and will reduce the costs of programs under the total-resource perspective. As long as uneconomical measures are eliminated at the screening stage of program planning and the diagnostic stage of implementation, raising utility funding of measure costs is almost certain to increase societal net benefits. Higher incentives will serve only to raise customer participation and measure penetration.

The worst that will happen if incentives are set higher than necessary is that these additional savings WRRT cost as much as those that would be achieved with lower incentives. More likely, the fixed costs of marketing and administering programs will be spread over more savings with full utility funding of measure costs. This will tend to increase the net benefits of the program under the total resource cost test.

Q: What evidence supports this claim?

A: There is mounting evidence indicating that full funding lowers the cost of electricity saved by DSM programs to society. Berry reported:

> In some cases, paying 100% of the energy-efficiency measure costs reduces the other program costs enough to make the total cost per kWh saved less than it would be at lower incentive levels. An experiment conducted by NMPC [Niagara Mohawk involving water-heating measures], ... market penetration was five times higher for the free

> offer and total costs per participant were less. ... Because more penetration was achieved at less costs, savings due to the free offer were ten times higher, at a per kWh cost that was nearly five times less, than consumption reductions from the shared savings offer. (Laim, Miedema, and Clayton, 1989) Condelli, et al. (1984) supported the same general point in their report on an insulation program for low-income housing in which promotional and advertising costs were greater in absolute terms than the costs for free, direct installation of the measure would have been.[44]

Elsewhere, Berry pointed out that "administrative costs per kWh saved are likely to be higher for information-only programs than for programs that pay the full cost of installing measures."[45] She observed that the costs of <u>delivering</u> programs:

> are likely to be about the same [per participant] regardless of the number of measures installed at a particular time in one building. ... Thus, it will be more cost-effective in terms of total resource cost to install everything at one time than it would to be to make several separate installations. The concept of 'lost opportunities' for energy-efficient new construction is based, in part, on this principle.[46]

b. Other elements of program design

Q: What are the other aspects of comprehensive program design contained in the collaborative utility plans?

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[44] <u>Id.</u> at 37-38.

[45] Berry, L., <u>The Administrative Costs of Energy Conservation Programs</u>. Oak Ridge National Laboratory; November 1989, p. 3.

[46] <u>Id.</u> at 21.

A: Other features of collaborative programs are summarized for four utilities in Exhibit __PLC-7. These programs follow the following general principles:

- Target program delivery strategies and marketing approaches according to the decision-makers and types of investments involved. Depending on the program, utilities should direct program incentives to utility customers, equipment dealers, architects, engineers, or building developers. Separate marketing and delivery is needed to influence investment decisions in new construction, remodeling/renovation, replacement, and retrofit. Nadel, Lessons Learned, op. cit., p. 186.

- Personal marketing is critical. The prime marketing mechanism for all programs should be personal contacts between utility field representatives and target audiences such as large customers (lighting rebates), HVAC dealers and contractors (HVAC rebates), and architects, engineers and developers (storage cooling and new construction). These personal contacts should strive to develop a regular working relationship with the target audience (e.g., periodic contacts, with the same staff person contacting a particular individual each time). Experience by many utilities, including several side-by-side experiments, shows that personal contact consistently results in higher participation rates than reliance on direct mail, bill stuffers, and other traditional mass-marketing approaches.[47]

- Avoid paying for "naturally-occurring" savings by maintaining high minimum efficiency thresholds. The

[47]For example, NYSEG offered energy audits to two carefully-matched groups of commercial/industrial customers. One group was personally contacted, the other group received a phone call to identify the key decision-maker followed by a direct-mail solicitation to this person. Participation rates averaged 37% for the personal contact group and 9% for the phone/mail group. Xenergy, Inc., Final Report, Commercial Audit Pilot, Burlington, Mass. Likewise, Niagara Mohawk Power Corp. conducted a similar experiment with lighting rebates. Response to the personal solicitation was substantially higher (21%) than it was to the mail solicitation (3%). Clinton, J. and Goett, A., "High-Efficiency Fluorescent Lighting Program: An Experiment with Marketing Techniques to Reach Commercial and Small Industrial Customers" Energy Conservation Program Evaluation: Conservation and Resource Management. Argonne National Laboratory; Argonne, Ill.: August 1989.

higher the minimum efficiency criteria utilities set for program eligibility, the more net savings each program dollar buys, assuming equipment complying with minimum standards is widely available. Utilities often see dramatic proof of this principle.[48] This is the best solution for avoiding free riders.

- Encourage measures that improve the efficiency of the overall system, not just equipment efficiency improvements. In many cases, the savings available from improving the overall design of a lighting or HVAC system (e.g., improved sizing, controls, and system layout) exceed the savings from small efficiency improvements in specific components (e.g., lamps, air-conditioners).

- Keep the mechanics of program participation as simple as possible for the customer. The more complex programs appear to customers, the lower participation will be. Make it easy for customers to participate, particularly by minimizing complex calculations and paperwork. For example, when a customer requests payment, he should not have to list details on individual measures, but should just refer to the original application number or submit a carbon copy of the original application with a small box at the bottom containing any needed post-installation information. The collaborative programs generally involve a minimum of unnecessary application and verification paperwork.

- Provide the right amount of technical assistance to customers free of charge. Energy audits should serve as the point of entry to utility efficiency programs and should therefore be marketed aggressively. The sophistication of technical support should vary according to the size and complexity of customers. Small customers generally do not need instrumented, computerized diagnosis provided by a professional engineer; a prescriptive approach should work with a walk-through audit. On the other hand, such a simple approach will not work with large customers, who demand an experienced professional knowledgeable in specific applications before they agree to major efficiency improvements, no matter who bears the cost. To maximize participation and savings in new construction programs, utilities must also

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[48]For example, PEPCo found out that, after the Company's response to a phone inquiry, local Sears stores immediately adjusted their appliance inventory in accordance with the minimum performance requirements of PEPCo's air-conditioner rebate program. Personal communication, John Plunkett with Edward Mayberry, PEPCo, January 4, 1990.

provide computerized analysis and pay for outside design assistance.

III. FAILURES IN SCE&G'S DSM PLANNING

Q: Summarize your findings on SCE&G's demand-side plans as they relate to the need for Cope.

A: Thus far, SCE&G has under-invested in energy-saving demand-side resources. While the Company has pursued peak demand savings with load management efforts, it has failed to target economical <u>energy-efficiency</u> resources adequately. The scope, scale, and pace of SCE&G's planned acquisitions of demand-side resources are inadequate given the magnitude, composition, and timing of its supply commitments. As shown in Exhibit __PLC-8, SCE&G's present commitments represent only 74 MW (excluding 51 MW of standby generator and interruptible savings) and 119 GWh from DSM resources through the year 1996. They account for 9% of projected peak demand <u>growth</u>, and 4% of energy sales <u>growth</u>, through 1996.

In sharp contrast to SCE&G's limited commitment to energy-efficiency resources, utilities with the most ambitious DSM programs -- those designed in collaboration with non-utility parties -- plan to meet significantly higher proportions of their load growth with DSM. The reasons for such higher DSM targets include unbiased and comprehensive DSM program planning and much stronger utility financial commitments. I show in Section IV that commensurate commitments by SCE&G would reasonably be expected to produce an additional 148 MW and 626 GWh by the year 1996.

Q: How does SCE&G's failure to pursue additional energy-efficiency resources relate to its application for a Certificate of Public Convenience and Necessity for Cope?

A: Because of the Company's inadequate approach and commitment to DSM, SCE&G has failed to establish that DSM cannot substitute more cost-effectively for some or all of the energy and capacity from Cope. SCE&G's resource plans omit energy-saving demand-side resources that could be cost-effective compared to Cope under the total resource cost test. Like leading utilities, SCE&G should fully develop and pursue <u>all</u> cost-effective alternatives to the supply resources contained in its benchmark plan. Its resource plan should include and be premised on timely acquisition of all cost-effective resources. Every kW and kWh of cost-effective demand-side resources that SCE&G could add over Cope's life represents a kW or kWh not needed from Cope, at least on the current schedule.

Q: In your opinion, what shortcomings in SCE&G's demand-side planning are responsible for its under-investment in DSM compared to Cope?

A: SCE&G's weak demand-side planning has prevented the Company from pursuing energy-saving demand-side resources to their cost-effective limits before deciding to pursue Cope. This weakness is attributable to deficiencies and omissions in the Company's approach to program design and implementation. The most significant are:

1. The Company's reliance on the RIM test for economic screening leads to the rejection of economical savings opportunities. The Company's use of the RIM is in direct opposition to the stated objectives and requirements of the IRP Procedures.

2. SCE&G's economic screening is further biased by the Company's failure to incorporate estimates of reserves, line losses, avoided T&D costs and environmental externalities in avoided costs used to evaluate DSM options. Furthermore, the Company did not screen DSM against the supply plan identified in the IRP.

3. SCE&G has conducted a limited review of DSM options and has arbitrarily rejected many options which appear cost-effective.

4. SCE&G fails to target DSM market sectors comprehensively. The Company omits essential sectors, end-uses, and measures.

5. SCE&G's existing programs inadequately address market barriers. Customer incentives are too low, direct installation programs are non-existent, and programs are fragmented.

6. SCE&G overemphasizes load management to the detriment of conservation. Load management may be developed in place of cost-effective energy conservation, thus limiting the cost-effective energy savings SCE&G can achieve in the long run.

7. SCE&G is not sufficiently ambitious. The Company has set its participation goals far too low.

A. SCE&G's economic screening tests are biased

Q: Why is SCE&G's economic evaluation of DSM biased?

A: The Company's screening of DSM measures and programs relies primarily on the RIM or no-losers test to evaluate DSM cost-effectiveness. As discussed above in Section II.B, DSM that is economical under the TRC test may be rejected under the RIM test.

Q: How do you know that SCE&G uses the RIM to restrict demand-side investments?

A: The IRP states "a cost/benefit analysis is conducted based on the expected savings from the demand side program, <u>the revenue loss</u> and estimated overhead."[49] [emphasis added] By including revenue loss as a "cost" of DSM, the company has elected to screen DSM options with the RIM.

Q: Does the Commission accept results of the RIM as sufficient to ensure cost-effectiveness?

A: No. The IRP Procedures explicitly reject use of the RIM as sufficient basis for the rejection of DSM measures that pass the TRC.

B. SCE&G omitted important elements of avoided costs

Q: What indication do you have that the Company omits important components of avoided cost?

A: In its evaluation of DSM options, the Company compares the busbar costs of "targeted generation," a CT or coal plant, with DSM measures.[50] This approach ignores many significant costs including reserves, transmission and distribution costs, losses, and environmental costs. This approach thus appears to understate the actual supply costs that will be avoided by

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[49]Integrated Resource Planning, August 1991, p. III-11.

[50]These costs were provided in response to Consumer Advocate Interrogatory 2-17.

DSM. Unfortunately, the Company does not offer any explanation for these omissions.[51]

Q: Why do you state that SCE&G did not screen measures against the supply plan identified in the IRP?

A: By virtue of screening measures against a "targeted generation," SCE&G has not screened DSM against the supply plan in the IRP. The supply plan identifies a mix of short-term power purchases, coal plant, and CTs that are required to serve load. Avoided costs from this plan will vary from year-to-year as the load and supply mix change. The avoided cost will also vary with the load shape of demand-side resources. The use of "targeted generation" ignores the costs of the plan that SCE&G intends to pursue.

Q: What is the consequence of this screening?

A: SCE&G has not conducted an analysis that demonstrates that its resource plan is least cost. The Company can neither claim that its DSM costs less than its supply plan, nor that there is not additional DSM that would cost less than the supply identified.

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[51]The Company also underestimates costs avoided by DSM, and therefore the magnitude of economical savings, by not estimating the cost savings associated with DSM as a Clean Air Act compliance strategy. Specifically, the Company does not allow for additional allowances due to DSM activities prior to 2000, or reduced requirements for allowances thereafter; nor does it model strategies that include intensified DSM as an alternative to scrubbing or fuel switching. It is not clear whether SCE&G has reflected changes in system operation due to compliance actions (reduced capacity, increased fuel and variable O&M costs) in its economic analyses. See generally the IRP, pp. VII-6-8.

Q: Does SCE&G present any analysis and results showing the use of the costs provided in response to Consumer Advocate Interrogatory 2-17?

A: No. The Company provides only results, and thus it is impossible to determine what avoided costs it used.

Q: Does the company present any other economic analyses which use avoided costs?

A: Yes. In response to Consumer Advocate Interrogatories 2-4 and 4-2, the Company provides an analysis for two measures which use entirely different marginal costs than those provided elsewhere by the Company. These costs also appear to differ from the cost of the targeted generation provided in response to Consumer Advocate Interrogatory 2-17, the cost of Cope, provided in response to Consumer Advocate Interrogatory 2-19, and the avoided costs in Mr. Marsh's testimony.

C. SCE&G conducted a cursory review of DSM options

Q. In what respects has SCE&G conducted only a limited review of DSM options?

A. First, SCE&G has not considered many technologies in its evaluation of DSM options. I discuss this further in Section III.D. Second, SCE&G has used overly restrictive and unreasonable load shape criteria to reject measures prior to economic screening. This approach is biased against energy savings options, particularly those which provide little or no peak reduction. Second, the Company has arbitrarily rejected or delayed implementation of measures which its own analysis indicate are cost-effective.

Q: Please discuss SCE&G's "load shape objective" screening.

A: In the IRP, SCE&G states that the first step of its DSM analysis "evaluates the load shape objectives for consistency with operational considerations."[52] The load shape objective is characterized by Company witness Marsh as either peak clipping, valley filling, or strategic conservation.[53] An initial benefit analysis is performed on those measures which contribute to the load shape objective.

The load shape objectives appear to have little relationship to the <u>economic</u> attractiveness of a DSM measure and thus to the Commission's IRP objective. The criteria could eliminate <u>energy-saving</u> options regardless of whether such savings are cost-effective as long as they do not meet these initial screening criteria.

Q: Please discuss those measures which SCE&G has rejected or set aside for future evaluation.

A: For those measures SCE&G did consider, it dismissed many without reason. Response 2-16 states that eleven measures passed the TRC. However, of those measures, three were rejected entirely from inclusion in SCE&G's DSM plan.

Q. Did the company provide any explanation for rejecting these measures?

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[52]IRP, p. III-9.

[53]Direct testimony of Kevin B. Marsh, pp. 11-12.

A. No. In the response, the measures are in a category "DSM Options rejected due to lack of commercial viability or historical test."[54] Response to Consumer Advocate 4-1 defines "historical test" as "... tests used in the past [prior to the IRP docket.] It was a preliminary cost-benefit analysis which enabled us to assess the impact of a particular technology on our system ..." In fact, the test referred to is the Company's load shape preliminary screening. "Commercial viability" is defined as "... verifiable potential represented by a particular technology as developed by manufacturers." Inexplicably, the Company uses this "test" to reject technologies that have been found to be both viable and cost effective by other utilities throughout the country. These include low flow showerheads, set back thermostats, and high efficiency refrigerators. Furthermore, each of these measures passes the TRC, and thus would contribute to the Commission's objective of lower total costs.

Q. Is the Company pursuing all options which passed the TRC?

A: No. Eight additional measures which passed the TRC are in a delaying category called "under consideration for 1992." These are measures which the Company knows to be cost-effective resource options and should thus be included in the Company's DSM portfolio. By failing to do so, SCE&G may be missing one-time opportunities for capturing significant cost-

[54]See response to Consumer Advocate 4-1. The concepts are not discussed in the IRP.

effective savings from long-lived equipment such as motors and HVAC systems. Once missed, these savings opportunities are foregone for the duration of the equipment's life.

Q: What is the result of SCE&G's DSM measure review process?

A: SCE&G has not reviewed DSM options in a thorough and unbiased manner. Furthermore, it has rejected societally beneficial options without merit, and may be pursuing options which will increase rather than decrease the total cost of providing energy.

D. SCE&G's programs are not comprehensive

Q: In what ways are SCE&G's programs not comprehensive?

A: Certain fundamental omissions keep SCE&G's program portfolio from being comprehensive, ignoring DSM resources that can provide significant sources of savings. SCE&G's omissions include:

- Customer sectors, in particular, lost opportunity sectors and low-income customers;
- end-uses, such as residential lighting and refrigeration and many HVAC components; and
- measures, most notably fuel-switching.

1. Missing customer sectors

a. Lost opportunities

Q: Summarize your findings on SCE&G's failure to pursue lost-opportunity resources.

A: SCE&G's current resource plan lacks an effective strategy for obtaining lost-opportunity measures and thus systematically excludes cost-effective demand-side resources from its resource plan. By failing to move vigorously to achieve all cost-effective lost-opportunity resources, SCE&G increases the total costs of providing electric service. Eventually the Company might end up acquiring <u>some</u> of these savings as more expensive retrofits. The rest of the cost-effective savings that SCE&G misses will be irretrievably lost; the Company will have to make up for these lost opportunities with more costly supply.

Q: How should SCE&G pursue lost-opportunity resources?

A: SCE&G should target programs to affect appliance replacement, new construction in the commercial and residential sector, commercial remodeling/renovation, and commercial and industrial equipment replacement. SCE&G should offer incentives for equipment whose efficiency exceeds current standards (either of law or practice). Section IV, below, summarizes the types of programs SCE&G should implement for each conservation market sector.

Q: What sources of lost-opportunity savings is SCE&G bypassing?

A: Unfortunately, SCE&G has so far ignored many of the lost opportunities presented by residential new construction and appliance and water heater replacement, and by commercial building design, refrigeration and HVAC.[55]

Q: Does SCE&G's plan contain any programs that explicitly target lost-opportunity resources?

A: Yes. SCE&G's Good Cents and Great Appliance Trade-Up (GATU) address lost opportunities in the residential sector. The commercial high efficiency chiller program may capture some lost opportunity savings in the commercial and industrial sectors.

Q: Is the Good Cents program likely to maximize the cost-effective savings SCE&G can obtain from new residential construction?

A: No. The program has two major flaws. First, the program may be promoting heat pumps, and thus increasing SCE&G's load. The penetration of heat pumps in the Good Cents program is 84% compared to 26.7% for the entire residential class. While SCE&G does present some comparisons of home owner heating and cooling bills with various combinations of systems, the Company does not present these results for the TRC. Furthermore, the Company has not demonstrated what efficiency and type of system, electric or gas, will result in the lowest total cost of providing heating and cooling. Second, it encourages cream-skimming and accentuates free-ridership by

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[55]SCE&G does have programs that address <u>some</u> of these areas. As discussed below, the programs are not comprehensive and do not promote the most efficient, cost-effective measures. Consequently, these programs, while better than nothing, are still not capturing all cost-effective savings.

limiting financial incentives far below incremental cost. Customers will opt not to pursue measures that are more costly, more difficult to implement, or perceived as risky. They will instead implement only the cheapest, simplest, and most predictable measures. Since these are the measures most likely to be implemented without a program, SCE&G risks paying for what would have been done anyway.

Q: Is the GATU program likely to be effective?

A: Not significantly so. The effectiveness of the GATU program will suffer for two reasons. First, the maximum possible savings will not be achieved because the rebates offered cover decreasing portions of the incremental cost for increasingly efficient units.[56] The Company's effort to provide a rebate which increases as efficiency increases is laudable. Setting the minimum eligible efficiency appears to be higher than national standards is also desirable.[57] However, the Company should take this program one step further, and provide the highest rebate for the most efficient units which are cost-effective. This is necessary to overcome consumer resistance to high initial costs. Second, many collaboratively-designed appliance programs have found that including some incentive

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[56]See responses to Consumer Advocate interrogatories 2-4 and 2-42g.

[57]According to the National Appliance Efficiency Act of 1989, 10 CFR CH. II, Part 430, Subpart C, §430:32), the minimum efficiency for a heat pump manufactured after January 1, 1992 is SEER 10. GATU has a minimum efficiency of SEER 11.

to trade allies is an effective means of getting participation from equipment vendors.

Q: Does the GATU program target all appliances?

A: No. The program provides rebates for air conditioners and heat pumps. The program omits considerable savings possible from other residential appliances, particularly refrigerators, freezers, and water heaters.

b. Lack of a program for low-income customers

Q: Does SCE&G's IRP include any programs specifically designed for low-income customers?

A: No. The Company may offer such programs, but they have not accounted for their costs or savings in the IRP.

Q: Are low-income customers likely to participate in SCE&G's existing programs?

A: Eligible low-income customers are not likely to be able to participate in SCE&G's existing programs. Low-income households offer a classic example of how market barriers can interact to retard efficiency investment. They have virtually no access to capital on any terms. Residents rarely own their own homes, and thus have little motivation to invest even if they had the means. Even with access to enough capital to finance efficiency investments and the incentive to invest it, the specific financial risks of parting with the funds would pose a high hurdle. Finally, low-income customers are less able to obtain and act on the information needed to choose between efficiency options. Those customers who do not speak English (or do not speak it well) will not benefit from the educational component of an audit.

This combination of forces is strong enough to justify direct utility investment in the dwellings occupied by low-income customers.[58]

Q: Why should SCE&G offer a program that meets the needs of its low-income customers?

A: Like all other customers, low-income customers must bear the cost of SCE&G's DSM programs. However, unlike other customers, low-income customers are effectively excluded from participation in any of SCE&G's existing programs. This raises problems of equity. In addition, helping to reduce low-income customers' consumption will help lower their bills. This in turn is likely to help lower SCE&G's uncollectible accounts.

2. **Missing end-uses**

Q: Which end-uses do SCE&G's programs fail to address?

A: SCE&G fails to offer efficiency measures for the following end-uses in the retrofit, replacement, or new construction market sectors:

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[58]Various regulators have required utilities to target low-income customers with efficiency investments, including Wisconsin (Findings of Fact and Order in Docket 05-UI-12, April 20, 1982, at 13-15), Vermont (Docket 5270, Vol. III, pp. 60-62, and 158-159), and New York (Case 89-M-124, Order of June 29, 1989).

Residential sector

- refrigerators and freezers;
- water heating;
- lighting;
- clothes washers and dryers, dishwashers, and electric ranges.

C/I Sector

- HVAC equipment;
- motors;
- commercial and industrial refrigeration.

Thus, SCE&G's current resource plan ignores numerous efficiency options available for many end-uses across all customer market segments.

3. Missing measures

Q: For the end-uses addressed in SCE&G's plan, are there efficiency measures missing from the Company's programs?

A: Yes. There are many measures which were never screened for cost-effectiveness. SCE&G has omitted measures that can offer substantial and long-lasting savings, including:

- measures related to domestic hot water including tank and pipe wraps, traps, faucet aerators, aquastat setback, and low water usage clothes washers;

- compact fluorescent lighting for residential customers;

- incorporating passive solar and daylighting into new construction designs;

- other residential envelope measures including infiltration reduction, ventilation, dehumidification, and air quality;

- economizers, variable air volume and air balancing for HVAC;

- reflectors, dimming ballasts, photosensors, fiber optics for commercial and industrial lighting savings; and

- fuel switching residential space heat and appliances to gas- or oil-fired.

Q: Why should SCE&G include fuel switching in its DSM program analysis?

A: Depending on the costs of selecting or converting to the alternative fuel and the relative end-use efficiencies, fuel-switching can be quite cost-effective.[59] In addition, the aggregate electric savings due to fuel switching can be substantial.

Q: Has fuel-switching been found to be cost-effective in other studies or adopted by utilities as part of their DSM programs?

A: Yes. The cost-effectiveness of fuel-switching has been addressed for various applications and various fuels in the studies I performed for Boston Gas in Massachusetts DPU 89-239 and DPU 90-261A,[60] in the work of several Vermont

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[59] The costs of fuel-switching vary with the application (e.g., scale, building layout), the building's status (e.g., new construction, retrofit, major renovation), and the length of gas service required, if any.

[60] Chernick, P., et al., Analysis of Fuel Substitution as an Electric Conservation Option. December 1989. Direct testimony of Paul L. Chernick, Massachusetts DPU Docket 90-261A, April 17, 1991.

utilities, in the Bonneville Power Administration Resource Plan,[61] and in a Lawrence Berkeley Lab study for Michigan,[62] among others. All of these studies indicate that alternative fuels can be less expensive than electricity for at least some applications of each end-use considered. Fuel switching for at least some end uses has been incorporated in the DSM programs of Green Mountain Power, Burlington (VT) Electric Department, New York State Electric and Gas, Long Island Lighting, Consumers Power, Madison Gas and Electric, and Consolidated Edison, to name a few. Most of these studies and programs involve fuel-switching to gas, but the Vermont utilities also determined that conversion of residential space and water heating to oil and propane will often be cost-effective.[63] Thus, fuel-switching is not a particularly exotic or obscure DSM option. The technology is also well-developed. Fuel-switching is particularly attractive for a combination utility, such as SCE&G, where administrative and transaction costs may be reduced.

E. Inadequacies of SCE&G's existing programs

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[61]Bonneville Power Administration, 1990 Resource Program Technical Report. July 1990.

[62]Krause, F. et al., Analysis of Michigan's Demand-Side Electricity Resources in the Residential Sector. MERRA Research Corporation. April 1988.

[63]Solar might also be included in this list, especially for water heating. I would generally treat solar as a conservation option, rather than fuel-switching, since it does not require any continuing energy input.

Q: What are the major inadequacies of SCE&G's existing programs?

A: SCE&G's programs are characterized by

- insufficient customer incentives;
- absence of direct delivery mechanisms; and
- a fragmented treatment of DSM market sectors.

1. Insufficient customer incentives

Q: Are SCE&G's incentives to customers likely to be effective in combating market barriers?

A: No. SCE&G's incentives are set too low for acquiring all cost-effective conservation resources. In response to Consumer Advocate Interrogatory 2-42g, the Company provides the percent of incremental costs covered by rebates offered. The incentives cover between 16% and 89% of incremental costs, but most incentives are less than 40% of incremental costs.[64]

Q: Why should SCE&G pay up to full incremental cost with rebates or provide for the direct installation of measures?

A: As discussed above, pervasive and multiple market barriers are strong deterrents to customer investment in efficiency. Utilities have found it necessary to offer incentives of more than 50% of measure cost in order to adequately combat these

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[64] In addition, the Company sponsors a rate discount program for residential customers. The residential rates for energy efficient homes are 2.5% to 9% lower than the standard residential rate. The savings depends on the amount of electricity used. It is unclear if reduced rates are the most effective means to overcome many of the market barriers to the implementation of all cost-effective DSM.

market barriers. Based on a survey of non-residential efficiency programs, Steve Nadel concludes that:

> Data on the effect of different incentive levels are limited but show that providing free measures results in the highest participation rates. High incentives (greater than 50% of measure costs) appear to promote greater participation than moderate incentives (on the order of 1/3 of measure cost).[65]

Q: How can SCE&G determine how much to pay for program measures?

A: SCE&G should start by identifying an efficient mechanism for delivering services in each market. Given that mechanism and the nature of the market barriers in each market, SCE&G should select a funding level that will achieve essentially all of the achievable potential by the time it is cost-effective and will not significantly increase the costs of program delivery. SCE&G should not arbitrarily refuse to pay for the full incremental cost, if that is the most effective and efficient means of securing those improvements.

To the extent that some program costs are recovered from participants, the participants should be given the option of having the recovery flow through their bills over a period of time. This may be very important for some customers (such as government agencies) which would have to secure numerous and complicated approvals to put up cash or to sign a loan agreement. It may also be important for customers with cash

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[65]Nadel, S., Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers. April 1990, p. 186.

constraints and may overcome a psychological barrier even for those customers who are not cash-constrained.

2. Lack of direct delivery mechanisms

Q: Does SCE&G offer programs that directly install efficiency measures?

A: No. All of the Company's conservation programs rely on the customer to install measures and then apply for rebates or receive a lower electric rate.

Q: Why should SCE&G utilize direct delivery mechanisms?

A: There are many barriers to customer action that will be inadequately or inefficiently addressed by information, loans, or rebates. Uncertainty, lack of knowledge, split incentives, lack of time for exploring options, limited retail availability, and aversion to dealing with contractors will not be overcome by partial rebates. In general, the easier the Company makes it for customers to participate and choose cost-effective measures, the more cost-effective savings SCE&G will acquire.

For some market sectors, SCE&G should offer direct design and/or installation services.[66] For example, a residential retrofit program should provide for an audit, selection of cost-effective measures, and installation, with as little demand on customer time and budget as possible. This is

[66]The actual delivery would usually be through a contractor, rather than by SCE&G employees.

particularly important for residential and small commercial customers, and may also be significant for larger customers in some segments.

3. SCE&G's fragmented treatment of DSM market sectors

Q: Substantiate your statement that SCE&G's demand-side plans are fragmented.

A: SCE&G makes the mistake of equating individual measures with "programs." Rather than proceed measure by measure in its pursuit of cost-effective conservation savings, SCE&G should proceed by market segment, seeking to acquire all cost-effective savings available from a full set of measures applicable to each customer's facilities. SCE&G's piecemeal strategies will inevitably raise costs, reduce savings, and delay results.

Q: Which of SCE&G's programs would you characterize as single-measure programs?

A: SCE&G's commercial and industrial rebate programs are most indicative of the single-measure approach.

Q: What is wrong with the Company's single-measure approach?

A: By pursuing single-measure strategies, SCE&G passes up opportunities to bundle measures in comprehensive programs. A comprehensive program delivers all the efficiency services that are economical as a package; the single cost of getting an installer to the building is spread across a large number of measures, and no potential cost-effective savings are left "on the table." Bundling measures would lower the overall cost of SCE&G's DSM portfolio by reducing delivery and administrative costs, while increasing the amount of savings SCE&G can expect from each customer visit. It may also increase participation: customers are more likely to participate in a program that offers several measures than in a single-measure program.

Unfortunately, SCE&G does not use this approach in its programs. For example, the Company offers thermal storage, high efficiency chiller, motor measures, and lighting. However, these measures are not offered in a program that seeks to encourage the customer to adopt the most cost-effective combination of measures.

F. SCE&G's DSM Portfolio places undue emphasis on peak savings

Q: Why do you believe that SCE&G's DSM portfolio places undue emphasis on peak savings?

A: A review of SCE&G's programs suggests that the Company devotes much of its DSM effort to measures that reduce peak, rather than to measures that reduce baseload energy use.[67] An analysis of the Company's MW and GWH savings estimates confirms that SCE&G's DSM effort focuses on load management

[67] By preferring those measures which contribute to its "load shape objectives," the Company may be encouraging off-peak load and thus the need for more expensive baseload units.

and peak savings to the detriment of energy-efficiency opportunities.

Q: By what measure did you assess the extent to which SCE&G's DSM resources are devoted to peak savings?

A: I determined the load factor of SCE&G's DSM portfolio, calculated as:

GWH saved / (MW saved * 8.760).

By 1996, SCE&G expects its programs to have a collective load factor of 18%. Adding in Rate 28 and Standby Generation reduces the overall load factor to 11%.

Q: How does this load factor categorize SCE&G's DSM resources?

A: Just as a power plant's load factor can categorize the plant as a base, intermediate, or peaking resource, so can DSM portfolios be categorized by their load factors.

Q: Is the 11% DSM portfolio load factor appropriate given SCE&G's capacity and energy needs?

A: No. With a 11% DSM portfolio load factor, SCE&G's plan acts as a peaking plant.[68] SCE&G's next unit, Cope, is expected to run as a baseload unit. Thus, there is a mismatch between SCE&G investing in a "DSM peaking plant" while at the same time seeking to build a baseload supply plant.

Q: Why else might SCE&G want to place more emphasis on acquiring energy savings rather than peak savings and promoting off-peak use?

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[68]In response to 2-17, the Company indicates a generic CT operates at a 9% capacity factor.

A: Kilowatt for kilowatt, efficiency resources are more valuable than load management. Unlike load management, efficiency resources save energy; reduce environmental impact (and hence costs of control); consistently reduce requirements for the generation, transmission, and distribution capacity; are more durable; and do not involve service degradation. Efficiency resources are particularly valuable for the following two reasons. First, load management savings will decline as efficiency programs affect equipment stock. As the equipment under control becomes more efficient, savings from load shifting will decline. Second, conservation helps avoid expensive baseload plants, and load management helps avoid cheaper peaking combustion turbine plants. Increasing off-peak loads will tend to increase the need for expensive baseload supply.

G. Unambitious plans

Q: Please explain why you characterize SCE&G's plans as unambitious.

A: In response to Consumer Advocate Interrogatory 2-35, the Company provides "expected" and "optimistic" penetrations. Many of the "expected" program penetrations range from 1% to 30% of the market. It is unclear for what year the examples are provided. Many of the "optimistic" penetrations are also less than 30%. This demonstrates that SCE&G is failing to capture substantial cost-effective DSM savings.

IV. POTENTIAL FOR SCE&G DEMAND-SIDE SAVINGS

Q: If SCE&G corrected the deficiencies in its demand-side planning, could the Company acquire significantly more cost-effective conservation resources?

A: Yes. As I show below, SCE&G could acquire substantially larger savings by expanding the scope and scale of its demand-side efforts to levels that are comparable to those attained in collaboratively-designed plans. From my comparative review of SCE&G's current plans and those of utilities with collaboratively-designed DSM programs, I find that SCE&G could reasonably expect to acquire at least an additional 148 MW and 626 GWh in annual savings from cost-effective DSM by the year 1996. These additional savings will only be achievable if SCE&G adopts the market-based, comprehensive approach to demand-side planning and acquisition in use in collaboratively-designed resource acquisition strategies.

Q: Can you categorize the efficiency resources missing from SCE&G's current resource plans which the Company should pursue now?

A: Based on the portfolios of programs being sponsored by other utilities with collaborative-designed programs, SCE&G should develop and implement programs that pursue all cost-effective efficiency savings from the following market sectors:[69]

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[69]SCE&G's programs may already serve a few segments of these market sectors. However, the Company's program strategy fails to target each market sector with appropriate delivery mechanisms.

Non-residential customers

- Commercial new construction
- Industrial new construction/expansion
- Commercial/industrial renovation/remodeling
- Non-profit/institutional/government custom retrofit
- More aggressive and comprehensive commercial lighting
- Direct investment for small commercial customers, focusing on all cost-effective lighting retrofits
- Commercial/industrial equipment replacement

Residential

- Residential new construction
- Residential comprehensive retrofit
  - High-use (central heating/cooling)
  - Moderate use (water heating)
  - General (lighting)
- Comprehensive retrofits for low-income customers
- Point of sale lighting
- Expanded incentives for energy-efficient appliance replacement (including room AC, hot-water heaters)
- Point of sale information and incentives for other appliances (e.g., refrigerators)
- Manufacturer incentives for super-efficient appliances

Q: How does the program scope that you recommend differ from SCE&G's approach to program targeting?

A: The program concepts I sketch are comprehensive in terms of the market segments targeted, end-uses covered, the strategies employed, and their inter-relationship to one another within overall customer groups. By contrast, SCE&G's approach inappropriately treats an end-use or technology separately, generalizing the measure to an entire customer group.

Q: How much more electricity should SCE&G be expected to save by investing in comprehensive efficiency resources?

A: A precise answer to this question will have to wait until SCE&G gains experience with comprehensive programs of the scope described above. Nevertheless, it is possible to extrapolate in general terms from the plans of utilities with the best and most comprehensive program designs -- that is, the plans of the collaborative utilities discussed in Section II.F. above. I have used such an approach to derive a rough but reasonable estimate of the additional demand-side resources that SCE&G should be expected to acquire if it follows the lead of utilities with aggressive and comprehensive demand-side plans.

Q: How much additional demand-side resources do you estimate that SCE&G should be able to obtain?

A: Using the plans of utilities with collaboratively-designed programs as a guide, I estimate that SCE&G should be able to acquire an additional 148 MW of cost-effective demand savings from further conservation investment by 1996. I present these projections in Exhibit __PLC-9. Including the Company's current plans for conservation and load management, SCE&G's total demand-side savings should be 222 MW by the year 1996 (excluding savings from standby generators and interruptible rates.) These totals represent 6% of 1996 system peak demand. By comparison, the Company's current plans account for 2% of 1996 peak load.

Q: Are there significant energy savings associated with the higher peak-demand reductions you project?

A: Yes, there are. By the year 1996, my demand-side resource projections include 745 GWh of energy savings, representing 5% of total sales. These energy savings levels would be more than six times those included in SCE&G's current plans, which account for less than 1% of total energy sales.

Q: Would the savings you estimate influence the timing of Cope?

A: By incorporating my estimate of additional peak demand savings in the loads and resource balance projected for SCE&G, the additional DSM may have a noticeable impact on the need for Cope to meet projected peak demand. Although the additional savings alone do not equal Cope capacity, these savings in combination with short-term purchases or accelerated addition of CT capacity to the system may defer or avoid the need for Cope.

Q: How would the additional energy savings you project influence the economics of Cope?

A: I have not performed the rigorous capacity-expansion analysis that would be required to answer this question with any real precision. Nonetheless, I believe that the substantial increase in energy savings would reduce the fuel-cost savings associated with the Cope project by reducing the marginal energy costs on SCE&G's system. This effect may be large enough to either substitute a CT or phased combined cycle unit for Cope.

Q: How did you estimate future energy and peak demand savings from a comprehensive portfolio of SCE&G DSM programs shown in Exhibit __PLC-9?

A: First, I projected that annual acquisitions of demand-side energy resources would equal specific percentages of projected annual sales growth. As explained below, I chose these percentages on the basis of DSM savings plans of six utilities with collaboratively-designed DSM portfolios for which I was able to obtain class-specific energy-savings projections. I multiplied these annual percentages by SCE&G's projected annual sales growth. The sum of these annual DSM energy acquisitions leads to cumulative energy resource acquisitions from DSM after 1991. To arrive at the total energy savings to be expected each year from all SCE&G's DSM programs, I then added these annual energy acquisitions to the 1991 DSM energy savings projected by SCE&G in its IRP.[70]

[70]Total savings figures exclude SCE&G's projections for the standby generator and interruptible rate programs.

Second, to project peak demand savings generated by intensifying SCE&G's DSM portfolio, I applied appropriate DSM capacity factors to the additional cumulative DSM energy resource acquisitions I estimated as explained above.

Q: How did you arrive at the annual percentages you applied to SEC&G to determine incremental annual DSM energy savings?

A: I relied on the projected energy savings from residential and non-residential customers shown for utilities with collaboratively-designed programs in Exhibit __PLC-2. For residential programs, these plans indicate a range of DSM energy savings of between 8% and 72% of cumulative sales growth. For non-residential customers, Exhibit __PLC-2 suggests that utilities with collaboratively-designed programs plan to save between 31% and 72% of cumulative growth in sectoral energy sales. From these plans, I projected that mature SCE&G DSM programs could generate energy savings equal to 43% of new (post-1991) growth in total energy sales.[71] I

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[71]The simple mean of these relative shares is 35% for residential programs and 52% for non-residential programs for the six utilities for which sufficient information was available. Weighted according to projected energy sales for SCE&G's residential and non-residential classes, the savings amount to 46% of projected energy sales growth.

My projections assume that DSM savings will be less than 46% of sales growth, because SCE&G's sales growth forecast is 10% higher than that of the collaborative utilities. Savings from retrofits and routine replacement of existing customer equipment may account for a large portion of total savings achieved by collaboratively-designed programs. To account for this, I assumed that savings due to load growth account for 20% of total savings, and therefore a 10% increase in load growth will increase total savings by only 2%. To reflect this relationship between load growth and total savings growth, I reduced the 46% figure to 43%.

allowed three years for program ramp-up by starting SCE&G's DSM energy savings at a rate of 35% of projected annual sales increases in 1992. I increased this fraction to 40% in 1993 and to 43% from 1994 to 2000. The result in each year is the incremental energy savings that SCE&G should be able to obtain with appropriately comprehensive programs.

Q: How did you arrive at the load factors you used to translate additional energy savings into additional peak load reductions?

A: I developed the DSM load factor to apply to the additional DSM energy savings on the basis of the DSM plans of six utilities with collaboratively-designed programs for which I was able to obtain projections of energy and demand savings.[72] I developed these load factors by calculating the weighted average DSM load factor from the DSM plans of BECO, EUA, NEES, NYSEG, NU, and UI.[73] The average is 41%; this compares to 18% for SCE&G's programs (exclusive of standby generator and interruptibles) by 1996.

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[72]Of the seven utilities cited in PLC-2, peak-savings projections for Commonwealth Electric were not available.

[73]The weighting was accomplished by summing the four utilities' cumulative energy savings from DSM and dividing by the sum of their respective peak demand savings, which are shown in Exhibit __PLC-2. This quantity was multiplied by 1,000 and divided by 8,766 hours/year.

V. CONCLUSIONS AND RECOMMENDATIONS

A. Conclusions

Q: Summarize your conclusions with respect to SCE&G's resource planning and the need for Cope capacity.

A: While the Company has identified a need for additional resources towards the middle of this decade, it has not established that Cope is the best alternative for meeting this need. On the contrary, SCE&G has failed to properly identify, develop, evaluate, and pursue significant opportunities for cost-effective demand-side savings. Every kilowatt and every kilowatt-hour of cost-effective capacity and energy from such alternatives that SCE&G has failed to include in its resource plan constitutes Cope capacity and energy that SCE&G does not need, at least on the current schedule.

Q: If SCE&G needs capacity and energy resources by the latter half of the decade, why should the Commission conclude that the Cope project is not needed to meet these requirements?

A: To conclude that Cope is needed on the current schedule, the Commission must find that cost-effective alternative resources, including demand-side management, cannot provide enough energy or capacity to affect the optimal timing or type of development at Cope.

No such finding is supported by the evidence presented by SCE&G. My testimony shows that SCE&G has not identified the amount of cost-effective DSM it could obtain in place of some or all of the Cope investment. The Commission certainly cannot find that SCE&G's application is premised on the exhaustive pursuit of all cost-effective alternatives to Cope.

The inescapable conclusion is that Cope has not established the need for building Cope; nor has the Company established that Cope is the least-cost resource available for meeting future capacity and energy needs.

Q: Summarize your conclusions with regard to SCE&G's demand-side resource planning.

A: SCE&G's DSM planning suffers from several major deficiencies, including:

- not comprehensively assessing, targeting, and pursuing energy-efficiency resources. SCE&G's piecemeal pursuit of savings will unnecessarily raise costs and reduce savings achieved from demand-side resources.

- neglecting large and inexpensive but transitory opportunities to save electricity in all customer classes. By failing to act to capture these valuable opportunities, SCE&G loses them. Such lost-opportunity resources arise when new buildings and facilities are constructed, when existing facilities are renovated or rehabilitated, and when customers replace existing equipment that reaches the end of its economic life. To make matters worse, SCE&G's partial treatment of individual customers through piecemeal programs will actually create lost opportunities.

- programs are not strong enough to overcome the pervasive market barriers that obstruct customer investment in cost-effective efficiency measures. Incentives are not high enough, and programs do not address many important barriers.

Q: Summarize your conclusions with regard to the reforms needed in SCE&G's demand-side resource planning.

A: SCE&G's approach to DSM planning must be improved if the Company's resource planning is to be truly integrated, and if the Commission expects SCE&G to deploy a least-cost resource portfolio. Correcting this approach should enable SCE&G to meet about 40% of its energy sales growth with additional demand-side acquisitions. This translates into additional demand-side savings of about 148 MW and 626 GWh through the year 1996.

SCE&G should re-orient its demand-side planning toward comprehensive investment in efficiency savings in all market sectors, and abandon its narrow focus on individual measures and end-uses. In pursuing savings potential identified through this comprehensive approach, SCE&G should devise demand-side strategies to eliminate the myriad market barriers obstructing customer investment in cost-effective energy-efficiency measures. In deciding how to proceed toward achieving the cost-effective demand-side savings identified under such improved planning, SCE&G should pursue all cost-effective lost-opportunity resources as quickly as administratively feasible.

B. Recommendations

Q: What are your recommendations with regard to SCE&G's application for a Certificate of Public Convenience and Necessity?

A: I would recommend that the Commission reject the Company's proposal to build Cope until the utility demonstrates: (1) that it has undertaken to implement all economic energy efficiency and load management that could displace new power plants and (2) that the proposed pulverized coal plant at Cope is still the least cost supply option available to meet any remaining requirements. Regardless of the Commission's ultimate decision on SCE&G's application, I recommend that the Commission direct the Company to improve its planning and acquisition of demand-side resources before it commits to the construction of the Cope project.

Q: Why should the Commission require SCE&G to reform its integrated resource planning before acquiring the Cope project?

A: Unless SCE&G reforms its planning efforts, the demand-side resources generated by its approach to program design will be unnecessarily small, slow, and expensive. Consequently, SCE&G should be directed to pursue and acquire demand-side savings much more aggressively, much more comprehensively, and on a much larger scale, before the Commission allows the Company to build Cope or any other major supply option.

Q: Please summarize how the Commission should require SCE&G to proceed to plan for and acquire demand-side resources.

A: The Commission should direct the Company to immediately initiate efficiency investments in accord with the principles set forth above. These efforts should be comprehensive, as that term is defined and illustrated above. In particular, SCE&G should immediately target lost opportunities arising in new construction and in equipment replacement.

Specific details of how SCE&G should accomplish these objectives are beyond the scope of this testimony. The responsibility for devising and executing these actions rests with the Company; however, it would be to SCE&G's advantage to enlist the expertise and creativity of other parties.

Q: Which fundamental principles of demand-side resource planning and acquisition should the Commission direct SCE&G to follow in the future?

A: I strongly urge the Commission to direct SCE&G to incorporate the following basic elements in its future demand-side planning and acquisition, all of which are inherent in the DSM program plans of other utilities engaged in truly collaborative processes:

- the explicit pursuit of all cost-effective demand-side resources;

- a commitment to a comprehensive approach to this objective, including a full complement of marketing, delivery, and customer incentive strategies designed to achieve installation of all cost-effective measures for customers in all significant market sectors;

- a high priority on aggressive investment in lost-opportunity resources presented in new construction, remodeling/renovation of existing facilities, and replacement of existing equipment; and

- a willingness to pay what is necessary to maximize achievement of cost-effective savings, including full funding for and direct investment in hard-to-reach and especially valuable efficiency resources (e.g., payment of full incremental costs of lost-opportunity measures, and fully-funded direct investment for small commercial and residential customers).

Q: What action can the Commission take on the Company's petition to emphasize the need for reforms?

A: The most appropriate action is for the Commission to reject SCE&G's application. In addition, the Commission could signal its intent to link Cope prudence determinations to the Company's progress in improving its demand- and supply-side planning and acquisition procedures.

Any of these approaches would allow adequate time for vigorous pursuit of the demand-side resources SCE&G has not yet developed before committing to the Cope project, while securing the option of developing the plant, if and when that action is appropriate. Appropriately structured, any of these options can serve as notice to the Company that all cost-effective demand-side resources must be acquired before it commits to the acquisition of Cope capacity.

Q: Are you recommending that the Commission direct SCE&G to acquire additional savings equivalent to the levels you have estimated as attainable by the Company?

A: No. Although they may be appropriate goals, my estimates are illustrative of the magnitude of savings available if SCE&G developed comprehensive acquisition strategies comparable to those adopted by other leading U.S. utilities. The true extent of achievable demand-side savings can only be determined as part of an extensive effort to develop DSM opportunities in SCE&G's service area.

Q: Is it reasonable and prudent for SCE&G to plan for the contingency that it will need additional power in 1996 or beyond?

A: Yes. In addition to developing contingency plans for adding resources to the system in 1996, SCE&G should also be developing strategies for minimizing the lead-time necessary to acquire resources when they are required or become cost-effective. However, <u>planning</u> to develop the resource is not the same as <u>committing to acquisition</u> of the resource. The acquisition decision does not need to be made immediately, as long as efforts are made to develop the option to acquire.

At the same time, SCE&G should be planning <u>and</u> acquiring all cost-effective demand-side resources. With additional demand-side resources in its resource portfolio, the Company may find that its deadline for making the decision to acquire additional capacity can be delayed beyond that originally anticipated or that power requirements can be met at lower cost with alternative supply options.

Q: When should the decision to acquire a supply resource be made?

A: If all steps are taken to permit and authorize the site, the decision essentially needs to be made only as far in advance as required by construction leadtime. While it may be reasonable to commit at an earlier date to allow for planning uncertainty, it would be premature and imprudent for the

Company to commit to acquiring a supply resource (particularly one so far in the future) until the Company can determine the magnitude of the demand-side savings available in its service territory.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX 1

MARKET BARRIERS AND THE THE PAYBACK GAP BETWEEN UTILITY AND CUSTOMER EFFICIENCY INVESTMENT DECISIONS

I. THE "PAYBACK GAP" AS EVIDENCE OF MARKET FAILURE

Q. How does a rapid payback requirement translate into a stricter investment criterion?

A. The required payback period for an investment translates directly into a required rate of return. A higher required return means one requires future benefits to be relatively large in order to sacrifice the use of funds today. Table I presents the required rates of return implied by different combinations of investment lives and payback requirements.

Table I. Required Rates of Return Implied By Payback Criteria Under Different Economic Lives

Payback Period (Years)	Economic Life of Investment (Years)				
	10	15	20	25	30
1	162%	162%	162%	162%	->162%<-
1.5	92%	92%	92%	92%	92%
2	63%	64%	64%	64%	64%
3	37%	39%	39%	39%	39%
5	17%	21%	22%	22%	22%
7	8%	13%	14%	15%	15%
10	0%	6%	8%	9%	10%
12		3%	6%	7%	-> 8%<-
15		0%	3%	5%	5%
20			0%	2%	3%

Note: Assumes monthly savings equate to a single cashflow at mid-year, with no inflation.

For example, a customer who requires a 20-year investment to pay for itself in two years reveals a 64% required rate of return (as shown in Table I, at the intersection of the 20-year investment column and the 2-year payback row). By discounting future benefits so highly such a customer would only spend a dollar today to save a $1.64 a year from now. By contrast, a utility that requires a 20-year supply project to yield a 6-percent return on investment (compared to alternatives) will accept a 12-year payback period (as shown at the intersection of the 20-year investment column and the 12-year payback row).

Q. How does a required return lead customers to reject efficiency investments that would otherwise be attractive under a utility's lower discount rate?

A. The payback gap between utility and customer investment horizons is equivalent to a high markup to the life-cycle cost a utility would estimate for efficiency measures <u>if the utility paid for them directly and entirely</u>.

For example, consider the impact of a one-year maximum payback period which home builders might require on efficiency investments. Suppose a new home builder and SCE&G are independently evaluating the merits of installing low-emissivity windows in new houses. ("Low-E" windows provide the heating and cooling savings of a third layer of glass for about a 10% price premium.) A 13% utility discount rate translates roughly into an 8% real rate (net of 5% inflation.)

Table II. Derivation of Customer Markup to Societal Cost of Efficiency Improvement

ASSUMPTIONS	
Societal discount rate	8%
Levelized cost per kWh saved by efficiency, at societal discount rate	3 ¢/kWh
Economic life of efficiency measure	30 years
Customer's required return, implied by 1-year payback on 30-year measure (From Table I)	162%
RESULTS	
One-time investment equivalent to levelized payments for efficiency, at societal discount rate	33.8 ¢/kWh-Yr
Levelized cost of efficiency to customer, based on required customer return	54.6 ¢/kWh
Implicit customer markup to societal cost: 54.6/3 - 1 =	1722%

The Company amortizes the price premium for the Low-E windows over their 30-year lives and comes up with a lifetime cost of 3 cents per saved kWh, which it considers a bargain compared to spending (say) 6 cents for new capacity over the same period. SCE&G would be indifferent to investing in the efficiency measure for a one-time capital cost of 33.8 cents/kWh-Yr (where the denominator equals the number of kilowatt-hours being saved each year), or paying 3 cents one kWh at a time over the 30-year life of the investment. (See Table II.)

Now consider the same choice from the home-builder's perspective. Referring to Table I, observe that her one-year payback period requires the same up-front investment of 33.8 cents/kWh-Yr savings to yield a return of 162%. At this rate, the low-E windows have a levelized cost of (same present worth as) 54.6 cents per kWh saved. Compared to the societal cost of 3 cents per kWh saved, the homebuilder treats the low-E windows as if she had to pay an extraordinarily high markup of 1722%.

Q. How would the 17-fold markup on efficiency measures in your example affect resource allocation?

A. If electricity costs 6 cents, the home builder would only be willing to invest in measures that would cost SCE&G 0.33 cents/kWh -- one-eighteenth of the price of electricity. She will reject all other measures (high-efficiency heat-pumps, extra wall insulation) that would cost more than a third of a cent per kWh from SCE&G's perspective. Her decision would force SCE&G to supply power for the less-efficient houses at our (assumed) marginal cost of 6 cents/kWh. Moreover, these opportunities will be lost for the lives of the houses once they go up, since it would not be economical to remove the conventional windows and replace them with the more efficient ones. Anything SCE&G can do to get the low-E windows and other measures into the house is cost-effective as long as the measures (and SCE&G's administrative costs) are less than 6 cents/kWh.[74]

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[74] The incentives (rebates, grants, etc) are not costs per se, since they would cancel out payments by the home builder.

Q. In general, what are the consequences when market barriers force customers to place a high markup on the costs of efficiency investments?

A. The result is that setting prices at marginal costs does not generate the market response predicted by economic theory; in reality, customers do not readily substitute efficiency for electricity. This is because the payback gap drives a wedge between what consumers will pay to save electricity and what utilities spend to produce it. The 17-fold markup in this example means that an electric rate of 6 cent/kWh would not motivate a customer to spend 6 cents per conserved kWh. Rather, the customer would only invest in efficiency that to a utility would cost about 1/3 cent/kWh. Equivalently, a utility would have to set prices seventeen times higher than marginal cost to stimulate the customer response that is optimal in this example, namely, installing the more efficient windows.

II. MARKET BARRIERS CONTRIBUTING TO THE PAYBACK GAP

Q. Are customers being irrational when they mark up the direct costs of efficiency measures?

A. Not at all. An aversion to capital-intensive electricity substitutes may be perfectly valid, especially since efficiency is paid for so much differently from electricity. The simplest reason that efficiency is so regularly passed over in favor of "business as usual" is that, as an investment, it is not available on the same pricing terms as electricity or fossil fuels already being purchased by customers. If it were -- either through market innovation, utility market intervention, or both -- even short-payback customers would be much more likely to choose efficiency whenever it was priced below electricity.

Q. What other factors contribute to customers' apparent aversion to efficiency investments?

A. At least four factors interact to compound the costs and dilute the benefits of efficiency measures to utility customers:

1. <u>Limited access to relatively high-priced capital</u> can constrain payback periods to durations far shorter than the useful lives of the investments;

2. <u>Split incentives</u> diminish the benefits that both owners and occupants of buildings receive from efficiency investments by conferring them on the other party;[75]

3. <u>Real and apparent risks</u> of various forms impede individual efficiency investments, particularly the illiquidity of conservation investments (financial risk), uncertainty over market valuation of efficiency (market risk), fear of "lemon technologies" (technological risk), and perceptions of service degradation; and

4. <u>Inadequate, conflicting, and expensive information</u> makes the search and evaluation costs of efficiency improvements high in terms of a customer's own time, effort, and inconvenience.

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[75]Economists refer to this market imperfection as "unassigned property rights."

Q. How does limited access to capital constrain efficiency investment?

A. Efficiency investments lower operating outlays over time in exchange for higher initial outlays on the part of the investor. Individuals and businesses are often in no position to obtain capital to fund such commitments.[76] Homeowners and small business are often fully leveraged and unwilling to deplete savings to finance all economically justifiable efficiency investments. And while some consumers may be able to borrow the money to finance desired efficiency investments, borrowing terms are often far shorter than the life of the efficiency investment. The short amortization schedule pushes debt-service costs above the cashflow savings of the efficiency investment, shortening the maximum acceptable payback period.

Q. What do you mean by split incentives?

A. Many property owners do not pay the utility bills of the buildings they lease. Many building occupants do not own the buildings for which they pay utility bills. Making investments to lower the operating costs of tenants is rarely a high priority for landlords, just as spending money to raise property values (and therefore rents) is not terribly attractive to renters.

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[76]This is frequently because lenders fail to appreciate the value of efficiency. This could be characterized as an institutional impediment, a further consequence of inadequate information and risk perceptions.

Equally serious institutional impediments retard efficiency investments at other stages of the real estate market. Developers do not pay to operate the appliances, heating and cooling systems, or lighting in the homes and offices they build. Quite often they see their objective as minimizing the completion costs of the their buildings. This keeps margins high during tight markets, and protects against losses during slow periods.

Q. Explain how the elements of risk you listed restrain efficiency investments.

A. A higher level of perceived risk raises the rate of return required on the investment. Energy efficiency investments expose individual consumers to a variety of risks which a utility can reduce through <u>diversification</u> in its demand-side resource portfolio. Specific risks that tend to raise consumers' required return include the following:

> <u>Financial risk</u>: Efficiency investments are illiquid. Future savings from efficiency improvements are not marketable securities: there may be substantial penalties for earlier withdrawal. Often the efficiency investment becomes part of the building it is installed in, making it extremely difficult to liquidate the investment without selling the building.
>
> <u>Technological risk</u>: Few volunteer to be guinea pigs. For example, the perceived technological risks of advanced lighting equipment may be the single greatest obstacle to widespread market acceptance to date.
>
> <u>Market risk</u>: Homeowners may reject efficiency investments whose annual savings look good on paper because they are unsure that the resale value of the home would increase enough to recover the costs. Similar concerns are justified for businesses contemplating an

investment in highly efficient chillers or state-of-the-art lighting.

Q. Why does lack of information about efficiency constitute such a significant barrier?

A. Acquiring and critically evaluating information on the costs and performance of competing efficiency options is often prohibitively expensive for all but the largest and most sophisticated end-users. Not only do consumers need to understand individual technologies; they need to know how measures interact. Savings from combining some measures are less than the sum of their individual savings (for example, high-efficiency glazing and insulation). Other measures are complementary (insulation and high-efficiency furnaces) or mutually reinforcing (lighting efficiency and cooling systems).

Exhibit____PLC-1

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PROFESSIONAL EXPERIENCE

President, Resource Insight, Inc.
August 1986 - present

Consulting and testimony in utility and insurance economics. Reviewing utility supply planning processes and outcomes: assessing prudence of prior power planning investment decisions, identifying excess generating capacity, analyzing effects of power pool pricing rules on equity and utility incentives. Reviewing electric utility rate design. Estimating magnitude and cost of future load growth. Designing and evaluating electric, natural gas, and water utility conservation programs, including hook-up charges and conservation cost recovery mechanisms.

Determining avoided costs due to cogenerators. Evaluating cogeneration rate risk. Negotiating cogeneration contracts. Reviewing management and pricing of district heating system.

Determining fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determining profitability of transportation services.

Advising regulatory commissions in least-cost planning, rate design, and cost allocation.

Research Associate, Analysis and Inference, Inc.
May, 1981 - August, 1986 (Consultant, 1980-1981)

Research, consulting and testimony in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions.

Consulted on utility rate design issues including small power producer rates; retail natural gas rates; public agency electric rates, and comprehensive electric rate design for a regional power agency. Developed electricity cost allocations between customer classes.

Reviewed district heating system efficiency. Proposed power plant performance standards. Analyzed auto insurance profit requirements.

Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

Utility Rate Analyst, Massachusetts Attorney General
December, 1977 - May, 1981

Analyzed utility filings and prepared, alternative proposals. Participated in rate negotiations, discovery, cross-examination and briefing. Provided extensive expert testimony before various regulatory agencies.

Topics included: demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power pool operations, nuclear power cost projections, power plant cost-benefit analysis, energy conservation and alternative energy development.

PROFESSIONAL AFFILIATIONS

Senior Associate, Cambridge Energy Research Associates, Cambridge, Massachusetts.
Associate, Rocky Mountain Institute Competitek Service, Old Snowmass, Colorado.
Member, International Association for Energy Economics, and past Vice-President, New England Chapter.
Member, Association of Energy Engineers, Lilburn, Georgia.

EDUCATION

S.M., Technology and Policy Program, Massachusetts Institute of Technology, February, 1978.

S.B., Civil Engineering Department, Massachusetts Institute of Technology, June, 1974.

HONORARY SOCIETIES

Chi Epsilon (Civil Engineering)
Tau Beta Pi (Engineering)
Sigma Xi (Research)

OTHER HONORS

Institute Award, Institute of Public Utilities, 1981.

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"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with E. Caverhill), Boston Gas Company, December 22, 1989.

"Conservation Potential in the State of Minnesota," (with I. Goodman) Minnesota Department of Public Service, June 16, 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12, 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June, 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18, 1981.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

EXPERT TESTIMONY

In each entry, the following information is presented in order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered. Abbreviations of jurisdictions include: MDPU (Massachusetts Department of Public Utilities); MEFSC (Massachusetts Energy Facilities Siting Council); PSC (Public Service Commission); and PUC (Public Utilities Commission).

1. MEFSC 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12, 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with S.C. Geller.

2. MEFSC 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29, 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. MEFSC 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27, 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. MDPU 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4, 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. MDPU 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G.& E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23, 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. MDPU 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2, 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. MDPU 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16, 1980.

   Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. MEFSC 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16, 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. MDPU 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19, 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. Texas PUC 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25, 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of cancelled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M.B. Meyer.

14. MEFSC 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5, 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. MDPU 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12, 1980.

    Conservation as an energy source; advantages of per-kwh allocation over per-customer-month allocation.

16. MDPU 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26, 1981 and February 13, 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. MEFSC 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12, 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. MDPU 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May, 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. MDPU 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7, 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. DCPSC FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29, 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. NHPUC DE1-312; Public Service of New Hampshire - Supply and Demand; Conservation Law Foundation, *et al.*; October 8, 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. Illinois Commerce Commission 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15, 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. New Mexico Public Service Commission 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10, 1983.

Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. Connecticut Public Utility Control Authority 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17, 1983.

Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. MDPU 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15, 1983.

Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. Massachusetts Division of Insurance; Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October, 1983.

Profit margin calculations, including methodology, interest rates.

28. Connecticut Public Utility Control Authority 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3, 1983.

Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. MEFSC 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14, 1983, Rebuttal, February 2, 1984.

Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. Michigan PSC U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21, 1984.

Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. MDPU 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6, 1984.

Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. MDPU 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13, 1984.

Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. Michigan PSC U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16, 1984.

Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. FERC ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27, 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. Maine PUC 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13, 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. MDPU 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6, 1984.

Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. Pennsylvania PUC R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November, 1984.

Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. NHPUC 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15, 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. Massachusetts Division of Insurance; Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November, 1984.

Profit margin calculations, including methodology and implementation.

40. MDPU 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12, 1984.

Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. Maine PUC 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11, 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14, 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. MDPU 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14, 1985.

Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vermont PSB 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21, 1985.

Construction schedule and cost of completing Millstone Unit 3.

45. MDPU 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25, 1985, and October 18, 1985.

Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. MDPU 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12, 1985.

Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in streetlighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Massachusetts Division of Insurance; Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November, 1985.

Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. New Mexico Public Service Commission 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23, 1985.

Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. Pennsylvania PUC R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14, 1986.

Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. MDPU 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19, 1986.

Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. Pennsylvania PUC R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24, 1986.

Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. New Mexico Public Service Commission 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7, 1986.

Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. Illinois Commerce Commission 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13, 1986.

Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. New Mexico Public Service Commission 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18, 1986. (Not presented).

Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

Recommendation for rate-base treatment; proposal of power plant performance standards.

55. City of Boston, Public Improvements Commission; Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18, 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. Massachusetts Division of Insurance; Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cashflows, installment income, income tax status, and return to shareholders.

57. MDPU 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21, 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. New Mexico Public Service Commission 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19, 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. MDPU 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9, 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. Massachusetts Division of Insurance 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

    Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. Texas PUC 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17, 1987.

STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. Minnesota PUC ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17, 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. Massachusetts Division of Insurance 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2, 1987. Rebuttal October 8, 1987.

Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. MDPU 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4, 1987.

Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. Massachusetts Division of Insurance 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14, 1987.

Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. Massachusetts Division of Insurance; 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5, 1988.

Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. Massachusetts Department of Public Utilities 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2, 1988.

Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. Massachusetts Department of Public Utilities 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18, 1988, and November 8, 1988.

Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. Massachusetts Department of Public Utilities 88-67; Boston Gas Company; Boston Housing Authority; June 17, 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. Rhode Island Public Utility Commission Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24, 1988.

Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. Massachusetts Division of Insurance 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues August 12, 1988, supplemented August 19, 1988; Losses and Expenses September 16, 1988.

Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. Vermont Public Service Board Docket No. 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26, 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. Vermont House of Representatives, Natural Resources Committee; House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21, 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. MDPU 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6, 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. Vermont Public Service Board Docket No. 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1, 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. Boston Housing Authority Court 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, *et al.;* Boston Housing Authority; June 16, 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. MDPU 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30, 1989.

    Prudence of BECo's decision of spend $400 million from 1986-88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. MDPU 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24, 1989. Rebuttal, October 3, 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. MDPU 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13, 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. Vermont Public Service Board Docket 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19, 1989. Surrebuttal February 6, 1990.

Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. MDPU 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December, 1989; April, 1990; May, 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. California Public Utilities Commission; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21, 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. Illinois Commerce Commission Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25, 1990. Joint rebuttal testimony with David Birr, August 14, 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. Maryland Public Service Commission Case No. 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18, 1990.

Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. Indiana Utility Regulatory Commission; Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1, 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. MDPU Dockets 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5, 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. MEFSC 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14, 1990.

Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. Maine PUC Docket No. 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19, 1991.

Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. Commonwealth of Virginia State Corporation Commission Case No. PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6, 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. Massachusetts DPU Docket No. 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17, 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. Commonwealth of Massachusetts; Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13, 1991.

NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. Vermont PSB Docket No. 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19, 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. South Carolina Public Service Commission Docket No. 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13, 1991. Surrebuttal October 2, 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. Maryland Public Service Commission Case No. 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19, 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. Bucksport Planning Board; AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1, 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. Massachusetts DPU Docket No. 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4, 1991. Rebuttal December 13, 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbrons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. Florida PSC Docket No. 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21, 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. Florida PSC Docket No. 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31, 1991.

Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. Pennsylvania PUC Dockets I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10, 1992.

Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

Exhibit ___ PLC-2 (part 1)
Cumulative and Total Demand Savings, as Percent of Growth and Peak

	Peak savings (MW)	Peak load (MW)	Peak savings as % of peak	Cum. growth in peak savings (MW)	Cum. peak growth (MW)	Growth in peak savings as % of peak grth
	[1]	[2]	[3]	[4]	[5]	[6]
BECo (growth 1990-94 inclusive)						
Res.:	8	734	1.1%	7	64	10.6%
C/I:	109	2,159	5.0%	109	295	36.9%
Total:	117	2,893	4.0%	116	359	32.3%
Eastern Utilities (growth 1991-95 inclusive)						
Res.:	7	NA		7	NA	
C/I:	73	NA		73	NA	
Total:	80	949	8.4%	80	99	80.8%
NEES (growth 1991-1995 inclusive)						
Res.:	NA					
C/I:	NA					
Total:	340	4,581	7.4%	221	403	54.8%
New York State Electric and Gas (growth in 1991-2008 inclusive)						
Res.:	NA					
C/I:	NA					
Total:	846	4,470	18.9%	788	1,810	43.5%
Northeast Utilities (growth 1992-2000 inclusive)						
Res.:	77	NA		52	NA	
C/I:	743	NA		613	NA	
Total:	819	6,208	13.2%	665	1,054	63.1%
United Illuminating (growth 1992-2010 inclusive)						
Res.:	48	NA		44	NA	
C/I:	262	NA		227	NA	
Total:	310	1,554	19.9%	270	445	60.7%

Exhibit ___ PLC-2 (part 2)
Cumulative and Total Energy Savings, as Percent of Growth and Sales

	Total energy savings (GWh)	Total projected sales (GWh)	Energy savings as % of sales	Cum. growth of energy svgs (GWh)	Cum. sales growth (GWh)	Energy savings as % of growth	DSM load factor
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
BECo (growth 1990-94 inclusive)							
Res.:	73	3,709	2.0%	66	295	22.3%	102%
C/I:	454	10,145	4.5%	454	1,205	37.6%	48%
Total:	527	13,854	3.8%	520	1,500	34.6%	51%
COM/Electric (growth 1991-95 inclusive)							
Res.:	62	2,134	2.9%	62	374	16.7%	NA
C/I:	688	3,239	21.2%	688	1,045	65.9%	NA
Total:	750	5,400	13.9%	750	1,426	52.6%	NA
Eastern Utilities (growth 1991-95 inclusive)							
Res.:	37	1,697	2.2%	37	100	37.1%	59%
C/I:	198	2,924	6.8%	198	276	71.8%	31%
Total:	236	4,622	5.1%	236	377	62.5%	34%
NEES (growth 1991-1995 inclusive)							
Res.:	222	8,208	2.7%	156	217	71.9%	NA
C/I:	757	14,487	5.2%	496	1,607	30.9%	NA
Total:	1,120	25,070	4.5%	750	1,936	38.7%	38%
New York State Electric and Gas (growth in 1991-2008 inclusive)							
Res.:	912	NA					NA
C/I:	1,867	NA					NA
Total:	2,794	22,170	12.6%	2,779	8,855	31.4%	38%
Northeast Utilities (growth 1992-2000 inclusive)							
Res.:	556	10,890	5.1%	504	978	51.5%	83%
C/I:	2,895	18,983	15.2%	2,722	4,376	62.2%	45%
Total:	3,460	30,180	11.5%	3,232	5,366	60.2%	48%
United Illuminating (growth 1992-2010 inclusive)							
Res.:	47	2,259	2.1%	36	451	8.0%	11%
C/I:	776	5,021	15.4%	739	1,640	45.1%	34%
Total:	827	7,347	11.3%	777	2,097	37.0%	30%

Weighted average of load factors for BECo, Eastern Utilities, Northeast Utilities, and United Illuminating:	Res.:	58%
	C/I:	42%
	Total:	43%

Weighted average of total load factors, for BECo, EUA, NEES, NYSEG, UI, NU.	41%

Notes to Exhibit ___ PLC-2, parts 1 and 2:

[1]: Energy (and peak) savings are for the final year of the interval indicated.

[2]: Total sales (and peak) figures are for the final year of the interval indicated, and are pre-DSM forecasts; that is, they do not take into account reductions due to DSM. Total sales and peak projections may not equal sum of residential and C/I sales and peak, because of contributions from street lighting, municipals, or other misc. customers.

[3]: [1]/[2]

[4]: [1] minus the savings (or peak) of the year preceding the first year of the specified interval.

[5]: [2] minus the sales (or peak) of the year preceding the first year of the specified interval. For example, BECo's projected sales growth equals 1994 sales minus 1989 sales.

[6]: [4]/[5]

[7]: (part 2 only) load factor is calculated as ([2] of part 2)/([2] of part 1)*1000/8760.

Sources:

Boston Edison savings figures are from "The Power of Service Excellence," (March '90), Appendix I-C.
Load figures from Long-Range Integrated Resource Plan 1990-2014, Vol. II. (5/1/90).

Com/Electric savings data from Mass. DPU 91-80, 4/15/91
Com/Electric sales and peak data from "Long Range Forecast of Electric Power Needs and Requirements," (12/1/89) Vol. 1.
Note that Com/Electric's savings as reported in column [1] of part 2 do not include the effects of DSM implemented prior to 1991; collaborative DSM savings have been added back to Com/Electric's forecasted peak and sales, to reflect pre-DSM levels.

Eastern Utilities load and sales projections from DRAFT Load Forecast, Vol 2.
Eastern Utilities data from "Energy Solutions: An Overview of Montaup's Residential C&LM Programs, 1991" and "Energy Solutions, An Overview of Montaup's C/I C&LM Programs, 1991" (2/91).
Note that EUA's savings as reported in column [1] of each table do not include the effects of DSM implemented prior to 1991.

NEES figures from "Integrated Resource Management Draft Initial Filing, Technical Volumes," May 20, 1991.

NYSEG figures from their "Demand Side Management Summary & Long Range Plan," (10/90), Vol. 1, Table 3.

Northeast Utilities data from Northeast Utilities, "1991 Forecast of Loads and Resources for 1991-2010," (March 1991).

United Illuminating data from UI's "Report to the Connecticut Siting Council," (3/1/91).

Exhibit ___ PLC-3
1991 DSM Savings as Percent of 1991 Peak and Sales

	DSM MW	Peak MW	MW svgs as % of peak	DSM GWh	Sales GWh	GWh svgs as % of sales
	[1]	[2]	[3]	[4]	[5]	[6]
BECo						
Res.	3	689	0.4%	18	3,523	0.5%
C/I	17	1,948	0.9%	74	9,404	0.8%
Total	20	2,637	0.8%	92	12,927	0.7%
Com/Electric						
Res.	NA			7	1,865	0.4%
C/I	NA			72	3,041	2.4%
Total	NA			79	4,906	1.6%
Eastern Utilities						
Res.	1	NA		5	1,601	0.3%
C/I	11	NA		23	2,613	0.9%
Total	12	860	1.4%	27	4,213	0.6%
NEES						
Res.	NA			NA		
C/I	NA			NA		
Total	46	4,441	1.0%	141	24,553	0.6%
Northeast Utilities						
Res.	25	NA		52	9,912	0.5%
C/I	129	NA		173	14,608	1.2%
Total	155	5,154	3.0%	225	24,520	0.9%
NYSEG						
Res.	15	NA		30		
C/I	20	NA		52		
Total	35	2,710	1.3%	82	13,578	0.6%
United Illuminating						
Res.	4	NA		11	1,808	0.6%
C/I	35	NA		36	3,380	1.1%
Total	39	5,530	0.7%	48	5,189	0.9%

Notes:

Boston Edison 1991 figures from Table 1 of Exh. BE-RSH-3 to DPU 90-335; figures are only for conservation program savings (load management excluded); sales and peak projections from "Long Range Integrated Resource Plan," Vol 2 (1/90).

Com/Electric savings data from Mass. DPU 91-80, 4/15/91

Com/Electric sales data from "Long Range Forecast of Electric Power Needs and Requirements," (12/1/89) Vol. 1.

Eastern Utilities data from "Energy Solutions: An Overview of Montaup's Residential C&LM Programs, 1991" and "Energy Solutions, An Overview of Montaup's C/I C&LM Programs, 1991," (2/91).

Eastern Utilities load and sales projections from DRAFT Load Forecast, Vol 2. Figures are for 1990, as no 1991 figures were available.

Effect of DSM has been added back to EUA's post-dsm forecast figures.

NEES 1991 figures from "Demand Side Management at New England Electric: Implementation, Evaluation and Incentives," Alan Destribats et al., NARUC Santa Fe 1991 Conference Proceedings (1991 dollars).

Northeast Utilities data from "1991 Forecast of Loads and Resources" (3/1991).

NYSEG figures from their "Demand Side Management Summary & Long Range Plan," (10/90), Vol 1, Table 3.

All UI data from United Illuminating's "Report to the Connecticut Siting Council," (3/1/91).

Exhibit ___ PLC-4
Utility Expenditures on DSM, as Percent of Revenues

	1991 expenditure (1991$)	[1] as % of '91 revenues	Total program expenditure (1991$)	# yrs covered	Avg annual expenditure	[5] as % of '91 revenues
	[1]	[2]	[3]	[4]	[5]	[6]
BECo						
Res.	$11,052,489	0.9%	$31,714,800		$6,342,960	0.5%
C/I	$22,823,845	1.9%	$190,685,040		$38,137,008	3.0%
Total	$33,876,334	2.8%	$222,399,840	5	$44,479,968	3.5%
Com/Electric						
Res.	$1,608,000	0.4%	$14,552,000		$2,910,400	0.7%
C/I	$13,310,000	3.3%	$116,910,000		$23,382,000	5.5%
Total	$14,918,000	3.7%	$131,462,000	5	$26,292,400	6.2%
Eastern Utilities						
Res.	$2,673,900	1.1%	$18,451,700		$3,690,340	1.4%
C/I	$7,198,180	2.9%	$58,194,080		$11,638,816	4.4%
Total	$9,872,080	4.0%	$76,645,780	5	$15,329,156	5.8%
NEES						
Res.						
C/I						
Total	$85,000,000	5.3%	$1,608,105,200	20	$80,405,260	4.7%
New York State Electric and Gas						
Res.						
C/I						
Total	$25,409,000	2.2%	$1,550,063,000	19	$81,582,263	6.7%

Notes:
Boston Edison 1991 figures (in '91$) from Table 1 of Exh. BE-RSH-3 to DPU 90-335; figures are only for spending on conservation (load management excluded); these figures are an update to BECO 1990 plan. Boston Edison figures other than 1991 are from "The Power of Service Excellence," (March '90), Appendix 1-A. BECo's figures, reported as 1990 dollars, have been adjusted to 1991 dollars (infl. = 4%).
Com/Electric expenditure data from Mass. DPU 91-80, 4/15/91 (1991 dollars).
Eastern Utilities data from "Energy Solutions: An Overview of Montaup's Residential C&LM Programs, 1991" and "Energy Solutions, An Overview of Montaup's C/I C&LM Programs, 1991," (2/91) 1991 dollars assumed.
NEES 1991 figures from "Demand Side Management at New England Electric: Implementation, Evaluation and Incentives," Alan Destribats et al., NARUC Santa Fe 1991 Conference Proceedings (1991 dollars). Remaining NEES figures from their "Conservation and Load Management Annual Report" (5/90) (1990 dollars, adjusted to 1991 (4% inflation assumed). NEES 1988 revenues from NEES' 1989 Annual Report, p. 18.
NYSEG figures from their "Demand Side Management Summary & Long Range Plan," (10/90) Vol. 1 (originally reported in nominal dollars; adjusted to '91$, 4% infl. assumed; prog. costs for 1991-2008). NYSEG ultimate consumer revenues from 1989 annual report, adjusted annually by 2% for growth and 4% for inflat
All utilities' (except for NYSEG and NEES) revenues from the Energy Information Administration's "Financial Statistics of Selected Electric Utilities, 1988" (published 1990). 1988 revenues have been adjusted annually by 2% for growth and 4% for inflation.

Exhibit ___ PLC-5
Cost of Residential and C/I DSM Savings

	Budget (1991$)	Incremental MW svgs	Incremental GWH svgs	DSM capacity factor	Amortized budget	Gross $/kWh
	[1]	[2]	[3]	[4]	[5]	[6]
BECO (DSM in 1990-1994)						
Res	$31,714,800	7	66	107.63%	$3,272,805	$0.0496
C/I	$190,685,040	109	454	47.55%	$19,677,719	$0.0433
Total	$222,399,840	116	520	51.17%	$22,950,523	$0.0441
Com/Electric (DSM in 1991-1995)						
Res	$14,552,000	NA	62	NA	$1,501,692	$0.0242
C/I	$116,910,000	NA	688	NA	$12,064,513	$0.0175
Total	$131,462,000	NA	750	NA	$13,566,204	$0.0181
EUA (DSM in 1991-1995)						
Res	$18,451,000	7	37	60.63%	$1,904,049	$0.0512
C/I	$58,194,080	73	198	31.12%	$6,005,331	$0.0303
Total	$76,645,080	80	236	33.70%	$7,909,379	$0.0336
NEES (DSM in 1990-2009)						
Total	$1,608,105,200	1162	2,285	22.45%	$165,948,212	$0.0726
1991 only	$85,000,000	46	141	34.99%	$8,771,564	$0.0622
New York State Electric and Gas (DSM in 1991-2008)						
Total	$1,550,063,000	788	2,779	40.26%	$159,958,555	$0.0576

Assumptions:

Life of DSM savings	15	years
Real discount rate	6%	

Notes:

[1],[2],[4]: see Exhibit PLC-2 for source, except for NEES, whose 1990-2009 figures are from the 1990 Conservation and Load Management Annual Report. and whose 1991 figures are from "Demand-Side Management at New England Electric: Implementation, Evaluation and Incentives," Alan Destribats et al., NARUC Santa Fe 1991 Conference Proceedings. All utilities' expenditures and savings are cumulative over the life of the program.

[3]: Note that line losses are not included; this results in overstating of the final cost of DSM.

[4]: [3]*1000/[2]*8760

[5]: [1], amortized over 15 years, at a 6% real discount rate (nominal discount rate is 10.7%, inflation is 4.4%, as cited in SCE&G response to Consumer Advocate interrgatory 2-19).

[6]: [5]/[3]*10^6

Exhibit ___ PLC-6 (part 1): Incentives Paid in Collaboratively-Designed Commercial/Industrial Energy Conservation Programs

	Programs targeting conservation market sectors							*Programs targeting end-uses*	
	New constrctn	Remodel/ replace	Retrofit Large C/I	Retrofit Small C/I	Existing industrial	Agric.	Industrial new constr	Motors	Lighting
BECo [1]	100% IC +d [2]	100% IC	100% TC or 1 yr pb [3]	100% TC					
COM/Elec [4]	100% IC +d [5]	100% IC +d (NC)	100% IC [6]	100% TC	90-100% IC [7]		1.5 yr pb	TBD	
CVPS	100% IC +d [8]	100% IC [9]	1.5 yr pb	1.5 yr pb	1.5 yr pb	1.5 yr pb	1.5 yr pb	100% avg IC	75% TC +f [10]
EUA	100% IC +d [11]	100% IC +d (NC)	100% TC [12]	100% TC [12]					
GMP	100% IC apx, +d [13]	100% IC	2 yr pb	1 yr pb		1 yr pb			
NEES	100% IC +d [14]	100% IC +d, (NC) [15]	100% TC/IC [16]	100% TC/IC					
NYSEG [17]	100% IC +d [18]	100% IC apx	1.5 yr pb +f	100% TC	100% avg IC [19]	100% avg IC [19]			100% avg IC [19]
UI	57-93% IC +d [20]	57-93% IC +d (NC)	25% TC, apx +f [21]	25% TC, apx +f [21]					
WMECo	100% IC +d [22]	TBD [23]	66% TC or 1 yr bp [24]	100% TC [25]					100% IC [26]

Key:

apx :	Approximately	IC:	Incremental Costs
avg :	Average	(NC):	Covered under new construction program
blank cell:	Utility does not have such a program	n yr pb:	n Year Payback Buydown (n=# of yrs)
+d :	+ Design assistance	TBD:	To be determined
+f :	+ Financing	TC:	Total Costs

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Notes to Exhibit ___ PLC-6, part 1:

[1]: BECo also offers a performance contracting program (incentive: 100% TC) and Design Plus, a prog. targeting large C/I customers willing to invest in upgrading their electrical systems (incentive: 50% measure cost, 100% design cost).

[2]: Design: based on annual kWh savings, $.005/annual kWh saved for bldgs < 80,000 sq ft; $.01/annual kWh saved for larger bldgs; 25% bonus for exceeding Article 20 code levels by more than 30%.

[3]: Full installation cost for institutions; non-institutional incentive is total cost of retrofit less projected value of first year energy and demand savings.

[4]: Commonwealth Electric also has a dedicated non-profit program and schools program which pay 100% of incremental costs.

[5]: Design incentive per annual kWh saved: $.01 for bldgs < 80,000 square feet, $.005 for larger bldgs, bonus incentive for comprehensive designs, total capped at $.025 (small bldg) and $.0125 (large bldg); caps periodically revised.
Industrial new construction: 1.5 yr payback buydown.

[6]: Incentives offered either as cash payment, bill credit, or payment to 3rd party such as contractor or bank; lower level of funding (90%) for single end-use projects.

[7]: Same as [4], except no penalty for a less comprehensive program.

[8]: Full incremental costs to Act 250 customers only; others will be offered incentives to offset incremental costs; capped design incentive based on estimated energy savings, bonus to encourage comprehensive, highly efficient designs.
Industrial new construction: 1.5 year payback buydown.

[9]: 1.5 year buyback for national accounts

[10]: Phase 1(test facilities for promotion of prog.): cust must pay 25% of cost of products and labor; CVPS will provide 0% financing. Phase II incentives are not specified.

[11]: Design: 6% of construction incentive, capped at $10,000; constuction: 100% of IC up to $50,000, after which customer must contribute 1 year's bill savings.

[12]: Retrofit: 100% full installed cost; replacement/upgrade: 100% incremental cost, capped at $100,000 per customer.

[13]: Design: incremental cost (to 5% of construction incentive); construction: approximately full incremental cost.

[14]: Design incentive of up to 6% of total equipment incentive.

[15]: Customers who are renovating are covered under new construction; official definition of "renovating" is still TBD; personal communication, Don Robinson (NEES) to Sabrina Birner, 4/18/91.

[16]: Except for lighting, where only the most efficient options have full incentives.

[17]: NYSEG also offers an HVAC program paying 100% of average incremental costs.

[18]: Capped design cost.

[19]: NYSEG bases incentive on average incremental costs, i.e., if a customer's incremental costs are unreasonably higher than average incremental costs, NYSEG reserves the right to pay only average incremental incremental costs.

[20]: 57% base incentive for meeting a component standard; higher incentive for exceeding standard; bonus for meeting standards on all components; design grant available, amount depends of size, complexity of project, and on engineer's experience.

[21]: Incentive schedule as follows: if measure pays for itself in 0-2 years, 0% incentive; 2-3 years, 20%; 3-4 years, 30%; 4+ years, 40%; on the average, UI expect this incentive to be approx. 25% of total installation cost.

[22]: Prescriptive area:up to full incr cost, based on kW and/or kWh reductions from baseline (subject to change in 1991); comprehensive area: up to full incr cost, capped at $.035/lifetime kWh for measures, $.005 for design; bonus incentives available; program cap being revised.

[23]: Incentive structure for WMECo's remodel/replace program still being determined (person communication, Nancy Benner to Sabrina Birner, 4/17/91)

[24]: Lighting: fixed $ amount per item (installation, design etc excluded); manufacturing: 1 year payback buydown of installed cost; non-manufacturing: least of 2 year payback buydown of installed cost or 66% of total cost; also valid for customer-initiated DSM.

[25]: For customers with an avg peak demand < 50 kW; customers with avg peak demand between 50 and 250 kW receive a free audit and installation of about $100 worth of low-cost measures, and have the option of participating in WMECO's lighting program.

[26]: Personal communication, Martha Samson (Northeast Utilities) and Sabrina Birner, 4/18/91.

Exhibit ___ PLC-6 (part 2): Incentives Paid in Collaboratively-Designed Residential Energy Conservation Programs

	Programs targeting conservation market sectors						*Programs targeting end-uses*				
	Gen'l use cust.	Multi-family	New constr.	Low income	Energy fitness	Public Hous'g	Lighting (CF bulbs)	Elec. heat cust.	Appliance	Efficient A/C	High-eff water heater
BECo	up to 100% TC	up to 100% TC	based on IC [1]		100% TC	up to 100% TC [2]	100% TC +cat, +pop [3]	up to 100% TC	labeling only [4]	tune-up, rebate TBD [5]	
Com/Elec	100% TC [6]	100% IC [7]	reduce or eliminate IC [8]	100% TC	100% TC	100% TC	100% TC +cat, +pop [9]	100% TC	labeling only		
CVPS	50% of cost [10]						apx 50% TC +cat, +pop [11]		coupons [12]		
EUA	100% TC [13]	100% TC [13]	apx avg IC [14]	100% TC [13]			100% TC +cat [15]	100% TC [13]	labeling only	$125/ton	
GMP	TBD [16]		TBD [16]				+pop, +cat [17]		coupons [18]		
NEES		100% TC/IC	100% TC/IC		100% TC/IC		100% TC/IC	100% TC/IC	[19]		100% TC/IC
NYSEG [20]	100% TC	100% IC +f [21]	apx 100% IC	100% TC			100% TC +cat, +pop [22]	100% TC	TBD		100% IC apx
UI [23]	100% TC		based on kWh savgs [24]				100% TC +pop [25]	100% TC [26]	rebates, labeling [27]	cust and dealer incentives	100% TC [28]
WMECo [29]	100% TC	100% TC	apx avg IC [30]	100% TC		100% TC [31]	100% TC +cat, +pop [32]	100% TC	2nd frig. disposal		100% TC

Key:

apx :	Approximately	+f :	+ Financing
avg :	Average	IC:	Incremental Costs
blank cell:	Utility does not have such a program	+ pop:	+ point-of-purchase discounts
+cat:	+ catalogue	TBD:	To be determined
+d :	+ Design assistance	TC:	Total Costs

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Notes to Exhibit ___ PLC–6, part 2:

[1]: Incentives are based on avoided costs and on average incremental measure costs, and will be designed to maximize participation rates and to eliminate market barriers.

[2]: BECo will consider incentives for measures that only become cost–effective when both the energy and non–energy benefits are considered; incentive would reflect payment needed to acheive desired market penetration; incentive would not exceed the lesser of measure costs or the value of the savings to BECo over the measure life.

[3]: BECo catalogue and point–of–purchase rebates are set to 2/3 of the retail cost for compact fluorescent bulbs, 1/4 of cost for halogen bulbs.

[4]: Incentives do not appear cost–effective at this time, but will periodically evaluate and implement rebates for high–efficiency eq't.

[5]: BECO will pay for a portion of the cost of an A/C or Heat Pump tune–up, will also offer rebates (level TDB) for efficient A/C, heat pumps.

[6]: 100% of total cost paid for hot water measures; four free compact fluorescent bulbs/household; add'l bulbs available at reduced price through catalogue; COM/Electric will pay some portion of hardwire fixture retrofits; free appliance maintenance and customer education.

[7]: For electric heat customers, in many cases, measures which are deemed important for the building owner to invest in will be cost–shared: COM/Electric will pay up to avoided costs, and the owner will provide the rest of the financing, part of which may be debt.

[8]: Level of incentive will be based on results of other Massachusetts utilities' residential new construction programs; 100% IC expected for multi–family housing.

[9]: Also, mail–order rebates for bulbs ($5 or $7.50 per bulb) and fixtures (up to $30); point of sale rebates.

[10]: Energy conservation measures available by mail order or at district office (no direct installation); there will be a maximum incentive per customer.

[11]: Point–of–sale discounts of 50% (approx $7.10) for bulbs, $20 for fixtures, + dealer incentive; mail order incentive of approx. 50% of bulb cost; other incentives to be investigated.

[12]: Refrigerator, $50; freezer, $50, room A/C, $20; also, $50 paid for disposal of second refrigerators.

[13]: Under its umbrella "Residential Retrofit Program," EUA has designed stategies to penetrate the following sectors: single family electric space and water heating; multi–family electric space and water heating; general use customers; and low income customers.

[14]: Fixed incentives offered through Energy–Crafted Homes program: single–family electric: $1650; multi–family electric: $900; lighting: $25/hard–wired compact fluorescent fixture; these incentives are meant to cover the average incremental cost to the builder for going for a Code–built house to an Energy Crafted Home.

[15]: Free compact fluorescent bulbs offered under programs listed in [13]; additional bulbs available through a catalog at 65% – 70% of retail cost.

[16]: Under review (incentives and fuel switching still unresolved).

[17]: Bulbs, 50%, fixtures $20 (point of sale or mail order)

[18]: Coupons of $50 for refrigerators and freezers; also $50 paid for second fridge disposal;dealer incentives.

[19]: Rebate anticipated to be less than incremental costs.

[20]: NYSEG also offers a "Renovation, Remodel and Equipment Upgrade" program to capture energy savings from the renovation and remodeling of residential properties; incentives approximate incremental costs.

[21]: 100% total cost for electrically heated properties; non electrically heated properties receive up to full incremental costs: financing available for non–electric heat customers.

[22]: In addition, charitable groups work w/ NYSEG to sell the bulbs door–to–door at low cost.

[23]: UI also offers an AC/heat pump tune–up program, and an energy conservation loan program for households undertaking large–scale energy efficiency improvements.

[24]: Total UI investment to be less than present value of avoided costs, currently estimated at approx. $1,100/unit.

[25]: UI also offers dealer incentives.

[26]: Full cost of measures installed directly; incentive payments and financial package for other measures implemented.

[27]: Rebates for efficient AC, based on avoided cost; appliance labeling for refrigerators, freezers, room AC.

[28]: Tank and pipe wrap, early retirement of rental water heaters, replacement with high–efficiency units.

[29]: WMECO also offers a "Neighborhood Program" which will target urban customers on a neighborhood–by–neighborhood basis.

[30]: 1–2 family: electric heat: $1,650/home; fossil fuel heat: $150/home; lighting: $200/unit.
Multifamily: electric heat: $900/unit; fossil fuel heat: $75/unit; lighting: $200/unit.

[31]: In some cases, the PHA may share in the cost of installation. This cost may be important with buildings requiring nonenergy–related modernization measures which can occur at the same time as measures installations.

[32]: Bulbs distributed free through other programs; mail order catalog offering bulbs at discount (discount not specified in Plan); point of purchase rebates offered (rebate not specified in Plan).

...and General Comments for Exhibit ___ PLC-6:

Comments

Utilities will not pay more than avoided costs for a measure.
Some customers may, for aesthetic reasons, pick a more expensive measure over the recommended measure. In this case, the customer must pay the incremental cost of the expensive measure over the recommended measure.
As of 4/15/91, CVPS' and GMP's programs have not yet been approved by the Vermont DPS.

Sources:

Boston Edison, "Energy Efficiency Partnership, Commercial Industrial Conservation Programs," and "Energy Efficiency Partnership, Residential Conservation Plans," (11/90).
Central Vermont Public Service Docket 5270-CV-3, Sept 7 1990, "Concensus Filing of CVPS Collaborative Requesting Approval of Conservation, Efficiency and Load Management Programs."
COM/Electric, "Mass. State Collaborative Phase II Detail Plans" (10/89).
Eastern Utilities, "Energy Solutions: An Overview of Montaup's Commercial/Industrial C&LM Programs - 1991" (2/91).
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New England Electric System, Mass. DPU Docket No. 90-261, discovery response DR-DPU-PD 2-6, and Appendix H to testimony of Witness Flynn, "Design 2000."
NYSEG, "Demand Side Management Summary and Long Range Plan," (Oct 1990).
United Illuminating, "Energy Action '90," (4/90).
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EXHIBIT____PLC-7: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

A: Boston Edison

Residential

Program	Target population	Measures	Delivery	Special features
Energy Eff. Lighting	All customers	cold-ballasted & other fluorescents, high pressure sodium	Direct installation	
Energy Fitness	general use, urban customers	lighting, appliance, elec. H2O heaters	Direct installation	
Appliance Labeling	Buyers of refrig., freezer, room A/C	Labeling	Point-of-purchase	
Heat Pump/AC Tune Up	customers with heat pump, central A/C; high use	Tune ups	Direct installation	
Multifamily Elec. Eff.	multi-family	space heat, lighting, elec. H2O heat, education	Direct installation	
Public Housing	public housing authorities	insul., vent., air seal, A/C filter replace, lighting	Direct installation	Considers incntvs. for custom measures
New Construction	new homes, high-rise, major remodeling	insul., vent., lighting, eff. heat, eff. appliances	Direct installation	
Elec. Heat/High Use	high use customers in 1-4 unit bldgs., low-inc.,	space heat/cool, lighting, elec H2O heat, education	Direct installation	Considers incntvs. for custom measures
WattBusters	customers with elec. H2O heat in 1-4 unit bldgs.	elec. H2O heat	Direct installation	
HVAC	A/C, heat pump new install. & replacement	central A/C, heat pump	Direct installation	

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
Encore	Institutional customers	varies with ESCO	ESCO's	Performance contracting
C/I New	New construction, major renovation	Lights, H2O heat, HVAC, refrig., cooking	Direct installation	Incentives for some other customer-proposed measures
C/I Small	Customers with 150- kW peak demand	Lights, HVAC, refrig., elec. H2O heat, cooking	Direct installation	Incentives for some other customer-proposed measures
C/I Large	Customers with 150+ kW peak demand	Lights, HVAC, refrig., ind. process		
C/I Remodel & Replace	Replacements, remodeling	Lights, HVAC, refrig., elec. H2O heat, cooking, motors	Direct installation	
Design Plus	Largest 1500 customers	Lights, HVAC, controls, elec. H2O heat, motors		

Notes:
Shaded programs are lost opportunity programs.
Boston Edison also offers a commercial/industrial load management program.

Source:
Boston Edison Energy Fitness Plan: Residential Conservation Programs.
Boston Edison Energy Efficiency Partnership: Commercial and Industrial Conservation Programs.

EXHIBIT____PLC-7: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

B: Eastern Utilities

Residential

Program	Target population	Measures	Delivery	Special features
Residential Retrofit	single/multi fam. elec. space & H2O heat, gen. use & low inc.	comp. fluor., refrig. coil clean, H2O heat wraps, pipe insl., repl. A/C filters	Direct installation	xtra insl. for space heat customers
Energy Crafted Home	new construction	insul., vent., high eff. lighting		incentives to builders
Appliance Labeling	all buyers of hi-eff. refrig., freezer, A/C, H2O heaters	Labels		
Efficient Central A/C	new or replacement A/C	A/C with 11.0+ SEER	Direct installation	Incentives to contractors

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
C/I Retrofit	All customers	lighting, elec. H2O heat, HVAC, motors	Direct installation	
Energy Eff. Construction	New construction	Lights, motors, HVAC, refrig., envelope		Incentives for some other customer-proposed measures

Notes:
Shaded programs are lost opportunity programs.
Eastern Utilities also offers a commercial/industrial load management program.

Source:
Energy Solutions: An Overview of Montaup's Residential C&LM Programs – 1991.
Energy Solutions: An Overview of Montaup's Commercial and Industrial C&LM Programs – 1991.

EXHIBIT____PLC-7: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

C: New England Electric

Residential

Program	Target population	Measures	Delivery	Special features
Appliance Efficiency	Buyers of refrig., A/C, freezer, elec. H2O heater	Labeling	NA	
Energy Fitness	Low-income, moderate use	Fluorescents, clean refrig. coils, change A/C filters	Direct installation	Water cons. measures included
Water Heater Rebate	all customers	Hi-eff. elec. H2O heater	NA	Rebates to wholesalers, dealers, plumbers
Water Heater Rental	all customers	Hi-eff. elec. H2O heater	Direct installation	
Water Heater Wrap	elec. H2O heating customers	water heater wrap	Direct installation	

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
Lighting Rebate	All customers	4&8 ft. fluor., U-shaped, compact fluor., ballasts & fixtures	Dealer rebate applications	Incentives to lighting dealers
Design 2000	New construction	Lights, heat vent., A/C, motors, HVAC, envelope	Archtcts. or menu-based	Incentives to dvlprs., owners, archtcts., engrs.
Energy Initiative	C/I; govt.	lighting, motors, adj. spd. drives, HVAC, shell, ind. processes	Direct installation	
Performance Contracting	Customers with 500+ kW demand	varies with ESCO	ESCO's	
Small C/I	Customers with 100- kW demand or 300,000- kWh usage	fluorescent, halogen, other lights	Direct installation	

Notes:

Shaded programs are lost opportunity programs.

NEES also offers commercial/industrial load management programs.

Source:

NEES *Conservation and Load Management Annual Report*. May 1, 1990.

EXHIBIT____PLC-7: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

D: Western Massachusetts Electric

Residential

Program	Target population	Measures	Delivery	Special features
Electric Heat	Customers in 1–4 unit bldgs. w/ 15,000+ kWh/year	H2O heat wrap, insul., comp. fluorescents, ventilation, windows	Direct installation	
Domestic Hot Water	All customers	H2O heat wrap, insul., comp. fluorescents, fixture replacements	Direct installation	
Multifamily	Private multifamily bldgs. w/ 5+ units	H2O heat wrap, insul., comp. & other fluors., vent., windows, fixt. replace.	Direct installation	
Public Housing	Units w/ elec. heat, dom. hot H2O; general service bldgs.	H2O heat wrap, insul., comp. & other fluors., hi–pressure Na, vent., windows	Direct installation	
Energy Eff. Lighting	All customers	comp. fluors., exit signs, fixt. replace., halogens, hi–pressure sodium	Direct; catalog; point–of–purchase rebate	
Appliance Pick–up	Buyers of new equipment	refrigerators, freezers	Direct installation	
Energy Crafted Home	New homes under three stories	lighting, space & H2O heat, insul., vent., windows	Direct installation	Incentives to builders

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
Energycheck	Customers with 250– kW	lights, ballasts, heat & cool, motors, adj. spd. drives	Direct installation	
Lighting Rebate	Small & medium customers	comp. & T–8 fluors., hybrid & elec. ballasts, reflectors, exit signs, sensors	Direct installation	
Energy Conscious Constr.	New construction and major renovation	Lights, HVAC, refrig., elec. H2O heat, cooking	Direct installation	$1,000 brainstorming incntv.; bonus for 20+% reduction
Energy Action Program	Customers with 250+ kW peak demand & 50,000+ sq. ft.	Lights, HVAC, chillers, condners., evaporators, compressors	Direct installation	
Customer Initiated	Customers with 250+ kW peak demand	HVAC, motors, lighting, industrial process	Direct installation	
Streetlighting	Municipal governments	4,000 lumen Hg vapors to 6,300 lumen hi–pressure sodium	Direct installation	

Notes:

Shaded programs are lost opportunity programs.

WMECo also offers a residential load management program.

Source:

Application of Western Massachusetts Electric Company for Pre–Approval of Conservation and Load Management Programs.

Exhibit ___PLC-8

South Carolina Electric and Gas Planned Demand Side Resources

Year	Cumulative Growth in Electricity Requirements From 1991			Cumulative Growth in Demand-Side Management From 1991 (Excluding Rate 28 and Stand-By)			Growth in DSM as Percent of Growth in Electricity Requirements		Total DSM as Percent of Total Electricity Requirements	
	Peak Load MW	Sales GWh	Load Factor	Peak Load MW	Sales GWh	Load Factor	Peak Load	Sales	Peak Load	Sales
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
1991	3,256	14,386	50%	31	58	21%			1%	0%
1992	111	380	50%	9	14	21%	8%	4%	1%	0%
1993	224	716	50%	18	26	20%	8%	4%	1%	1%
1994	309	1,047	49%	27	39	19%	9%	4%	2%	1%
1995	388	1,353	49%	36	51	18%	9%	4%	2%	1%
1996	464	1,692	49%	43	61	18%	9%	4%	2%	1%
1997	554	2,050	49%	50	71	18%	9%	3%	2%	1%
1998	638	2,407	49%	57	81	18%	9%	3%	2%	1%
1999	721	2,768	49%	65	91	18%	9%	3%	2%	1%
2000	811	3,133	49%	72	101	18%	9%	3%	3%	1%

Notes:

Unless otherwise stated, citations refer to Integrated Resource Planning August 1991.

[2]: Customer Peak Demand (Chart II-6) + Combined Programs Reduction (Chart II-8) - Interruptible Rate 28 (Chart III-6) - Stand-By Generator (Chart III-7)

[3]: Sum of residential, commercial, industrial, street lighting, and other public authority sales, adjusted for DSM (page I-52), and IRP Estimates of Total Effect on kWh for 1990 to 2010 from the response to Consumer Advocate Question No. 2-35.

[4]: Based on total energy and peak requirements derived from columns [2] and [3].

[5]: Combined Programs Reduction (Chart II-8) - Interruptible Rate 28 (Chart III-6) - Stand-By Generator (Chart III-7)

[6]: IRP Estimates of Total Effect on kWh for 1990 to 2010 from the response to Consumer Advocate Question No. 2-35.

[7]: Based on total energy and peak reductions derived from columns [5] and [6].

[8]: [5]/[2]

[9]: [6]/[3]

[10]: ([5]+[5] in 1991)/([2]+[2] in 1991)

[11]: ([6]+[6] in 1991)/([3]+[3] in 1991)

Exhibit ____PLC-9

South Carolina Electric and Gas Company's Demand Side Reources, Based on Plans of Utilities With Collaboratively Designed Programs

Year	Percent of New Sales Met With New DSM	Annual Gross Sales Growth GWh	Annual Incremental New DSM GWh	Cumulative DSM GWh	Cumulative DSM MW	IRP Planned DSM GWh	IRP Planned DSM MW	Potential Additional DSM GWh	Potential Additional DSM MW
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
1991				58	31	58	31		
1992	35%	380	133	191	68	72	40	119	28
1993	40%	336	135	325	105	84	49	241	56
1994	43%	330	142	467	145	97	58	371	87
1995	43%	306	132	599 @ 4%?	181	109	67	490	114
1996	43%	339	146	745 − 58 207 = 191 + 35	222	119	74	626	148
1997	43%	358	154	899	265	129	81	770	184
1998	43%	357	154	1,052	308	139	88	914	219
1999	43%	361	155	1,208	351	149	95	1,059	255
2000	43%	365	157	1,365	394	159	103	1,206	292

Notes:

Unless otherwise stated, citations refer to Integrated Resource Planning August 1991.

[2]: The derivation of these targets, based on collaboratively designed DSM programs, is described in the text.

[3]: Annual growth in gross energy demand which is calculated as the sum of: residential, commercial, industrial, street lighting, and other public authority sales, adjusted for DSM (from page I-52), and IRP Estimates of Total Effect on kWh for 1990 to 2010 (from the response to Consumer Advocate Question No. 2-35).

[4]: [2]*[3]

[5]: Existing 1991 DSM (GWh), plus cumulative sum of [3]

[6]: Existing 1991 DSM (MW), plus the cumulative sum of [3]*1000/8766/41%. The 41% DSM load factor is derived in the text.

[7]: IRP Estimates of Total Effect on kWh for 1990 to 2010 from the response to Consumer Advocate Question No. 2-35.

[8]: Combined Programs Reduction (Chart II-8) - Interruptible Rate 28 (Chart III-6) - Stand-By Generator (Chart III-7)

[9]: [5]-[7]

[10]: [6]-[8]