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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of the DETROIT EDISON COMPANY for Authority to amend its rate schedules governing the supply of electric energy.	Case No. U-10102

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DIRECT TESTIMONY

of

PAUL CHERNICK

for the

Michigan United Conservation Clubs

February 17, 1993

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I. IDENTIFICATION AND QUALIFICATIONS

Q: Please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

Q: Summarize your professional education and experience.

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 since August 1990, in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, 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 I-____(PLC-1).

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately eighty times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Vermont Public Service Board, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously before this Commission?

A: Yes. I testified before the Michigan PSC in Docket Nos. U-7775 and U-7785, on power plant performance standards.

Q: Have you been involved in least-cost utility resource planning?

A: Yes. I have been involved in utility planning issues since 1978, including load forecasting, the economic evaluation of proposed and existing power plants, and the establishment of rate for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to the Conservation Law Foundation's (CLF's) conservation design project in Jamaica; to CLF interventions in a number of New England rulemaking and adjudicatory proceedings; to the Boston Gas Company on avoided costs and conservation program design; to the City of Chicago in reviewing the Least Cost Plan of Commonwealth Edison; to the South Carolina Consumer Advocate on least-cost planning; to environmental groups in North Carolina, Florida and Ohio on DM planning; and to several parties on incorporating externalities in utility planning and resource acquisition. I also assisted the District of Columbia PSC in drafting order 8974 in Formal Case 834 Phase II, which established least-cost planning requirements for the electric and gas utilities serving the District.

Q: Have you testified previously on demand-side management (DM) cost-recovery issues?

A: Yes. I testified specifically on this issue in Vermont, Massachusetts, South Carolina, Pennsylvania and Florida.

Q: Have you worked on cost recovery issues in collaboratives between electric utilities and other parties?

A: Yes. I have consulted on cost recovery in separate collaborative projects with Central Vermont Public Service, New York State Electric & Gas, New England Electric System, Baltimore Gas & Electric, Vermont Gas Systems, and Potomac Electric Power Company.

Q: Have you advised other clients on issues relating to utility cost recovery for DM?

A: Yes. I assisted Boston Gas Company in development of its cost-recovery proposal to the Massachusetts DPU and assisted the Washington State Public Counsel in reviewing incentive proposals for Puget Power.

II. INTRODUCTION

Q: What is the purpose of this testimony?

A: In this testimony, I assess the planning process, screening analyses, and cost recovery proposals of the Detroit Edison Company (DECo) for its demand management (DM) programs.

Q: Please summarize the Company's DM filing in this proceeding.

A: According to Company witness Welch, DECo is requesting Commission approval of:

- the Company's DM planning strategy:
- a proposed mechanism for recovery of program costs, lost revenues, and shareholder incentives; and

- collection of a specific level of program costs, lost revenues, and shareholder incentives in 1994 rates.[1]

Q: Is the Company requesting pre-approval of a specific portfolio of DM programs?

A: No. DECo has not yet developed programs to attain the savings levels it estimates it can acquire in the years 1994 to 1997. Instead, the Company requests that the Commission approve its planning strategy for developing such programs, and then for the Commission to permit "... flexibility in designing and implementing its strategy...." (Welch direct, p. 20, Tr. 1582)

Q: What basic perspective do you take in this testimony?

A: Demand management can dramatically reduce the cost of providing energy services, such as warm space in the winter, cool space in the summer, hot water, lighting, and moving materials through industrial processes. DECo should be required and encouraged to use DM to minimize energy service costs to ratepayers.

Q: Please summarize your findings regarding DECo's DM planning.

A: The Company's DM "strategy" is not premised on basic least-cost planning principles. In particular, the Company does not recognize the principal least-cost planning objective of

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[1]Mr. Welch's direct (pp. 22-23, Tr. 1584-1585) describes the need for PSCR-type hearings to set 1994 surcharge levels, after the order in this case. However, at Tr. 1868, Mr. Welch says that DECo is requesting authorization in this case for the 1994 surcharges. It appears that DECO intends that the surcharge hearing would be *pro forma*, updating the ¢/kWh charge to reflect sales projections.

minimizing total costs, or the concomitant requirement to acquire all cost-effective DM resources at the lowest feasible cost. Instead, DECo has adopted planning guidelines that sacrifice least-cost objectives in order to satisfy unspecified and unsubstantiated rate impact concerns. As will be shown, this DSM strategy is fundamentally flawed. By adopting it, the Company has faltered in its attempt to become a "best-in-class" utility.

DECo's failure to adopt least-cost planning principles leads to several deficiencies in its DM planning. These deficiencies include the following:

- DECo's DM planning arbitrarily rejects cost-effective DM measures and cost-effective strategies for maximizing customer participation and measure penetration. Thus, DECo neglects DM savings that it acknowledges would be less expensive than the displaced supply resources.

- DECo's DM planning is guided by an overriding concern about unsubstantiated and unevaluated rate impacts. The Company excludes cost-effective savings from its DM plan due to rate impact concerns without first (1) determining that potential rate impacts from a truly least-cost DM strategy would create unacceptable problems; (2) determining whether the bill *reductions* from additional DM would offset rate increases; (3) investigating alternative strategies for mitigating rate effects without sacrificing savings; or (4) structuring its DM reductions (if needed) to defer rather than permanently forfeit opportunities for savings.

- As discussed in detail in the testimony of MUCC witnesses Hamilton and Robertson, the Company is not comprehensively identifying or implementing energy-efficiency resources. Its DM planning omits DM market segments, end-uses, and measures that are significant sources of cost-effective savings. In each customer class, DECo neglects large, inexpensive, but transitory opportunities to save electricity. Such *lost-opportunity* resources arise when new buildings and facilities are constructed, during renovation and remodeling, and as existing equipment is replaced at the end of its physical or economic life. By failing to capture these valuable DM resources as they arise, DECo loses them for decades.

- DECo's economic screening understates the benefits of DM resources. The Company's avoided costs exclude the transmission, distribution, Clean Air Act compliance, uncertainty, and environmental externalities costs avoided by DM, and all off-system sales opportunities promoted by DM. In addition, DECo's avoided costs understate line losses. DECo has not provided the information necessary to test the accuracy of its avoided energy costs, so I have not been able to validate those projections.

- DECo understates all benefits for long-lived or late-installed measures, by comparing the full cost of the measure against only those benefits that occur during the planning period.

- Although DECo has nominally adopted the Total Resource Cost (TRC) test, its screening and program design still rely heavily on the Rate Impact Measure (RIM) or related tests. DECo uses the RIM to reject cost-effective DM.

- DECo does not consistently and systematically screen measures and programs. DECo mixes these very different DM concepts, precluding comprehensive development of cost-effective programs.

- DECo displays considerable ambivalence as to whether its DM objective is to minimize costs, or to maximize the benefit:cost ratio of its DM programs. The latter objective is inconsistent with least-cost planning.

- The Company's preliminary DM screening utilized qualitative screening criteria that may have inappropriately rejected cost-effective DM options. Moreover, the screening criteria inexplicably promote high free-ridership by favoring options that would be adopted by customers in the absence of utility DM programs. In other words, the Company's programs are designed to spend money without reducing sales.

Q: What is the overall effect of these planning flaws on the Company's DM acquisition efforts?

A: DECo's planning strategy will lead to a collection of piecemeal DM programs that inefficiently acquire relatively small savings at a needlessly high cost. Moreover, the Company's efforts will neglect significant portions of the attainable efficiency potential in its service territory. The Company may be able to acquire some of this neglected potential in the future at a higher cost than if it were acquired today. The remainder will not be cost-effective to acquire later, and the Company will be forced to substitute more expensive supply for these lost savings. In either case, DECo will have failed to acquire all cost-effective savings at the lowest feasible cost.

Q: What do you conclude regarding additional DM savings available for acquisition by DECo?

A: I have estimated the levels of efficiency savings that could be reasonably expected if DECo corrected the flaws in its DM planning and developed comprehensive programs as aggressive as those developed by leading utilities. By 1997, I estimate DECo could increase its total energy savings from *efficiency* programs (i.e., exclusive of load management) by 1,800 GWh, and 270 MW to 460 MW, over the level it currently projects. #1 97

These additional savings may be understated. As discussed by MUCC witnesses Hamilton and Robertson, the Company provides no substantive basis for its estimates of DM "program" costs and savings impacts. As the Company has acknowledged, it has not developed program designs or estimated costs and savings for these designs. Instead, DECo simply screened individual DM "options" for cost-effectiveness, and then made assumptions about the number of options installed by unspecified programs to derive program-related costs and savings.[2] The Company thus provides little foundation for the program cost, lost revenue, and shareholder incentive estimates proposed for recovery from ratepayers. If DECo's program impacts are overstated, the additional potential would be even larger.

Q: How long would it take DECo to develop a DSM plan capable of achieving such a level of savings?

A: As discussed by MUCC witness Coakley, program design details might be most effectively and efficiently developed through a collaborative process. In that context, a comprehensive DSM plan could be developed within approximately 9 months.

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

A: No. My estimates are intended to give the Commission a sense of the magnitude of savings DECo is likely to attain if it adopts the comprehensive acquisition strategies used

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[2]As I discuss below in Section VI, it is not clear whether DECo screened individual measures, programs, or a mix of the two. For example, the Company lists both "efficient air conditioning" (a group of measures) and "new construction" (a program) as residential DM "options."

by "best in class" utilities. The magnitude of DECo's DM savings can only be determined through program design and implementation.

Q: What do you conclude regarding the Company's proposed cost recovery, lost revenue, and incentive mechanisms?

A: The general structure of DECo's proposed cost recovery mechanism seems reasonable, but several important aspects of the proposal contain problems. The cost recovery mechanism is designed to maximize short-term rate effects, which DECo professes a desire to minimize; uses unnecessarily inaccurate estimates of savings in computing lost revenues and incentives, encouraging DECo to game the system; provides preferential ratemaking to load management programs that do not require such treatment; would reward DECo for inadequate and ill-conceived DM proposals; and fails to address the opportunity to decouple revenues from sales. #98

Q: Based on these findings and conclusions, as well as the findings and conclusions of MUCC's other witnesses, what are your recommendations with regard to Commission action on DECo's DM program planning?

A: I would recommend that the Commission deny approval of DECo's proposed DM program strategy or any program designs based on its program strategy. Furthermore, I recommend that the Commission deny the recovery of all proposed program costs, lost revenues, or shareholder incentives until the Company demonstrates that it has undertaken to implement all feasibly attainable and cost-effective DM. DECo should be required to file for Commission approval a DM plan that provides complete descriptions, including cost and savings estimates, of fully-developed program designs, a monitoring and evaluation plan, and a comprehensive rate and bill impact analysis. In that regard, the Commission should direct DECo to:

(1) properly screen DM measures and programs, using the total resource cost test with avoided costs that include all identifiable benefits of DM, including avoided transmission, distribution, Clean Air Act compliance, and externality costs and revenues from increased off-system sales;

(2) acquire all cost-effective DM resources throughout its service area with comprehensive energy-efficiency programs; and

(3) design programs and develop monitoring and evaluation plans in accordance with the guidelines recommended by MUCC witnesses Hamilton, Robertson, and Oswald, preferably through a collaborative process as recommended by MUCC witness Coakley.

If DECo believes that rate constraints preclude the acquisition of all cost-effective DM, it should be required to demonstrate both the necessity for mitigating rate effects and the inadequacy of alternative strategies to mitigate rate impacts to the desired degree.

Finally, the Commission should advise the Company that until and unless it implements these reforms, its resource planning cannot be considered either adequately integrated or capable of producing the most cost-effective resource choices. Without effective integrated resource planning, DECo cannot establish that either DM or supply resource additions are prudent or likely to be used and useful in providing future service to ratepayers. DECo will be at risk for investments and operating costs, including fuel, incurred due to the inadequacies in its DM programs.

Q: Should the Company be allowed flexibility in designing programs, as it has requested?

A: No. Although the Company is ultimately responsible for designing and implementing its DM programs, it has not demonstrated at this time that its actions are guided by least-cost planning principles. Without clear Commission guidance, DECo's program design efforts will probably lead to an ineffective and needlessly expensive DM portfolio and, ultimately, an economically inefficient integrated resource plan.

Q: What are your recommendations with regard to Commission action on the Company's proposed mechanism for recovering program costs, lost revenues, and shareholder incentives?

A: DECo's proposal should be changed so that the regulatory signals will be consistent with least-cost planning. Most importantly:

- These special cost recovery procedures should only be applied to energy efficiency programs.
- DM costs should be amortized, to minimize adverse rate impacts.
- DECo should negotiate with other parties to this case, to develop a general decoupling proposal for Commission review.

- Lost revenues and incentives should be reconciled, based on the best data available within a reasonable time frame after the revenues are lost.

- Lost revenues should be computed net of quantifiable cost reductions captured by the utility, the effects of promotional programs, and the promotional effects of conservation or load management programs.

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- *Providing that DECo implements an aggressive, well-designed, and well-managed program*, the incentive should be structured to provide the utility with a share of net TRC benefits above a threshold of about 50% of target levels, reaching about 1% of equity at the target savings.

- The energy efficiency recovery mechanism should not appear as a separate item on the customer bills.

- Monitoring and evaluation should be required to support recovery of lost revenues and incentives, and to demonstrate the continuing prudence of program design. M&E verifies the magnitude of savings and lost revenues and is essential to ensuring that the DM portfolio is prudent. The monitoring and evaluation function is a very important part of the overall DM effort.

III. DEMAND MANAGEMENT IN LEAST-COST INTEGRATED RESOURCE PLANNING

A. Objective of Least-cost Planning

Q: What is least-cost integrated resource planning?

A: *Integrated* resource planning attempts to identify the combination of resources that constitutes the best resource plan, rather than evaluating options in isolation. As a result, integrated planning is concerned with a diverse set of resource options, including utility-owned generation, non-utility generation, utility purchases, transmission and distribution investments, and DM.

Demand management expands the range of options available to balance demand and supply. Rather than building or buying supply, the utility can reduce the level of electricity necessary to meet the demand for energy service.[3] DM is thus an extension of the continuum from utility-owned generation, to purchases from other utilities, to purchases from non-utility generators, to the reduced use of electricity. In each case, the same level of service is provided, but with different types and amounts of investment by different parties.

Least-cost resource planning attempts to minimize the total cost of providing energy services, where an energy service is the heating, cooling, lighting, drive power, etc., that is produced by energy-using equipment. As described by the Indiana Utility Regulatory Commission:

> Least-cost planning is a planning approach which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined.... The goal should be to minimize long-run costs of providing adequate and reliable service to customers. Minimizing total cost requires that utilities choose resources with the lowest cost first, then draw on progressively more expensive options until demand is satisfied. (Decision, Cause No. 38738, October 25, 1989)

Least-cost integrated planning attempts to minimize all costs associated with resource options, including:

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[3]DM avoids transmission, distribution, and line-loss costs, as well as generation costs. See the discussion of avoided costs, below.

- monetary costs to the utility;
- the cost of demand-management options that customers pay themselves (e.g., the price premium for a high-efficiency refrigerator);
- the environmental and other external costs created by the generation and distribution of electricity;
- cost risks; and
- system reliability.

Q: Is least-cost integrated resource planning solely concerned with minimizing the costs of meeting load growth?

A: No. Least-cost planning is not solely concerned with finding the lowest-cost option to meet new load. From a least-cost perspective, any available action that will lower the total costs of providing energy services is needed to minimize cost, whether or not it is needed to keep the lights on. A new resource is needed in the least-cost plan if it can substitute for a more expensive resource, whether or not the displaced resource already exists or is considered to be a committed project or transaction.

Q: How do the principles of least-cost planning relate to Detroit Edison's DM planning strategy?

A: DECo's resource plan will not be least-cost if it does not incorporate all DM resources that are less expensive than supply alternatives. DECo's customers may be induced either by energy prices or by efficiency standards to capture some portion of this cost-effective DM potential on their own initiative. However, a significant share of the potential will remain untapped because of a market failure: customers are unwilling to spend more than a small fraction of the price they pay for <u>using</u> electricity on <u>reducing</u> its use. This market failure leaves a large -- though unquantified -- potential for economical efficiency which can be captured by DECo for less than the cost of supply alternatives.

Thus, the Company's principal DM planning strategy should be to identify and pursue DM actions -- by itself, customers, third-parties, or a combination thereof -- that yield the maximum net benefits (i.e., avoided supply costs less DM costs) to utility customers and society at large. Net benefits will not be maximized (and thus resource plan costs minimized) if the Company

- acquires uneconomical DM options;
- acquires cost-effective options at more than the lowest feasible cost (e.g., with suboptimal program designs); or
- limits its pursuit to the cheapest DM options or those that yield the largest savings.

DECo's goal should be to efficiently acquire *all* DM available at a lower cost than the supply it avoids, but no more.

Q: Must DECo acquire all DM resources immediately?

A: Not necessarily. As discussed below in Section II.C.4, delaying acquisition of discretionary DM resources may sometimes be appropriate either to increase net benefits or to respond to constraints such as limits on rate increases or rate levels. However, lost-opportunity resources -- savings opportunities that are cost-effective only if acquired when they arise -- cannot be deferred. Lost-opportunities are discussed further in Section III.C.2.

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B. Integrating DM Resources in Least-cost Plans

Q: What are the key planning strategies that DECo should adopt to ensure that it integrates and acquires all cost-effective DM at the lowest feasible cost?

A: To maximize the net benefits from DM resources, the Company must

- assess the cost-effectiveness of DM measures and programs using a screening protocol that accounts for all DM costs and benefits to the utility, its customers, and society;
- comprehensively invest in customer efficiency opportunities;
- distinctly target lost-opportunity resources;
- build the capability to effectively deploy full-scale DM programs; and
- if faced with constraints to maximum acquisition of cost-effective DM resources, select the constraint-mitigating mechanism that does the least harm to the overall cost-minimization strategy.

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I discuss issues relating to DM screening and avoided-cost determination in Sections VI and VII, respectively.

1. Comprehensiveness

Q: Please provide a definition of "a comprehensive DM portfolio."

A: The Vermont Public Service Board described the several dimensions in which DM should be comprehensive:

> 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.[4]

Comprehensive program planning and design maximizes DM net benefits by acquiring cost-effective savings from each DM market segment, and from each customer end-use within the market segments. Moreover, comprehensive investment strategies maximize the savings potential of each end-use by applying the DM measure or bundle of measures that yields the greatest net benefit.

Q: Please define the concept of DM market segments.

A: Opportunities to improve energy efficiency in each customer sector -- residential, commercial, and industrial -- arise in different circumstances. The barriers to efficiency investments also vary with market setting. Program development should therefore start by addressing distinct DM

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[4]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.

market segments, differentiated by the context in which customers make energy-efficiency decisions, which define potential points of market intervention.

The broadest market distinction is between lost-opportunity and discretionary resources. Discretionary resource programs are targeted to capture resources that can be acquired whenever they would be most beneficial. Lost-opportunity programs capture DM resources that cannot be postponed, because the opportunity to cost-effectively acquire them arises and then disappears quickly.

Q: Why is a comprehensive approach to DM resource acquisition essential for minimizing the cost of DECo's resource plan?

A: A utility that does not pursue DM comprehensively will neglect cost-effective DM resources. This will lead the Company to increase its supply expenditures while a more cost-effective resource remains unutilized.

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

A: Comprehensively acquiring efficiency savings is a markedly different proposition from selling or marketing individual DM measures. The latter tends to concentrate on individual technologies. It often leads utilities to fragmented and weak efforts to convince customers to adopt individual measures that marketing research indicates will be easiest to promote.[5] Single-measure programs designed around the treatment of a single end-use (e.g., water heating) with one technology (e.g., water heater wraps) are typical of this approach.

Q: What are some of the advantages of comprehensively covering all of a customer's end-uses, and offering all cost-effective measures for an end-use?

A: As discussed by MUCC witnesses Hamilton and Robertson, a DM delivery strategy that addresses not just one end-use or measure, but the entire range of a market segment's efficiency potential, can thoroughly mine each customer's DM resources, and can do so with a minimum of overhead costs to the utility. Utility programs that treat only isolated parts of a customer's efficiency potential must revisit customers many times over to tap all available cost-effective efficiency savings. This is especially problematic for small customers. In addition, installing a moderately efficient measure (or a small bundle of measures) may preclude the installation of the highest-efficiency measure (or more expansive bundle of measures). In the end, less of the efficiency resource would be recovered, and at higher costs, than if the utility extracted all the

[5] DECo's pre-screening emphasizes this type of measure.

efficiency potential one customer at a time.[6]

Q: Is it realistic to expect utilities to pursue all customer efficiency opportunities?

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; for smaller customers, the site visit would also install a few straightforward and common 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 measures, end-uses, and DM market segments. 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

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[6] 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.

and timing of the decisions involved.[7] Such an approach is comprehensive if the two programs are linked where appropriate.

2. Lost-opportunity resources

Q: What are lost-opportunity resources?

A: The Northwest Power Planning Council (NPPC) defines lost-opportunity resources as savings that, "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." (Northwest Power Planning Council, 1986, Volume 1, Glossary-6). [*NOTE: All source references in this testimony that appear in parentheses are set forth fully in the Bibliography*]. 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 (Northwest Power Planning Council, 1987, 7).

Q: Where are lost-opportunity resources usually found?

A: Lost-opportunity resources are usually found in one-time opportunities to save energy through improved energy efficiency, and typically arise in four general market segments: (1) during the design and construction of new building space, (2) during the design and construction of

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

remodeled or renovated existing space, (3) when existing equipment either fails or approaches the end of its anticipated useful life, and (4) when retrofit actions are being taken. If foregone, these resources would have to be replaced in the future either with alternative supply or more costly DM as retrofits to the newly-built facilities. In the case of new equipment such as appliances, all efficiency potential may be lost until the end of its useful life.

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

A: The two dominant factors that determine whether a DM option 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. In new construction and renovation, when walls are being built or replaced, the cost of designing for daylighting is much less than it would be in existing space. In replacement, the difference in cost between buying an efficient motor or refrigerator and buying an inefficient unit is small compared to the cost of discarding a working inefficient unit and installing an efficient one. In the process of efficiency retrofit, if a lighting fixture is open to install an efficient ballast, the incremental labor cost of adding a reflector and delamping is much lower than it would be in a second operation.

Q: How important is the acquisition of lost-opportunity resources?

A: For at least three reasons, acquisition of all cost-effective lost-opportunity resources should be a utility's top planning priority:

1. Lost-opportunity resources represent extremely cost-effective savings whose acquisition cannot be postponed.[8] To claim these savings, actions must be taken at the time of construction or at the time of equipment replacement. For example, not only is energy efficiency most cost-effectively pursued in new construction, but the consequences of decisions taken in new construction can last, in some cases, for as long as 80 years. 104

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2. Customer decisions to add new or expand existing electricity-using facilities are primarily responsible for electricity load growth.[9] These are the same decisions that create the potential for lost-opportunity resources.

3. Lost-opportunity resources most readily adapt to a utility's changing needs. Their benefits tend to mirror growth in demand, since rapid demand 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.[10]

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[8] In addition, market barriers to customer investment in lost-opportunity resources are among the most pervasive and powerful, including limited time and information, risk aversion, equipment availability, and split incentives. Program strategies for overcoming these barriers are addressed by Messrs. Hamilton and Robertson.

[9] The other important source of load growth is increased use of existing buildings and equipment.

[10] 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*, Docket No. 5270, III-110.

3. Capability building

Q: Please define demand-management capability building.

A: The Northwest Power Planning Council (1987, 2, 4, and 7) originally developed the concept of the capability-building stages of DM programs to provide essential experience for turning efficiency potential into real resource options before they are actually needed. These capability-building programs are implemented in the absence of data on measured costs and savings, as a means of verifying working assumptions and predictions. The Council notes that capability-building programs tend to be more costly, per unit of electricity saved, than the resource-acquisition programs they may eventually lead to. Because the initial development and demonstration costs are high, electricity savings will appear much more expensive than when programs are taken to the acquisition stage.

Capability-building is thus analogous to the pre-operation expenditures that utilities make in pursuing promising supply resources. Demand-management programs require start-up and testing equivalent to the environmental, engineering, feasibility, and design studies that routinely precede commercial operation of utility supply resources.

DM capability-building and the subsequent full-scale DM resource acquisition should not be confused. Although the capability-building stage of program implementation will produce energy savings, such savings are secondary. The primary objective of capability-building is to provide information about costs, magnitudes, and performance of demand-side resources, to allow for informed resource acquisition decisions.

Q: Why do utilities need to build capability?

A: If DM programs are to yield demand-management resources that compete directly with supply, utilities must be confident of their ability to obtain cost-effective electricity savings from their customers. Utilities therefore need to build and maintain the *capability to deliver* full-scale efficiency savings before they can freely deploy and integrate them as supply substitutes. Successful deployment depends on a demonstrated ability to motivate large numbers of residential, commercial, and industrial customers to install a variety of energy-efficient equipment.

Each component of capability building is necessary to the effective and timely full-scale deployment of programs. Building the capability to deliver DM resources is necessary to establish reliably the costs and magnitudes of achievable resources, and to ready DM resources for acquisition. Maintaining the capability to deliver DM resources is also essential for holding DM resources in a state of readiness. Even if most discretionary resources are not cost-effective at a particular time (or would yield greater net benefits later), the utility may need to deploy programs at their

minimum feasible levels of operation, so that they can be scaled up when resource needs warrant.

A utility with ambitious DM targets may have difficulty realizing its objectives if it fails to field-test the delivery mechanisms for acquiring DM resources.[11] Without verifiable information about the costs and performance of DM acquisitions, utilities will be unprepared to acquire DM resources when needed and unwilling to modify supply plans in anticipation of untested DM acquisitions.

Capability building not only builds proficiency but also lowers institutional barriers to acquiring the efficiency resource. As the Northwest Power Planning Council (1989, 4) notes, "Utility enthusiasm for conservation is ... restrained by a lack of information on conservation's long-term cost-effectiveness, its reliability as a resource and its potential impacts on electricity's market share." Capability-building activities, in conjunction with aggressive monitoring and evaluation, help familiarize management and staff with the practical process of acquiring the efficiency resource and with its unique attributes and potential for meeting energy service demand.

Q: What are the essential requirements for DM capability-building?

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[11]These need not be lengthy pilot programs. Depending on the uncertainties to be resolved, a few months of demonstration may be adequate.

A: To build the capability to deliver the DM resource, utilities must master new and rapidly advancing technologies; tailor and perfect marketing methods, incentive structures, and program delivery for different types of customers and efficiency measures; adopt reliable measurement and evaluation techniques, and management strategies that accept rapid feedback to allow mid-course correction. Most of all, they must advance the existing market infrastructure: the vendors, installers, engineers, and architects who need familiarity and confidence with energy-efficient equipment to specify and supply it.

Transforming the market infrastructure is especially critical for utility capability-building. Customers cannot invest in more efficient equipment if it is not available locally. Architects and engineers who are unfamiliar with more efficient equipment will not specify it.[12] Suppliers tend not to carry more expensive high-efficiency equipment if customers do not ask for it. Utility demand-side programs can create the necessary demand for such products.

Building capability to acquire any resource takes time. Capability-building therefore should begin well in advance of need. This is especially true for resources with which utilities lack experience. Even though the lead time for

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[12]These practitioners rarely will take the initiative with new products unless they are presented with convincing evidence, technical assistance and financial incentives.

relatively small increments of demand-side resource is short, it takes time for such savings to accumulate. In order for demand-side resources to compete with supply, utilities must begin investing in comparable DM far enough in advance of the planned in-service date of the supply project for demand-side resources to displace the need for its output.

4. Constraints to least-cost planning

Q: Are there mitigating circumstances that might lead DECo to delay acquisition of all cost-effective DM?

A: Yes. Although rate increases, rate levels, and associated equity considerations are most likely to cause concern, limited managerial resources, financial resources, or time can also be barriers to immediate acquisition. The Company thus may need to develop a DM resource plan that accommodates these real-life constraints while minimizing the economic loss of delayed acquisition.

Q: What should the Company have to show before it delays its DM plans?

A: Before modifying its DM portfolio to accommodate a constraint, DECo should first establish that there is no better alternative for balancing the constraint with least-cost objectives. Specifically, if the Company plans to forego some of the least-cost level of DM savings, it should be able to show that

- the constraint is actually binding;

- 108 the effects of the least-cost plan would be unacceptable;
- 109 the magnitude of the unacceptable effects is sufficient to justify adjustment to the least-cost plans;
- the integrated resource plan is least-cost, and does not include any components that unnecessarily contribute to the constraint;
- the constraint cannot be accommodated by actions that do not materially sacrifice the benefits of the least-cost plan, such as modifying cost-recovery mechanisms or some aspects of program design;
- reduction of DM efforts will accommodate the constraint at a lower cost than would adjustments to supply additions or other activities;
- the proposed reduction of DM acquisition imposes lower costs than alternative reductions;
- 110 no significant lost opportunities are created, and the reductions do not themselves result in cream-skimming and the creation of lost opportunities.

Q: Given the Company's concern about rate impacts, how can the Company assess the magnitude of and tolerance for rate effects of DM spending?

A: Whether a particular DM-related rate increase is tolerable depends on how much bills decline as rates rise, the existing level of rates and bills, the extent to which rates are rising to reflect other costs, and the extent to which customers experiencing rate increases are eligible to decrease their bills through participation in the DM program.

Once DECo has compiled a least-cost resource portfolio, 111 it must determine whether the rate effects of the plan portfolio spending are unacceptable. Although the final determination of the reasonableness of rate impacts will be largely judgmental, the Company should present a rate-impact analysis and adopt a protocol for establishing rate constraints that is consistent for DM and supply actions. The evaluation of rate impacts should estimate annual rate and bill impacts separately for each customer or rate class and, for DM spending, separately for participants and 112 involuntary non-participants.

Rate impact evaluations must not focus solely on the effects of DM spending on customer rates and bills. Other elements of the resource portfolio -- supply additions, transmission or distribution upgrades, environmental compliance projects, etc. -- may also contribute to rate constraints. Focusing solely on the rate impact of DM spending may ignore rate increases required for supply expenditures to replace the DM.

A full rate-impact analysis of the overall resource portfolio would include the following:

- a quantitative analysis of annual rate and bill effects for each rate class, sub-class, or other affected group, where sub-classes may include:
  - commercial and industrial groups within a non-residential rate class,
  - large and small customers within a rate class,
  - end-use groups (e.g., residential customers with and without electric water heating),
  - socio-economic groups, such as low-income, multi-family, and rental customers;
- a quantitative analysis of the combined effect of the DM-related savings and rate effects on the bills of

customer groups of special concern for the financial well-being of the service territory, such as new and expanding industrial customers, economically vulnerable industrial customers, and local governments;

- a discussion of the potential for DM programs to contribute to economic development and the attraction of industry, and coordination of the utility's industrial DM programs and economic development activities;

- a determination of whether the aggregate effects (including bill reductions) on any group are excessive and problematic, and if so, an explanation of the nature of the problem.

Q: What guidelines do you recommend if the Company's rate analysis indicates that effects are best mitigated through DM deferral?

A: When evaluating opportunities for deferral of DM, DECo should clearly distinguish between lost opportunities, which can only be lost, not deferred, and discretionary resources. Within discretionary resources, care should be taken to continue programs required to build and maintain DM delivery capability. Maintaining delivery capability and relationships with contractors, providers, and trade allies will generally preclude the complete shutdown of any program's delivery. Once a utility has established the capability to deliver programs, discretionary resources can be scaled back to minimum viable levels of operation.

Only DM resources that contribute to the rate constraint should be reduced. For example, if several programs for residential space- and water-heating customers will dramatically increase rates of small residential

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customers, the utility should consider scaling back the specific programs causing the increase. Scaling back other residential or commercial programs will not reduce, and may even exacerbate, the burden on small residential customers.

To the extent feasible, the resources selected for deferral should be those that will do the most to relieve the constraints at a minimal net cost; in other words, the deferred programs should be those with the highest ratio of contribution to the constraint per dollar of net benefit.[13] If excessive residential rate increases in 1996 are the problem, then the options weeded out should be those with a high ratio of 1996 residential rate effects per dollar of net benefit.

In most cases, to avoid cream-skimming, the utility should reduce the number of participants in a program, rather than the savings for each participant. Returning to upgrade equipment installed under an investment cap will tend to be prohibitively expensive. The deferred measures are likely to become lost opportunities.[14]

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[13]DECo's use of benefit-cost ratios does not achieve the same goal, as discussed in Section VI.C.

[14]There are exceptions to this rule, where the delay in installation of certain measures will not significantly increase costs, decrease long-run participation, or decrease the effectiveness of the measures. This is most likely to occur when the measures are functionally independent, would be delivered by different contractors, and are expensive enough to justify return visits. For example, in a comprehensive residential space-heating retrofit program, the utility could concentrate on the highest cost-effective level of relatively economical measures, such as infiltration reduction, duct repair, and attic insulation.

Additional considerations that should govern the selection of discretionary resources for acquisition deferral include:

- preservation of portfolio equity, by attempting to maintain programs for all groups that will be paying for DM resources, and by maintaining programs for low income and other vulnerable customers;
- integration with other activities, such as efforts to retain industrial customers; and
- maintaining discretionary acquisitions that interact with lost opportunities, such as discretionary lighting retrofits to reduce cooling load at the time of lost-opportunity chiller replacement.

C. The Potential for DM in Least-cost Plans

Q: How much DM is included in the plans of utilities with comprehensive and aggressive program designs?

A: These utilities are identifying and pursuing electricity savings that are significant fractions of their projected demand growth. These sizable savings are associated with major financial commitments: aggregate DM expenditures represent a few percent of total utility revenues. The efficiency resources these utilities are buying compare favorably to new utility supply -- all the more so when the

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Acquisition of other measures, such as heat-pump tune-ups and window replacement, can be deferred, since they can be captured later without any significant loss of synergies, particularly if the team delivering the basic retrofit service gathers the data necessary to guide the subsequent phases (e.g., condition of windows, existence and age of heat pump). The deferral of part of the retrofit package will tend to reduce equity concerns, since all customers can be reached by the first phase of the program, before they are charged for the costs of the second phase. (To further increase equity, the last participants in the first phase could be given first priority for service under the second phase.)

costs of environmental externalities are included in the costs of new supply. Finally, the long-range DM plans of these leading utilities aim at achieving all cost-effective DM savings from utility customers, over time.

Q: Which are the "leading" utilities you refer to here?

A: I am referring to the plans of several utilities in California, the Northeast, and Mid-Atlantic U.S., most of whom have designed DM programs in collaboration with non-utility parties. The utilities examined here include Boston Edison (BECO), Eastern Utilities Associates (EUA), New England Electric System (NEES), Western Massachusetts Electric (WMECO), New York State Electric and Gas (NYSEG), Potomac Electric Power (PEPCO), United Illuminating (UI), Pacific Gas & Electric (PG&E), and Sacramento Municipal Utilities District (SMUD).

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Q: Why have you focussed your examination on these utilities in particular?

A: More so than their peers, these utilities have designed DM plans that meet the integrated resource planning objectives described above.[15] Accordingly, the energy and capacity savings of these utilities indicate the level of savings that can be expected by a utility that implements aggressive and comprehensive DM programs in all major DM market segments. Moreover, these efforts should be considered

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[15]Utilities in the Pacific Northwest also are implementing aggressive and comprehensive DSM programs.

representative of what a utility dedicated to maximizing the amount of cost-effective DM savings can achieve.

Q: What planning characteristics do the DM plans of these utilities share?

A: The program plans of these leading utilities are generally aimed at achieving all cost-effective DM savings from utility customers over time, although some of these utilities have been slow to ramp up programs for certain market segments.

Q: How much electricity are these comprehensive DM plans expected to save?

A: Exhibit I-____(PLC-2) provides several measures of aggregate electricity savings for these leading utilities' efficiency plans. Planning periods vary, ranging from 5 years to 20 years. Column 3 shows energy savings in the last year of the planning period as a percent of pre-DM sales in that year. Longer projections include larger DM achievements. SMUD's 19-year program plan generates the largest portion of future sales, with total energy savings amounting to 23.1% of its projected energy sales.

Column 6 of Exhibit I-____(PLC-2) shows projected annual load reductions for the reference utility DM plans. This computation normalizes for differences in DM planning periods between utilities, producing a result analogous to a sales-growth projection. Average sales reductions range from 0.5% to 1.2% annually. For the group, annual energy savings represent 0.7% of annual sales.

Finally, Column 9 of Exhibit I-____(PLC-2) shows the fraction of new energy sales that each of these utilities expects to meet by new DM. New energy savings range from 28% to 59% of sales growth, averaging 41%.

Q: How much are these leading utilities planning to spend on DM efforts?

A: Exhibit I-____(PLC-3) compares total DM spending planned by seven of the utilities appearing in Exhibit I-____(PLC-2). Utilities with ambitious DM acquisition plans plan to spend between 3% and 9% of their annual electric revenue on DM, with an average of 4.6%.

Q: What are the costs of the kWh savings expected from these programs?

A: Exhibit I-____(PLC-3) also provides a rough indication of how much DM costs per unit of energy savings acquired. Annualized DM costs are estimated by amortizing DM budgets over an estimated average measure life of 15 years. Dividing the annual cost by cumulative annual energy savings produces the cost of conserved electricity, which ranges from 1.4¢/kWh to 5.8¢/kWh. On average, electricity savings cost 3.6¢/kWh saved.[16]

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[16]Although spending is expressed in terms of kWh saved, DM spending will also cut peak demand, leading to reduced investments in generating, transmission, and distribution capacity. The higher-cost DM programs may be particularly targeted to reducing peak loads.

IV. PROBLEMS IN DECO'S DM PLANNING PROCESS

Q: Does the Company's DM planning strategy conform to the least-cost planning principles discussed in Section III?

A: No. DECo's planning strategy is based on objectives and guiding principles that do not recognize, and may be inconsistent with, the Company's obligation to minimize total costs by acquiring all cost-effective DM resources. Consequently, the Company's strategy leads to an ineffective plan that forgoes economical DM opportunities.

Q: Does the Company adopt the guiding principle that its DM programs must reduce total resource costs?

A: In part. DECo has not really made cost-effectiveness its top priority. The Company readily abandons cost-effective strategies in the face of imagined obstacles, such as the vague prospect of rate increases or loss of "customer value".

not aware
116 of all goal

Adopting the TRC is a necessary first step toward the development of a least-cost plan. However, this principle is insufficient, since it requires the acquisition of *some*, but not *all*, cost-effective DM resources. DECo's DM planning is further limited by its concentration on deferral of new supply resources. The Company has not focused on opportunities for reducing the costs of existing supply, including reduced fuel use, delayed reactivations, off-system sales, and avoided transmission and distribution investments.

Q: How does the failure to adopt a least-cost planning perspective affect DECo's DM planning?

A: The Company's failure to adopt and prioritize basic least-cost principles leads to several weaknesses in its DM planning. These weaknesses include:

1. DECo's DM planning arbitrarily rejects cost-effective DM measures and cost-effective strategies for maximizing customer participation and measure penetration. Thus, DECo forgoes DM savings that its own analyses indicate can be acquired less expensively than the supply resources these savings would displace. 117

   - DECO does not plan to offer cost-effective DM options to its large manufacturing customers.

   - DECo caps customer incentives below the level that maximizes cost-effective DM penetration.

2. DECo's DM planning is guided by an overriding concern about unsubstantiated and unevaluated rate impacts.

   - DECo has not performed a comprehensive rate and bill analysis, or established consistent threshold levels of rate impact that would signal the need for action.

   - DECo has not developed a consistent protocol for mitigating rate impacts at minimum economic loss.

   - DECo's DM deferral strategy may miss one-time savings opportunities and create lost opportunities.

3. DECo is not comprehensively identifying or implementing energy-efficiency resources. Its DM planning omits DM market segments, end-uses, and measures that are significant sources of cost-effective savings. 118

4. DECo's qualitative and economic screening is biased against DM. Although DECo has adopted the Total Resource Cost test (TRC), its economic screening understates the benefits of DM resources.[17]

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[17] I discuss problems with DECo's screening methodology and avoided costs in Sections VI and VII, respectively.

Q: How do these planning flaws relate to the Company's DM savings projections?

A: DECo's flawed planning strategy leads to an under-investment in DM savings. As shown in Exhibit I-____(PLC-4), DECo's present commitments represent only 299 GWh and 43 MW from efficiency (i.e., exclusive of load management) resources from 1994 through 1997. They account for approximately 0.6% of 1997 energy sales and 0.4% of 1997 peak demand.

Even these low targets may be overstated. As discussed by MUCC witnesses Hamilton and Robertson, the Company provides no substantive basis for its estimates of DM "program" costs and savings impacts. As the Company has acknowledged, it has not developed program designs, or estimated associated costs and savings. Instead, DECo screened DM options (mostly individual measures) and then assumed the number of options installed through the (unspecified) programs to derive program-related costs and savings.

Q: Is DECo's DM planning strategy consistent with its overall goal of becoming a "best-in-class" utility?

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A: DECo's DM planning strategy is not consistent with the goal of ranking with leading utilities, which have adopted least-cost resource strategies. As long as it continues to forego cost-effective savings, DECo's resource plan will be unnecessarily expensive.

However, it is not clear whether the Company's goal is to be ranked with the best or whether it is to be the best of some class of utilities that have underinvested in cost-effective DM. In support of DECo's planning strategy, Dr. Chamberlin compares the Company's DM spending projections with DM budgets for a sample of 100 other utilities, in Exhibit A-14, Schedule K20, reproduced here as Exhibit I-____(PLC-5). Dr. Chamberlin shows that the Company's spending target of about 0.61% of electric operating revenue equals the median of all utilities, is slightly below the average, and falls far below that of the top spenders. Oddly, Dr. Chamberlin describes this mediocre effort as evidence of DECo's "somewhat aggressive" commitment to acquiring DM, and justifies this poor showing by arguing that DECo's avoided costs are low. (Chamberlin supplemental, p. 7, Tr. 1384)

Q: Do DECo's avoided costs justify its low DM spending?

A: No. Dr. Chamberlin's argument misses the point, since the Company readily admits that it (1) rejected measures it found to be cost-effective using its low avoided costs; and (2) limited penetration of cost-effective measures by capping spending on customer incentives. Thus, DECo limited spending below levels that would acquire all DM that is cost-effective under its low avoided costs. I discuss the Company's arbitrary rejection of cost-effective DM in the following section.

In addition, DECo understates its avoided costs, as I discuss in Section VII.

A. Arbitrary Rejection of Cost-effective DM

Q: Please describe DECo's analytical process for deriving its DM spending and savings projections.

A: As I discuss in Section VI, DECo developed its cost and savings projections through a multi-step process of qualitative and economic screening. Starting with an initial set of DM options, this process identified those options which meet certain qualitative selection criteria and are cost-effective under the TRC. As part of this screening process, DECo estimated DM measure penetration using its judgement and experience from other utilities on the relationship between customer incentive levels and penetration rates (Tr. 1854-1855).

Q: Were all cost-effective DM options included in DECo's proposed DM plan?

A: No. As Company witness Welch acknowledges, all of the DM options except dispersed generation were excluded from the portfolio for the large manufacturing sector.

Q: Why did the Company exclude these cost-effective options for the large manufacturing sector?

A: According to Mr. Welch, several large manufacturing customers indicated to him that they were not interested in participating in DM programs. Based on these discussions, Mr. Welch excluded these cost-effective options because he

> ... subscribe[s] to the proposition that if a customer doesn't want it, it's probably not

> best to make him do it for a lot of reasons: they'll try to defeat the program and they're never going to be happy with you. (Tr. 1677-1678)

Q: Does Mr. Welch indicate the reasons for the lack of interest in DM programs by large manufacturers?

A: Yes. During cross-examination, Mr. Welch cited two reasons for these customers' disinterest in utility DM efforts:

> ... there are some programs there that are beneficial to those customers but they're choosing not to do them, and they're choosing not to do them for a variety of reasons. It is true that as a percentage of their income and a percentage of their sales, some of these programs seem pretty trivial.... The other thing I'm being repeatedly told by these customers that they have very high demands for very limited resources, and that limited resource is cash....[18]

Q: Is Mr. Welch's rationale for excluding cost-effective large manufacturing DM options reasonable?

A: No. Although there will always be some customers unwilling to participate in DM programs, DECo should be developing program strategies for lowering the barriers to customer participation and thus maximizing participation. DECo has identified some of the barriers the large manufacturers are facing, such as capital constraints, yet apparently is

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[18] Tr. 1678. In addition, Mr. Welch alludes to the high price sensitivity of large manufacturers, particularly in terms of competitiveness. However, Mr. Welch never specifies whether he believes that price sensitivity reduces these customers' interest in DM, or that industrials are concerned that DM program costs be allocated to customer classes participating in DM programs. Price sensitivity also argues for DM programs to reduce bills and improve customers' competitiveness.

unwilling to design strategies to overcome these barriers. Instead of financing the DM that customers cannot afford, DECo has chosen to abandon all DM in this sector.

DECo's policy in the large manufacturing sector is inconsistent with its strategy for other customer segments. During cross-examination, Mr. Welch asserted that a customer survey had found that

> ... only 26 percent of the residential customers supported any kind of conservation program sponsored or driven by the electric utility. That number was only slightly higher in the small manufacturing and non-manufacturing segment at 30 percent. Broadly speaking, 70 percent of the customers don't want us to do this. (Tr. 1615)

Instead of surrendering in the face of these customers' misunderstanding of DM[19], or distrust of the Company, DECo attempts to design programs acceptable to residential and small commercial customers. DECo should take at least as active an approach to overcoming the preconceptions of large manufacturers.

Q: Have other utilities successfully motivated large industrial participation in DM programs?

A: Yes. As discussed by MUCC witness Robertson, several utilities have designed programs targeted to industrial customers. As Mr. Robertson explains, these programs have

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[19]This misunderstanding may reflect DECo's misconceptions, such as Mr. Welch's belief that DM requires customer capital, or the assertion in the IRP that the best DM options are those that require the smallest utility expenditure.

not only achieved cost-effective savings, but also improved customer competitiveness.

Q: How else has DECo excluded cost-effective savings from its DM plan?

A: DECo recognizes that, in general, it can increase penetration of cost-effective DM measures by increasing customer incentives. Moreover, the Company acknowledges that it could increase savings by offering higher incentives. However, the Company has chosen to forego these additional cost-effective savings by capping incentives at too low a level.

Q: Why is the Company not pursuing these savings?

A: The Company has not clearly stated its reasons for capping incentives and thus foregoing savings. DECo's rationale appears to consist of three parts:

1. Additional spending increases rates in the short-term.

2. The additional savings, although cost-effective over their lifetimes, do not immediately yield large benefits.

3. Because the greatest benefits do not occur for several years, there is greater uncertainty as to the overall cost-effectiveness of the savings.[20] Thus, DECo assumes that it can lower the risk of spending money uneconomically by adopting a wait-and-see strategy with regard to DM.

Q: Is DECo's cautious approach prudent?

A: No. There are two fundamental flaws in the Company's

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[20]DECo's decision to expense DM costs guarantees that the total resource costs of most options will exceed their benefits in early years.

rationale. First, the Company has failed to consider that the acquisition of lost-opportunity resources cannot be deferred. If the Company does not spend money today to acquire cost-effective lost opportunities, these savings will be lost for the life of the opportunity. For example, cost-effective savings not acquired due to a cap on incentives for efficient refrigerators will be lost until the refrigerators are replaced in about 20 years. Once the consumer passes up the opportunity to purchase the efficient model, acquiring the potential savings would be prohibitively expensive.

Second, the Company's perspective on uncertainty and risk is poorly formulated. DECo seems to be concerned only with the ramifications of a decline in the projected value of avoided cost and thus net benefits. As Mr. Welch explains:

> What I'm saying is if you give me this set of circumstances and I spend that money, it is true that, based on these circumstances, I could increase value. However, the value that is created comes from a plant being deferred way out in the future, O.K.? Let's assume that for some reason that load forecast now changes and drops. That plant that was being deferred way out in the future is now way, way out in the future and those benefits go away. (Tr., 1621)

Mr. Welch fails to consider the possibility that load could also rise above expected levels, increasing the benefits of DM, or that other changes (e.g., fuel prices, environmental regulations) could increase avoided costs.

More critically, DECo appears to confuse *risk* and *insurance*. People are usually willing to pay more to reduce risks. Anyone who purchases insurance, invests in long-lived DM, or otherwise locks in costs on a long-term basis reduces exposure to changes in future costs. If the insured property burns or avoided costs turn out to be less expensive than anticipated, hindsight will indicate that the reduction in risk was not necessary. In planning for the future, however, reduction in risk is almost always desirable.

DECo should be concerned with the effects of uncertainty on its resource planning. The Company should be formulating planning strategies under uncertainty by defining clearly the purpose of risk management and evaluating the effects of uncertain futures on alternative resource plans.

Q: Could the Company's wait-and-see strategy be appropriate for additional spending on discretionary DM options?

A: Deferring discretionary expenditures may be helpful in mitigating rate effects. However, a deferral decision should be premised on a complete rate and bill analysis. In addition, deferral should be pursued only if can be shown to be a least-cost option for reducing rate effects, producing minimal lost opportunities. Finally, a deferral plan should be designed to support capability-building efforts.

B. DM Planning Objectives Hindered by Rate Concerns

Q: How do DECo's concerns about the rate impacts of DM spending affect its DM planning strategy?

A: As noted above, DECo's decision to forego cost-effective savings in all customer classes is motivated in large part by concerns over the rate impacts of DM spending. The Company limits customer incentives, and thus cost-effective DM penetration, in order to constrain rate increases to a level deemed acceptable by the Company.

Q: What general rate impact-mitigation strategy should the Company adopt if rate effects are a concern?

A: As I discuss above in Section III.C.4, if rate effects are a constraint to least-cost planning, the Company should pursue a mitigation strategy that most effectively treats the constraint at the minimum economic loss. DECo should not limit its actions to the demand side; rate impacts may be more effectively moderated with modifications to supply investment strategies. Moreover, the Company should attempt to treat DM-related rate constraints with cost-recovery solutions before restraining or deferring DM spending. Finally, if DM spending must be deferred, the Company should only reduce spending on discretionary resources and only in ways that do not create lost opportunities.

DECo should undertake a complete rate and bill evaluation of its *least-cost* resource plan before it adopts any rate-mitigation plan. The Company must first determine the rate and bill impacts of its least-cost plan, and then identify exactly which components of that plan lead to unacceptable rate effects. An evaluation of a suboptimal plan may lead to spurious conclusions about the rate effects of the least-cost plan and of the economic loss associated with different approaches to rate-impact mitigation.

Q: Did the Company undertake a rate and bill analysis of its resource plan before it decided to reduce rate effects by capping customer incentives?

A: Apparently not. DECo does not appear to have determined the rate and bill effects of a least-cost resource plan, or the contributions of supply and demand investments to those effects. Nor does the Company appear to have established what level of rate effect would be unacceptable for each customer class, or how best to moderate these impacts. According to Mr. Welch:

> ... I didn't have in mind right out of the get-go anything that was unacceptable. I was waiting for the results and then I wanted to see the range. ... And I was very sensitive to the large manufacturing group from a pricing standpoint, and candidly I was very sensitive to the rest of the groups and I guess I tried to reach the balance, and I think that this is as good a judgement as I could have made. (Tr. 1742)

Q: Was it unreasonable for Mr. Welch to rely on his judgement as to an acceptable level of rate impacts?

A: Not as long as such judgement is clearly stated and applied to detailed evaluations of rate and bill effects. The

Company apparently did not conduct such evaluations. DECo has not even considered whether the bill savings from additional DM might offset rate increases from additional DM spending.[21]

Q: Did DECo investigate alternative strategies for moderating rate effects besides limiting DM expenditures?

A: Again, apparently not. The Company does not acknowledge, either in testimony or cross-examination, the availability of possible alternatives such as deferring supply investments or capitalizing DM expenditures. DECo's proposal to expense DM investments will exacerbate DM's rate impacts.

Q: If rate effects were best mitigated by limiting DM expenditures, would the Company's plan to cap incentives minimize long-term economic loss?

A: No. The Company's approach is flawed in several respects. First, when capping incentives, DECo does not distinguish between lost-opportunity and discretionary resources, and thus permanently forgoes savings from lost-opportunity resources.

Second, DECo's approach leads to piecemeal treatment of customer homes and facilities, resulting in additional costs for repeated treatment and in lost opportunities. The

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[21] In fact, it is unclear whether the Company included in its rate impact analysis all of the offsetting rate effects of deferring supply investments, including reactivations.

Company can limit spending on discretionary resources by either (1) limiting customer participation, (2) spending less on each participant by offering fewer measures, and/or (3) spending less on each participant by capping incentives. The first approach can reduce total program spending while allowing for comprehensive treatment of each participant. Additional participants can then be treated in later years, spreading out rate impacts.

The second option, reducing the number of measures offered, can work in some circumstances, when the measures withdrawn are carefully chosen to avoid lost opportunities. The deferred measures should be selected so that they do not interact substantially with the implemented measures, and so that later implementation will be feasible at a minimal cost differential.

Unfortunately, the Company has adopted the third approach. Under this approach, each participant may adopt less expensive, yet less efficient, measures or only install a limited portion of the measures offered. Returning to upgrade the equipment installed in the initial treatment or to add additional equipment will tend to be prohibitively expensive. If it is no longer cost-effective to upgrade or add deferred measures, these measures are likely to become lost opportunities.

Finally, DECo's approach may frustrate efforts to build the capability to develop full-scale DM programs that substitute for supply. As acknowledged by Mr. Welch, the Company must implement programs in order to gain information on the incentive level required to maximize cost-effective measure penetration:

> But understand that you're not inputting this like into a computer program and it's saying for a $5 rebate on a light bulb I'll get a 20-percent penetration rate. You're basing that on what's happened in other parts of the country ... and you're going to have to still put your program out.... You don't know exactly what this is going to be till you go do it. (Transcript, 1854)

By initially capping incentives, the Company will not find out how high incentives must be in order to maximize savings. In order to gain such information, DECo should set incentives at levels that other utilities' experience indicates will maximize cost-effective penetration. The Company could then reduce incentives if subsequent implementation experience indicates that such reductions would not entail long-term economic loss.

C. Piecemeal Investment in DM

Q: Apart from the DECo's decision to forego savings due to rate concerns, is the Company planning to comprehensively invest in its customers' DM potential?

A: No. DECo's plans call for piecemeal investment in its customer's efficiency resources. The Company's program-design strategies neglect significant cost-effective resources in a variety of market segments, end uses, and measures. In addition, the weak program-delivery mechanisms envisioned by the Company will fail to acquire all cost-effective savings from the segments and end uses targeted by its programs. DECo's program design strategies are discussed in detail by MUCC witnesses Hamilton and Robertson.

Q: What aspects of DECo's planning strategy give rise to its piecemeal program designs?

A: Two deficiencies in DECo's planning strategy contribute to the development of weak program designs. First, as I discussed above, the Company has not committed to acquiring all cost-effective DM at the lowest feasible cost. This flaw may lead to program designs that overlook some sources of cost-effective savings and ineffectively acquire others. For example, DECo might decide to use customer rebates rather than direct installation to promote the adoption of compact fluorescents in the residential sector. Although the rebate approach might allow for lower DECo expenditures, it may not be the most beneficial option, if direct installation yields greater penetration and higher net benefits.[22]

Second, DECo's planning fails to distinguish between lost-opportunity and discretionary resources, and thus lacks an effective strategy for distinctly targeting and capturing

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[22]Programs that do not work at all will cost DECo very little in direct expenditures, although they will cost a lot in additional supply resources.

lost-opportunity resources when they arise. As a result, the Company allows lost-opportunity savings to slip away through inaction, either intentionally or inadvertently.[23]

By failing to move vigorously to obtain all cost-effective lost-opportunity resources, DECo increases the total costs of providing electric service. DECo might eventually acquire <u>some</u> of these savings as more expensive retrofits. The rest of the potential savings that DECo misses will be irretrievably lost; DECo and its ratepayers will have to make up for these lost opportunities with more costly supply.

Q: Why doesn't the Company distinguish between lost opportunities and discretionary resources in its planning strategy?

A: Apparently, DECo believes that this is not a critical distinction for planning purposes. When asked whether DECo should put priority on targeting lost opportunities, Dr. Chamberlin responded:

> Well, I think it's important for the company to consider lost opportunities. I think Detroit Edison has a little more comfort zone than a number of other companies do with respect to the lost-opportunity issue. The need for capacity isn't as current with the company as it is with a number of other utilities. So there's more slack essentially that the company has, more comfort. (Tr. 1484)

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[23]"Intentional" lost opportunities would include those that DECo treats as discretionary resources, and attempts to defer.

Q: Is Dr. Chamberlin's rationale a reasonable basis for not aggressively pursuing lost-opportunity resources?

A: No. Dr. Chamberlin's point is not clear, but neither of the arguments he might be raising here argue for ignoring lost opportunities. First, Dr. Chamberlin might be arguing that lost opportunities are not as critical for DECo because low avoided costs result in fewer cost-effective lost opportunities to target. Even if DECo would find fewer cost-effective lost opportunities than some other utilities, this argument does not reduce the importance of identifying those lost opportunities that can be captured.[24]

Second, Dr. Chamberlin appears to be suggesting that the "comfort zone" and "slack," due to the reduced "need for capacity," allows DECo to defer lost opportunities. If this is his point, he misunderstands the nature of lost opportunity resources.

V. ADDITIONAL SAVINGS ATTAINABLE WITH COMPREHENSIVE PROGRAMS

Q: If DECo corrected the deficiencies in its DM planning, could the Company acquire significantly more cost-effective savings?

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[24]Indeed, low avoided costs affect discretionary resources more than lost opportunities. Discretionary resources that are marginally cost-effective today may produce a much higher net present value benefit once avoided costs rise; in that situation, discretionary programs beyond capability-building levels may then be prudently deferred. Lost opportunity resources that are marginally cost-effective with low avoided costs must be captured today, or they are lost forever.

A: Yes. DECo could acquire substantially larger savings by expanding the scope of its DM efforts to levels that are comparable to those in the DM plans of leading utilities.

Q: How much more electricity could DECo expect to save by investing in comprehensive efficiency resources?

A: A precise answer to this question will have to wait until DECo 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 leading utilities discussed in Section II.D above. I used that data to derive a rough estimate of the additional DM resources that DECo might acquire if it follows the lead of utilities with aggressive and comprehensive plans.

Q: How much additional energy might DECo save?

A: As shown in Exhibit I-____(PLC-6), the plans of utilities with comprehensive DSM plans suggest that DECo might acquire an additional 1,800 GWh of cost-effective efficiency savings by 1997, for a total savings of 2,100 GWh. This total represents 4.8% of 1997 energy sales. By comparison, the Company's current efficiency plans account for 0.7% of 1997 energy sales.

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

A: Yes, there are. Depending on the DM load factor assumed, the additional potential energy savings would be associated with 270 MW to 460 MW of peak-demand savings by 1997. These additional peak savings would be about 6 to 10 times more than DECo is planning. My estimates of additional peak demand savings potential are also provided in Exhibit I-____(PLC-6).

Q: How did you estimate future energy savings shown in Exhibit I-____(PLC-6)?

A: First, I assumed that annual acquisitions of demand-side energy resources would equal specific percentages of projected annual sales. I based these percentages on the plans of the utilities with the most comprehensive DM portfolios, by class. I multiplied these annual percentages by DECo's projected average annual sales in the period 1994-97, and by the four years of program operation in that period.

Second, to project peak demand savings generated by intensifying DECo's DM portfolio, I applied an appropriate DM load factor to the difference between my projection and the Company's projection of cumulative energy savings. The total potential peak savings from all of DECo's DM programs are the sum of these additional peak savings and DECo's projection of peak savings for 1994 to 1997.[25] I separated the analysis into two parts, because DECo projects an

[25]Total savings are for efficiency resources only. Thus, all figures exclude DECo's projections for load management.

unusually high load factor for its DM programs.

Q: What DM load factors did you use to translate additional energy savings into additional peak load reductions?

A: I calculated additional peak savings using DECo's class load factors, as well as for a range of peak savings assuming load factors that are 15 percentage points lower and higher than the Company's class load factors.

VI. SCREENING OF DM MEASURES AND PROGRAMS

A. The TRC Test and the RIM

Q: What test does DECo use in screening DM options?

A: DECo claims to use the total resource cost (TRC) test. The TRC equals the difference between total benefits (avoided costs, including non-electric costs avoided by participants) and total DM costs (utility and participant expenditures, including capital and O&M).[26] The TRC includes all identified costs and benefits, regardless of who pays or receives them.[27]

However, DECo also appears to use the rate impact measure (RIM), implicitly or explicitly, in screening programs and measures, and in designing programs. The RIM,

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[26]When externalities are included in the costs reflected in Total Resource Costs, the resulting test is often called the "Societal Test." I use the term "TRC" in this section without making any assumption regarding the treatment of externalities.

[27]Dr. Chamberlin confuses the TRC with the utility cost test when he says that "The TRC test selects DSM measures that reduce the utility's revenue requirement." (Direct, p. 7, Tr. 1349)

as DECo appears to use it, is a rough estimate of the effect of a DM option on average system rates over the life of the option, or some other lengthy analysis period.

Q: How does DECo appear to rely on the RIM?

A: DECo uses the RIM to reject DM measures, programs, delivery mechanisms and incentives that are selected by the TRC test. For example,

- Dr. Chamberlin suggests that "Rate increases can be tempered . . . by limiting the number of dollars spent on programs that do not pass the RIM test" (Direct, p. 8, Tr. 1350).

- Mr. Welch (who selected and designed DECo's proposed DM programs) suggests that DECo should "first implement all programs that were RIM-passing," and only then "implement TRC-passing programs" (Tr., p. 1637).[28]

- Detroit Edison's Integrated Resource Plan for 1992-2006 (IRP) describe~~s~~d the prescreening of DM options to favor those that fare best under the RIM, although the references to the RIM are not explicit. DECo favor~~s~~ed options that primarily affected peak load, rather than energy, and that "did not detract from the Company's competitive position," *i.e.*, raise rates (IRP, p. 24). Stet

- As discussed in Section IV.A above, DECo appears to have restricted participant incentives on the assumption that higher incentives produce excessive rate impacts.

Q: Does DECo use the RIM appropriately?

A: No. The TRC should guide DM portfolio design, since the goal of least-cost planning is to minimize Total Resource Costs. The RIM should not be used in program design for at least ~~three~~ four reasons:

- the RIM does not include all costs and benefits of DM;

[28]Mr. Welch implies that the "RIM-passing" programs need not even pass the TRC.

- the RIM attempts to measure only the effect on rates, not on bills;

- the standard RIM does not accurately measure rate impacts; and

122 - utilities do not consider rate impacts in selecting supply resources.

Q: What costs and benefits are omitted from the RIM?

A: The RIM does not include costs paid by the participant, bill reduction benefits to the participant, or any externalities. In fact, the RIM includes the participants' bill reductions as *costs*.

Q: What is the relationship between the effect of DM on rates, and the effect of DM on bills?

A: DM that passes the TRC test will almost always reduce the present value of total revenue requirements, average utility bills, and total costs of energy services, including the costs paid directly by participants.[29] Thus, even if rates rise, energy consumption will fall by a larger percentage, resulting in a net decrease in bills.

Q: How should the effect of DM on rates be determined?

A: The ratepayer impacts of the DSM portfolio should be examined carefully to flag any equity problems or disruptive rate impacts. The standard RIM test, however, is not a very

[29]The only DM selected by the TRC that could increase these costs are those options selected solely due to externality benefits. These options may slightly raise energy service costs, but decrease other costs to ratepayers, such as health insurance and compliance costs for transportation and industries. 123

meaningful test of equity or rate changes. It looks at rate effects on a measure-by-measure or program-by-program basis, and measures only the average effect on rates, over a long period of time. Individual measures and programs cannot really be considered equitable or inequitable in isolation. Equity effects should be evaluated for the portfolio as a whole; the standard present-value RIM test is not useful for this purpose. It does not assess the equity effects of DSM among and within classes and it does not determine the pattern of rates and bills over time.

The DM option that most conclusively fails the RIM test can increase the equity of the portfolio. Suppose the failing option is a residential lighting program, the only program that might be under consideration for small customers without electric heat, hot water, or central air conditioning. These small customers are likely to bear a portion of the costs of programs directed to the other members of the class; without the lighting program, the distribution of costs and benefits would be inequitable.[30] The lighting program would increase the equity of the DM offerings, while reducing total revenue requirements and bills, even though it would slightly increase residential rates.

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[30]This particular problem can also be addressed by collecting the costs of the other DM programs from sales over a threshold, such as 200 kWh/month.

The fact that an option, or an entire DM portfolio, fails the RIM test does not imply that rate effects are distributed unfairly, or that rate increases are too large compared to bill reductions. If there are equity problems, they can be addressed by changing cost recovery patterns, by altering the allocation of expenditures among and within rate classes, by increasing the penetration of programs to groups that would otherwise face higher bills, and possibly by changing the timing of particular programs. DM should not be rejected because it fails the RIM test.

The California Standard Practice Manual for Economic Evaluation of DSM Programs specifies a number of different rate impact tests that should be performed, including determination of the annual effect on customers' bills, rather than rates, by class (pages 17-23). Even the EPRI Technical Assessment Guide recommends that rate impacts be evaluated in the context of overall system rate levels, rather than as a stand-alone computation (p. 1-19). Neither document supports the use of a RIM test that looks only whether a DM option increases average rates in the long term.

Q: Do cost-effective supply options create adverse rate effects?

A: Yes, in at least three ways. Least-cost supply options can raise rates and bills for "non-participants" in at least three ways: raising bills for customers who do not participate in growth, who do not remain on the system for many years, or who use a different mix of demand and energy than the system as a whole.

First, load growth can result in increased rates, and thus increased bills to non-participants in the growth. The lowest-cost option for meeting load growth can raise a typical existing customer's bill to accommodate new customers. Each new customer pays less than the cost of the additional equipment constructed to serve the new load. The new customers probably save even more, compared to the cost of building a separate system to serve themselves. Allowing new customers to share in the existing system saves money for these "participants" in growth, but raises bills to "non-participants."

Second, the supply option that is least-cost in the long term increase costs in the short term. For example, consider the following choice:

Option	Levelized Rate over 27 years	Levelized Rate over 5 years
A (coal)	9.00¢/kWh	7.04¢/kWh
B (gas)	9.02¢/kWh	7.00¢/kWh

Selecting Option A over Option B would require customers in the first few years to pay more so that customers in the later years can pay less. Some of the customers who pay more in the short term will not be customers long enough to profit from the choice of Option A over Option B, especially the elderly and marginally viable businesses.

Third, even in the long term, the choice of supply has different effects on rates and bills for different types of customers. Selecting Option A over Option B might have the following effects on levelized rates:

Non-fuel costs and demand charges increase $2.70/kW-yr

Fuel costs and energy charges decrease by 0.072¢/kWh

Bill change for customers using 100,000 kWh with peak demand of:

100 kW	$188 increase
50 kW	$58
20 kW	($20) decrease
15 kW	($33)

Thus, selecting the supply option with the lower total cost increases bills for some customers and decreases bills for other customers.

Q: How do utilities, including DECo, screen supply options?

A: Supply options are screened on their effect on total system costs over the long term. No rate impact analysis is normally performed in the selection of supply resources.

Q: Do utilities review rate effects in a more detailed fashion in other contexts?

A: Yes. Extensive rate impact analyses are performed in the review of cost allocation and rate design, determining the effect of the proposal on rates and bills for each class, and for various sizes and types of customers within each class. The rate impact analyses performed for cost allocation and rate design are much more detailed than the simple RIM test usually applied to DM options, which computes only the long-term effects on the total system. This more detailed analysis is necessary before DECo can determine whether a potential DM portfolio creates rate-effect problems, and if so, what ameliorative measures would be helpful and should be taken.

B. DM Resource Screening

Q: How should DECo screen DM resources?

A: DECo should screen DM resources in several steps, including separate analysis of measures and of the programs through which they can be delivered. At all levels, screening should determine the incremental cost-effectiveness of options.

Q: What do you mean by "incremental cost-effectiveness"?

A: DM planning involves many important decisions about enhancing the levels of program intensity, efficiency or comprehensiveness, such as whether to include smaller customers and low-hours-usage applications, whether to raise insulation or efficiency standards, and whether to include additional measures in the program. Where the enhanced program increases savings without increasing costs, or reduces costs without reducing savings, the decision to expand is noncontroversial. In the more common case, the version of the program with greater savings also has greater costs. In these situations, the enhancement should be pursued if the incremental benefits exceed the incremental costs.

The incremental net benefit test should be noncontroversial; a change in program design should be pursued if and only if it reduces net costs. DECo does not appear to have examined alternatives in this manner.

Q: How does DECo screen DM resources?

A: DECo screens "DM options," which are a mix of measures, groups of measures, and programs. For example, the list of options in DECO's IRP (Table 4.1-4) includes such measures as "efficient freezer" and such programs as "low income weatherization."

Q: How should DECo have screened DM resources?

A: The DM program design and screening process can be thought of as consisting of six phases, some of which overlap chronologically. These phases are:

- measure screening[31],
- measure enhancement and design,
- program screening,
- program specification,
- resource allocation, and

[31]Some generic programs, especially in the commercial and industrial sectors, will not specify measures. For such programs, the review of cost-effectiveness will essentially start with the third step, program screening.

• project screening.

Measure screening examines the cost-effectiveness of individual measures in isolation from the program delivery mechanisms for installing the measure. In this phase, the analysis ignores all costs shared with other measures in the program, such as costs of marketing, administration, setting up visits, traveling to the site, and auditing the building. Only the direct incremental costs of the measure are included at this stage: materials, direct labor, and any other costs of installing this measure. The savings to the electric system are taken from the screening tool, which gives the present value of savings in \$/kWh and \$/kW for various measure lives. Multiplying the value per kWh saved times the number of annual kWh produces the total system benefit of the program. If the costs are less than the savings, the measure is screened in; if the costs exceed the savings, the measure is screened out.

This measure-screening process will avoid mistakenly assuming that a DSM measure would be cost-effective merely because the package or program in which it might be included would be cost-effective. Such an assumption could lead to uneconomic investments -- *i.e.*, individual measures with costs exceeding their incremental benefits. Measure screening should also exclude administrative and overhead costs except those incrementally caused by inclusion of the measure. Measures that may not be cost-effective

individually if required to support program delivery costs may be economic when combined in a program whose fixed delivery costs can then be distributed over numerous measures.[32]

Measure design and enhancement similarly involves comparing the incremental cost of measure improvements (*e.g.*, replacing 2" water-heater wraps with 4" wraps) with the incremental savings from the improvement. Incremental screening is particularly important in measure enhancement, which deals primarily with incremental changes to measure design and specification. Measures must be optimized before initial program screening; at sub-optimal levels, measures may not generate enough net benefits to cover program delivery costs.

In addition to higher levels of intensity (*e.g.*, thicker insulation), DECo will need to screen other improvements and enhancements, such as combining measuring (*e.g.*, installing daylighting and automatic dimmers in addition to high-efficiency lighting) and lowering

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[32]Some measures may only be cost-effective in a small but significant number of applications (*e.g.*, houses with large heating loads, lights in use over 5,000 hrs/yr). The screening process should retain these measures for possible inclusion in suitable programs, following more detailed market segmentation or field-screening of the measure with other options. A measure need not be universally applicable to be included in a program. It need only be cost-effective often enough to be worth on-site screening.

thresholds (lower hours use, smaller motors).[33]

Once DECo has identified the set of cost-effective measures and selected the optimal level of measure enhancement, it can move on to program screening. The savings include the effects of the mix of measures likely to be installed, which will often be fewer than all eligible measures.[34]

Program screening takes into account the costs of fielding the programs and reflects specific marketing approaches, customer incentive structures, and delivery mechanisms. The total cost of the program includes the direct costs of the assumed mix of measures[35] plus all joint costs omitted from the screening of measures: marketing, administration, setting up visits, traveling to the customer, and initial site audits. Program screening is the first step in the process in which free riders and free

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[33]In practice, the degree of measure optimization described here is more prevalent in residential than in non-residential program design. Non-residential applications are more site-specific, so some of this optimization occurs in the field, project by project.

[34]For a residential water heating direct-installation program, for example, some customers will already have water heater wraps or low-flow showerheads, or will not allow installation, or will not have suitable applications (*e.g.*, no shower).

[35]The objective here is to reflect reality. Most direct costs are incurred only where an installation actually occurs. However, if some of the incremental cost of the measure (such as additional time for an audit or inspection) will be incurred even if the measure is found not to be applicable, that cost should be included for all participants.

drivers are relevant.

Some programs may change significantly over time, as the program changes the market, produces a better-educated professional community, encourages code changes, and so on. Program costs may fall over time, as effectiveness rises. If possible, program screening should reflect conditions over the life of the program, not just in the first year.

Full program specification is necessary only for those programs that pass the screening. Specification includes determining such factors as delivery mechanisms, marketing mechanisms, cost shares between the utility and participants, and the structure of participant co-payments. As was true for all other design decisions, the objective is to maximize net benefits. Whatever produces the greatest spread between total savings and total costs should be selected.

The resource allocation phase combines the programs designed by DECo and considers issues such as financial feasibility, rate and bill effects, equity, and administrative feasibility. If constraints are identified, program designs may be revised, such as by stretching out the ramp-up for discretionary programs. Re-screening of marginally cost-effective measures, enhancements, and programs may become necessary if the magnitude of the portfolio significantly reduces avoided costs.

In many programs, project screening may be necessary to determine the optimal combination of measures to install in a particular facility, in retrofits for large customers, and in custom designs (industrial process design, new construction). In other cases, installing a measure or set of measures with minimum analysis may be more cost-effective. For example, installing electronic ballasts throughout a small commercial building may cost less than specifying the optimal number of ballasts by determining the break-even duty cycle of the lights. Alternatively, creative approximations may be sought, such as installing electronic ballasts in all corridors and workspaces and occupancy sensors in all low-use areas.

In any case, measure screening for projects should use the same incrementalist concepts as in the original generic measure screening discussed above. Overhead costs should be included in measure costs only to the extent they vary with the number of such measures installed. Sunk joint and delivery costs, such as the project screening itself, are irrelevant to project screening.

C. Net Present Value and Benefit/Cost Ratios

Q: How does DECo compare competing cost-effective DM resources?

A: DECo's position on comparing cost-effective options is ambiguous. The IRP says that "If options are to be ranked relative to each other they should be ranked by the net present value (benefits minus costs) and not the benefit/cost ratios" (IRP p. B13). But Mr. Welch testifies that "I would implement all TRC-passing programs in a descending order of their benefit/cost ratio from the highest benefit/cost to the lowest benefit/cost." (Tr. 1637)

Q: Which statistic is more useful in selecting options, the net present value or the benefit:cost ratio?

A: The two tests usually indicate the same results. A DM option is cost-effective if it reduces the total cost of energy services, *i.e.*, if its benefits exceed its costs. Where the alternative to the DM option is inaction (*e.g.*, this luminaire is replaced or it is left unchanged), the option is cost-effective if it has:

- a positive net present value (NPV), defined as the present value of benefits minus the presents value of costs, or
- a benefit-cost ratio (BCR) exceeding unity, where the BCR is the ratio of the present value of benefits to the present value of costs.

Both standards require the present value of benefits to exceed the present value of costs. Anything that passes the NPV test also passes the BCR test.

However, NPV and BCR do not produce the same ordering of multiple alternative actions. Moving from the current or standard situation (*e.g.*, an air conditioner with SEER 10) to option A (*e.g.*, a unit with SEER 13) may produce a higher NPV but a lower BCR than option B (*e.g.*, a unit with SEER 12). This apparent inconsistency in the test results frequently causes confusion when options compete.

Among those competing, mutually-exclusive DSM decisions that pass the TRC test, the one delivering the maximum net benefit should be selected. The objective of least-cost planning -- to minimize costs -- can be achieved by selecting actions maximizing the difference between the benefits and costs. Therefore, DM screening should not seek to maximize the BCR of the DM portfolio or individual programs or measures.[36] The BCR test selects the option that provides the "biggest bang for the buck," but does not directly indicate whether a smaller added bang from investing more dollars is also cost-effective.

The difference in the roles of the two tests can be restated in physical terms. The BCR represents a slope, while the NPV represents a height. The objective of DSM program design is to maximize net savings, to get to the top of the highest mountain of savings, as measured by NPV. The BCR indicates the steepness of the slope, but not the total height of the mountain.

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[36]Financial and economic theory generally rejects the use of the BCR for screening investments, except where capital is constrained. See Brealey and Myers (1988), pp. 85-86, Copeland and Weston (1983), pp. 55-57. DECo DM investment is unlikely to be constrained by the availability of capital. Kilmarx and Wallis (1991) suggest using the BCR for screening DSM programs (with some implicit caveats regarding protection of lost-opportunity), but incorrectly confuse rate-effect constraints with budget constraints. See Chernick *et al.* (1992).

D. Consistent Analysis Over Time

Q: How should DECo compare the costs and benefits of DM options over time?

A: At various points in the screening process, DM should be evaluated for a single measure installation, for a year's program implementation, or for a multi-year program ramp-up. In each case, costs must be matched with their benefits to ensure fair comparisons for the full lifetime of the measures under analysis.

Q: Has DECo compared cost and benefits consistently?

A: No. DECo's DSManager analysis limits cost-effectiveness analyses to 22 years, 1994-2015, while the LMSTM analyses appear to use only 13 years, 1994-2006 (Hearing Room Requests #40 and #41).[37] Since many options would be expected to produce benefits for up to 40 years, this treatment excludes a significant fraction of the benefits of DM installations, even those made as early as 1994.

not from deposition

DECo compounds this error with an even more serious problem. DECo includes *costs* of program implementation for many years, but does not extend the period of benefits. In DSManager, DECo continues program costs through 2010, so that only 6 years of benefits are included for the last measures installed. LMSTM includes program costs for varying periods, with some programs running through 1997;

[37]The available documentation appears to contradict Mr. Welch's statement that DM was evaluated for a 20-year period. DECo has informed me that LMSTM uses a longer analysis period than indicated in the documents provided.

these installations are credited with only 10 years of savings. This approach to comparing costs and benefits is incorrect and strongly biased against DM.

DECo would not use the same approach in evaluating supply options. If DECo were determining the optimal timing of a series of coal plants, it would compare the costs of *each* coal plant over its life to the benefits over its life. No utility would compare the cost of the coal plants to be installed in 1994-2010 with the plants' benefits over 1994-2015.

E. Qualitative Screening

Q: Did DECo apply other screening criteria, besides the TRC and RIM?

A: Yes. DECo eliminated a large number of options through a two-step qualitative pre-screening process (IRP, pp. 24-25).[38] Of the 101 options that entered this process, only 40 emerged for further analysis.[39]

Q: Were the criteria used in the pre-screening reasonable?

A: Of the eight criteria, only two appear to be sensible. At first blush, "Customer Acceptance" sounds like a reasonable criterion, since DECo would be wasting its time marketing

[38]DECo does not explain how the two steps of the process related to one another, nor whether the point system described in the IRP determined the options that would be passed on to formal screening.

[39]Another 22 options were added later; it is not clear how these relate to the 71 options rejected in pre-screening.

measures that customers would not accept. Unfortunately, we do not know whether this, or any other criterion, was applied realistically. Given DECo's lack of sophistication in DM program design, DECo may not be able to determine what would be acceptable to customers.

"Societal Acceptance" is described as covering reduced emissions, increased employment, decreased utility bills, and other unidentified social goals. This also sounds like a reasonable criterion, but it is not clear how DECo applied the criterion.

Most of the criteria used in the IRP are inappropriate or perverse (that is to say, backward or reversed). As noted previously, the "Relative Cost-Effectiveness: Company" (which down-rates energy-saving options) and "Effect on Competitive Position" criteria are at least partly proxies for the RIM test.[40] "Relative Cost-Effectiveness: Company" and "Potential Size of Program" (which is measured in MW of peak load) arbitrarily downgrade high-load-factor options, without any analysis of the cost-effectiveness of the option. "Potential Size" also expresses an arbitrary preference for options that *individually* produce large savings.

Among the perverse (that is to say, backward or reversed) criteria, "Relative Cost-effectiveness: Customer"

[40]None of the criteria, even those described as measuring "Cost-effectiveness" actually consider either costs or benefits.

is described as favoring options that allow for low incentives, while the "Naturally Occurring" criterion selects for those that would occur without incentives. DECo should be concentrating on the options that most require utility intervention, not those that would occur anyway.

Similar counter-productive screening results from DECo's criteria favoring "Reliability of Projections" and "Speed of Implementation." Since DECo does not intend to seriously start full DM implementation for some years, the first discretionary options it should prioritize are those requiring capability-building, such as those for which impacts are not well known and those requiring long lead times.[41]

Q: Did DECo use any other inappropriate criteria?

A: Yes. In selecting options, DECo appears to have been guided by a misconception that baseload conservation is only justified by "a lot of base growth or a need for a lot of baseload generation." (Welch, Tr. 1785) Hence, DECo's DM portfolio "is oriented towards peaking-type capacity and peak growth because that's what we're experiencing," and a "high proportion of the programs that we have here are oriented towards peak reductions." (Id.)

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[41]DECo creates a Catch-22 situation for DM, by refusing to implement DM options "for which the Company would have to rely completely on theoretical studies." If the options are not implemented, DECo will never have the information it considers a prerequisite to implementation.

A DM measure with baseload effects is justified if its savings, including its large energy savings, exceed its costs. Neither the utility's supply plan nor the utility's load forecast have any direct effect on the desirability of energy conservation. Baseload DM tends to be less expensive than low-load-factor DM, since the savings from a heavily-used piece of equipment accrue over more hours than those from rarely-used equipment.

VII. AVOIDED COSTS

A. Role of Avoided Cost

Q: Why are DECo's avoided cost estimates important?

A: Avoided costs are used to determine the cost-effectiveness of DM, used in screening DM. DECo's cost-effectiveness analysis of DM options is in two stages: initial screening using the DSManager model and a second analysis using the LMSTM model and a lower load forecast. The DSManager analysis screened out several measures. In addition, many options that were determined to be cost-effective in the DSManager analysis were subsequently found to be uneconomic in the LMSTM analysis (Welch Direct, pp. 14-15, Tr. 1576-1577 & Exhibit A-14, Schedules K12 and K13).

Q: Please summarize your evaluation of DECo's avoided cost estimates.

A: Both the analyses used underestimated avoided costs.

Q: Why did options that pass the DSManager screening fail the

LMSTM analysis?

A: While Mr. Welch suggests that the only difference between the two analyses is LMSTM's more detailed modeling of avoided cost (Welch Direct, pp. 14-15, Tr. 1576-1577), LMSTM simply uses lower avoided costs than does DSManager.

Q: Is the decrease in the avoided costs justified?

A: Some of the decrease may be justified. DECo performed the LMSTM screening later, with avoided cost estimates based on the more recent, lower load forecast. A lower load forecast would tend to reduce avoided-cost estimates. For example, avoided energy cost will decline as high-cost energy sources are less frequently dispatched. Avoided capacity cost may decrease as planned supply additions are delayed.

However, DECo's avoided costs are lower than can be explained by the lower load forecast.

Q: What deficiencies have you identified in the Company's avoided cost modeling that would result in underestimating the benefits of DM?

A: The Company's avoided cost modeling will undervalue DM because of the following errors and omissions:

- DECo's approach to determining the avoided supply resource understates generation capacity cost.
- The analysis omits avoided T&D costs.
- It understates avoided demand and energy losses.
- The analysis neglects costs of compliance with the Clean Air Act Amendments.
- It omits environmental externalities.

- It gives DM no credit for risk mitigation.

B. Development of Avoided Costs for DM

Q: How should DECo estimate the supply costs avoided by DM?

A: DECo should capture the avoidable costs of

- generating capacity, both that related to demand and that related to energy, and including purchases, capital recovery and O&M costs;
- transmission capacity, including capital recovery and O&M costs;
- distribution capacity, including capital recovery and O&M costs;
- fuel and other variable O&M generation energy costs;
- compliance with environmental regulations;
- line losses in the transmission and distribution system; and
- externalities.

1. Generating Capacity

Q: How should utilities estimate the generating capacity costs avoidable by DM?

A: The utility should estimate the cost savings of altering the least-cost supply plan without the DM to the least-cost supply plan with the DM. The DM should be assumed to have a realistic load shape (generally, similar to overall system load), and the amount of DM should be comparable to the capacity of avoidable supply. The portion of the avoided capacity cost that is comparable to the cost of peaking capacity (generally combustion turbines (CTs)) should be assumed to be related to demand or reliability, while the excess should be assumed to be related to energy load.[42]

2. Variable Generation Energy Costs

Q: How should DECo estimate the variable generation energy costs avoided by DM?

A: DECo should compare the dispatch costs (fuel, variable fuel handling, variable O&M) of the base case to the dispatch costs of the same case, minus the energy load of DM (and without any avoided supplies), again at an appropriate DM load shape. The difference is the avoided variable energy costs.

The generation energy costs (the dispatch costs, plus capitalized energy) at each load level can then be multiplied by losses at that load level and weighted by the load level, to derive a weighted loss factor.

3. Transmission and Distribution Capacity

Q: How should DECo estimate avoidable transmission and distribution capacity for DM?

A: In general, it is not possible to directly compute the difference in T&D investment for the base and DM cases, due to the lack of system planning models comparable to the

[42] The supply additions in DECo's supply plans are peaking capacity, or low-cost reactivations, so no energy-related capacity costs appear to be avoidable for some time, except through off-system sales. If a fuel-saving investment like the combined-cycle conversions of three existing steam turbines (1992 IRP, p. 31) were included in the base case supply plan, then the capital cost in excess of the cost of a peaker would have to be reflected in avoided energy cost.

system models used in generation planning. Hence, it is usually necessary to estimate T&D costs from historical (and perhaps projected) relationships between investments and loads, and between O&M and loads.

Regardless of where the customer's usage is metered, someone must provide distribution to the end use, which is almost always at secondary. Hence, avoidable T&D should be computed to the secondary level for all customer classes.

4. Line Losses

Q: What line losses should be included in DM avoided costs?

A: Marginal losses should be included for energy costs, recognizing the variation in marginal losses with load level. Marginal energy losses should reflect the range of loads and costs within a period, rather than losses at the average load level in the period. Like distribution costs, losses should be included to the end-use level, which is almost always secondary. Demand-related costs should include average losses at the peak load.

5. Environmental Compliance Costs

Q: How should DECo include the costs of environmental compliance?

A: First, for effects that will be <u>mitigated</u>, DECo should include reasonable estimates of the cost of mitigation. The incremental costs of all emissions-control and effluent-reduction equipment and measures, including all capital and operating costs, the costs of additional fuel consumed due to an increase in plant heat rate, and all other incremental costs should be included in the costs of the resource. The costs in this category cover current costs of existing rules, future costs of existing rules, and future costs of expected rules.

Second, for residual effects that will be <u>internalized</u> through taxes, fees, emissions caps or another method, DECo should include a forecast of those costs, just as it considers future fuel prices in its cost analysis. Examples include the trading allowance provisions of the Clean Air Act Amendments (CAAA), and other rules that can be anticipated today, such as CO_2 emissions reductions and air toxics reductions. The costs in this category are simply projections of future internalized costs, and should be treated in the same manner as fuel price or other forecasts.

6. Externalities

Q: How should externalities be incorporated into utility planning?

A: The residual environmental and other external effects of power plant construction and operation (the effects that remain after mitigation efforts and that will not be internalized) should be expressed in monetary terms, and estimates of the cost should be included in resource planning and acquisition. DECo's existing system contributes to regional and global environmental concerns in a way that DM or other clean resources would not.

7. Risk Mitigation

Q: How should the effects of risk be incorporated in DM valuation?

A: DM improves a utility's ability to manage supply risk. This results in lower expected costs, and lower volatility and long-run uncertainty in costs. Base-case avoided supply cites 125 costs should thus be increased to reflect both the difference between base case avoided costs and the avoided costs under uncertainty, and the value of reduced volatility and uncertainty.

Q: Which attributes of efficiency resources improve a utility's ability to manage risk?

A: Studies by the Northwest Power Planning Council, Oak Ridge National Laboratory, and others have found that, more than any other resource, efficiency can help utilities adapt to an uncertain future through: (1) flexibility; (2) short lead time; (3) availability in small increments; and (4) tendency to grow with load.

Q: In what ways do efficiency resources exhibit these characteristics?

A: Demand-side resources are flexible because once a utility has developed the capability to acquire them, it can change its acquisition plans relatively quickly and inexpensively as needs change.

If a utility maintains the capability to deliver full-scale efficiency programs, it can measure the time between resource expenditure and resource service in days or weeks rather than in years. Because efficiency investments produce electricity savings almost immediately, a utility need not invest in resources far in advance of need, as is the case with many supply options. Together, the short lead times and small increments associated with efficiency resources allow a utility to more closely match resource acquisition with resource need.

Q: How do efficiency resources coincide with variations in load?

A: Potential for lost-opportunity resources varies directly with service area load growth. Thus, a utility committed to pursuing lost opportunities will automatically synchronize its new resource acquisitions with swings in resource needs.

In addition, the savings produced by previous efficiency investments will also tend to track load. For example, increasing industrial output in existing facilities will raise electricity use. If those facilities use high-efficiency motors, the increase in electricity use will be less than with standard motors. Similar expectations should also hold for commercial and residential customers; for example, thermal efficiency improvements in building construction will reduce the effect of weather on load.

Compared to supply, efficiency resources therefore reduce the uncertainty surrounding the rate and magnitude of future load growth, thereby reducing the number of options that must be readied for the future.

Q: Have any regulators explicitly recognized the risk-mitigating advantages of energy-efficiency resources?

A: The NPPC (1991, pp. 930-931) considered the "added advantages" of energy efficiency, including "the ability to track local growth" and the tendency to "savings [to] increase as the weather becomes more severe." Based on the risk analyses and other studies,[43] NPPC increased the avoided costs for energy-efficiency programs by 30% to account for these planning benefits. Ontario Hydro includes a 10% preference for DM, to reflect fuel-price risks.

C. DECo's Avoided Costs

Q: Did DECo correctly estimate avoided costs for the purposes of DM analyses?

A: No. DECo's understates avoided costs in both the DSManager and LMSTM analyses.

Q: What is the basis for your understanding of DECo's approach?

A: I have reviewed the available documentation of DECo's avoided costs and resource planning in the Company's testimony, 1992 IRP, and responses to discovery.

The available documentation of DECo's avoided costs is very limited.

1. Generation Capacity Cost

Q: What avoidable generation capacity is reflected in DECo's

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[43]NPPC also recognizes the environmental benefits of energy efficiency.

avoided costs?

A: DECo assumed different avoided capacity costs in the DSManager and LMSTM screening analyses. The avoidable resources include the same set of resources: unit restarts, completion of the Trenton Channel project, and new combustion turbines. The avoided capacity costs differ between the two analyses, because the timing of the resource additions differ (DECo Discovery Response MUCC-1.3/549). Exhibit I- ____(PLC-7) provides avoided capacity costs and supply plans assumed in DSManager and LMSTM.

Q: What problems have you identified in DECo's approach to estimating avoided production cost?

A: DECo's approach to estimating avoided production cost has the following deficiencies:

- DECo assumes that in any given year DM avoids the most recent planned addition, rather than the highest cost avoidable resource.
- DSManager assumes zero capacity cost in some years, even after DECo would need additional capacity.
- LMSTM does not credit DM with avoiding capacity in 1994.
- DECo overlooks the possibilities for off-system sales of capacity and energy.
- The LMSTM analysis does not credit DM for deferring the planned CTs.[44]

Q: Why is it inappropriate to define the avoided capacity in

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[44]In LMSTM, for all years from 2000 on, it is assumed that DSM can defer only the St. Clair 5 restart; yet, the supply plan includes additions of new, higher cost CTs beginning in 2002 (DECo Discovery Response MUCC-1.2/548, p. 3).

any given year as the most recent planned addition?

A: Avoided generation cost should reflect the difference in costs between the least-cost supply plan with the DM and the least-cost supply plan without the DM. Equivalently, avoided costs should reflect the adjustment to the base-case supply plan that produces the greatest savings.

The most cost-effective response to an additional increment of DM may be to delay the first planned unit for some years, then build that unit but avoid the next unit, and so on. But when the first unit is more costly than the second, further deferral of the first planned resource and installation of the second is more cost-effective.

The DSManager analysis assumes that DM in 1994 can delay the restart of Conners Creek, saving $27.84/kW-yr; for 1995, DECo assumes DM could delay the Trenton Channel project, saving only $19.28/kW (DECo Discovery Response MUCC-1.2/548).[45] DECo should have credited DM with 30% higher savings in 1995 by assuming that DM would allow further deferral of the first unit, even if the second unit were installed in 1995.

In this respect, DECo's approach to estimating avoided capacity cost is inconsistent with its own supply planning. In response to a lower forecast, DECo deferred the high-cost Conners Creek addition from 1994 (in the DSManager supply

[45]In 1994$.

plan) to 1996 (in the LMSTM supply plan), rather than altering the planned in-service date of the less expensive Trenton Channel addition in 1995 (DECo Discovery Response MUCC-1.3/549).

Exhibit I-____(PLC-7) demonstrates the effect on capacity costs when the highest cost resource, rather than the most recent addition, is selected as the avoided resource.[46]

Q: Is there a plausible explanation for DECo's assumption that the capacity costs are zero in some years, after capacity becomes avoidable?

A: No. In the DSManager analysis, capacity is first avoidable in 1994. From then on, in every year, capacity can be either installed or deferred. Therefore, in every year, it should be treated as avoidable.

The DSManager analysis gave DM capacity credit only in the years new units are added. DECo's approach simply made no sense, and in fact, was revised for the LMSTM analysis (DECo Discovery Response MUCC-1.4/550).

Q: Why should LMSTM credit DM with avoiding capacity in 1994?

A: In the LMSTM analysis, the base-case supply plan does not

[46]The unit restarts are not added in order of cost. With the exception of the first resource in the DSManager supply plan, the decline in load forecast does not affect the order of the resources, only the timing. It is not clear from DECo's documentation whether the ordering is constrained. If it is constrained, then it is likely that DECo understated the cost of the lower cost restarts.

add capacity in 1994.[47] However, even without the need for new generating capacity, DM can produce capacity benefits. In particular, DM can produce cost savings by permitting the deactivation of the Marysville HP unit. The fixed O&M costs, which DM can avoid, amount to $28.41/kW-yr (in 1992 dollars) (1992 IRP, p. 32). While DECo ignored this capacity benefit in its valuation of DSM, in the IRP's risk analysis, DECo considered the return of Marysville to economy reserve to be a possible response to reduced load (1992 IRP, p. 56).

Second, reduced sales and peak load may allow for increased off-system sales of energy and capacity. Assuming that reactivation of Marysville was prudent, its cost must be less than the market value of capacity.

Q: More generally, how should the possibility of off-system sales be taken into account?

A: Avoided capacity cost is the higher of the opportunity cost of foregone capacity sales and avoided unit restarts.

Q: Is there likely to be a market for DECo's surplus capacity?

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[47]The 1995 capacity addition is the Trenton Channel project. In the screening of DSM, DECo appropriately has treated this resource as deferrable. However, Mr. Andres asserts, without adequate support, that the Trenton Mills project is committed. Avoided costs can be understated by assuming that near term resources are committed and the avoidable resources are more remote in time. In estimating avoided cost, resource additions should be treated as avoidable unless DECo has no control over the remaining costs.

A: Yes. DECo is interconnected with utilities that do need capacity. Nearby utilities in the ECAR and MAIN reliability councils plan capacity additions in the next 10 years. Exhibit I-____(PLC-8) provides a summary of their supply plans.

Q: Are there other problems with DECo's general approach to estimating avoided production capacity cost?

A: Yes. DECo's DM strategy to increase load factor by promoting off-peak sales (Welch Direct, p. 10, Tr. 1572) is based on a fundamental misconception about the factors that drive system capacity needs. In particular, DECo incorrectly believes that the promotion of sales off the system peak increases utilization of existing facilities without creating any additional capacity costs.

Q: How does energy use affect capacity costs?

A: Sales in hours other than system peak increase capacity costs in four ways. First, these increased loads can contribute to capacity need, which is determined by high loads throughout the year. Even loads outside the daily peak hour can increase loss-of-load probability, and hence the reserve requirement. Second, broader peaks and high off-peak loads reduce the capacity benefits of pumped hydro, since the same amount of water will produce less capacity over a longer high-load period and high off-peak loads may limit pumping. Third, increased loads outside the peak season limit opportunities for maintenance, thereby increasing reserve requirements. Fourth, off-peak loads can necessitate tomorrow's baseload additions, as off-peak energy use surpasses the capability of current baseload capacity. Sales that do not change the total amount of generating capacity needed may increase the fraction of future capacity that is expensive baseload generation.

The cost of operating today's coal plants does not represent the total long-term cost of serving increased sales. Such costs include the extra capital costs of new baseload facilities, the effects of increased load factor on reserve requirements, changes in transmission and distribution investments (due to higher local peaks and higher load factors), and costs associated with mitigating the environmental damage from burning coal.

2. T&D Capacity Cost

Q: Has DECo included any T&D costs in its DM screening analysis?

Q: In DSManager, DECo included avoided transmission costs of $26-$27/kW-yr (in 1994 dollars), but omitted distribution costs. In LMSTM, DECo excluded both transmission and distribution costs.[48]

[48]The Company's testimony on this point is contradictory. Dr. Chamberlin has testified that DECo did include avoided T&D costs (Tr. 1453), while Mr. Welch testifies that it did not (Tr. 1603). In a telephone communication on February 2, 1993, John Locher of Detroit Edison confirmed that the DSManager screening included avoided transmission costs, but not distribution costs, and the LMSTM analysis excluded T&D entirely.

Q: Does DECo provide adequate justification for neglecting T&D costs?

A: No. In fact, DECo expects that DM will have some T&D capacity benefits (DECo Discovery Response AG 3.101/498). Dr. Chamberlin also clearly states that DM should be credited with avoided transmission capacity costs (Chamberlin Direct, p. 7, Tr. 1349).

However, DECo claims it cannot estimate these avoided costs without further experience in pilot and full-scale DM programs. DECo's current DM activities, which focus on load management, will not provide useful experience. DECo's load control programs are targeted at reducing system peak demand, not peak demands on the T&D system, and therefore will not have much affect on T&D capacity needs (DECo Discovery Response AG 3.101/498).

DECo's rationale poses another Catch-22 situation. Many cost-effective conservation options may fail screening because DECo has ignored a significant portion of their benefits. As a result, DECo will never gain the experience it claims to need to assess DM properly, and as a result is unlikely to implement an aggressive DM program.

Q: Did DECo make a reasonable attempt to estimate T&D capacity benefits?

A: No. Mr. Welch claims that the effects of DM on T&D were evaluated, but DM was not found to have any T&D capacity value "at this time" (Tr. 1603). According to Mr. Welch, transmission and distribution is avoidable only if new load centers develop. In the near term, given the current low load growth, Mr. Welch asserts that DM will not avoid T&D investment, but merely result in excess capacity:

> ...you build facilities to serve a geographical location. You have load centers develop and so you build a network to go in there. The only time that you could ever create a savings in transmission and distribution is if you were going to do it new.
>
> In other words, it's true that you could free up some possible capacity in an area, but if that's an area that has saturated and isn't experiencing load growth, there is no savings, you've just idled capacity in that case. So that in the time frame we're looking at, you know, we could not find any true savings or identify it.

(Tr. 1603)

Mr. Welch's evaluation of avoided T&D capacity is deficient for at least three reasons. First, it is based on a faulty understanding of how the T&D system is actually designed. Second, Mr. Welch overstates the influence of the current low system load growth on avoided T&D. Third, Mr. Welch appears to be looking at the wrong time frame, basing judgments about long-term avoided costs on a short-term decline in system load. According to DECo's most recent load forecast (Detroit Edison's 1992-2007 Economic and Load Forecast Report, Table A-1), system peak will exceed the historic maximum by 1995.

Q: Why should transmission capacity be treated as avoidable?

A: Transmission is a bulk service, driven by demand growth. For almost all utilities, virtually all new transmission investment is related either to load or to interconnection of generation. The lower the load and the lower the need for new generation capacity, the lower the need for transmission from generation sources. DM can also help extend the life of existing equipment by reducing the frequency and magnitude of overloads.

Q: Is your view consistent with DECo transmission planning?

A: Yes. According to the testimony of Mr. Roberts, DECo projects transmission expenditures based on peak load growth.

Q: What do you expect DECo's avoided transmission costs to be?

A: Mr. Roberts reports that DECo projects annual transmission and sub-transmission expenditures to be about $240/kW for 1992-1998 (Direct Testimony, p. 27-28 and Exh. A-17, F3-3, p. 1).[49]

Q: Does low or declining load growth necessarily mean that there are no avoided distribution costs?

A: No. Mr. Welch's discussion of avoided T&D costs suggests that DECo has designed the system for an expected load growth that is much higher than what it actually experienced. If this were so, it would be likely that for

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[49] A lower load forecast would not necessarily change this average expenditure per kW. It is not known, for example, whether the planned transmission projects will be at all affected by the closing of the General Motors plant.

significant parts of the service territory, avoided T&D costs would be low. When a system is overbuilt, there are fewer replacements and additions that can be avoided through DSM.

However, a decline in system demand does not by itself mean that the demand has fallen in every area of the service territory or that the distribution system is overbuilt everywhere. There may be areas of growth, such as suburbs and commercial districts, along with areas of stagnation, such as certain industrial centers.

If avoided distribution costs vary significantly by location, the solution is not to ignore distribution costs entirely, but to develop different avoided costs for different areas or classes.

Q: Can areas with stagnant or declining load growth still have avoidable T&D costs?

A: Yes. First, T&D expenditures may be required to catch up with past load growth. Second, current and expected load determines the sizing of equipment replacing older equipment that wears out with age. Third, existing distribution equipment wears out faster if more heavily loaded.

Q: How is DECo's omission of avoided T&D costs inconsistent with the Company's actual system planning?

A: It is clear from DECo's own assessment of its T&D investment needs in the following categories, that it expects significant expenditures that are largely load-related and avoidable (Roberts Direct and Exh. A-17):

- New business line extensions;
- System Strengthening investments, including
  - Distribution reliability projects;
  - Investments for equipment relocation, reliability upgrades, and other continuing costs; and
  - Other load-related investments.[50]

Q: Please explain how these expenditures are avoidable.

A: A portion of new business line extensions is avoidable. The 130 loads of new customers and their neighbors affects the sizing and number of distribution circuits and transformers. Therefore, some of the investment added to serve "new business" can be avoided by reducing those loads.

Mr. Roberts states that load growth is the driving factor underlying the "System Strengthening" investments (Direct, 23-27).

Mr. Roberts distinguishes "reliability projects" as expenditures intended to reduce outages, not to serve load growth. These reliability projects are nonetheless load-related and avoidable. In fact, a large portion of these 131 projects are directly load-related. Because of load growth and increasing customer density, DECo's 13.2 kV distribution system, in particular, has experienced an increasing frequency and duration of customer interruptions.

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[50]According to Mr. Roberts, these load-related investments constitute a major portion of the System Strengthening projects (Direct, 23-27).

Additional feeders are needed because DECo must limit the load and customers per distribution circuit to maintain reliability (Roberts Direct, 12-14). These expenditures are therefore directly load-related.

Investments for equipment relocation, reliability upgrades, miscellaneous investments to improve operating conditions, and other continuing costs should be included in the analysis, since increased installations today will result in more of these continuing costs in the future. These continuing costs might be treated as capital additions or capitalized O&M, expressed in $/kW-year of total installed distribution capacity.[51]

Q: By ignoring avoided T&D capacity costs, how much could DECo be understating avoided costs?

A: The marginal demand-related costs of transmission and distribution capacity can be quite high; when considered together, they often exceed avoided generating capacity costs per kw of load reduction. Reductions in customer loads will tend to reduce loading on the company's transmission, sub-transmission, primary distribution, and secondary distribution circuits. Such reduced loading will translate into cost savings, since DECo will be able to postpone or avoid investments to expand or upgrade existing

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[51] Treating these costs as being related to current load growth is often much easier than segregating them, and should produce roughly the same total cost.

or planned transmission and distribution circuitry. Reduced loading can also enable DECo to install smaller, less expensive equipment to serve new loads.

Utility estimates for the value of avoided transmission and sub-transmission capacity costs per coincident peak kW fall in the range of $20-30/kW-yr. Utilities that include all load-related distribution costs (e.g., substations, feeders, laterals, transformers, and secondary lines) as being avoidable find that the costs range from $50-$150/kW-yr.[52] Exhibit I-____(PLC-9) provides a survey of the avoided T&D cost estimates of several utilities.

3. Losses

Q: What loss factors has DECo used in its avoided cost analysis?

A: According to the LMSTM input sheets, DECo assumes loss factors of 8.5% for residential and small manufacturing/non-manufacturing and 4% for large manufacturing/non-manufacturing customers (Exh. A-14, Sch. WP2).

Q: Are these values appropriate for screening DSM?

A: No. DECo's approach understate avoided costs for the following reasons:

- DECo incorrectly applies average line losses, rather than marginal losses;
- DECo's analysis fails to recognize that marginal losses vary between and within rating periods, as load level varies; and

[52]These are real-levelized 1991$ costs stated at the generation voltage level.

- In applying a lower 4% loss factor to reductions due to large manufacturing/non-manufacturing programs, the analysis ignores avoided losses on the customer side of the meter.

Q: How do losses vary with load level?

A: Variable losses as a percentage of load or of generation increase roughly linearly with load, as explained in Exhibit I-____(PLC-10), and hence by time period. Marginal losses (the losses on the marginal kWh delivered) are roughly twice as large as average losses at any given load level.

Q: Why are marginal losses the appropriate loss factors for purposes of DM screening?

A: Average losses are the total line losses incurred during a rating period, divided by the total energy sold. This measure is the loss factor commonly reported in aggregate energy sales tabulations. Marginal losses, on the other hand, equal the difference between total losses at a higher, pre-DM load level, and total losses at a lower, post-DM level. What is important for valuing DM savings is that percentage losses tend to increase linearly with load level. Thus, marginal losses will always exceed average losses at any given load level.

Q: How do marginal losses at any hour compare with average losses in that hour?

A: As explained in Exhibit I-____(PLC-10), total variable losses are proportional to the square of load. As load increases, the average losses (losses divided by load) rise linearly. Marginal losses (the derivative of losses with respect to load) also increase linearly, and are approximately twice average variable losses.

Q: Why is it appropriate to include losses on the customer side of the meter?

A: Most utilities include distribution losses to secondary for residential customers, and for non-residential customers served at secondary. However, they typically include only losses to primary for customers served at primary. This treatment understates losses. Virtually all power is used at secondary levels, regardless of the voltage at the meter.

The laws of physics do not change at the meter. Energy is lost as heat as current flows through transformers and secondary distribution, regardless of whether those are owned by the utility or by the customer and where the delivered power is metered. Utilities should include losses in all line transformers and secondary lines, regardless of ownership or metering arrangements. Indeed, utilities should include line losses within the building wiring.

Omitting losses on the customer side of the meter is inconsistent with the TRC test, as it ignores costs incurred by customers.

4. Environmental Compliance Costs

Q: Does DECo include environmental compliance costs in its IRP?

A: DECo selects its optimum resource plan by calculating the plan which results in the "lowest average study period rate," defined as cumulative net present worth of the yearly revenue requirements divided by cumulative net present value of the yearly total sales (IRP, p. 4). In this calculation, DECo includes the costs of purchasing SO_2 allowances and installing low-NO_ω burners on its facilities, which are direct costs of compliance to the acid rain provisions of the CAAA. No consideration is made of the differing environmental attributes of competing plans or individual resource options.

Q: To what extent can DSM reduce DECo's air emissions?

A: In Exhibit I-____(PLC-11), I calculate the marginal emissions of CO_2, SO_2, and NO_x, based on DECO's modelling of total system air emissions. These rates are based on the reduction in emissions that would result under the "2.5% DSM Case 2" rather than the "Base Case 1% DSM." Annual reductions of each emission were divided by annual reductions of sales to determine emission rates in each year. Averaging the annual emission rates of CO_2 and NO_x over the entire planning period (1994-2006) yielded average rates of 2,146 lbs/MWh and 4.3 lbs/MWh, respectively. After 1999, DECO's modelling reflects adjustments in the sulfur content of the Monroe units' coal, making the difference between the two cases' sulfur emissions inconsequential in those years. So, I have based the average avoidable SO_2 emissions rate (11.6 lbs/MWh) on 1994-1999 data only.

Q: What are DECo's SO_2 allowance costs?

A: DECo will be required, under the CAAA, to hold emissions allowances for every ton of SO_2 it emits. DECo estimates that it will have emissions of 251,000 tons (base emissions) in the year 2,000, and will receive 238,000 allowances in 2000-2009, and 222,000 thereafter. Therefore, DECo will have to reduce its emissions or purchase 13,000 allowances in 2000-2009 and 29,000 allowances thereafter. If DECo chose to reduce emissions on its own system, the first 15,000 tons could be eliminated at a cost of $550/ton and the remaining amount for $900/ton in the year 2000 or $900/ton and $1,250/ton in the year 2006. These cost estimates are based on switching to low-sulfur coal at St. Clair 6&7 and Monroe 1-4. ICF Resources estimates allowances to cost less than fuel switching, about $400/ton in the year 2000 and $850/ton in the year 2006.[53] Therefore, DECo plans to purchase allowances rather than blending fuel to comply with Title IV. Every additional ton of SO_2 that DECo plants emit annually will force DECo to buy one more allowance, or sell one less allowance should it ever be in the position of holding excess allowances.

Q: What are the potential additional direct costs to DECo of emissions of NO_x?

[53] Specifically, DECo states that ICF estimates allowance costs of $391/ton in the year 2000 (IRP, 42 and Appendix A). It is not clear in what year's dollars these figures are expressed.

A: DECo is required to install low-NO_{ω} burners on its fossil facilities under Title IV of the CAAA, and it may be subject to additional costly controls, depending on the NO_{ω} reductions required by the State Implementation Plan (SIP) to comply with Title I of the CAAA. Detroit-Ann Arbor and Grand Rapids are moderate non-attainment areas for ozone under Title I. The NO_{ω} reduction requirements will depend on the results of the airshed modelling the State is undertaking to determine the relative effectiveness of NO_{ω} and Volatile Organic Compounds (VOC) emissions to reducing ozone levels in the Detroit area. DECo claims that the Detroit area has a VOC/NO_{ω} ratio less than 10 and therefore will not be subject to additional NO_{ω} controls. This is not necessarily the case, as illustrated for example by the significant NO_{ω} controls required in Northeast cities such as Boston and Philadelphia (NESCAUM, 1992), both of which have VOC/NO_{ω} ratios of less than 10 (National Research Council, 1991).

The results of the airshed modelling will affect both the Best Available Control Technology (BACT) requirements for new facilities and the Reasonably Achievable Control Technology (RACT) requirements for retrofitting existing facilities. If Selective Catalytic Reduction (SCR) is required to reduce emissions from new turbines to 9 ppm, the incremental cost would be on the order of \$3,000-\$10,000/ton NO_{ω} (Cleaver-Brooks, 1992). For a new fluidized bed unit at

Michigan State University, Selective Non-Catalytic Reduction (SNCR) was required to lower emissions to 0.16 lbs/MMBtu at a marginal cost estimated to be $3,610 per ton. For retrofits, typical RACT requirements include measures costing up to $2,000/ton, or more depending on the jurisdiction. Exhibit I-____(PLC-12) shows average costs for RACT NO_x measures required by the Texas Air Control Board, which exceed $2,000/ton for utility boilers and $5,000/ton for industrial boilers. Although Michigan's <u>average</u> RACT costs may be lower than those of Texas, because of its higher air quality, <u>marginal</u> RACT costs in Michigan are likely to be in the same range as average Texas costs.

Q: What are the potential additional direct costs to DECo of emissions of particulates and toxics?

A: DECo may be subject to additional controls of particulates and airborne toxics under Title III of the CAAA. This title addresses control of emissions of 189 toxic pollutants from stationary sources, several of which are emitted by coal combustion.[54] Utilities are not immediately covered by the provisions of this title, but, as DECo admits in its IRP (pp. 16-17), utilities may be subject to future controls, particularly as they contribute to degradation of the Great Lakes' water quality and the accumulation of mercury. DECo anticipates that no emissions reductions will be required

[54]Pollutants emitted by coal combustion include chlorine, mercury, and other heavy metals.

under this title since DECo already achieves greater than 99% reduction in particulate emissions with electrostatic precipitators (ESPs) (IRP, p. 17). Additional reductions may indeed be required, since the very smallest particulates, which escape the particulate controls, are usually the most hazardous. Control equipment exists to achieve even levels of control on the order of 99.9% and higher.[55] In addition, while emissions of some toxics can be reduced through the use of high efficiency particulate control, other toxics cannot. In particular for coal plants, gaseous mercury and chlorine are not well controlled by particulate controls, and must be addressed through more expensive flue gas treatment measures.

Q: What are the potential additional direct costs to DECo of emissions of CO_2?

A: DECo may be subject to carbon taxes, now being discussed at the federal level. Estimates of this tax range up to $30/ton carbon. DECo may also be subject to CO_2 caps or reduction requirements.

Q: Has DECo included allowance costs, potential future costs of compliance with Titles I and III of the CAAA, or carbon taxes or limits in its DM screening analysis$?

A: No. According to Mr. Welch (Tr. 1823), DECo has not even incorporated allowance costs in screening DM. Neither does

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[55] ESPs are usually replaced with fabric filters at this level of control.

it appear to have included potential future control costs or taxes.

Q: How would including allowance costs, potential future costs of compliance to Titles I and III of the CAAA, and carbon taxes affect DECo's avoided cost?

A: Including these costs would serve to increase DECo's avoided cost, increasing the amount of cost-effective DM. The amount by which these costs would increase DECo's avoided cost depends on the resources avoided by additional DM. Assuming SO_2 allowance costs of $400/ton, and a carbon tax of $30/ton carbon, the additional cost would be about 1 cent/kWh.[56]

5. Externalities

Q: Please define "external costs."

A: External costs include monetary and non-monetary costs imposed on human health, the quality of life, and the health of other species and ecosystems. Monetary costs include health-care costs and economic damages to crops, forests, fisheries, tourism, and materials; non-monetary costs include pain and suffering, the aesthetic cost of visibility reduction, lost recreation benefits, and the existence value of species and ecosystems. Other social and economic externalities include changes in employment, social cohesion, the balance of trade, national security, and

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[56]Assuming marginal emissions of approximately 1 T/MWh CO_2 and 12 lbs/MWh SO_2, as calculated in Exhibit I-____(PLC-11).

depletion of finite resources.

For the purposes of utility resource planning, externalities include any social cost that is not included in the direct costs used in comparing utility resource options.[57] Hence, the net social cost of a resource equals the sum of its costs — external and internal. This definition of externalities is slightly different from the classic textbook definition, in which an externality is any cost not borne by the actor who imposes it. In utility planning based on total social costs, it is irrelevant that a cost is eventually borne by the utility if that cost is not properly accounted for in resource planning.

Q: Would the public interest be served by DECo including externalities in its IRP?

A: Yes. Significant benefits to ratepayers and the State as a whole are lost by the failure to properly reflect all costs -- external as well as internal -- in resource planning.

Utility resource decisions that involve trade-offs between direct costs and non-price factors include selection of new resources, fuel choice, and power-plant dispatching. Traditionally, these decisions include some non-price

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[57]Unless otherwise stated, the term "externalities" is used throughout this testimony to describe both costs and benefits. For convenience, externalities are often referred to as "external costs;" in this context, benefits can be considered negative costs. For simplicity, the discussion frequently equates externalities with environmental effects; references to "dirty" and "clean" resources can be generalized to "externally unfavorable" and "externally favorable" resources.

factors, such as fuel diversity and system reliability, but have been blind to others, such as environmental costs. The practice of valuing externalities is a relatively new tool for regulators to fulfill their traditional role of minimizing ratepayer costs while considering such non-price factors as reliability and social costs. Valuation tools allow regulators to include external costs in utility decisions systematically.

In new-resource selection, valuing externalities allows utilities to select resources with the least total social costs, by finding the external costs associated with competing resources and adding those costs to the resources' direct costs. Decisions that are informed by these external costs are better than those that are not, even if they cause some individual customers to experience greater costs in the short term.[58]

Similarly, external costs could be used to make decisions regarding power plant dispatch (by selecting resources in the order of least social cost), fuel choices (by comparing the least-polluting fuel's cost with its external benefits), and pollution control (by determining the cost-effectiveness of pollution-control equipment or other mitigation measures). Such measures are often effective ways of reducing the overall social costs of

[58]Sound program and rate design can ensure that the costs of any decisions are shared equitably.

generating electricity.

Whether the utility uses explicit externality values to select options, or selects resources that imply externality values, the end result is a set of resources and a set of externality values. However, development of explicit externality values results in consistent treatment of externalities when implicit valuation does so only by coincidence. The elimination of a pound of SO_2 emissions through additional conservation is as valuable as the elimination of a pound through the use of scrubbers, lower-sulfur fuel, or any other means. Minimizing the social costs of energy resources can only be achieved using a consistent set of externality values for all resources and all decisions.[59]

Explicit valuation also provides signals to utilities and others that encourage innovation and reduction in total energy-resource costs. Dollar values for externalities inform interested parties (vendors, contractors, developers, utility staffs) of the desired trade-off between direct costs and externalities, allowing for focussed efforts to

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[59]Consistent values are not always identical values, since the externality effects of different resources may differ. An externality that is globally important, such as CO_2, has the same value, regardless of the source of the emissions. Externalities which are regionally important, such as emissions of SO_2 and NO_ω, or thermal pollution from cooling water use in the Great Lakes, should be valued similarly within the region of concern, regardless of the source. On the other hand, local externalities, such as emissions of carbon monoxide or fisheries effects of hydro-electric facilities, may vary dramatically with small changes in location.

develop more desirable resources. Less quantitative methods of reflecting externalities cannot provide as clear a signal to promote desirable innovations.

Q: How would including externalities affect DECo's avoided cost?

A: Including externalities would increase DECo's avoided cost, which would in turn increase the amount of cost-effective DSM. The amount by which externalities would increase DECo's avoided cost depends on the resources avoided by additional DSM, their environmental effects and the value to Michigan of avoiding those effects.

Q: Please estimate the NO_ω externality.

A: The regulatory-cost-of-control approach (also called "implied valuation") uses existing data on the costs and efficiencies of control measures, required through federal and state regulations, to determine the incremental external costs of utility resource options. If it is worth one dollar per ton to avoid emissions at the margin through a control measure, it is worth one dollar per ton to avoid those emissions through any pollution-reducing method, including opting for cleaner resources. This is particularly true where the region is required to comply with a pollution cap, such as the CAAA limit on ozone. Any additional emissions must be offset by additional controls, at marginal cost. The approach values each effect in appropriate units (such as $/lb emitted or $/gal water consumed) based on the costs of control measures required under current or anticipated regulations.

In Michigan, new pollution control requirements are principally governed by CAAA requirements, as discussed above. From federal cost estimates of these requirements as they apply to Michigan, and thus externality values, incremental costs of reducing emissions can be determined. Based on the control requirements discussed above, a NO_x externality on the order of $2,000/ton would not be unreasonable for Michigan, and may be significantly understated.

Q: Please estimate the CO_2 externality.

A: A CO_2 value of $22/T was adopted by the Massachusetts DPU and Nevada PSC, based on my analysis for the original Massachusetts proceeding on externalities (Docket 89-239, August, 1990). It is roughly consistent with the value of $10/T used by the National Research Council (1991) as a definition of "low-cost" CO_2 reduction measures. In utility terms, the NAS value would be about $17/T.[60]

In order to keep the rate of climate change close to that experienced in the geological record, it appears to be necessary for the developed countries to reduce CO_2 emissions by roughly 20% from 1990 levels by 2005 or 2010,

[60] The NAS value is for costs computed at a 6% real discount rate without taxes, which would imply a 7% carrying charge for long-lived measures; typical real carrying charges for investor-owned utilities are on the order of 12%.

and by 80% by 2030. With 2% base case growth in carbon emissions, this would require reductions of 45% from the base case by 2010; even stabilizing emissions at 1990 levels would require an 18% reduction from the base case by 2000 and a 33% reduction by 2010. As shown in Exhibit PLC-13, the estimates of the marginal cost of control to achieve significant reductions in emissions are estimated to range from $23/T to $261/T, depending on the geographical area, time period, and sectors covered, as well as the assumptions and methodology used.

A great deal of optimism is necessary to conclude that global warming can be controlled for $22/T. Improvements in energy efficiency technology, widespread utility sponsorship of aggressive DM programs, and breakthroughs in the cost of renewable energy might bring the cost of control this low. A less optimistic view would put the cost of control in the $50-$100/T range.

Q: How would these values affect avoided costs?

A: Looking only at air emissions of NO_x and CO_2, the environmental costs might be on the order of 1-3 cents/kWh, depending on the avoided unit. Including other air emissions such as mercury, and water and land impacts would further increase the avoided cost.

Q: If the Commission determined that the effects of increased atmospheric CO_2 were as likely to be beneficial as damaging, should the Commission use a zero value for CO_2?

A: No. The uncertainty in the effects argues for avoidance of global warming. Increasing CO_2 levels would amount to a massive experiment with the entire world, with effects that may be disastrous and irreversible; correspondingly large benefits are unlikely.

Q: **What other states use this method for determining externality values?**

A: In the late 1980s, Wisconsin became the first state to require utilities to consider externalities in their new resource selection. Since then, about one-third of U.S. states have also made regulatory or legislative commitments to including externalities in utility planning. The method by which utilities must include externalities varies from state to state.

The public utility commissions of California, Massachusetts, Nevada, New York, New Jersey, and Wisconsin require their utilities to assign specific dollar values to externalities; this practice is known as "monetizing" externalities. Of these six states, all but New Jersey estimate externality values based on the costs of regulations.[61] The Bonneville Power Administration also monetizes externalities with damage costs.

Arizona, Colorado, Connecticut, Hawaii, Illinois, Iowa, and South Carolina only require qualitative consideration of

[61]New Jersey uses the damage cost method.

environmental costs.

The state of Vermont imposes an externality adder on avoided costs, for comparing DM costs to the avoided costs of supply.[62]

6. Risk Mitigation

Q: Does DECo reflect the risk-mitigating advantages of DM in its avoided cost estimates?

A: No. Such advantages are not considered. DECo should do an analysis of the risk mitigating advantages of DSM, similar to that of the NPPC.

VIII. COST RECOVERY AND SHAREHOLDER INCENTIVES

A. Introduction to DM Cost Recovery and Incentives

Q: What should be the Commission's objective in establishing systems to recover DM costs and provide incentives to shareholders?

A: The Commission should act to reduce or remove institutional and ratemaking barriers to cost-effective DM. The utility's least-cost resource plan (one which will include a large amount of DM) should be the most rewarding resource plan.

Appropriate DM activity should receive the easiest and most rewarding regulatory treatment of any resource acquisition option. Conversely, resource plans that do not fully utilize DM should be more difficult and less rewarding

[62]Vermont is currently revising its externality policy.

for the utility and its shareholders.

Q: Why should the Commission even consider changes in normal cost-recovery mechanisms for DM?

A: If DM were just like any other utility activity, with costs just like other utility costs, a special mechanism would be unnecessary. Hence, in considering the form of DM cost recovery, the Commission should first consider the features of DM that justify special treatment.

Under traditional ratemaking, utility interest in maximizing customer efficiency is diminished by disincentives for the utility that are absent or minimal for other activities. Disincentives include problems with cost recovery timing and the creation of lost revenues. In addition, reducing sales opposes a number of long-standing utility traditions and must overcome considerable institutional inertia and resistance. Institutional inertia results from most utilities' lack of a strong interest for energy conservation and the apparent inconsistency between end-use efficiency and traditional utility goals: selling more kWhs, building more plants, and (where consistent with other objectives) lowering rates.

Q: What characteristics of DM should the Commission bear in mind in establishing cost recovery procedures?

A: In addition to the disincentives embedded in traditional cost-recovery practice and the institutional barriers within the utility, the Commission should bear in mind four considerations.

First, if the Commission intends to provide ratepayers with reliable energy services at the lowest possible cost, DM is not an optional activity,[63] but an aspect of resource planning and acquisition as fundamental as fuel procurement or construction management. DM cost recovery should be based on a preference for <u>maximum</u> development of cost-effective DM.

Second, the potential for DM is very large, as discussed in Section III above. The Commission should establish cost recovery mechanisms and procedures that will be capable of handling programs of the magnitude underway in other jurisdictions.

Third, the current regulatory system is generally structured to encourage utilities to minimize expenditures. Utilities that allow costs to rise are generally not compensated for the time lag between expenditure and recovery. The same limitations work in the wrong direction for DM, discouraging utilities from incurring additional DM costs by pursuing additional DM beyond projected or pre-approved levels. While ratepayers are rarely better off paying more than expected for other cost components, they are often better off paying for more DM than previously

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[63]Many utilities approach DSM as if they were art collectors, selecting a few intriguing paintings to hang on the walls and waiting for internal and external reactions before selecting further items.

expected.

Fourth, most DM aspects that justify special ratemaking treatment will likely be temporary. In the longer term, DM will be embedded in corporate culture, regulatory practice, historical rates, and customer expectations. DM ratemaking can gradually converge with treatment of other costs and activities.

Q: How should DM cost recovery be structured?

A: ~~As discussed in Exhibit I ____ (PLC-14),~~ There is no one right answer to this question. The most appropriate form of cost recovery depends in part upon factors that are uniform (or nearly so) for all utilities in the state, including the Commission's regulatory powers and the resources of the Commission, its Staff, the Attorney General (AG), and other parties. Other important considerations vary between utilities, including financial condition, frequency of rate cases, and familiarity with DM. Cost recovery techniques that may be suitable to DM include forecasting of costs in rate cases, deferral of costs between rate cases, and interim rate adjustment mechanisms. Different cost-recovery mechanisms may be appropriate for different utilities.

For the purpose of exposition in this testimony, I assume the Commission will establish a surcharge mechanism for DECo to periodically recover at least some of its DM-related costs. I refer to that mechanism as an Energy Efficiency Surcharge (EES). Most of my comments would not be changed significantly if the EES were replaced by an energy efficiency deferral mechanism that accumulated DM costs above those already included in rates.

Q: For which types of DM programs should the Commission allow special cost recovery procedures, such as some form of EES?

A: Special cost recovery procedures should be extended only to energy efficiency programs. Utilities have generally required no special cost recovery for promotional, load management, and rate design programs on the demand side, or for supply-side efficiency improvements. Utilities understand and usually advocate these activities.[64] Special cost recovery is certainly unnecessary for promotional or load-building programs, which are designed to increase the penetration of electric technologies.[65] These promotional programs already reward utilities with increased sales and profits. The Commission need not be concerned with

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[64]I do not mean to imply that all utilities are engaged in optimal amounts of load management and supply-side efficiency. If the Commission identifies opportunities to improve utility performance in these areas, it should be able to encourage utilities to take appropriate actions without any special cost recovery mechanisms.

[65]Examples include discounts to builders for installing electric heat, incentives to residential customers with fossil heating for installing dual-fuel heat pumps, rebates to commercial customers for retaining electric air conditioning instead of switching to gas or steam cooling, payments to large customers for deferring cogeneration projects, and encouragement of industrial customers to replace fossil energy sources with electricity (*e.g.*, in paint drying). Economic development programs, which encourage large customers to locate in the utility's service territory, can also be included in the promotional category.

facilitating activities in which utilities have willingly or enthusiastically engaged for decades.

Exhibit I-____(PLC-14) lists the types of programs that might be included in special mechanisms for cost recovery, lost revenue recovery, and/or incentives. As summarized in that table, I do not believe that programs other than energy efficiency require special ratemaking, with the occasional exception of radical rate design innovations.[66]

Q: How is the remainder of this section organized?

A: Subsections B through E consider in turn the major categories of revenues and expenditures that should be considered in this proceeding: direct DM program costs in Section B, lost revenue recovery in Sections C (decoupling) and D (direct lost-revenue recovery), and explicit incentives in Section E. Section F discusses aspects of the cost recovery mechanism that cut across these three recovery categories. Section G considers the standards and process for regulatory review of all cost recovery.

Each portion of my discussion assumes that all other parts of the cost recovery process will be executed properly. This is particularly true for monitoring and evaluation, which verifies the magnitude of savings and lost revenues and is essential to ensuring that the DM portfolio

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[66]For example, a utility implementing demand metering or real-time pricing for a large number of residential customers may have difficulty accurately estimating the resulting load shape changes and revenue effects.

is prudent. The monitoring and evaluation function is a very important part of the overall DM effort, as discussed in the testimony of MUCC witness Oswald.

This section of my testimony does not discuss recovering DM costs from participants. The design of the program will determine the portion of each measure's costs that can be recovered from participants without reducing the effectiveness of the program. In turn, the charges to participants are part of the program design.

Cost recovery and program design issues overlap in several ways, including participant cost-sharing, determination of prudence, integration of monitoring and evaluation, and limiting rate effects to acceptable levels. The program costs discussed in this section of my testimony include administrative costs, joint program delivery costs, and whatever portion of direct costs is not recovered from participants, without any attempt to determine that portion.

B. Direct Costs

1. Scope of costs to be recovered

Q: What types of costs should be eligible for recovery under the EES?

A: Eligible costs should include at least the costs of DM planning, data acquisition, program design, program supervision, and monitoring and evaluation; incentives paid to customers and trade allies; and such direct costs as delivery contractors, equipment, and installed materials.[67]

However, allowing special cost recovery for corporate staff and allocations of overhead costs, such as for staff office space and desks, can pose serious problems and present opportunities for gaming.

Tracking staff, identifying incremental costs, and determining which functions staff actually performs can be difficult. For example, if marketing staff moves to the DM organization, the Commission may have a hard time determining that the staff now markets conservation rather than sales. The utility also incurs no additional cost, since the increase in DM labor is offset by a decrease in marketing labor.

Similar issues arise for overhead costs. The EES mechanism is intended to capture short-term cost changes; many overhead costs, such as personnel administration and office space costs, vary with program scale in the long term but not necessarily in the short term.

Hence, the utility will often have a greater burden in demonstrating that the in-house costs of DM are really incremental between rate cases than they will for outside

[67]Dr. Chamberlin asserts that "The TRC test assumes that all dollars spent to obtain cost-effective savings are fully recovered by the utility." This statement is incorrect, given the definition of TRC. The TRC test is indifferent to who pays for programs. The TRC test for Boston Edison was the same when it was paying $75 million in shareholder funds for DM as when it was paying for DM with ratepayer funds.

services clearly related to the DM program.

Q: Should cost recovery be limited to expenditure levels previously approved or otherwise under an overall cost cap?

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A: No. DECo should be encouraged to accelerate its DM programs when opportunities arise. For example, some New England utilities found early in 1991 that the recession had resulted in ~~a~~ considerable spare time available from electrical and HVAC contractors. These contractors prepared applications for utility customers to participate in the utilities' retrofit programs for large commercial/industrial customers. As a result, the utilities received in the first few months of 1991 applications for retrofits costing about three times the entire 1991 budget for the programs. The utilities were able to accelerate their retrofit programs, limited only by the utility's management ability, since they had no artificial budget constraints.

Q: How should recovery of direct DM costs be related to program preapproval?

A: The Commission should offer DECo the opportunity for preapproval of the basic design of programs and the overall portfolio of programs. Other regulatory bodies have used these reviews to reject programs that were not cost-effective, to order the expansion of programs, to order the design or acceleration of programs to address particular end-uses or market segments, and otherwise to alter program or portfolio design in advance.

Many details of program implementation may not be finalized at the review. The Commission probably should not preapprove such details of program management as the selection of contractors and the design of marketing brochures. While the Commission should review the overall goals of the programs and the portfolio -- participation rates, annual kWh and kW savings, and expenditure rates -- all parties should expect the actual scope of the programs to vary from the approved targets. As discussed above, opportunities arise to capture greater savings than previously expected; conversely, spending is often lower than projected, especially in the ramp-up phase, when delays in hiring contractors, designing program materials, and other important details can delay implementation.[68]

The utility's implementation decisions made either after or without the Commission's pre-approval should receive a prudence review. Those decisions generally should not be restricted otherwise unless the Commission has a particular reason to expect a particular error by the utility. In general, commissions have more often needed to order utilities to act and spend money, rather than to order

[68]Economic conditions can also reduce spending. For example, a number of New England utilities found in the early 1990s that new construction programs were undersubscribed for lack of new construction.

restraint in the DM field.[69]

Q: Is any spending cap appropriate?

A: No. The Commission should not establish any spending cap, since that would limit DECo's ability to manage its DM program, resulting in lost opportunities.

The Commission might reasonably require DECo to inform and consult with interested parties on major program changes. Regular reports on spending and achievements might also be required. The combination of prior warnings from other parties, the prospect of a retrospective prudence review, and a clear signal from the Commission that the costs of imprudent resource acquisition (either imprudent acquisition of DM or imprudent failure to acquire DM) would not be recoverable, should discourage DECo from frivolous and irresponsible program expansion or contraction.

2. Expensing and amortization

Q: Should the Commission establish a preference for a specific method for accounting for DM expenditures, and if so, should it be amortization or expensing?

A: The Commission should establish a preference for a specific accounting method, which should be amortization. In general, cost recovery for expenditures is tied to the useful lives of those expenditures. Expenses that will

[69] See, for example, Massachusetts DPU 89-260 and 91-44 (Western Massachusetts Electric), DPU 88-67 and 90-55 (Boston Gas), and DPU 87-221A (Cambridge Electric); Vermont PSB 5270 (all jurisdictional utilities); and District of Columbia PSC 9509 (PEPCo).

provide service for up to one year (e.g., the annual salaries of power plant operators) are expensed, while those that provide service for longer periods (e.g., rehabilitation of plants, building new facilities) are capitalized and amortized through the ratebasing mechanism. By this standard, DM expenditures, which provide energy services for many years, should be recovered over many years. Dr. Chamberlin acknowledges that ratebasing of DM would be consistent with traditional ratemaking (Direct, p. 12, Tr. 1354).

Q: Does this reasoning also apply to DM planning and management?

A: Yes. The costs of designing, siting, and managing construction of power plants are capitalized and recovered over the life of the plants, since the expenditures benefit customers in that period. Following this line of reasoning, DM program design would be capitalized.

Q: Should all DM costs be amortized over their useful lives?

A: While general ratemaking considerations would argue for this approach, amortization over the full life of the installed measures is not necessarily the best cost-recovery mechanism. Depending on current and future rates, it may be appropriate to expense DM costs, amortize them over a short period (3-5 years), or amortize them over the full life of the measures (10-20 years).

DECo should consider its forecasts of rates and revenue requirements, and propose a cost recovery pattern that reflects those projections.

Q: Does DECo propose to amortize DM costs?

A: No. DECo "proposes to expense all DM costs in the year they occur" (Welch Direct, p. 21, Tr. 1583). Mr. Welch relies on Dr. Chamberlin for his justification of expensing these long-lived investments (Direct, p. 22, Tr. 1584).

Q: Does Dr. Chamberlin offer a coherent justification for expensing DM?

A: No. Dr. Chamberlin avoids any substantive discussion of amortization by posing it as an alternative to the surcharge mechanism (Direct, p. 12, Tr. 1354). In fact, the amortization could operate through a surcharge, either indefinitely or until the next rate case.

Dr. Chamberlin agrees that amortization of DM costs is consistent with traditional ratemaking and that amortization is "advantageous to spread cost recovery out, particularly if these is a short-term spike in expenditures" (Direct, p. 12, Tr. 1354). The latter point would seem to be very important for DECo, with its professed concern about rates. Nonetheless, Dr. Chamberlin dismisses amortization due to alleged "delays in cost recovery and more significant long-term impacts" (Id.) Despite the importance of this issue, Dr. Chamberlin devotes only two lines of his testimony to the "flaws" of amortization.

Q: Will annual DM expenditures likely be large enough so that expensing could have a significant effect on rates?

A: Yes. For example, Boston Edison's filing for its 1992 programs, in Massachusetts DPU Docket 90-335, expensing its DM portfolio would result in a rate increase of 5.6%, adding 0.54¢/kWh to its average rates.

Q: Is there any inherent difficulty in delaying cost recovery?

A: No. Most utility ratemaking involves delay in cost recovery, through ratebasing, amortization, deferral, and similar mechanisms. The norm is that costs are recovered as benefits are received, not as the costs are incurred.[70]

Q: Is amortization more expensive than expensing, as Dr. Chamberlin suggests?

A: The answer to that question depends on the relationship between customer discount rates and utility finance costs. Delaying cost recovery by one year increases the nominal cost by:

$$1 + ROR + Tax,$$

where:

$$ROR = \text{utility incremental cost of capital},$$

$$Tax = \text{income tax paid to allow payment of equity return}$$

$$= (\%\ \text{equity}) * (\text{equity return}) * \left[\frac{\text{tax rate}}{(1-\text{tax rate})} \right]$$

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[70] Elsewhere in his testimony, Dr. Chamberlin suggests that delayed cost recovery is highly desirable from the perspective of shareholders, since it increases ratebase.

If the customer discount rate exceeds ROR + Tax, the customer will prefer to have the utility capitalize costs; if the discount rate is lower, the customer will prefer to have the utility expense costs. The preference for expensing or capitalization is independent of the cost's origin: deferring a dollar of fuel expense or power plant capital is just as desirable (or undesirable) as deferring a dollar of DM expenditure.

Empirical evidence shows that ratepayers prefer to defer cost recovery. Consumer advocates generally prefer lower depreciation rates, longer amortization, and capitalization over expensing. Utilities generally prefer the opposite.[71]

If expensing were generically preferable to amortization, the Commission would already be expensing DECo's supply-side investments. The Commission does not expense power plants because, among other things, that ratemaking treatment would cause huge rate shocks and limit DECo's ability to recover the costs of cost-effective supply resources. Since expensing power plant construction costs would not be feasible, DECo would avoid building capacity, even where that was in the best interest of customers. Similarly, if the Commission were to insist on expensing DM,

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[71]This phenomenon hints that ratebasing of DSM in itself will not provide much of an incentive for DSM investment, since utilities would rather expense most expenditures.

it could create an artificial ratemaking constraint, potentially resulting in the unnecessary delay of highly cost-effective DM.

Q: Should the EES use a fixed amortization period?

A: No. The Commission should list the concerns DECo should weigh in developing an annual cost-recovery proposal, including matching measure lives and maximizing rate stability. The Commission should instruct DECo to propose cost recovery patterns (e.g., expense, short amortization, long amortization) for each years' costs and explain why that recovery pattern represents the best balancing of relevant considerations.

Q: How should the interest credit for amortization be computed?

A: Without some compelling reason to the contrary, the treatment of capitalized DM costs should resemble the treatment of capitalized supply costs as closely as possible.[72] Hence, the interest credit on the amortized balance should be one of the following:

- If DM costs are financed through general corporate funding and if carrying costs are recovered currently (as is the case for rate-based supply investment), the interest credit should be DECo's overall cost of capital, plus tax adjustment for the equity portion of the cost.

- If DM costs are financed through general corporate funding and if carrying costs are deferred (as is the case for AFUDC on CWIP), the interest credit should be substantially the same as DECo's AFUDC rate, which

[72]This is true regardless of whether the costs are amortized and recovered EES, deferred to the rate case and capitalized, or collected temporarily through the EES until the rate case.

includes significant amounts of short-term debt.

- If DM costs are financed through a DM-specific financing arrangement, such as a bank credit line, the computation of the interest credit should be based on the cost of the special financing.

Q: Should the interest credit be recovered currently or capitalized?

A: If the treatment of the interest credit is to mirror the treatment of in-service supply investments, the interest credit for in-service DM should be recovered on a current basis. However, this issue should be addressed as part of the rate effect analysis.

C. Decoupling Revenues from Sales

Q: What is the relationship between DM and lost revenues?

A: Successful energy efficiency programs result in reduced sales and thus, in lost revenues. Since most of the short-term cost savings are in reduced fuel costs (which flow through the PSCR), the effective lost revenues for the utility are roughly equal to the lost base rates.

All successful energy-efficiency programs result in the loss of revenues, whether they affect existing loads or new loads. A kWh of DM results in the loss of a sale that would otherwise have been made, regardless of whether that sale would have been made to a new or existing building.

In each rate case, the Commission sets rates that DECo can charge until rates change again. Under the current regulatory structure and <u>without</u> DM, DECo receives the additional revenues from continuing and new sales. These additional revenues help offset cost increases from inflation. Under the current regulatory structure and with DM, the utility loses these revenues, while still bearing inflationary costs.

Q: How do lost revenues differ from normal utility costs?

A: It is generally reasonable and appropriate for utilities to attempt to minimize costs. However, it is in the interests of the utility's ratepayers for the utility to maximize lost revenues by maximizing the scope of its DM programs.

Q: For how long is lost-revenue recovery from a DM measure necessary?

A: Lost-revenue recovery is necessary only until the next rate case. In the next rate case, rates will be computed on the basis of sales that reflect the DM-related reduction; no additional revenues will be lost after the effective date of the new rates.

Q: What options are available to eliminate the lost-revenue problem?

A: Two basic approaches have been developed, each of which has numerous potential variants. *Full decoupling* makes the utility's base revenues entirely independent of sales variation, regardless of cause. *Direct recovery* restores the revenues that the utility is estimated to have lost specifically from energy efficiency programs.

1. Full Decoupling

Q: Please explain how full decoupling approaches operate.

A: Traditional ratemaking effectively indexes the utility's revenues to sales growth between rate cases: the utility is allowed to retain a pre-determined sum per MWH sold.[73] Decoupling changes the indexing system, so that revenue between rate cases varies with other factors. The resulting rate adjustment mechanism (RAM) is intended to determine an amount of revenues likely to cover the utility's legitimate expenses, without rewarding it for sales growth.

In the older decoupling systems, such as California's Electric Rate Adjustment Mechanism (ERAM), each rate case projects sales and costs for a future test year. Differences between actual revenues and the projected costs are recovered or refunded in later years. During the three years between rate cases, various limited proceedings update the revenue target for inflation, attrition, and changes in the cost of capital.[74]

More recently, Maine and Washington have started single-utility experiments with indexed adjustment mechanisms. Both of these states increase target revenues with the number of customers, as a substitute for the

[73] David Moskovitz appears to have originated the concept that traditional ratemaking indexes revenues to sales.

[74] The NYPSC has instituted similar mechanisms for several utilities.

inflation and attrition adjustments in the California ERAM system. The Washington RAM also allows the flow-through of a wide range of "resource" costs, including production rate base and fixed O&M.

Q: Does decoupling guarantee utility earnings?

A: No. Earnings are driven by many factors other than revenues: patterns of expenses (e.g., O&M, environmental requirements), depreciation (which may fall in the years following the incorporation of a large power plant), taxes, and interest expenses (which vary with rate base and with interest rates), among other things. Hence, a utility may meet its revenue projections and earn either a higher or lower return on equity than allowed by the Commission.

Q: What are the generic advantages and disadvantages of decoupling?

A: A utility's incentive to increase its sales by: (1) encouraging the selection of electricity as an energy source, (2) promoting extra end-uses and amenities, (3) discouraging efficiency improvements, or (4) attracting development, is reduced by decoupling. This change in incentives is desirable, though not all are seen as positive: the California PUC considered dismantling ERAM because of the perception that the utilities had lost the incentive to resist uneconomic bypass. A utility that was less vulnerable to decreasing sales due to decoupling might be less concerned about high rates and the resulting lost sales. Nonetheless, experience with utilities operating under RAMs indicate that they are no less vigorous than their traditionally-regulated brethren in opposing bypass, courting new load, promoting electric sales, and opposing factors that would raise rates without helping the utilities (e.g., high-cost non-utility purchases).

Decoupling also corrects for all other factors that change sales, including weather and economic conditions. This effect is largely unintended, although generally desirable. For example, a hot summer will raise revenues, which under traditional regulation would be retained by the utility. Under ERAM, some of the extra revenues flow back to the ratepayers in the next year, fairly quickly moderating the financial effect. Unfortunately, in a recession, ERAM operates to increase rates to make up in the utility's revenue shortfall. The midst of a recession is probably a bad time to raise rates.[75]

Finally, some consumer advocates have expressed concern that decoupling utility revenues from weather and economic swings will make utilities more willing to promote sales to weather-sensitive loads and economically volatile industries, since the risks of sales variations will be borne by other ratepayers (Sterzinger, 1991, 1992). This

[75]The deferral of unrecovered costs until the triennial rate case may avoid any short-term burden on ratepayers; if necessary, the deferral can be amortized over time.

strikes me as a fairly academic concern, since most utilities have eagerly sought these loads under traditional regulation, even providing discounted rates to compete with other energy sources and utilities.

Q: **What are the advantages and disadvantages of the traditional ERAM approach?**

A: ERAM allows utilities to recover prudently incurred fixed costs, updated on a regular basis. Since base rates are only adjusted once every three years in the base rate proceedings, the periodic updates can be fairly leisurely.

For California and New York, with a predilection for complex regulation, future test years, mechanisms for tracking a variety of costs, and regularly scheduled rate cases, and regulatory parties with relatively abundant resources, ERAM is a fairly simple and straightforward incremental addition. Elsewhere, moving to ERAM would be a very big step for regulators, utilities, and other parties. Even with a future test year, ERAM requires resetting the target revenue level with either frequent rate cases or frequent proceedings to compute surcharges or deferrals.

Q: **What are the advantages and disadvantages of the indexed RAM approach?**

A: The major advantages and disadvantages of indexed RAM mechanisms are the inverse of those of ERAM. Indexed RAMs are intended to avoid the continuous rate proceedings of the California and New York systems, trading off simplicity against precision. Allowed revenues are adjusted by a simple index, such as customer number,[76] rather than through attrition and inflation proceedings. Annual reviews may be required to update the deferrals, but these would generally be rather simple undertakings.[77]

The disadvantages of the indexed RAM system are mostly related to its simplicity. For example, the Maine PUC apparently overstated Central Maine Power's (CMP's) revenue per customer value by overstating sales in the future test year and using an historic test year for customer number. This overstatement would not have been particularly important in most time periods, since revenue/customer would have risen to meet the overestimated starting point. Unfortunately, Maine established a RAM in 1990, at the beginning of the recession, as revenue/customer was beginning to fall. Hence, the deferrals have been very large, raising the prospect of a major rate increase late in 1993 to compensate CMP for costs it never incurred. To make matters worse, the cost of capital has fallen over the last three years, so CMP is earning much more than it would be

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[76]While Maine and Washington have chosen to use customer number as the index, other indices might be used, including inflation or a predetermined expansion factor (*e.g.*, 2% per annum).

[77]The Washington reviews are complicated by the determination of the non-indexed "resource" costs, which involve such normal rate-case issues as test year timing, prudence, usefulness, and cost recovery method, as well as special problems in the determination of whether a particular cost falls into the "resource" or "base" category.

allowed to earn in a rate case today. Neither of these problems would occur in an ERAM; the periodic adjustment proceedings avoid the need for the revenue/customer constant, and annual cost-of-capital reviews would adjust for changing market conditions. Nor would either problem arise in traditional ratemaking: CMP revenues would fall in the recession, forcing CMP to file a rate case, in which it would be allowed a lower, updated return.

Q: What lessons do you draw from the experience with decoupling in other jurisdictions?

A: Care must be exercised in designing a decoupling mechanism that meets the needs of the particular utility, regulator, and other parties. In particular, the Commission should be alerted by the Maine experience to the need for an index that reasonably tracks costs, and for a mechanism to flag major unanticipated changes in utility costs.

A classic ERAM approach, if it is procedurally viable for the Commission and the parties, is attractive because it is so well-tested in California and to a lesser extent in New York. Indexed RAM systems may work as well or better, if the details can be worked out.

The RAMs in New York, Maine, and Washington have all been worked out through negotiation between the utility, Commission staff, and other parties. Oregon has recently ordered Portland General Electric and Pacific Power and Light to enter "collaborative processes" to develop decoupling mechanisms (Order No. 92-1673, 11/23/92).[78] This negotiated approach appears to be an important aspect of designing a decoupling system that is functional, efficient, and unbiased.

2. Direct Recovery of Lost Revenues

Q: While a decoupling mechanism is under development, what treatment of lost revenues is appropriate?

A: The direct estimation of lost revenues due to efficiency programs would eliminate the disincentive for cost-effective DM. Lost revenues are estimated by rate schedule as the product of kWh saved times the tailblock base rate in ¢/kWh. The same computation is performed for kW savings for classes with demand charges.

Q: What are the advantages and disadvantages of direct estimation, compared to decoupling?

A: Direct estimation only attempts to deal with revenue losses directly due to DM, and does not affect the utility's other incentives to promote sales; this may be thought of as an advantage in some circumstances, but is generally a disadvantage. Direct estimation is more easily grafted onto existing regulatory processes without fundamental changes. On the other hand, estimating lost revenues from DM is inherently much more complex than determining the difference

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[78]This appears to be a settlement negotiation, rather than a utility-funding collaborative analysis in the model of New England, New York, and Maryland.

between allowed and received revenues.

Q: Which measures should be eligible for lost-revenue recovery?

A: All prudent efficiency measures should be eligible. I do not recommend that any other measures be eligible.

Special lost-revenue recovery has not usually been necessary for routine rate design changes; except in extraordinary circumstances, rate design should not be covered by the DM lost-revenue mechanism. Similarly, including load management in the mechanism is probably unnecessary; most utilities have routinely engaged in load management without any lost-revenue adjustment mechanism. Furthermore, load management causes little, if any, revenue loss from residential and other small customers, who are metered with single-period energy-only meters. Many load management programs for larger customers will have little effect on metered customer undiversified peak or on time-of-use energy patterns, and will thus also produce little in the way of lost revenues.

Supply-side efficiency does not create any lost revenues. Promotional programs increase revenues; if these revenue effects are reflected at all, it would be as an offset to the revenue losses from efficiency programs.

Q: Should revenue losses from efficiency programs be reduced to reflect promotional programs?

A: The revenue losses of efficiency programs should at least be reduced by any incidental promotional effect of the efficiency programs themselves. For example, suppose that evaluation determines that the average heat pump installed was 25% more efficient, due to the program, but that 5% more heat pumps were purchased due to the reduced first cost. The net revenue loss would thus be about 21% of base heat-pump consumption.[79] To avoid a perverse incentive for utilities with existing purely promotional programs, the increased revenues from those programs should be subtracted from the efficiency-program lost revenues only if those increased revenues would otherwise have been recaptured for ratepayers.

Q: How should lost revenues be estimated?

A: Lost revenues may be included in rates in at least two ways. First, they may be projected, either in an adjustment mechanism or in a base rate case, and then reconciled to later estimates. Second, they can be estimated only after the fact, based on actual installations and the best available estimates of savings per installation. Even in the latter case, some reconciliation will probably be warranted. Completion of full impact evaluation will often take a couple years; utility nervousness about lost-revenue

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[79]The total consumption is increased 5% for increased penetration, and decreased 25% for efficiency, so the consumption is 1.05 * .75 = 78.75% of the consumption level without the program.

recovery will be mitigated by allowing at least partial recovery prior to the end of the evaluation process.

The kWh and kW inputs to lost revenue estimates should rely on the best data available within a reasonable time frame for the required application. For projections, the best data may include:[80]

- engineering estimates,
- end-use metering,
- time-series bill comparisons, and
- cross-sectional bill comparisons.

Engineering estimates should be adjusted to reflect a number of factors known to produce biases in such estimates, including:

- the difference between "typical" installations modeled in the engineering calculation and the range of actual installations;
- installation quality;
- vacancy rates;
- interactions with other measures (e.g., the energy saved by efficient windows will be reduced if the building's HVAC system has been upgraded); and
- behavioral considerations (e.g., use of thermostats).

Other data sources (end-use, time-series, and cross-sectional) may use experience at other utilities (adjusted

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[80]Note that projections are unnecessary if lost revenues are recovered only retroactively, in which case the techniques listed here may be used for initial post-installation estimates, and for later adjustment and reconciliation of the initial estimates.

for customer size, climate, etc.) or at the particular utility in earlier year.

After program implementation, projected lost revenue recovery should be reconciled through the use of comprehensive monitoring and evaluation (M&E) programs. Reconciliation avoids an over-emphasis on up-front projections.

Q: Does DECo propose that recovery of lost revenues should be based on the best available information?

A: No. DECo urges that estimates of savings, both for lost revenues and for incentives, be based on the speculative estimates of load reductions made before program implementation. Dr. Chamberlin (Direct, pp. 18-20, Tr. 1360-1362; Direct, pp. 29-30, Tr. 1371-1372) clarifies that the initial estimates would be reconciled to the actual number of participants in a program, but not to the number of measures implemented per participant, the size of the participant, or the percentage energy reduction per participant. A tremendous amount of attention in Dr. Chamberlin's direct is focussed on justifying the use of these *ex ante* estimates, which he asserts are preferable because:

- Waiting for more realistic estimates delays collection of lost revenues (p. 12, Tr. 1354).
- Using updated estimates "adds significant risk, as intervenor groups are likely to seek to lower load impact estimates in order to reduce the lost revenue collection surcharge" (p. 12, Tr. 1354).

- The ex ante estimates are the same ones used in "to select a program in the first place" (p. 12, Tr. 1354). Similar points are made on pp. 20 and 33 (Tr. 1362 and 1375).

- Ex ante estimates add certainty. (pp. 20, 32; Tr. 1362, 1374)

- "[T]he ex ante approach . . . [provides a] direct signal [to] utility personnel for aggressive program marketing." (p. 20, Tr. 1362)

- Ex post "determinations can be both time consuming and complex." (p. 20, Tr. 1362)

Dr. Chamberlin does not generally explain why he believes these assertions are true or important. However, his central point appears to be related to the effect of reconciled savings on utility morale and enthusiasm for DM.

> The effectiveness of a DSM incentive is related to the degree to which a utility can be certain of the value of that incentive. Incentives that are based on after-the-fact reviews have far lower potential for motivation than incentives that are predetermined and are free of controversy." (Direct, p. 32, Tr. 1374)

Q: Would ex ante estimates provide the right signals for DECo?

A: No. The ex ante estimates would reward DECo for maximizing participation, while providing no reward, or even penalties, for maximizing measure penetration, the quality of installation, or the identification of the best candidates for DM treatment. Dr. Chamberlin (Direct, p. 31, Tr. 1373) acknowledges that actual savings may be larger or smaller than ex ante estimates; he neglects to mention that DECo can manipulate actual savings to be lower than the ex ante values, and profit from the difference.

Q: Please describe an example of how reliance on pre-implementation estimates of savings in lost-revenue and incentive computations create perverse motivation for DECo.

A: Suppose DEco is assured of receiving compensation for a fixed amount of lost revenues per installation, say 400 kWh. Suppose further that DECo can skew installations toward larger and smaller customers and can affect installation effectiveness. If DECo minimizes the installations' size and effectiveness, it can save just 200 kWh per installation. If lost revenues are worth 5¢/kWh, paying for lost revenues based on the initial estimates would create a windfall of $10 per installation for <u>reducing</u> the benefit of the program.

Similarly, if DECo could increase effectiveness of the program to 500 kWh/installation, it would suffer $5 in net lost revenues installation, with no hope of recovering the difference. Thus, DECo would be rewarded for a worse-than-projected job of delivering DM savings; over-achievement would be punished.

The same is true for intentionally using inaccurate estimates of savings in computing incentives; DECo can earn a larger incentive for providing smaller benefits to customers.

Q: Is Dr. Chamberlin's concern with litigation over ex post savings estimates justified?

A: No. The estimates of savings are generally not particularly

138 contentious issues, particularly where each class is paying for its own programs. An intervenor who succeeded in reducing estimates of past savings would also usually reduce estimates of future savings, and hence make the programs most beneficial to its class less attractive.[81] Successful challenges to an ex post evaluation by a truly independent contractor, especially one controlled by a DM design collaborative, are unlikely.

Q: How should DECo compute lost revenues per kWh?

A: Lost revenues should be based on tailblock energy and demand charges. If a significant percentage of participants has its marginal consumption in a block other than the tailblock for the rate, the lost revenues should be the sum of kWh (or kW) lost in each marginal block times the rate in that block. The same is true for seasonal or time-of-use rates. The billing demand reduction may be very different from the coincident peak reduction. If DECo hopes to recover lost demand revenues, it will need M&E programs capable of producing credible estimates of billing demand reductions.

Lost revenues should be computed net of any quantifiable cost reductions prior to the next rate case, including:

- bad debt,
- average or marginal energy cost reductions,

[81]This equivalence breaks down if DECo is allowed to manipulate savings to maximize its lost-revenue and incentive windfall.

- reduced T&D investments,
- off-system capacity sales, and
- avoided off-system purchases.

Reduced T&D costs are relevant only if the period between rate cases is long. Significant changes in T&D investments will probably not flow through the system in less than three years. The last two items (off-system transactions) should be reflected in the lost-revenue computation only to the extent they are not already captured in the PSCR mechanism.

As noted above, lost revenues should be computed net of any promotional effects of DM programs. Particularly in end-uses for which other fuels are often used (space heating, water heating, cooking, clothes drying, and increasingly commercial cooling), the M&E program will need to determine the extent to which DM programs increase market share.

Q: How should lost revenues be collected and reconciled?

A: Lost revenue collection should usually start as close as practicable to the date at which revenues are lost. The Commission could reasonably require that DECo actually start implementation, and demonstrate a rate on installation, prior to the recovery of any lost revenues. To encourage more aggressive DM activities, DECo could be allowed to collect an estimated level of lost revenues at essentially the same time that the program starts to reduce sales, subject to reconciliation.

Reconciliation should attempt to adjust total lost revenue collection to the revised estimate (from the M&E program) of actual lost revenues. Reconciliation for changing estimates of lost revenues should not continue indefinitely. For each program in each year, the Commission should set a final adjustment date, perhaps 3 to 5 years from the start of the program year, at which the estimate of lost revenues will be finalized. The final adjustment date will depend on the nature of the M&E program, on the schedule on which DECo can report results, and on the speed with which the parties can review them.[82]

D. Incentives

1. Purpose and scope of incentives

Q: What should the Commission attempt to do with DM incentives?

A: The Commission should try to overcome institutional resistance within the utilities, as well as counterbalance any rational residual concern with DM cost recovery. The Commission's objective should be to induce utilities to do things they would not do otherwise, thus reducing total service costs.

Q: Why are incentives necessary?

A: DM investment by utilities tends to be impeded by organizational inertia, vested interests, and risk aversion, long-standing utility traditions, habits, and resistance.

[82]This review process will be facilitated by collaborative control of the M&E program.

Utility management is accustomed to selling more kWhs and building more power plants. Managers understand the activities required by the build-and-sell process; they have chosen to work in utility management to pursue those activities and presumably enjoy them; they are accustomed to defining their success in terms of load growth and plant construction; and they know how success is measured in these activities. They are apt to be less comfortable with the process of planning, financing, managing and measuring success in delivery energy efficiency services. Without some impetus for change, managers are likely to continue with the business they know best.

Q: Does Dr. Chamberlin properly describe the need for DM incentives?

A: No. Since most of the self-interested reasons for utility management opposition to DM are inconsistent with their responsibilities to shareholders and ratepayers, DECo can hardly be expected to put on a witness to discuss those interests. Instead, Dr. Chamberlin advances a series of faulty criticisms of DM, to justify incentives.

First, Dr. Chamberlin suggests that shareholders are harmed when "DSM forecloses the opportunity to earn on the traditional supply-side investments it displaces" (Direct,

p. 10, Tr. 1352).[83] This argument has at least three basic flaws:

- 131 If the Commission is setting return on equity properly, the cost of the additional equity raised to build new supply will exactly equal the return allowed in rates. Existing shareholders earn the same fair return regardless of whether new capacity is added. If Dr. Chamberlin believes that additional investment creates a windfall for shareholders, he is essentially arguing that the Commission has set DECo's return too high, and should lower it.

- Rating agencies generally downrate utilities with large construction programs;[84] the financial community recognizes that building large, long-lead-time generation facilities, in particular, imposes costs on shareholders.[85]

- DECo can earn a return on capitalized DM investments, just as on supply investments. Despite his assertion that increased ratebase benefits shareholders, Dr. Chamberlin opposes the ratebasing of DM. As in other areas, Dr. Chamberlin's testimony on the effects of ratebase is internally inconsistent.

Second, Dr. Chamberlin asserts that "DSM exposes the utility to a variety of technological and economic risks" (Direct, p. 10, Tr. 1352). On page 21 (Tr. 1362), line 24, Dr. Chamberlin clarifies that this statement primarily reflects the subjective reaction of DECo's management. The

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[83]This point is elaborated on p. 21 (Tr. 1363) and repeated on pp. 28 (Tr. 1374) and 32 (Tr. 1370) of his Direct. Considering the number of times Dr. Chamberlin asserts that supply investments offer shareholders windfall profits, it is surprising that he never attempts to document these claims.

[84]While Dr. Chamberlin asserts that "some observers in the financial community may believe that supply growth indicates financial strength" (Direct p. 21, Tr. 1352), the opposite is clearly the case.

[85]The lack of connection between utility sales growth and shareholder returns is discussed in Kihm (1992).

truth is that DM reduces risks to ratepayers and shareholders. Neither Dr. Chamberlin nor DECo has offered any examples of utilities that suffered financially due to "technological and economic risks" of approved DM programs. Of course, such risks on the supply side frequently reduce shareholder income.

Third, Dr. Chamberlin suggests that shareholders bear "regulatory risk" from DM (Direct, p. 22, Tr. 1364). While this is a theoretical possibility, Dr. Chamberlin does not offer any examples of such risks of DM actually affecting shareholders. Regulatory risk has been very important for supply, especially large baseload plants.

Fourth, Dr. Chamberlin suggests that shareholders bear "impact risk" and "market acceptance risk" if DM programs are not as successful as projected (Direct, pp. 22-23, Tr. 1364-1365). It is difficult to see how a prudent utility could be at much risk for these factors; I know of no utility that was penalized for undertaking a good-faith DM program that happened to be less cost-effective or to have less effect than predicted. Monitoring and evaluation will catch these problems early, avoiding excessive investments in ineffective programs.[86] In particular, programs that are not accepted by customers will generate little cost to be disallowed or to trouble the Commission.

[86]Supply options generally do not have similar protections.

Fifth, Dr. Chamberlin suggests that DM raises a "competitive risk" by increasing rates, "driving away incremental customers or sales" (Direct, pp. 23-24, Tr. 1365-1366). This argument misstates the effects of DM on DECo's competitive position. Since bills will be lower with DM, DECo services will be more attractive, not less. A comprehensive new-construction program runs the risk of reducing the cost to builders of heating electrically, and uneconomically increasing the penetration of electric heat.[87] More pleasantly, a comprehensive industrial conservation program will reduce the cost of doing business in DECo's service territory, keeping customers viable and attracting new loads. Targeting early DM treatment to vulnerable facilities, or those that agree to expand employment, can further leverage the DM program to support economic development.[88]

Finally, Dr. Chamberlin posits the existence of "balance sheet risk," which he believes will result from the lower security of DM amortized investments and from the lack of bondable DM property. I would be surprised if DM investments that have been allowed into rates turn out to be

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[87]This problem can be mitigated through good program design; nonetheless, the risk is that DM will increase electric saturations, not the opposite.

[88]These "found" revenues should be netted against lost revenues, if a direct recovery method is used. Since not all found revenues are likely to be identified, the shareholders are likely to receive some windfall from DM-induced sales.

less secure than comparable supply costs, including plants that are prematurely retired, found to be excess (e.g., Greenwood), or operate inefficiently or unreliably. Nor does DECo appear to lack bondable plant to support its financial requirements.

Q: Are special cost recovery and lost revenues equivalent to incentives?

A: No. Recovery of lost revenues only removes an existing disincentive against DM. The same is true to a large extent for facilitated DM cost recovery. However, DM cost recovery that is easier and less risky than supply-side cost recovery can also act as an incentive for DM investment. It may require a few years of experience before utilities really believe DM cost recovery will be relatively easy and painless.

Q: What are the implications of the basic rationale for DM incentives?

A: There are several such implications. First, the Commission should exclude incentives for actions utilities have taken and will continue to take without special encouragement, including load management, rate design, supply-side efficiency investments, and load-building.[89]

[89]Many improvements are likely to be possible in various utilities' rate designs, load-management programs, and supply-side efficiency efforts. If the Commission identifies opportunities to improve utility performance in these areas, it should be able to encourage utilities to take appropriate actions without any special cost recovery mechanisms.

Second, the incentive mechanism should reflect utility performance. It should cover all savings, whether from on-peak or off-peak savings. Incentives should increase if the utility does a better job, that is, if (a) more kWh are saved, (b) more valuable kWh are saved, or (c) the cost of DM is reduced for the same saving. This objective leads to the shared-savings approach that Dr. Chamberlin sponsors and DECo requests.[90]

Third, incentives should be offered for superior performance, not for weak or half-hearted efforts. Combined with the second point, this suggests that the incentive should be structured as a share of net savings, above some threshold. I will return to this point below.

Fourth, the incentive should be large enough to capture management attention, overcome inertia, and change the utility's behavior. For example, it is unlikely that DECo management will be much influenced by the opportunity to earn incentives on the order of $100,000 annually.

Fifth, explicit incentives should be necessary only during the DM capability-building period. They should be phased out once DM is a routine portion of utility planning

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[90]While I believe that shared savings represent the best basis for incentives, my enthusiasm for shared savings does not equal that of Dr. Chamberlin, who asserts that shared-savings incentives do not "exert additional upward pressure on rates," in contrast to "pure incentives or bonuses," whatever they may be (Direct, p. 24, Tr. 1366). Every dollar of incentives, no matter how it is computed, must be recovered through rates, so Dr. Chamberlin's distinction makes no sense.

and operations, institutional barriers have been overcome, and the Commission, customers, and other parties can evaluate utility DM performance as they do fuel purchasing, distribution maintenance, and other utility activities. The normal regulatory mechanism can then reward utilities for efficient resource planning or penalize them for wasteful decisions in DM and other fields.

Q: Should incentives be directed to shareholders or to utility management?

A: The incentives should be paid to the utility, that is, to the shareholders. Incentives directly from the Commission to management would result in management reporting to two bosses: the corporate board of directors and the Commission. This situation would be complex and confusing, and would obscure the traditional obligation of the utility's shareholders and directors for managing the utility.

On the other hand, the shareholders should be aware that any incentives they receive are due to the actions of utility management. Hence, the utility's directors should be encouraging management to change attitudes and behaviors with respect to DM, since those changes will be critical to long-run DM savings for ratepayers and DM incentives to shareholders. It would be imprudent for the directors to tie executive compensation to indicators, such as sales growth, that are inconsistent with least-cost planning.

Similar considerations continue down the chain of command, with directors and executives responsible for ensuring that incentives to middle management and field staff are consistent with the objectives of least-cost planning and with the incentives to shareholders.

Q: Is there any role for penalties in the incentive scheme?

A: Yes. Inadequate or counterproductive utility action on DM should result in reductions in allowed return on equity, rejection of proposals to acquire new supply-side resources, and even disallowance of avoidable supply costs, such as fuel, purchases, new T&D, new generation, and existing generation that could have been mothballed or sold.

2. Computation of incentives

Q: How should the size of the incentive be determined, as a share of net savings?

A: The share cannot be specified prior to determination of program scope. As a realistic matter, there seems to widespread agreement that the prospect of a 1% increase in the return on equity is sufficient to capture the attention of management and directors and overcome considerable internal resistance.[91] Much lower incentives (e.g., a 0.1% equity increment) are probably too small to have much

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[91]Examples of regulatory orders that have settled on incentive targets in this range include Massachusetts DPU 90-55 (0.5% for Boston Gas), DPU 89-195/195 (1% for MECo), DPU 89-260 (0.3% for WMECo), Rhode Island PUC 1939, Order of 55/16/90 (1% for Narragansett), and New York PSC 89-E-041 (0.3% to 0.75% for ORU) and PSC 89-E-175 (0.9% for ORU).

effect.[92] Much larger incentives will likely be unnecessary and difficult to justify. Hence, the incentive should be structured to provide about a 1% increase in return, *if* the DSM program is aggressive, well-designed, and well-managed program.

The utility's share of net savings will then depend on the level of avoided costs used in the computation, the anticipated cost of the programs, and the targeted program scale. I would not expect the utility share to exceed 25% of net benefits, and it may be much lower.

The incentive should not be subject to an arbitrary cap. If the utility can deliver twice the cost savings previously thought possible, it should receive a commensurate bonus.

Q: How should net benefits be computed?

A: The net benefit for incentives should be calculated in the same way as the net benefit used for screening programs and measures; net benefits for both purposes should be computed from the most important of the cost-effectiveness tests, the Total Resource Cost (TRC) test. The TRC measures the contribution of a DM measure or program to achieving a least-cost resource mix. Only an incentive based on the TRC

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[92]This is not entirely clear, however. PEPCo appeared to be badly stung by a 0.15% reduction in ROE due to deficiencies in its DSM programs. (District of Columbia PSC Order 9509, July 24, 1990.) A smaller incentive may be effective for utilities that are particularly sensitive to issues of regulatory relations.

provides directions to the utility consistent with the objective of least-cost planning.

Q: How should the incentive level earned be determined?

A: As is true for lost revenues, incentives should be based on the best data available within a reasonable time frame. Forecasts are usually unnecessary. Incentives are additional benefits to the utility, rather than recoupment of expenses. The utility should be able to wait for them until at least preliminary M&E results are available. Tying incentive payment to M&E results will be an additional spur to rapid and efficient M&E implementation.

3. Structure of incentives

Q: How should incentives vary with utility performance, as measured by net benefits?

A: Four basic schemes have been applied to relate incentives to performance:

- linear,
- step function,
- linear above a step, and
- linear from zero above a threshold.

These relationships are illustrated in Exhibit I-____ (PLC-15). The four examples are constructed so that the incentive would be the same for 80% of the target.

The linear form gives the utility a fixed fraction of savings and provides incentives for even feeble DM efforts. However, it is easy to define and implement.

The step function approach has at least four disadvantages of the step function. First, it creates an excessive focus on reaching the step threshold within the allowed time period (e.g., the program year), which may result in inefficient program design and implementation. Second, it eliminates any incentive for achievements above the threshold. Indeed, the utility may be discouraged from exceeding the minimum requirement, since reaching the incentive threshold next year may be easier if it does not use up readily available savings this year. Third, accounting for the timing of installations becomes very important; if new construction program savings are credited when the design work is done, they will usually affect incentives in a different year than if the savings are counted as the buildings are occupied. This would not be a concern with an incentive scheme that gave about the same size credit for savings in each of several program years; with step incentives, the savings from the new-construction program may be vital to meeting the target in one year, and be useless in the next. Fourth, the duration of the incentive period becomes very important. A few months difference in the start of the program year, or in its length, can make the difference between a utility earning no incentive or earning the full allowed incentive.

The linear-with-step approach avoids the problems of the step approach that result from the lack of additional incentives over the threshold, but shares the disadvantage of the pure step approach in making the small increment around the step excessively important and making results very sensitive to timing.

The best option is a linear incentive above a threshold. This approach is used in Massachusetts, Rhode Island, California and Vermont.[93] These approaches avoid the pure linear approach's potential for rewarding mediocre performance and also avoids the game-playing, inefficiencies, and inequities associated with the step functions.

Q: How should program goals be set?

A: Target levels should reflect the maximum cost-effective DM program feasible for the utility, considering its avoided costs and its capabilities. The threshold should reflect a significant level of effort, greater than the industry norm. Thresholds are often set at 40-50% of the target levels.

E. Cost Recovery Mechanism

Q: Do you have any comments on DECo's proposed cost-recovery mechanism?

A: Yes. The general format of the mechanism appears to be appropriate. In particular, I agree with the inclusion of the reconciliation factor. In the absence of the

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[93]The Massachusetts DPU approach uses ¢/kWh, $/kW-yr, and $/MMBtu incentives, rather than split-savings. The incentive starts at a preset threshold for each utility.

reconciliation factor, the cost recovery proceedings may be excessively burdened by arguments about projections of short-term sales growth. The reconciliation mechanism eliminates this complication. If DECo overstates its sales, it will have an opportunity to make up the undercollection. If sales are underestimated, the overcollection will be returned to the ratepayers.

Q: Is DECo correct that the surcharge mechanism is uniquely suited to recovery of DM costs?

A: No. Dr. Chamberlin notes that costs could be deferred to a rate case or special proceeding, and then raises a number of objections to deferrals.[94] None of these objections are substantive.

Dr. Chamberlin asserts that deferral can cause "lumpiness" in rates "when costs are expensed" (Direct, p. 12, Tr. 1354). This is a criticism of *expensing* long-lived resource investments, not of deferring them. See Section VI.B.2, above.

Dr. Chamberlin worries that deferrals might not include carrying charges (Direct, p. 11, Tr. 1353). This problem is easily solved in deferrals for DM and many other costs, including AFUDC.

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[94]Dr. Chamberlin further confuses the issue by counting amortization as an alternative to deferral and his preferred surcharge (Direct, p. 12, Tr. 1354). In fact, costs recovered through deferral or a surcharge can be either amortized or expensed, so the alternatives Dr. Chamberlin poses are not alternatives at all.

Dr. Chamberlin also asserts that "deferral of large dollar amounts may create cash flow problems, because DSM spending must be financed from sources other than rates for long periods of time" (Direct, p. 12, Tr. 1354).[95] This is a frivolous argument with respect to the utility that simultaneously built Fermi 2 and Belle River, and is now depreciating those two plants. DECo has not even attempted to show that the most aggressive conceivable DM program would result in any significant financial problems, particularly if programs are pre-approved and some of the deferred costs are approved for subsequent collection.

Dr. Chamberlin notes that "Use of a surcharge, with interest accrued on any outstanding balances, makes utilities whole on their DSM investments and encourage pursuit of additional cost-effective DSM measures. . . Ratepayers are protected by providing recovery only for dollars actually spent on DSM, and the incentive to hold down spending on programs that are working well is eliminated." (Direct, p. 13, Tr. 1355) The same points are made on p. 33 (Tr. 1375) of Dr. Chamberlin's direct. This statement can be true for surcharge mechanisms, although it would not be true for the mechanism proposed by Dr.

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[95] Dr. Chamberlin also makes a vague reference to a problem with "costs that . . . may not be received in a timely fashion." (Direct, p. 10, Tr. 1352). Many utility costs are not received in a timely fashion: consider the cost recovery period for the funds DECo expended on Fermi 2 in the early 1970s.

Chamberlin and DECo.[96] It can be equally true for properly defined deferral mechanisms.

Dr. Chamberlin notes that "A surcharge collects DSM costs more or less as they occur." (Direct p. 33, Tr. 1375) Simultaneous cost recovery is possible, but not necessary, with a surcharge; I am not convinced that this feature is a benefit. At the end of 1994, the average measure installed in 1994 will have saved less than a half a year's worth of energy;[97] Dr. Chamberlin apparently proposes that ratepayers should pay in 1994 for all the measures installed in that year. Since the average measure may take several years to fully repay its costs, Dr. Chamberlin's combined insistence on the surcharge and expensing will cause rates and bills to rise unnecessarily in the short term. Given DECo's obsession with avoiding rate increases,[98] Dr. Chamberlin's surcharge proposal will stiffen DECo's resistance to any significant level of DM activity.

Finally, Dr. Chamberlin associates surcharges with the allocation of costs to rate classes. (Direct, p. 14, Tr. 1356) This result can be achieved at least as easily

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[96]For example, Dr. Chamberlin proposes that ratepayers should pay DECo for "lost revenue" costs that it does not incur.

[97]Once programs are fully ramped up, the average savings from measure in its installation year will be about half a year's worth of energy.

[98]Dr. Chamberlin supports DECo's concern, but offers no evidentiary support for its importance (Direct, p. 8, Tr. 1350).

without a surcharge. Deferral to a rate case would allow DM costs to be assigned to the sub-classes, rate riders, and billing determinants (e.g., demand versus energy charges, tailblock versus inner blocks) that best reflect the distribution of benefits within a class.

Q: What mechanism do you propose be adopted for DECo's DM cost recovery?

A: I see no substantive difference between the surcharge and deferral approaches. If no other party has a good argument for opposing the surcharge, DECo's preference for this form suggests that it should be adopted. DECo management is clearly ambivalent about major DM investments, as is clear from the testimony of Mr. Welch. DECo may project this ambivalence onto the Commission, and thus fear that any DM costs not promptly reflected in rates will become recoverable after some subsequent change in Commission philosophy. The surcharge will provide DECo with a "bird in the hand," possibly boosting the credibility of DM advocates within the utility.

On the other hand, if other parties have good reasons -- legal or practical -- for opposing the surcharge, deferral is a perfectly acceptable substitute. A good deferral mechanism is preferable to a bad surcharge, such as one that would list DM costs separately on the bill, limit expenditures, preclude the use of monitored results, or otherwise constrain cost-effective DM. DECo's fixation on a surcharge should not be allowed to damage the DM programs.

Q: Do you have any recommendations about the public presentation of the cost recovery mechanism?

A: Yes. I recommend that the EES not appear as a separate item on the customer's bill. Even small charges, separately identified, tend to cause considerable customer resentment. There are many cost components that could be broken out on utility bills, but are not; examples include nuclear plant outage costs, nuclear decommissioning, property insurance, shareholder profits, employee fringe benefits, and management perks.[99] Separately identifying any of these costs as a line item on bills would attract attention, mostly negative. DM costs should neither be singled out nor preferentially sheltered from public scrutiny. Bill stuffers could certainly describe the magnitude of the DM portfolio, with projections of the number of participants, the costs, and the savings.

Q: How should the EES be reflected in bills?

A: The EES should be rolled into the base rates. Revisions of the EES should be timed to coincide with seasonal rate changes, where applicable.

Q: DECo has proposed that the EES be allocated to rate classes

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[99] The participants in this proceeding may all recognize the legitimacy of each of these cost categories, but large portions of the public will not. It is easy to imagine the indignity of customers who have no health insurance or pension fund at paying those costs for utility employees, or renters without property insurance at paying to insure someone else's property.

in proportion to their participation in programs. Do you agree?

A: Yes. DM costs usually should be collected primarily from the classes receiving the DM services, since those classes are receiving the bill reductions due to lower energy and demand consumption. The participants' class directly receives the benefits associated with the DM expenditure and avoids paying for power, resulting in lost revenues. The participants' class will continue receiving smaller allocations of joint costs, due to reduced energy and demand.

In some situations, small rate classes with large potential for efficiency improvements might experience significant short-term rate effects from restricted recovery of lost revenues. In such cases, the costs can be collected from a wider group of customers, with the expectation that the smaller group will be required to bear a share of the larger group's cost recovery over time.

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Allocating the direct costs of DM resources in other ways, such as in proportion to revenue, energy usage, or peak demand usage, will tend to create tensions between classes for a utility like DECo, whose embedded costs are above or close to marginal costs. Each class will want to maximize its programs (which would be primarily paid for by other classes) and minimize all other classes' programs (from which our class derives little benefit and for which our class will have to pay).[100] No such tension arises if each class pays for its own programs. 148

Q: How should DECo's cost recovery proposals be reviewed?

A: Cost recovery proposals should be subject to public review, including an adequate schedule for review of the cost recovery, discovery, filing of testimony, and cross-examination. Since cost recovery is so tightly interconnected with the prudence of program design and execution, pre-filed program designs should be subject to public review. In Massachusetts, this process takes about 8 months from filing to decision. In some cases, a collaborative design process has accelerated the review, since most issues were resolved before the case went before the Commission.

Q: What should DECo be required to demonstrate to be eligible for EES cost recovery?

A: To be eligible for EES cost recovery, DECo should demonstrate that its energy efficiency programs are prudent. To be eligible for lost-revenue recovery, DECo should also demonstrate that its monitoring and evaluation is adequate to support the recovery claimed. To be eligible for

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[100]Allocating costs in proportion to revenues is particularly inequitable. This approach would allocate a substantial amount of DSM costs to customer-related costs that neither affect or are affected by DSM expenditures, such as meters and services. This allocation is unfair to classes, such as residential and streetlighting customers, with larger-than-average portions of customer-related costs.

incentives, DECo should demonstrate that its programs represent essentially the highest feasible level of effort, given DECo's institutional abilities, cost-effective opportunities, and well-demonstrated rate impact constraints. Many leading utilities have used the collaborative process to demonstrate that their programs are prudent, comprehensive, and adequately monitored.

The Commission might also allow DECo to defer costs and lost revenues from prudent and well-monitored programs, if there is a significant lag until DECo can ramp up its DM efforts and file a comprehensive portfolio of programs.

Q: What do you mean by a "prudent" DM plan?

A: The definition of prudent DM portfolio design should include

- avoidance of lost opportunities;
- avoidance of cream skimming;
- minimizing free riders through high minimum efficiency thresholds and high incentives;
- comprehensiveness in all respects, such as covering all market segments (new construction, retrofit, routine replacement; plus such special cases as government buildings, low-income residentials, tenants), all end-uses, all measures, and the full cost-effective depth of measures (e.g., air conditioning incentives that rise with SEER, up to the maximum cost-effective level);
- the building of capability; and
- program designs and customer incentives that are strong enough to overcome the prevailing market barriers.

Q: Please review the role of monitoring and evaluation in DM cost recovery.

A: As discussed by MUCC witness Oswald, monitoring and evaluation will be required to support recovery of lost revenues and incentives. The utility should propose an M&E plan for each program, detailing the approaches to be taken for measuring or estimating savings. Many judgments must be applied in making the choices necessary in designing and implementing M&E programs; since M&E is such a new and evolving field, there are no standard choices or defaults. It is difficult for other parties to trust utility self-evaluation, so independent M&E contractors are very helpful. These should be collaboratively managed, as recommended by MUCC witness Coakley.

F. Summary of Problems in DECo Proposal and Suggested Corrections

Q: Please summarize the problems you have identified in DECo's cost recovery proposal.

A: There are five major problems with DECo's proposal. First, DECo proposes to use pre-installation estimated savings for lost revenues and incentives when more accurate monitored savings estimates will be available. This proposal would provide DECo with a set of perverse rewards.

Second, DECo requests that it be allowed an incentive for mediocre performance. Its proposed programs deserve no DM reward at all. The information provided by DECo itself (e.g., Chamberlin supplemental, Exhibit A-14, Schedule K 20) indicates that DECo's DM efforts are half-hearted. As I explained in Section IV, DECo has chosen not to pursue all cost-effective efficiency, without sufficient justification.

Third, DECo does not demonstrate that its proposed incentive has any rational relationship to the scale of incentive necessary to encourage its managers to pursue the least-cost options for meeting the energy service needs of its customers.

Fourth, despite its concern with rate effects, and its willingness to abandon cost-effective DM rather than increase rates, DECo has proposed a combination of policies designed to maximize rate effects. The use of a pre-installation surcharge to expense direct costs, lost revenues, and incentive prior to receipt of a full year's savings, would unnecessarily increase rates and bills in the short term. The use of ex ante savings estimates in lost-revenue and incentive computations would further exacerbate rate and bill increases, by allowing and encouraging DECo to collect rewards without reducing customer costs.

Finally, DECo has requested favorable ratemaking, including excessive incentives and a lost-revenue mechanism that will provide additional rewards to shareholders, without actually committing itself to any specific DM portfolio. In essence, DECo has asked for a large amount of its customers' money, in exchange for a promise to eventually deliver a pig in a poke.

Q: How should the Commission change DECo's proposed DM cost recovery?

A: The Commission should

- withhold approval of any special DM cost recovery until DECo commits to a prudent DM portfolio;

- require DECo to develop a decoupling proposal in collaboration with other parties;

- base lost-revenue recovery and incentives on the best estimate of savings developed through an independent monitoring and evaluation program;

- limit DM incentives to a savings over a reasonable threshold;

- set the incentives savings share to allow DECo to achieve a 1% increase in return on equity for a first-class DM program, as defined earlier; and

- require DECo to use the cost-recovery mechanism that minimizes rate-effect constraints on DM program implementation.

IX. SUMMARY OF RECOMMENDATIONS

Q: Please summarize your recommendations.

A: My principal recommendations for DECO's DM planning and screening include:

- DECo should evaluate all potential DM measures, without arbitrary pre-screening.

- DECo should design programs on the basis of the TRC and abandon explicit and implicit use of the RIM.

- Measure and program screening should be distinct and methodical.

- Screening should compare the present value of all costs and benefits of DM, without arbitrarily limiting the duration of benefits or relying on the benefit-cost ratio of options.

- DECo should evaluate the rate and bill effects of the least-cost DM portfolio with a comprehensive rate impact analysis, identifying and resolving specific rate effects so as to minimize the increase in total costs.

- DECo should prioritize acquisition of lost opportunities, and build capability to deliver discretionary programs.

- DECo's DM portfolio should be comprehensive in covering market segments, end uses, and measures.

- DECo should be acquiring much more efficiency than it has proposed.

My principal recommendations with regard to the estimation of DECo's avoided costs for DM include:

- Generation capacity costs should include all deferrable capacity, and recognize the potential for off-system sales.

- Generation costs should reflect current and anticipated environmental compliance costs.

- Energy costs should be sufficiently documented, and recognize the potential for off-system sales.

- Transmission and distribution capacity costs should be included for all classes.

- Marginal line losses should be included to the end use for all classes; those losses vary with load.

- The substantial risk-reduction benefits of DM should be quantified and recognized.

- The environmental and other external benefits of DM should be quantified and included in avoided costs.

My principal recommendations with regard to DM cost recovery include:

- Appropriate DM activity should receive the easiest, most rewarding, and least painful regulatory treatment of any resource acquisition option.

- DECo should be encouraged to accelerate DM programs when opportunities arise. The Commission should not establish any spending cap that would limit DECo's ability to manage its DM program.

- The cost recovery mechanisms and procedures should be able to handle very large and rapidly expanding DM programs.

- The cost recovery mechanism should be flexible enough to allow the capture of all lost-opportunity DM resources without penalty to the utility.

- Special DM ratemaking treatment should be regarded as temporary.

- DECo should be allowed to combine projections, deferrals, and/or interim adjustments to collect its DM costs, subject to Commission approval.

- Special cost recovery procedures are justified only for energy efficiency programs.

- The Commission should establish a preference for amortization of DM costs over the full life of the installed measures, as opposed to expensing the costs in a single year.

- Cost-recovery patterns for DM may be altered to maintain rate continuity, avoid rate shock, and improve utility cash flow at critical times.

- The interest credit for capitalized DM costs should mirror the treatment of capitalized supply costs as closely as possible.

- DECo should be instructed to negotiate with other parties to this case and formulate a decoupling proposal suitable for its current situation.

- Until a decoupling mechanism is in place, lost revenues resulting from prudent efficiency programs should be recoverable.

- Lost revenues should be reconciled, based on the best data available within a reasonable time frame after the revenues are lost.

- Lost revenues should be computed net of any identifiable and quantifiable cost reductions captured by the utility prior to the next rate case, including:

  - bad debt,

  - average or marginal energy cost reductions,

  - reduced T&D investments,

- off-system energy sales,
- off-system capacity sales, and
- avoided off-system purchases.

- Lost revenues should be computed net of the effects of promotional programs and of the promotional effects of conservation or load management programs.

- Inadequate or counterproductive utility action on DM should result in

  - reductions in allowed return on equity,
  - rejection of proposals to acquire new supply-side resources, and
  - disallowance of avoidable supply costs, such as fuel, purchases, new T&D, new generation, and existing generation that could have been mothballed or sold.

- The incentive should be structured to provide about a 1% increase in return on equity for an aggressive, well-designed, and well-managed program.
- The incentive should be computed as a percentage of net benefits under the Total Resource Cost (TRC) test.

- Incentives should be based on the best data available within a reasonable time frame.

- Incentives should be linear with respect to net savings above a threshold of roughly 40-50% of the target levels.

- The EES should not appear as a separate item on the customer bills.

- DM costs should be collected primarily from the classes receiving the DM services.

- To be eligible for EES cost recovery, DECo should be required to demonstrate that its efficiency programs are prudent.

- To be eligible for lost-revenue recovery, DECo should be required to demonstrate that its programs are prudent, and that monitoring and evaluation is adequate to support the recovery claimed.

- To be eligible for incentives, the utility should be required to demonstrate that its programs represent the maximum feasible level of effort.

- Monitoring and evaluation will be required to support recovery of lost revenues and incentives, and to demonstrate the continuing prudence of program design. M&E verifies the magnitude of savings and lost revenues and is essential to ensuring that the DM portfolio is prudent. The monitoring and evaluation function is a very important part of the overall DM effort.

Q: How should the Commission dispose of DECo's request in this case?

A: DECo's request surcharge should be denied at this time, due to DECo's failure to define a reasonable DM portfolio. The Commission should also emphatically reject DECo's DM planning approach, and instruct DECo to correct the errors I previously discussed, in its DM planning, screening, and avoided costs.

To ensure that DECo corrects those errors in a timely fashion, the Commission should order DECo to file a complying DM program within 9 months of the order in this case, and a plan for producing that program within 30 days of the order in this case. The Commission might also point out to DECo that a collaborative, as discussed by MUCC witness Coakley, would facilitate compliance.

Q: Does this conclude your testimony?

A: Yes.

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Projected Energy Savings from Demand Management by Selected Third Generation Utilities

	Energy savings, last yr of DM prog GWh [1]	Pre-DM energy req'ts, last yr of DM prog GWh [2]	DM as % of energy req'ts last yr of DM prog [3]	Avg annual incr. DM GWh [4]	Avg Annual energy req'ts in prog period GWh [5]	Avg Annual DM as % avg energy req'ts in prog period [6]	Growth in DM GWh [7]	Growth in energy req'ts GWh [8]	New DM as % of new energy req'ts [9]
Boston Edison (1990 - 1994)									
Residential	73	3,709	2.0%	13	3,593	0.4%	66	295	22.4%
Com/Ind	454	10,145	4.5%	91	9,705	0.9%	454	1,205	37.6%
System	527	13,854	3.8%	104	13,298	0.8%	520	1,500	34.6%
Eastern Utilities (1991 - 2000)									
Residential	26	1,875	1.4%	3	1,724	0.2%	26	277	9.4%
Commercial	275	2,599	10.6%	27	2,159	1.3%	275	782	35.2%
Industrial	15	917	1.6%	2	854	0.2%	15	85	17.9%
System	339	5,683	6.0%	34	4,996	0.7%	339	1,220	27.8%
New England Electric (1991 - 2010)									
Residential	555	9,201	6.0%	24	8,549	0.3%	489	1,210	40.4%
Commercial	1,692	12,390	13.7%	74	10,012	0.7%	1,471	4,624	31.8%
Industrial	523	7,546	6.9%	24	6,297	0.4%	483	2,432	19.9%
System	2,956	32,385	9.1%	129	27,812	0.5%	2,586	9,251	28.0%
New York State Electric & Gas (1993 - 2008)									
Residential	530	7,168	7.4%	30	6,225	0.5%	479	1,617	29.6%
Com/Ind	783	4,878	16.1%	39	4,123	1.0%	629	1,487	42.3%
System	1,598	19,773	8.1%	85	17,478	0.5%	1,367	4,513	30.3%

Projected Energy Savings from Demand Management by Selected Third Generation Utilities

	Energy savings, last yr of DM prog GWh [1]	Pre-DM energy req'ts, last yr of DM prog GWh [2]	DM as % of energy req'ts last yr of DM prog [3]	Avg annual incr. DM GWh [4]	Avg Annual energy req'ts in prog period GWh [5]	Avg Annual DM as % avg energy req'ts in prog period [6]	Growth in DM GWh [7]	Growth in energy req'ts GWh [8]	New DM as % of new energy req'ts [9]
Northeast Utilities (1991 - 2000)									
Residential	556	10,890	5.1%	56	10,395	**0.5%**	556	1,390	**40.0%**
Commercial	1,987	12,330	16.1%	199	10,585	**1.9%**	1,987	3,349	**59.3%**
Industrial	907	6,652	13.6%	91	5,835	**1.6%**	907	1,205	**75.3%**
System	3,460	30,756	11.3%	346	27,695	**1.2%**	3,460	5,857	**59.1%**
Potomac Electric - Maryland (1992 - 1996)									
Residential	70	5,740	1.2%	14	5,611	**0.2%**	70	481	**14.5%**
Commercial	823	9,259	8.9%	165	8,834	**1.9%**	823	1,099	**74.8%**
System	892	15,227	5.9%	178	14,652	**1.2%**	892	1,621	**55.0%**
United Illuminating (1991 - 2010)									
Residential	47	2,259	2.1%	5	2,040	**0.2%**	41	432	**9.6%**
Commercial	519	3,435	15.1%	25	2,838	**0.9%**	507	1,176	**43.1%**
Industrial	257	1,586	16.2%	13	1,313	**1.0%**	251	525	**47.8%**
System	827	7,284	11.4%	40	6,195	**0.6%**	803	2,137	**37.6%**
Sacramento Municipal Utility District (1992 - 2010)									
System	3,418	14,790	23.1%	178	11,877	**1.5%**	3,378	5,760	**58.6%**
Pacific Gas & Electric(1993 - 2011)									
System	9,890	106,170	9.3%	521	94,020	**0.6%**	9,890	25,437	**38.9%**
Aggregate figures:									
Residential	1,857	33,674	5.5%	144	38,136	**0.38%**	1,727	5,702	**30.3%**
Commercial	5,296	40,013	13.2%	490	34,427	**1.42%**	5,062	11,030	**45.9%**
Industrial	1,702	16,701	10.2%	129	14,299	**0.90%**	1,656	4,246	**39.0%**
Com/Ind	8,234	71,737	11.5%	749	62,554	**1.20%**	7,801	17,969	**43.4%**
System	23,907	245,922	9.7%	1,616	218,023	**0.74%**	23,235	57,296	**40.6%**

Notes:

General comments:
Aggregate figures are the sum of all available data.
All sales forecasts are pre-DM, i.e., the effects of DM have not yet been netted out.
All growth calculations are inclusive of the first year of the period.
For example, growth in sales for the period 1991-2010 inclusive is measured as sales in 2010 minus sales in 1990.

Utility-specific comments:
BECO's DM only includes conservation programs and not load management savings.
EUA totals in main table include losses (and streetlighting).
ie, class numbers are at sales level, total # at generation level, for savings and needs.
Figures assume that all DM given in load forecast is new, i.e., it includes no savings from previous DM efforts.
NEES DM savings by class are at customer level; they do not include include losses. NEES System savings are at generation level, they do include losses.
NEES' system sales is not the sum of residential, commercial and industrial sales because the system figure includes losses, streetlights, and sales for resale.
NEES's DM includes savings from load management.
NYSEG's DM includes savings acquired prior to 1993.
The GWh demand by class is at the customer level (i.e., pre-losses).
The GWh demand for the system includes streetlighting and other misc. uses, and also includes losses.
Total DM savings are the sum of res., C/I, and agricultural DM. Load management has not been netted out.
NU figures are exclusive of load management programs. System sales include sales for resale, streetlighting, and railraod sales. NU's original sales and peak projections include reductions due to DM. In order to obtain a pre-DM forecast, we have added NU's DM savings back into the Company's sales and peak projections. NU system DM includes reduction due to streetlighting.
PEPCo has no industrial DM programs. No load management programs are included.
UI's load and sales projections include reductions due to DM. In order to obtain a pre-DM forecast, we have added UI's DM savings back into the Company's sales and peak projections. System DM savings include savings from streetlighting. UI DM savings are net of load control, interruptible, TOU rates, and cool storage programs, but might include other smaller load control.
SMUD's system energy requirements and DM include transmission and distribution losses.
Load management has not been netted out of the DM savings.
PG&E's load forecast is interpolated for the years 1990-1995.
Load management and building standards are excluded from PG&E's DM savings.

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Exhibit PLC___3: Total Demand-Management Spending by Selected Leading Utilities

	Demand Management Budget[a] (1991$)	*Average Annual DM budget*	*Average DM Budget as Percentage of 1990 Revenues[b]*	*DM savings GWh[a]*	*Amortized budget[c]*	*Gross $/kWh[d]*
Boston Edison (1990–1994)						
	$223,156,000	$44,631,200	3.9%	520	$22,976,759	$0.044
Eastern Utilities (1991–1995)						
	$69,549,000	$13,909,800	3.1%	235	$7,160,957	$0.030
New England Electric (1991–1995)						
	$421,793,000	$84,358,600	4.6%	750	$43,428,973	$0.058
New York State Electric and Gas (1993–1997)						
	$159,104,679	$31,820,936	3.0%	641	$16,381,857	$0.026
Potomac Electric–Maryland (1992–1996)						
	$124,437,000	$24,887,400	4.8%	892	$12,812,377	$0.014
United Illuminating (1990–1992)						
	$34,899,000	$11,633,000	2.0%	72	$3,593,297	$0.050
Western Massachusetts Electric (1991–1995)						
	$93,141,000	$18,628,200	5.1%	266	$9,590,055	$0.036
Sacramento Municipal Utility District (1993–2000)						
	$488,038,278	$61,004,785	8.9%	1,240	$50,249,770	$0.041
Aggregate	$1,579,218,956	$279,240,920	4.6%	4,544	$162,600,749	$0.036

Notes:

[a] Expenditures and savings are cumulative over the program period. UI data available only for 1990–92.

[b] Utility 1990 ultimate consumer revenues from *PUR Analysis of Investor-Owned Electric and Gas Utilities,* 1991 edition; 1990 figures inflated to 1991, 5 percent inflation assumed. SMUD 1990 revenues from personal communication with D. Estrada of SMUD.

[c] DM budget amortized over 15 years, at a 6 percent real discount rate.

[d] Amortized budget ÷ gross $/kWh × 10^6

Sources:

Boston Edison, "The Power of Service Excellence," 3/90.

Eastern Utilities Association, "An Overview of Montaup's Residential and Commercial C&LM Programs," February 1991.

New England Electric System, "Integrated Resource Management Draft Initial Filing," (5/91)

New York State Electric and Gas, *Demand-Side Management Filing,* Volume II, October 1990.

Potomac Electric Power Company, "Conservation Program Designs," Phase I (8/91) and II (12/91)

United Illuminating, "Energy Action '90."

Western Massachusetts Electric Application for Pre-Approval of Conservation and Load-Management Programs, "Testimony of Earle F. Taylor, Jr.," 3/91.

SMUD, "Business Plan for Achieving Energy Efficiency Goals 1992–2000," April 8, 1992, Tables 22, 23, 89–90.

Exhibit___PLC-4
DECO's Efficiency Resources
Compared With the Load Forecast

Summary of Cumulative Efficiency Savings

Year	Res. Peak Savings MW [1]	Res. Energy Savings GWh [2]	Com Peak Savings MW [3]	Com Energy Savings GWh [4]	Ind Peak Savings MW [5]	Ind Energy Savings GWh [6]	Total Peak Savings MW [7]	Total Energy Savings GWh [8]
1994	2	13	1	7	1	5	4	25
1995	6	50	4	20	3	15	13	86
1996	12	107	9	46	7	36	28	189
1997	20	174	13	70	11	55	43	299

Notes:

[1]: Response to Hearing Room Request #42, Scenario 3M1 MW Impacts, Residentail. Load management programs and dispersed generation are excluded.

[2]: Response to Hearing Room Request #42, Scenario 3M1 NSO Impacts, Residentail. Load management programs and dispersed generation are excluded.

[3]: Response to Hearing Room Request #42, Scenario 3M1 MW Impacts, Small Mfg. & Non-Mfg.. Load management programs and dispersed generation are excluded.

[4]: Response to Hearing Room Request #42, Scenario 3M1 NSO Impacts, Small Mfg. & Non-Mfg.. Load management programs and dispersed generation are excluded.

[5]: Response to Hearing Room Request #42, Scenario 3M1 MW Impacts, Large Mfg. & Non-Mfg.. Load management programs and dispersed generation are excluded.

[6]: Response to Hearing Room Request #42, Scenario 3M1 NSO Impacts, Large Mfg. & Non-Mfg.. Load management programs and dispersed generation are excluded.

[7]: [1]+[3]+[5]

[8]: [2]+[4]+[6]

Summary of Demand Forecast

	Pre-Efficiency Summer Peak				Pre-Efficiency Sales			
	Res. MW [9]	Com MW [10]	Ind MW [11]	System MW [12]	Res. GWh [13]	Com GWh [14]	Ind GWh [15]	System GWh [16]
1994	3,443	2,202	3,183	9,121	12,918	10,101	20,222	45,842
1995	3,532	2,235	3,195	9,261	13,004	10,251	20,174	46,083
1996	3,582	2,274	3,241	9,402	13,106	10,430	20,417	46,659
1997	3,609	2,313	3,302	9,537	13,207	10,617	20,784	47,365

Notes:

The source for the load forecast data is DECO's 1992-2007 Economic and Load Forecast Report, January 1993.
Loss factors from pg. 73 are used to calculate sectoral demand at generation level.
Loss factors are applied as percent of output, as defined on pg. 92 of the 1993 Load Forecast Report.

[9]: Table A-2, Dom. column.
[10]: Table A-2, Comm. column.
[11]: Table A-2, Pri. column.
[12]: Table A-2, Peak column.
[13]: Table A-1, Dom. column.
[14]: Table A-1, Comm. column.
[15]: Table A-1, Pri. column.
[16]: Table A-1, NSO. column.

Exhibit___PLC-4
DECO's Efficiency Resources
Compared With the Load Forecast

Page 3 of 6: Residential Sector

Year	Cumulative New Electricity Requirements After End of 1993 Peak Load MW	Sales GWh	Load Factor	Cumulative New Efficiency Savings After End of 1993 Peak Load MW	Sales GWh	Load Factor	New Efficiency as Percent of New Electricity Requirements Peak Load	Sales	Efficiency as Percent of Total Electricity Requirements Peak Load	Sales
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
1994	244	198	9%	1.6	13	94%	0.7%	6.7%	0.0%	0.1%
1995	333	284	10%	5.8	50	97%	1.8%	17.5%	0.2%	0.5%
1996	383	386	12%	12.3	107	99%	3.2%	27.6%	0.3%	1.0%
1997	411	487	14%	19.8	174	100%	4.8%	35.7%	0.5%	1.6%

Notes:
[2]: Exhibit___PLC-4, page 2, column [9] for year, minus 1993 value
[3]: Exhibit___PLC-4, page 2, column [13] for year, minus 1993 value
[4]: [3]*1000/([2]*8766)
[5]: Exhibit___PLC-4, page 1, column [1] for year, minus 1993 value
[6]: Exhibit___PLC-4, page 1, column [2] for year, minus 1993 value
[7]: [6]*1000/([5]*8766)
[8]: [5]/[2]
[9]: [6]/[3]
[10]: [5] of this page / [9] of Exhibit___PLC-4, page 2
[11]: [6] of this page / [13] of Exhibit___PLC-4, page 2

Exhibit___PLC-4
DECO's Efficiency Resources
Compared With the Load Forecast

Page 4 of 6: Commercial Sector

Year	Cumulative New Electricity Requirements After End of 1993			Cumulative New Efficiency Savings After End of 1993			New Efficiency as Percent of New Electricity Requirements		Efficiency 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]
1994	47	224	54%	1	7	62%	2.7%	3.2%	0.1%	0.1%
1995	81	374	53%	4	20	61%	4.7%	5.5%	0.2%	0.2%
1996	119	553	53%	9	46	61%	7.2%	8.3%	0.4%	0.4%
1997	159	740	53%	13	70	61%	8.2%	9.4%	0.6%	0.7%

Notes:
[2]: Exhibit___PLC-4, page 2, column [10] for year, minus 1993 value
[3]: Exhibit___PLC-4, page 2, column [14] for year, minus 1993 value
[4]: [3]*1000/([2]*8766)
[5]: Exhibit___PLC-4, page 1, column [3] for year, minus 1993 value
[6]: Exhibit___PLC-4, page 1, column [4] for year, minus 1993 value
[7]: [6]*1000/([5]*8766)
[8]: [5]/[2]
[9]: [6]/[3]
[10]: [5] of this page / [10] of Exhibit___PLC-4, page 2
[11]: [6] of this page / [14] of Exhibit___PLC-4, page 2

Exhibit___PLC-4
DECO's Efficiency Resources
Compared With the Load Forecast

Page 5 of 6: Industrial Sector

Year	Cumulative New Electricity Requirements After End of 1993 Peak Load MW	Sales GWh	Load Factor	Cumulative New Efficiency Savings After End of 1993 Peak Load MW	Sales GWh	Load Factor	New Efficiency as Percent of New Electricity Requirements Peak Load	Sales	Efficiency as Percent of Total Electricity Requirements Peak Load	Sales
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
1994	45	210	53%	1	5	59%	2.1%	2.3%	0.2%	0.0%
1995	57	162	32%	3	15	60%	5.2%	9.6%	0.5%	0.1%
1996	103	404	45%	7	36	59%	6.7%	8.9%	1.1%	0.2%
1997	164	771	54%	11	55	59%	6.4%	7.1%	1.7%	0.3%

Notes:
[2]: Exhibit___PLC-4, page 2, column [11] for year, minus 1993 value
[3]: Exhibit___PLC-4, page 2, column [15] for year, minus 1993 value
[4]: [3]*1000/([2]*8766)
[5]: Exhibit___PLC-4, page 1, column [5] for year, minus 1993 value
[6]: Exhibit___PLC-4, page 1, column [6] for year, minus 1993 value
[7]: [6]*1000/([5]*8766)
[8]: [5]/[2]
[9]: [6]/[3]
[10]: [5] of this page / [11] of Exhibit___PLC-4, page 2
[11]: [6] of this page / [15] of Exhibit___PLC-4, page 2

Exhibit___PLC-4
DECO's Efficiency Resources
Compared With the Load Forecast

Page 6 of 6: System

Year	Cumulative New Electricity Requirements After End of 1993: Peak Load MW	Sales GWh	Load Factor	Cumulative New Efficiency Savings After End of 1993: Peak Load MW	Sales GWh	Load Factor	New Efficiency as Percent of New Electricity Requirements: Peak Load	Sales	Efficiency as Percent of Total Electricity Requirements: Peak Load	Sales
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
1994	345	672	22%	4	25	75%	1.1%	3.8%	0.0%	0.1%
1995	485	913	21%	13	86	78%	2.6%	9.4%	0.1%	0.2%
1996	626	1,489	27%	28	189	77%	4.4%	12.7%	0.3%	0.4%
1997	761	2,195	33%	43	299	78%	5.7%	13.6%	0.5%	0.6%

Notes:
[2]: Exhibit___PLC-4, page 2, column [12] for year, minus 1993 value
[3]: Exhibit___PLC-4, page 2, column [16] for year, minus 1993 value
[4]: [3]*1000/([2]*8766)
[5]: Exhibit___PLC-4, page 1, column [7] for year, minus 1993 value
[6]: Exhibit___PLC-4, page 1, column [8] for year, minus 1993 value
[7]: [6]*1000/([5]*8766)
[8]: [5]/[2]
[9]: [6]/[3]
[10]: [5] of this page / [12] of Exhibit___PLC-4, page 2
[11]: [6] of this page / [16] of Exhibit___PLC-4, page 2

EXHIBIT ____ PLC-5

Case No. U-10102
Exhibit A-14
Schedule K20 Page 1 of 1
Witness Chamberlin
Date

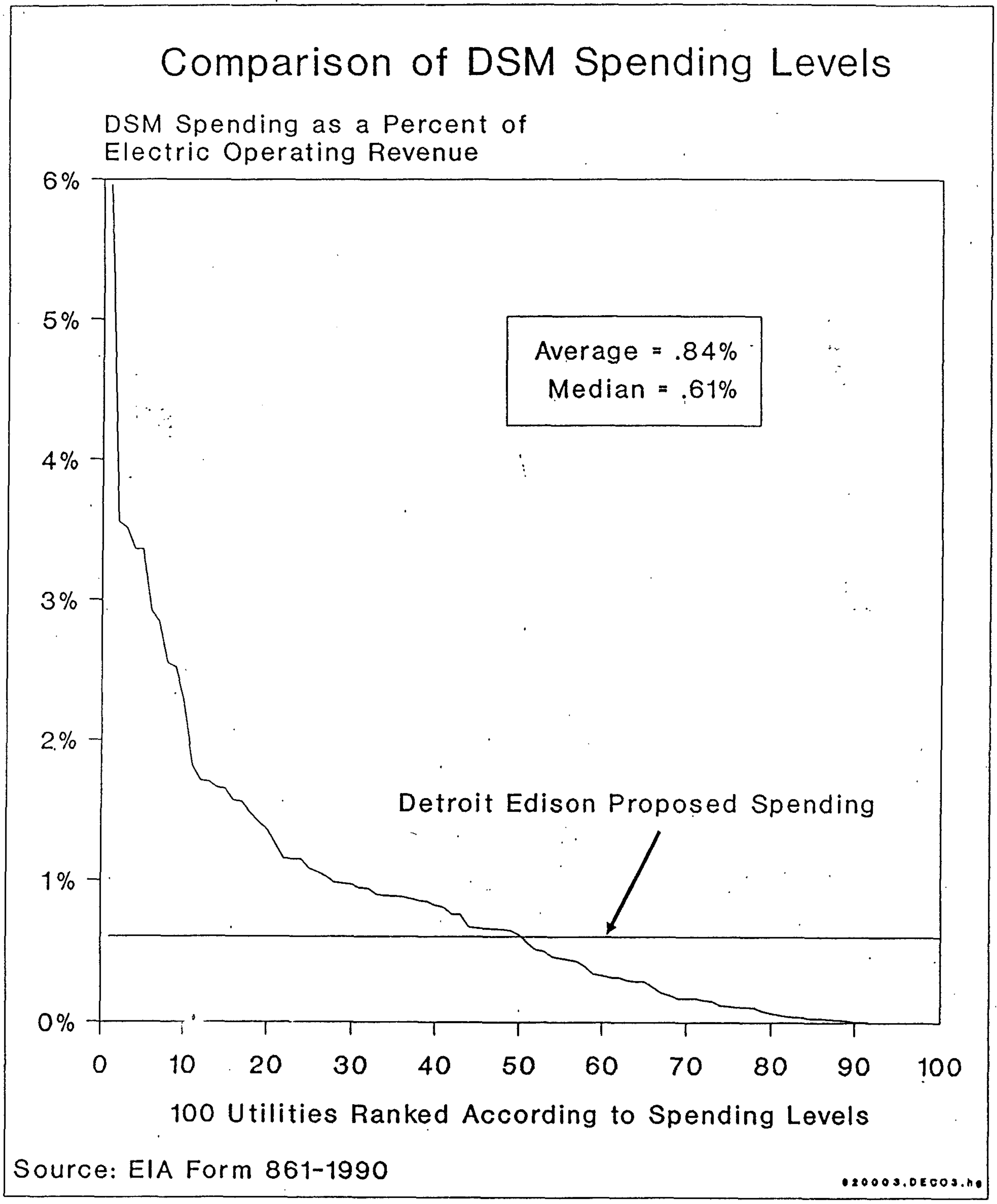

Exhibit ____ PLC-6

DECO Efficiency Resources Based on Efficiency Savings of Third Generation Programs

		Third Generation Target					Additional Efficiency Savings			
								Peak Reduction (MW), Assuming:		
	Average Sales 1994-1997 (GWh)	Annual Percentage Savings	Percentage Savings Over 4 Years	1997 Savings (GWh)	DECo 1997 Projected Savings (GWh)	DECo 1997 Load Factor	Energy Reduction (GWh)	1997 Load Factor +15%	1997 Load Factor	1997 Load Factor -15%
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Residential	13,059	0.5%	2.0%	261	174	41.8%	87	18	24	37
Commercial	10,350	1.9%	7.6%	787	70	52.4%	717	121	156	219
Industrial	20,399	1.3%	5.2%	1,061	55	71.9%	1,006	132	160	202
Total	43,808	NA	NA	2,109	299	NA	1,810	271	340	458

[1] From Exhibit PLC-4. The Total is the sum of residential, commercial and industrial only, and does not include sales from "other".
[2] Based on range of savings in Exhibit PLC-2.
[3] 4*[2]
[4] [1]*[3]
[5] From Exhibit PLC-4.
[6] Calculated from load forecast in Exhibit PLC-4.
[7] [4]-[5]
[8]: [7]/([6]+0.15)/8.76
[9]: [7]/[6]/8.76
[10]: [7]/([6]-0.15)/8.76

Exhibit PLC−7: DSManager and LMSTM Supply Plans and Avoided Capacity Costs

DSManager				LMSTM			
Year	Unit Added [1]	DECo Annual Capacity Credit ($/kW) [1]	Least−Cost Revised Annual Capacity Credit ($/kW) [2]	Year	Unit Added [3]	DECo Reported Annual Capacity Credit ($/kW) [3]	DECo Actual Annual Capacity Credit ($/kW) [4]
1994	Conners Creek HP	$27.84	$27.84	1994			
1995	Trenton Channel HP	$20.24	$29.23	1995	Trenton Channel HP	$20.24	$20.24
1996	River Rouge 1	$19.63	$30.69	1996	Conners Creek HP	$30.40	$30.40
1997		$0.00	$32.23	1997		$31.92	$31.92
1998	St. Clair 5	$58.12	$58.12	1998	River Rouge 1	$21.64	$21.64
1999		$0.00	$61.03	1999		$22.72	$22.72
2000	CT 1	$69.18	$69.18	2000	St. Clair 5	$64.08	$64.08
2001	CT 2	$72.64	$72.64	2001		$67.29	$67.29
2002	CT 3	$76.27	$76.27	2002	CT 1	$76.27	$70.65
2003		$0.00	$80.08	2003	CT 2	$80.08	$74.19
2004	CT 4	$84.09	$84.09	2004	CT 3	$84.09	$77.90
2005	CT 5	$88.29	$88.29	2005	CT 4	$88.29	$81.79
2006	CT 6	$92.71	$92.71	2006	CT 5	$92.71	$85.88

NOTES:
[1] IR MUCC−1.2/548, p. 2
[2] See text
[3] IR MUCC−1.2/548, p. 3
[4] Exh. A−14, Sch. WP2, p. 72.

Exhibit ___ PLC-8: Planned Capacity Additions in ECAR and MAIN

ECAR Utilities:

	Size (MW)	Date	Type
Centerior	15	1992-95	unspecified
	212	2000	upgrade existing units
Duquesne	140	1996	combustion turbine
	140	2001	combustion turbine
Ohio Edison	109	1997	add unit to existing plant
	94	1998	add unit to existing plant
Cincinnati Gas & Electric	77	1993	combustion turbine
	77	1997	combustion turbine
	154	1999	combustion turbine
	77	2000	combustion turbine
	77	2001	combustion turbine
Dayton Power & Light	65	1995	combustion turbine
	65	1997	combustion turbine
	65	1999	combustion turbine
	65	2001	combustion turbine
East kentucky Power Corp.	200	1994	combustion turbine
	100	1995	combustion turbine
	100	1998	unknown
	200	2000	coal unit
Indianapolis Power & Light	80	1994	combustion turbine
	80	1995	combustion turbine
	80	1997	combustion turbine
	400	1998	undesignated
	80	2000	combustion turbine
	80	2001	combustion turbine
Kentucky Utilities	200	1994	gas turbine
	200	1995	gas turbine
	100	1997	unknown
	100	1998	unknown
	100	1999	unknown
	100	1999	unknown
	200	2001	unknown
Public Service of Indiana	96	1994	combustion turbine
	96	1995	combustion turbine
	180	1995	combustion turbine
	166	1999	combustion turbine
	130	2001	combustion turbine
Total, ECAR	4500		

ECAR data from Electric Utility Week, May 11, 1992.

MAIN Utilities

	Size (MW)	Date	Type
Commonwealth Edison	480 Summer / 600 Winter	1997	peaking capacity
	480 S / 600 W	1998	peaking capacity
	400 S / 500 W	1999	peaking capacity
	480 S / 600 W	2000	peaking capacity
	400 S / 400 W	2001	CAES
Central Illinois Light Co.	78 S / 94 W	1994	combustion turbine
	36 S / 44 W	1995	cogeneration
	36 S / 44 W	1997	cogeneration
	78 S / 94 W	1998	combustion turbine
Illinois Power/Soyland Power Pool	75 S / 75 W	1996	combustion turbine
	75 S / 75 W	1997	combustion turbine
	75 S / 75 W	1998	combustion turbine
	75 S / 75 W	1999	combustion turbine
	75 S / 75 W	1999	combustion turbine
	75 S / 75 W	2000	combustion turbine
	75 S / 75 W	2000	combustion turbine
	75 S / 75 W	2001	combustion turbine
Total, MAIN	3069 S / 3576 W		

MAIN data from MAIN Regional Reliability Council Coordinated Bulk Power Supply Program, April 1992, DOE code IE-411. Only Illinois utilities have been included.

Exhibit PLC–9: Comparison of Selected Electric Utilities' Transmission and Distribution Costs (1991$/kW–yr)
(Kilowatts measured as coincident peak at generation)

Function	PEPCo (MD) [1]	BECo [2]	EECo [3]	NEPCo/ MECo [4]	Citizen's (VT) [5]	Central Vermont [6]	NYSEG [7]	Comm Ed [8]	LADWP [9]	Bangor Hydro [10]	BG&E [11]	SMUD [12]
a. Transmission	$4	$26	NE	$19	$45	$17	$39	$31	$22	$22	$28	$11
b. Sub–transmission	$17				$15				$10			
c. Primary distrib.	$70	$57	$72	$31	$68	$38	$44	$87	$33	$24	$77	$13
d. Secondary distrib.	$92	$52	$110	$31	$6	$11	$24	$58	$42	$17	$19	NE

Notes:
[3][c,d]]: Used as class NCP.
[4]: All understated by about 50%, due to removal of new customers and "reliability–related" costs.
[7][a]: Understated, should be about $67.
[8]: primary and secondary distribution not clear.
[h]: assumed 2:1 ratio of customer peak to coincident peak.
[9][d]: Includes some primary costs not listed in [c]. Approximation, due to documentation limits; probably understated.
4% inflation assumed throughout.
NE: Not Estimated.
[11][b,c]: Not all distribution included.
[12][a]: Some projects excluded.
[12][c]: Substations only.

Sources:
[1]: Personal communication with E. Mayberry, Potomac Electric Power Company.
[2]: Boston Edison Company, "Marginal Cost Study." 1989.
[3]: Eastern Edison Company, "1987 Marginal Cost–of–Service Study." Submitted in Massachusetts DPU 88–100.
[4]: Massachusetts Electric Company, "Marginal Distribution Cost Study." Submitted in Massachusetts DPU 91–52.
New England Power Company, Rate W–10 filing at FERC. July 1990.
[5]: Citizens Utilities Company, "Marginal Cost Study." November 1990.
[6]: Cater, James C., Testimony in Vermont PSB Docket No. 4634. August 10, 1988. (Central Vermont Public Service)
[7]: New York State Electric & Gas Corporation, "Marginal Costs of Demand Related Facilities."
[8]: Commonwealth Electric Company, "Long–Run Marginal Cost Study." Submitted in Massachusetts DPU 90–331.
[9]: Parmesano, H.S., "The Time–Differentiated Marginal Costs of the Los Angeles Department of Water and Power." September 1989.
[10]: Bangor Hydro–Electric Company "Long Run Marginal Cost Study, Docket No. 86–242," March 30, 1988.
[11]: Baltimore Gas & Electric, "Electric Marginal Cost Study." May 1990.
[12]: Sacramento Municipal Utility District, "Marginal Cost Study." June 29, 1990.

EXHIBIT ____ PLC-10

DERIVATION
OF
LOAD-RELATED
TRANSMISSION AND DISTRIBUTION
MARGINAL LINE LOSSES

Derivation of Load-Related Transmission and Distribution Marginal Line Losses

Figure 1 illustrates a simplified transmission or distribution circuit, with a single input and a single output load. For simplicity, only simple direct-current resistance is included; the complications of inductive and capacitive loads, and of alternating current, would not change the basic results. The circuit could be

- the transmission system, where the input is the generator and the output is the secondary winding of the distribution substation transformer;
- the primary distribution system substation, where the input is the distribution substation and the output is the line transformer;
- the secondary distribution system, where the input is the line transformer and the output is the customer's end use; or
- a composite of the above.

From Joule's Law,

$$V = I \times R,$$

where V = the voltage across a load,

I = the current flowing through the load, and

R = the resistance of the load.

To maintain a constant voltage of V_o (which would be 120V for most residential loads) across an output load with resistance R_o hence requires a current

$$I = V_o \div R_o$$

From Ohm's Law,

$$P = V \times R = I^2 \times R,$$

where P = the power consumed in the load.

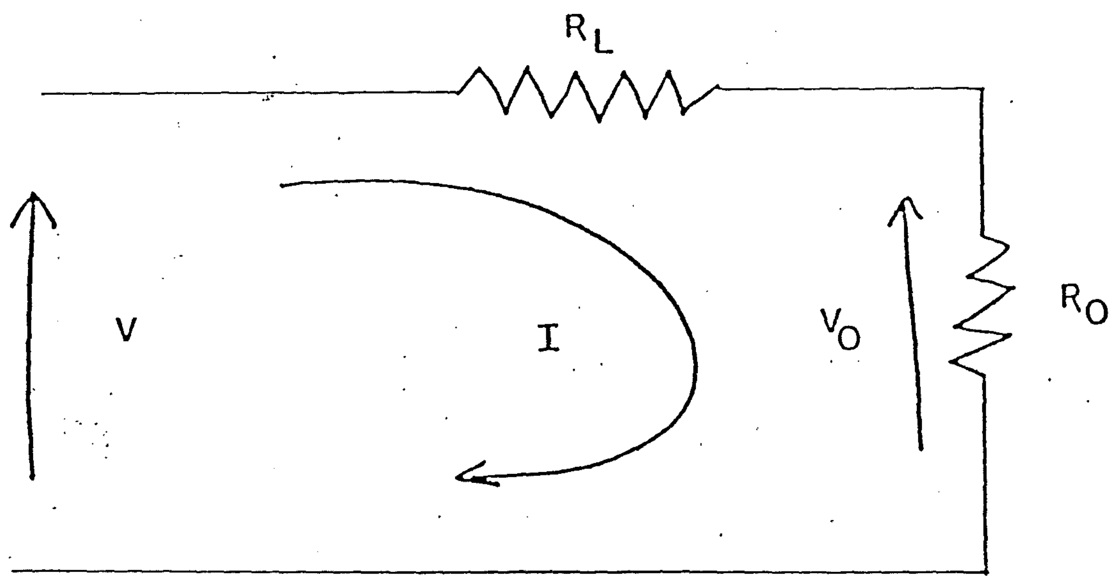

FIGURE 1

Hence, the losses in the circuit can be expressed in terms of the constant R_l, the resistance of the line:

$$\text{Loss} = I^2 \times R_l = \{V_o^2 \div R_o^2\} \times R_l$$

The power output at the load is

$$\text{Output} = I^2 \times R_o = V_o^2 \div R_o$$

Alternatively,

$$R_o = V_o^2 \div \text{Output}$$

The power input to the circuit is

$$\text{Input} = \text{Output} + \text{Loss} = I^2 \times (R_l + R_o)$$
$$= V_o^2 \times (R_l + R_o) \div R_o^2$$

Hence,

$$dR_o/d\text{Output} = -V_o^2 \div \text{Output}^2$$
$$= -V_o^2 \div \{V_o^2 \div R_o\}^2$$
$$= -R_o^2 \div V_o^2$$

$$d\text{Input}/dR_o = -V_o^2 \div R_o^2 - 2V_o^2 \times R_l \div R_o^3$$

These two derivatives can be combined as

$$d\text{Input}/d\text{Output} = d\text{Input}/dR_o \times dR_o/d\text{Output}$$
$$= \{-V_o^2 \div R_o^2 - 2V_o^2 \times R_l \div R_o^3\} \times \{-R_o^2 \div V_o^2\}$$
$$= 1 + 2 \times \{[V_o^2 \div R_o^2] \times R_l\} \times \{R_o \div V_o^2\}$$
$$= 1 + 2 \times \text{Loss} \div \text{Output} = 1 + 2L_o$$
$$= 1 + 2 \times \text{Loss} \div \{\text{Input} - \text{Loss}\}$$
$$= \{\text{Input} + \text{Loss}\} \div \{\text{Input} - \text{Loss}\}$$
$$= \{1 + L_i\} \div \{1 - L_i\} > 1 + 2L_i$$

where L_o = Loss ÷ Output = average losses as a fraction of output

L_i = Loss ÷ Input = average losses as a fraction of input

Hence, marginal losses as a fraction of output are twice as large as the average ratio of losses to output, and an even larger multiple of the average ratio of losses to input.

Exhibit ____ PLC–11
DECo Marginal Emissions Rates

DSM Case 1

Year	DSM Sales GWh	Total System Emissions (1000 tons) CO2	SO2	NOx
	[1]	[2]	[3]	[4]
1992		40,077	210	123
1993		41,091	214	125
1994	49	43,300	224	129
1995	134	43,252	230	135
1996	206	42,088	222	130
1997	434	43,876	235	136
1998	585	44,342	236	139
1999	710	43,762	234	136
2000	833	45,577	220	96
2001	953	46,325	222	97
2002	1,072	45,459	220	96
2003	1,189	47,373	226	100
2004	1,300	48,237	229	101
2005	1,405	47,458	227	99
2006	1,300	49,612	213	103

DSM Case 2

DSM Sales GWh	Total System Emissions (1000 tons) CO2	SO2	NOx
[5]	[6]	[7]	[8]
	40,077	210	123
	41,091	214	125
366	42,966	223	128
734	42,601	227	134
1,099	41,200	218	128
1,464	42,746	229	135
1,827	42,955	226	135
2,179	42,149	222	133
2,540	43,753	223	92
2,908	44,078	223	93
3,281	43,023	219	91
3,672	44,894	226	95
4,072	45,222	227	95
4,472	44,113	224	93
4,885	46,012	220	96

Difference: Case 1–Case 2

Year	Extra DSM GWh	Total System Emissions (1000 tons) CO2	SO2	NOx	Marginal Emissions Rates (lbs/MWh) CO2	SO2	NOx
	[9]	[10]	[11]	[12]	[13]	[14]	[15]
1992	0	0	0	0			
1993	0	0	0	0			
1994	317	334	1	1	2,107	6.3	6.3
1995	600	651	3	1	2,170	10.0	3.3
1996	893	888	4	2	1,989	9.0	4.5
1997	1,030	1,130	6	1	2,194	11.7	1.9
1998	1,242	1,387	10	4	2,233	16.1	6.4
1999	1,469	1,613	12	3	2,196	16.3	4.1
2000	1,707	1,824	(3)	4	2,137		4.7
2001	1,955	2,247	(1)	4	2,299		4.1
2002	2,209	2,436	1	5	2,206		4.5
2003	2,483	2,479	0	5	1,997		4.0
2004	2,772	3,015	2	6	2,175		4.3
2005	3,067	3,345	3	6	2,181		3.9
2006	3,585	3,600	(7)	7	2,008		3.9
CHOSEN					**2,146**	**11.6**	**4.3**

Exhibit ____ PLC−11
DECo Marginal Emissions Rates

Notes:
The chosen factors for CO2 and NOx are based on the 1994−2006 average. The SO2 factor is based on the average of 1994−1999.
After 1999 SO2 emissions factors were not calculated, because DECo adjusts sulfur levels at the Monroe units in the 2.5% DSM Case reflecting allowable limits.

[1]−[4]:	From Response to AG3.108/505. (Alternate Load/Rate Case Fuel), 1992 IRP Resource Plan Summary, 1% DSM Option − Base Case.
[5]−[8]:	From Response to AG3.108/505. (Alternate Load/Rate Case Fuel), 1992 IRP Resource Plan Summary, 2.5% DSM Case 2.
[9]:	[5]−[1]
[10]:	[2]−[6]
[11]:	[3]−7[]
[12]:	[4]−[8]
[13]:	[10]/[9]
[14]:	[11]/[9]
[15]:	[12]/[9]

Exhibit ____ PLC–12
Texas Air Control Board RACT NOx Control Costs

		Reduction (tons/year)	Annualized Control Costs (million $)	Control Costs ($/ton)
Utility Boilers				
BPA	Gulf States Utilities	5619	13.5	2,403
DFW	Texas Utilities Electric	13589	32.9	2,421
DFW	City of Denton	39	0.03	769
DFW	City of Garland	234	0.5	2,137
ELP	El Paso Electric	1390	2.1	1,511
HOU	Houston Lighting and Power	10400	16.1	1,548
HOU	Gulf States Utilities	4292	6.4	1,491
Internal Combustion Engines				
	Rich Burn	11444	1	87
	Lean Burn 4–cycle	6530	7	1,072
	Lean Burn 2–cycle	9453	7.7	815
Industrial Gas Turbines				
BPA	>30 MW	1274	1.2	942
BPA	<=30 MW	374	1.7	4,545
HOU	>30 MW	39260	15.8	402
HOU	<=30 MW	2968	15.7	5,290

Source: Texas Air Control Board, 1992, "Draft NOx RACT Rule Discussion Paper".
Area Codes:
BPA = Beaumont/Port Arthur
DFW = Dallas/Fort Worth
ELP = El Paso
HOU = Houston/Galveston

Exhibit ____ PLC–14

Summary of Cost Recovery Considerations for Utility DSM and Efficiency Programs

	General		Cost Recovery Issues		Lost Revenue Issues		Incentives		
	Extensive Utility Experience?	Results Readily Measurable?	Significant costs?	Special Treatment Necessary?	Revenues Lost?	Special Recovery Justified?	Generally Good for Ratepayers?	Short–term Benefits for Shareholders?	Incentives Required?
Program Type	1	2	3	4	5	6	7	8	9
Energy Efficiency									
Investment	no	yes	yes	yes	yes	yes	yes	no	yes
Information	yes	no	no	no	maybe	no	yes	no	no
Load Management	yes	yes	yes	not usually	small	no	sometimes	often	no
Promotional	yes	sometimes	sometimes	no	negative	no	sometimes	yes	no
Rate Design	yes	sometimes	no	not usually	sometimes	rarely (set in rate case)	yes	sometimes	no
Supply–Side Efficiency	yes	yes	sometimes	no (capitalized)	no	no	yes	no	no

Notes:

[4]: Special treatment is necessary if the utility lacks extensive experience and will bear significant costs.

[6]: Special recovery is justified if the utility lacks extensive experience, results are readily measurable, and revenues are lost.

[9]: Incentives are necessary if the utility lacks extensive experience, results are readily measurable, ratepayers will generally benefit from the programs, and the shareholders will receive no short–term benefits from the programs.

Exhibit ____ PLC-15

Comparison of Incentive Structures