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COMMONWEALTH OF PENNSYLVANIA
PUBLIC UTILITIES COMMISSION

# INVESTIGATION INTO DEMAND SIDE MANAGEMENT BY ELECTRIC UTILITIES: UNIFORM COST RECOVERY MECHANISM

DIRECT TESTIMONY OF

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ON BEHALF OF THE

PENNSYLVANIA ENERGY OFFICE

Resource Insight, Inc.
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## I. Introduction and Qualifications

Q: Mr. Chernick, 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. Resource Insight, Inc.

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 Attachment 1 to this testimony.

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 Pennsylvania PUC in Docket No. R-842651, a 1984 Pennsylvania Power & Light rate case involving the need for and costs of a Susquehanna unit. In 1986, I testified in two Philadelphia Electric rate cases: Pennsylvania Docket No. R-850152, about the rate effects of the Limerick plant; and Pennsylvania Docket No. R-850290, on rates charged to small power producers.

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

A: Yes. I testified specifically on this issue in Vermont PSB Docket 5270 on behalf of Central Vermont Public Service Company, Conservation Law Foundation, Vermont Natural Resources Council, and Vermont PIRG. I have also testified on cost recovery in Massachusetts (Massachusetts DPU 472; 86-36; and 88-67), Michigan (Michigan PSC U-7775 and U-7785), and South Carolina (South Carolina PSC 91-216-E). I drafted comments on cost recovery for Pace University in New York PSC Case No. 28223.

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 DSM?

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.

Q: What is the purpose of this testimony?

A: In this testimony, I discuss the Commission's options regarding issues raised in the October 7, 1991 order in this docket and make recommendations on most of the Commission's major choices. I also comment on the specific proposals made by the Commission's Bureau of Conservation, Economics, and Energy Planning (CEEP) and incorporated in the Commission's order of October 7, 1991 in this docket. Page references to the CEEP proposal are to the October order.

In addition to the relatively brief comments in the body of this testimony, I am sponsoring a report prepared by Resource Insight for the Pennsylvania Energy Office on cost recovery and ratemaking for utility investment in demand management. That report, Attachment 2 to this testimony, discusses many of the same points covered in the text of the testimony in more detail and with a broader perspective. It also covers topics beyond the scope raised in the September order.[1]

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[1]For example, Attachment 2 discusses the importance of clarifying the application of "used and useful" and "excess capacity" concepts to DSM cost recovery.

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

A: The fundamental consideration in the Commission's deliberations on utility cost recovery is that 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. Utilities should be encouraged to use DSM to minimize energy service costs to their ratepayers.[2] The Commission should act to reduce or remove institutional and ratemaking barriers to cost-effective DSM. The utility's least-cost resource plan (which will include a large amount of DSM) should be the most rewarding resource plan.[3]

Appropriate DSM activity should receive the easiest, most rewarding, and least painful regulatory treatment of any resource acquisition option. Conversely, resource plans that do not fully utilize DSM should be more difficult, less rewarding, and at least potentially unpleasant for the utility and its shareholders.

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

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[2]Some regulators have interpreted their responsibility to the reduction of costs to a broader conception of society, reaching beyond the confines of their jurisdictions.

[3]This goal was recognized in the Commission's October 2, 1990 order, which initiated this docket.

A: If DSM 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 DSM cost recovery, the Commission should first consider the features of DSM 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 advocacy 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 DSM 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 Pennsylvania ratepayers with reliable energy services at the lowest possible cost, DSM is not an optional activity,[4] but an aspect of resource planning and acquisition as fundamental as fuel procurement or construction management. DSM cost recovery should be based on a preference for <u>maximum</u> development of cost-effective DSM. As noted by CEEP (p. 24, paragraph 2), a "minimum" amount of cost-effective DSM is a threshold requirement for acceptable utility planning.

Second, the potential for DSM is very large. Table 1 summarizes the level of DSM effort planned or underway for several utilities that have aggressively incorporated DSM in their resource plans. While efforts vary, the average level of effort for these utilities includes spending about 5% of revenues on DSM and reducing load growth by about 1% per year.

The proper level of DSM activity for any particular utility should be determined by careful integrated resource planning. Since the Pennsylvania planning processes have not yet adequately incorporated DSM, the experience of other utilities provides a useful ballpark estimate of the potential level of DSM activity. Table 2 extrapolates other utilities' plans to the Pennsylvania utilities. While I believe that the proper level of DSM activity should be

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[4]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.

## Table 1: Demand and Energy Savings, as Percent of Peak and Sales, and DSM Expenditures as Percent of Revenues

| | Peak savings (MW) [1] | Peak load (MW) [2] | Peak savings as % of peak [3] | Total energy savings (GWh) [4] | Total projected sales (GWh) [5] | Energy savings as % of sales [6] | Avg. annual DSM expenditures (1991$) [7] | 1991 Revenues (1,000,000 1991$) [8] | DSM expenditures as % of 1991 revenues (1991$) [9] |
|---|---|---|---|---|---|---|---|---|---|
| BECo (growth 1990-94 inclusive) | | | | | | | | | |
| Res.: | 8 | 734 | 1.1% | 73 | 3,709 | 2.0% | $6,342,960 | | 0.5% |
| C/I: | 109 | 2,159 | 5.0% | 454 | 10,145 | 4.5% | $38,137,008 | | 3.0% |
| Total: | 117 | 2,893 | 4.0% | 527 | 13,854 | 3.8% | $44,479,968 | $1,271 | 3.5% |
| Annual | | | 0.81% | | | 0.76% | | | |
| Eastern Utilities (growth 1991-95 inclusive) | | | | | | | | | |
| Res.: | 7 | NA | | 37 | 1,627 | 2.3% | $3,690,340 | | 1.4% |
| C/I: | 73 | NA | | 198 | 2,924 | 6.8% | $11,638,816 | | 4.4% |
| Total: | 80 | 869 | 9.2% | 236 | 4,622 | 5.1% | $15,329,156 | $264 | 5.8% |
| Annual | | | 1.84% | | | 1.02% | | | |
| NEES (growth 1991-1995 inclusive) | | | | | | | | | |
| Res.: | NA | | | 222 | 8,208 | 2.7% | | | |
| C/I: | NA | | | 757 | 14,487 | 5.2% | | | |
| Total: | 340 | 4,581 | 7.4% | 1,120 | 25,070 | 4.5% | $80,405,260 | $1,711 | 4.7% |
| Annual | | | 1.48% | | | 0.89% | | | |
| New York State Electric and Gas (growth in 1991-2008 inclusive) | | | | | | | | | |
| Res.: | NA | | | 912 | NA | | | | |
| C/I: | NA | | | 1,867 | NA | | | | |
| Total: | 846 | 4,470 | 18.9% | 2,794 | 22,170 | 12.6% | $81,582,263 | $1,218 | 6.7% |
| Annual | | | 1.05% | | | 0.70% | | | |
| Northeast Utilities (growth 1992-2000 inclusive) | | | | | | | | | |
| Res.: | 77 | NA | | 556 | 10,890 | 5.1% | | | |
| C/I: | 743 | NA | | 2,895 | 18,983 | 15.2% | | | |
| Total: | 819 | 5,543 | 14.8% | 3,460 | 30,180 | 11.5% | | | |
| Annual | | | 1.64% | | | 1.27% | | | |
| United Illuminating (growth 1992-2010 inclusive) | | | | | | | | | |
| Res.: | 48 | NA | | 47 | 2,259 | 2.1% | | | |
| C/I: | 262 | NA | | 776 | 5,021 | 15.4% | | | |
| Total: | 310 | 1,554 | 19.9% | 827 | 7,347 | 11.3% | | | |
| Annual | | | 1.05% | | | 0.59% | | | |
| Wisconsin Electric (growth 1991-2000 inclusive) | | | | | | | | | |
| Res.: | 77 | NA | | 291 | 6,808 | 4.3% | | | |
| C/I: | 211 | NA | | 739 | 19,358 | 3.8% | | | |
| Total: | 288 | 5,140 | 5.6% | 1030 | 29,902 | 3.4% | | | |
| Annual | | | 0.56% | | | 0.34% | | | |
| Average of annual figures | | | 1.2% | | | 0.8% | | | 5.2% |

*Notes to Table 1:*

| | |
|---|---|
| *[1]:* | *Energy (and peak) savings are for the final year of the interval indicated.* |
| *[2]:* | *Total sales (and peak) figures are for the final year of the interval indicated, and are pre–DSM forecasts; that is, they do not take into account reductions due to DSM.* |
| *[3]:* | *[1]/[2]* |
| *[4]:* | *[1] minus the savings (or peak) of the year preceding the first year of the specified interval.* |
| *[5]:* | *[2] minus the sales (or peak) of the year preceding the first year of the specified interval. For example, BECo's projected sales growth equals 1994 sales minus 1989 sales.* |
| *[6]:* | *[4]/[5]* |
| *[9]:* | *[7]/[8]* |

*Sources:*

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

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

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

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

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

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

*WEPCo figures from "Supplemental Information to Advance Plan 6", filed March 1 1991.*

*Revenues from Public Utilities Reports, Inc., "The P.U.R. Analysis of Investor–Owned Electric and Gas Utilities." 1991.*

# Table 2: Plausible Pennsylvania DSM Expenditures and Savings – 15 Year Program

| Utility | 1990 peak demand (MW) | Peak savings (MW) | 1990 energy sales (GWh) | Energy savings (GWh) | 1990 electric revenues (million 1991$) | Annual DSM expenditures (million 1991$) |
|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] |
| Duquesne Light | 2,379 | 428 | 13,637 | 1,636 | $1,185 | $62 |
| Metropolitan Edison | 1,773 | 319 | 9,718 | 1,166 | $706 | $37 |
| Pennsylvania Electric | 2,282 | 411 | 12,221 | 1,467 | $810 | $42 |
| Pennsylvania Power | 667 | 120 | 4,804 | 576 | $330 | $17 |
| Pennsylvania Power & Light | 5,661 | 1,019 | 34,603 | 4,152 | $2,496 | $130 |
| Philadelphia Electric | 6,755 | 1,216 | 34,310 | 4,117 | $3,470 | $180 |
| West Penn Power | 2,703 | 487 | 24,961 | 2,995 | $1,023 | $53 |
| Total | 22,220 | 4,000 | 134,254 | 16,110 | $10,020 | $521 |

*Notes:*
*[1], [3], [5] From Public Utilities Reports, Inc., "The P.U.R. Analysis of Investor–Owned Electric and Gas Utilities." 1991.*
*Penn Power's figures are from the company's 1989 Ferc Form 1 and the 1989 Financial Statistics of Selected Electric Utilities.*
*[2] Assumes 15 * 1.2 % saving, from Table 1.*
*[4] Assumes 15 * .8% saving from Table 1.*
*[6] Assumes 5.2% * [5].*
*1991 dollars were calculated assuming a 4.5% inflation rate.*

determined by a careful integrated resource planning process, the New England experience can give a ballpark approximation of the potential level of DSM activity in Pennsylvania. Once they ramp up their programs, those utilities might collectively spend as much as $500 million annually to achieve all cost-effective energy-efficiency savings in their service territories. The resulting programs might reduce load by about 4,000 MW and 16,000 annual GWh over the next 15 years, saving the equivalent of 4,800 MW of capacity (with 20% reserves) and the energy production of 2,600 MW of baseload coal plants at a 70% capacity factor. The Commission should establish cost recovery mechanisms and procedures that will be capable of handling programs of this magnitude.

Third, many attractive DSM opportunities will disappear if they are not pursued as soon as they become available. Examples of such "lost-opportunity" resources include new construction, routine replacement of failed or outdated equipment and appliances, and industrial expansion or process changes. Unlike most supply resource options, these demand resources cannot be captured later. Hence, utilities should promptly implement effective programs for these resources without waiting for an imminent capacity need.

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

Q: How should DSM cost recovery be structured?

A: As discussed in Attachment 2, 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 Office of Consumer Advocate (OCA), and other parties. Other important considerations vary between utilities, including financial condition, frequency of rate cases, and familiarity with DSM. Cost recovery techniques that may be suitable to DSM 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 mechanism for periodic recovery by each utility of at least some of its DSM-related costs. I refer to that mechanism by the title used by CEEP, the Energy Efficiency Adjustment (EEA). Most of my comments would not be changed significantly if the EEA were replaced by an energy efficiency deferral mechanism that accumulated DSM costs above those already included in rates.

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

A: Special cost recovery procedures will likely be needed only for 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.[5] Special cost recovery is certainly unnecessary for promotional or load-building programs, which are designed to increase the penetration of electric technologies.[6] These promotional programs already reward utilities with increased sales and profits. The Commission need not be concerned with

[5] 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.

[6] 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.

Table 3 lists the types of programs proposed by CEEP, Pennsylvania utilities, or other utilities for inclusion 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 large and innovative load management programs or radical rate design innovations.[7]

Q: How is the remainder of this testimony organized?

A: Sections II through IV consider in turn the three major categories of revenues and expenditures that should be considered in this proceeding: direct DSM program costs, lost revenue recovery, and explicit incentives. Section V discusses aspects of the cost recovery mechanism that cut across these three recovery categories. Section VI considers the standards and process for regulatory review of all cost recovery. Section VII summarizes my major recommendations.

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

[7]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.

# Table 3: 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.*

evaluation, which verifies the magnitude of savings and lost revenues and is essential to ensuring that the DSM portfolio is prudent. The monitoring and evaluation function is a very important part of the overall DSM effort.[8]

This testimony does not discuss recovering DSM 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. I understand that the Commission will be considering program design in another portion of this proceeding. The Commission should not make policy on participant cost shares in the context of the cost recovery investigation.

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. Fully covering any of these topics in this part of the proceeding is probably not useful, as they would distract the Commission's attention from the central issues of cost recovery. Hence, the program costs discussed in this testimony include administrative costs, joint program delivery costs, and whatever portion of direct costs is not

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[8]The Pennsylvania Energy Office has discussed with several utilities and other interested parties a cooperative effort to define minimum standards for monitoring and evaluation programs.

recovered from participants, without any attempt to determine that portion.

## II. Direct Costs

### A. Scope of costs to be recovered

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

A: Eligible costs should include at least the costs of DSM 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.

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 DSM 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 DSM labor is offset by a decrease in marketing labor.

Similar issues arise for overhead costs. The EEA 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 DSM are really incremental between rate cases than they will for outside services clearly related to the DSM program.

Q: The CEEP suggests that cost recovery should be limited to expenditures under an "overall cost cap" of 105% of the approved expenditure level. Is this spending cap appropriate?

A: No. Utilities should be encouraged to accelerate their DSM 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 DSM costs be related to program preapproval?

A: The Commission should offer the utilities 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 factors can delay implementation.[9]

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

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[9]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.

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 restraint in the DSM field.[10]

Q: Is any spending cap appropriate?

A: The Commission should not establish an a priori spending cap, since that would limit the utility's ability to manage its DSM program. Opportunities, such as those encountered by the New England utilities, would be lost.

The Commission might reasonably require the utility 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 DSM or imprudent failure to acquire DSM) would not be recoverable, should discourage utilities from frivolous and irresponsible program expansion or contraction.

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[10]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 Order No. 9509 (PEPCo).

B. Expensing and amortization

Q: Should the Commission establish a preference for a specific method for accounting for DSM 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 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 power plants, building new facilities) are capitalized and amortized through the ratebasing mechanism. By this standard, DSM expenditures, which provide energy services for many years, should be recovered over many years. This suggests amortization of DSM expenditures. These amortized costs could either be recovered through the EEA or capitalized and recovered in rates.

Q: Does this reasoning also apply to DSM 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, DSM program design would be capitalized.

Q: Should all DSM 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 DSM costs, amortize them over a short period (3-5 years), or amortize them over the full life of the measures (10-20 years).

A ratemaking consideration that may be particularly important for Pennsylvania utilities in the next decade is the effect of the Clean Air Act Amendments of 1990. Some utilities will face significant compliance costs in 1995 or 2000. For the Phase I utilities, expensing DSM expenditures until 1994 and amortizing them from 1995 onward may be desirable to minimize the effect of 1992-94 DSM efforts on post-1994 rates and bills.

Each utility will have a different projected rate and revenue requirement forecast. The cost recovery pattern for each utility should reflect those projections.

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

A: Yes. According to Boston Edison's filing for its 1992 programs, in Massachusetts DPU Docket 90-335, expensing its DSM portfolio would result in a rate increase of 5.6%, adding .54¢/kWh to its average rates.

Q: Is amortization more expensive than expensing?

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 = utility incremental cost of capital,

Tax = income tax paid to allow payment of equity return

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

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 DSM 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.[11]

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[11]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.

If expensing were generically preferable to amortization, the Commission would already be expensing utility supply-side investments. The Commission does not expense power plants because, among other things, that ratemaking treatment would cause huge rate shocks. Since expensing power plant construction costs would not be feasible, utilities would avoid building capacity, even where that was in the best interest of customers. Similarly, if the Commission were to insist on expensing DSM, it could create an artificial ratemaking constraint, potentially resulting in the unnecessary delay of highly cost-effective DSM.

Q: Should the EEA specify an amortization period or a method for computing such a period?

A: No. The Commission should list the concerns utilities should weigh in developing an annual cost-recovery proposal, including matching measure lives and minimizing rate instability. The Commission should instruct the utility 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: The CEEP has proposed that the interest credit be computed from yields on long-term Treasury securities, grossed up for taxes. Is this appropriate?

A: No. First, the utility cannot borrow at Treasury rates. Second, the utility will probably need or use equity, as well as debt. Third, the debt expense will be tax-deductible, so the cost of debt borrowing should not be grossed up for taxes. The first two factors increase the cost of financing, while the third decreases it, compared to the CEEP proposal.

The CEEP formula might happen to produce about the right rate for the cost of financing, but this result would be coincidental.

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

A: Without some compelling reason to the contrary, the treatment of capitalized DSM costs should resemble the treatment of capitalized supply costs as closely as possible.[12] Hence, the interest credit on the amortized balance should be one of the following:

- If DSM 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 the utility's overall cost of capital, plus tax adjustment for the equity portion of the cost.

- If DSM 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 the utility's AFUDC rate, which is usually close to the overall cost of capital. Where utilities include in their AFUDC rate significant amounts of short-term debt or an adjustment for the

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[12]This is true regardless of whether the costs are amortized and recovered through an adjustment mechanism, deferred to the rate case and capitalized, or collected temporarily through the EEA until the rate case.

debt portion of the cost, those items should be reflected in the DSM deferral cost as well.

- If DSM costs are financed through a DSM-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 should mirror the treatment of in-service supply investments, the interest credit for in-service DSM should be recovered on a current basis. However, this issue should be addressed as part of the rate effect analysis.

## III. Lost Revenues

### A. Scope of recovery mechanism

Q: What is the relationship between DSM 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 ECR), the effective lost revenues for the utility are roughly equal to the lost base rates.

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 <u>maximize</u> lost revenues by maximizing the scope of its DSM programs. Hence, cost recovery for lost revenues should not assume that utilities will attempt to minimize lost revenues due to DSM, and should not encourage utilities to minimize lost revenues.

Q: For how long is lost-revenue recovery from a DSM 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 DSM-related reduction; no additional revenues will be lost after the effective date of the new rates.

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 DSM 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.[13] 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: Should all lost revenues from eligible and prudent programs be recoverable?

A: Yes. A utility which undertakes significant energy efficiency improvements without a mechanism for recovering lost revenues faces a significant penalty in the form of lost revenues. The Commission should eliminate, not just reduce, this penalty.

CEEP proposes to retain some existing disincentives that impede utility investment in DSM by supporting an arbitrary disallowance of 5% of lost revenues in the first year of a program's operation, 10% in the next year, 15% in the third year, and so on. Thus, utilities would be

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[13]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.

encouraged to terminate every program after a single year of operation, even if it were operating well. Even in that first year of operation, the utility would have to expect its shareholders' earnings would be reduced by the 5% disallowance.

CEEP also suggests that the duration of lost revenue recovery last five years, a period that will sometimes be shorter than the smaller of (1) measure life, and (2) time to the next general rate case effective date. This limitation would have some interesting effects. It would discourage DSM if rate case filings are rare; it would encourage rate cases if the utility finds that DSM is unavoidable or overwhelmingly desirable for other reasons. Discouraging DSM would be an unequivocally adverse effect. Encouraging the filing of rate cases may be good or bad; if the Commission wants to encourage frequent rate cases, it probably has better ways of doing so.

Q: Is the need for generation capacity within a reasonable amount of time related to the appropriateness of lost-revenue recovery, as suggested by the CEEP proposal (page 16)?

A: No. Even without a need for new generating capacity, a long list of costs may be avoided, including:

- fuel,
- variable O&M, fuel handling, and related overheads,
- purchased power,

- environmental compliance costs (e.g., the sulfur allowances required under the Clean Air Act Amendments),
- transmission and distribution investments (and associated O&M), and
- life extensions, demothballing, and some other costs of existing generation.

In addition, reduced sales and peak load may allow for increased off-system sales of energy and capacity and for mothballing of excess capacity.

The total benefits of DSM can be quite substantial even without need for new capacity. If DSM undertaken prudently -- which requires a reasonable expectation that the DSM will be cost-effective given reasonable estimates of avoided costs and other parameters -- then the utility's lost revenues should be recovered.[14]

If it has any effect at all, the lack of short-term generation capacity needs increases the propriety of lost-revenue recovery. Avoiding the need to build expensive and risky capacity may be some compensation for lost revenues; without this offsetting consideration, utilities will find DSM even less attractive.

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[14] If a program or measure is not cost-effective, due to lower effectiveness, the lost revenues will be lower than originally estimated, but they will probably be greater than zero. If the DSM option is not cost-effective for some other reason (such as high costs, or low avoided costs), lost revenues may be just as high as expected. The revenues actually lost should be collected, regardless of their relationship to earlier estimates, and regardless of the after-the-fact determinations of program cost-effectiveness.

Q: CEEP has suggested that the lost revenue mechanism exclude measures producing only off-peak savings. Does this make sense?

A: No. Some measures are cost-effective even though they save only off-peak energy.[15] If the measure is cost-effective, the utility should pursue it. If the utility should pursue it, the Commission should remove the lost-revenue disincentive.

Q: Do DSM programs for new loads create lost revenues?

A: Yes. In the absence of DSM, the utility would have made the new sales and received the additional revenues. DSM results in the loss of those revenues. A kWh of DSM 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 the utility will be allowed to charge until rates change again. Under the current regulatory structure and <u>without</u> DSM, the utility receives the additional revenues from sales growth. These additional revenues help offset cost increases from inflation.[16] Under the current regulatory structure and

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[15] It is not clear what CEEP means by "off-peak demand and/or energy savings." (p. 15) The off-peak energy period is defined differently by different utilities, and for different purposes.

[16] The load growth may not fully offset other cost increases or it may more than offset those increases and produce an excessive return on equity.

with DSM, the utility loses these revenues, without any compensation.[17]

CEEP proposes that lost revenue recovery be limited to existing load (p. 16).[18] This proposal would encourage utilities to ignore transitory DSM opportunities, which will then be permanently lost.[19]

Q: Should load growth affect recovery?

A: No. Lost revenues must be considered from a "but for" perspective: how much better off would the utility's shareholders have been, but for the DSM the company undertook? If load growth reduces lost revenue recovery, it should also be grounds for automatic rate reductions without DSM. Otherwise, the scales would be tilted against DSM.

Q: If the Commission wanted to include an offset for load growth, does the CEEP proposal suggest an appropriate base line?

A: No. CEEP proposes to use growth rates from a long-term load forecast to adjust DSM cost recovery (p. 22, first

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[17]Any cost savings that may result from the reduced load growth should be reflected in the valuation of lost revenues, as discussed below.

[18]CEEP does not specify how "new" loads would be defined. Is additional equipment in an existing building a "new" load? What if some existing equipment will be retired or used only for back-up? Is a larger replacement unit a "new" load? Is a new building a "new" load? What if it replaces an older building?

[19]"Lost opportunity" resources, such as increased wall insulation or increased motor efficiencies, can be economically captured only when the building is built or the equipment is purchased.

paragraph). Lost sales due to DSM would "be reduced by 50% of the amount, if any, by which actual KWH sales exceeded sales" projected in the twenty-year forecast. This proposal has at least four problems.

First, long-term forecasts are generally not intended to be the best short-term estimate. Different techniques are used for short-term and long-term forecasts, and the results are used for different purposes. There is no reason to believe that a long-term forecast developed for resource planning will be useful in predicting short-term sales trends for budgeting or for lost revenue adjustments.

Second, it is my understanding that the utilities' forecasts are not normally critically reviewed and approved by the Commission or any other regulatory body. Using utility-generated forecasts for regulatory purposes without external review invites abuse.

Third, the CEEP proposal would encourage the utility to overstate short-term sales projections to minimize the probability that post-DSM sales will exceed the forecast. This overstatement of sales may result in inefficient short-term decisions, such as excessive T&D investment, fuel stocks, and off-system purchases; and inadequate off-system sales.

Fourth, since the CEEP proposal would force utilities to write off lost revenues in periods of unexpectedly high growth, it would encourage them to reduce DSM in such periods. Ironically, utilities should be encouraged to accelerate DSM programs in periods of high growth to minimize the volatility in growth.[20] Indeed, DSM programs targeted at new construction tend to accelerate automatically in periods of high growth and hence high rates of new construction and lost opportunities.

Q: Without an offset for load growth, might lost revenue recovery result in the utility's earning more than its allowed rate of return?

A: No. Properly designed lost revenue recovery will restore the utility to the earning situation in which it would have been, but for the DSM. If the utility would have been overearning without DSM, and the DSM portfolio reduces or eliminates the overearning, the lost revenue recovery will simply put the utility back to the earning level it would have enjoyed without DSM. Some events independent of DSM activities must cause overearning; lost-revenue recovery may restore, but can never cause, overearning.

Q: Is it appropriate to cap lost-revenue recovery so that it does not restore the utility to overearning?

A: Maybe. The utility should not be made worse off by the DSM program. If the utility could have overearned without the DSM program, and would have been allowed to continue

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[20] Hirst, E., Benefits and Costs of Small, Short-lead-time Power Plants and Demand-side Programs in an Era of Load-growth Uncertainty. ORNL/CON 278, March 1989.

overearning for an extended period without being forced to reduce rates, then the initiation of an effective DSM program should not become an opportunity to impose an earning cap.

On the other hand, if overearning without DSM would have caused the Commission, Staff, or OCA to force the utility into a rate case or a negotiated rate reduction, then the lost-revenue mechanism should mirror this fact. PEPCo's Maryland DSM cost recovery mechanism has just such a test: the utility recovers all DSM costs unless recovery would produce a rate of return above the level allowed in its last rate case.[21] The description of the PEPCo cost-recovery mechanism is attached as Attachment 4.

Q: Is the PEPCo mechanism preferable to the CEEP approach?

A: Yes. The PEPCo mechanism focuses directly on earnings, while CEEP uses sales as a proxy for earnings. A utility may have higher-than-expected load growth but only moderate financial results, or low load growth but very high returns. Earnings are driven by many factors other than energy sales: patterns of expenses (e.g., O&M, coal-gasification cleanup requirements), revenues (e.g., from off-system sales, changes in sales mixes), depreciation (which may fall in the years following the incorporation of a large power plant),

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[21]The Maryland parties all appeared to believe that, in the absence of DSM, the utility would not be allowed to continue charging rates that provide a return on equity in excess of the latest allowed return. Hence, the excess earnings tests maintains the status quo.

and interest expenses (which vary with rate base and with interest rates), among other things.

Q: Should the Commission impose earning limits on the energy utilities under its jurisdiction?

A: That is a far-reaching policy issue, well beyond the scope of the ratemaking phase of a DSM proceeding. If the Commission wishes to impose earnings limits on utilities, those limits should function regardless of whether the utility is engaged in a vigorous DSM effort. The limit would be imposed through periodic earnings reviews and Commission-ordered rate reductions.

Rather than limiting earnings, which depend to some extent on the ability of utility management to minimize costs, the Commission might prefer to establish a revenue-sales decoupling mechanism, such as the per-customer ERAM discussed in Section IV.B.5.c of Attachment 2. Decoupling has a number of advantages for utilities and their customers, in addition to eliminating disincentives for efficiency programs and undue incentives for promotional programs. The Commission might explore decoupling alternatives in future proceedings.

Q: Should lost revenue recovery be limited to "energy production costs saved" as proposed by CEEP (p. A-2)?

A: No. This limitation appears to be arbitrary and irrelevant. Again, if a program is cost-effective and prudent, the utility should undertake it; utilities should be allowed recovery of all lost revenues from prudent programs.[22]

Q: Please discuss CEEP's suggestion that lost revenue recovery be allowed only where (1) capacity is needed within 10 years, and (2) the DSM program would produce "more than short-term capacity savings."

A: I have difficulty following CEEP's reasoning in this section. The suggestion appears to be based on the statement:

> If the non-energy production related component of KWH estimated to be saved by a program measure exceeds the energy cost component, ratepayer costs would be increased, since the lost revenue to be recouped from ratepayers would exceed energy production cost savings. Thus we normally will not approve such measures, when a utility does not need capacity. (pp. 16-17)

This seems to suggest that the Rate Impact Measure or something similar be applied to lost-revenue recovery and to screening of DSM measures and programs. The RIM is useless for screening measures or programs, as discussed in Attachment 3 to this testimony. There is certainly no basis for using the RIM in determining lost-revenue recovery.

The CEEP discussion may be based on an assumption that some fixed relationship exists between the cost-effectiveness (or rate effect) of a program and the

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[22]CEEP does not define "energy production costs." Avoided costs attributable to energy should include fuel, net purchased power, variable O&M, related overheads, and the capitalized energy cost represented by the difference between the cost of avoidable units and the cost of peaking capacity.

percentage of the avoided rate that is composed of "energy" costs. It is unclear why CEEP believes this relationship holds. In fact, some measures that are valuable primarily for energy savings are highly cost-effective, while some measures that save primarily peak demand are not cost-effective, or are only marginally cost-effective.

B. Estimation of lost revenues

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 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:[23]

[23]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

- 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 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, which are discussed further in Section VI. Reconciliation avoids an over-emphasis on up-front projections.

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later adjustment and reconciliation of the initial estimates.

Q: The CEEP proposal suggests that retroactive adjustments to preliminary estimates of lost revenues would be "speculative." Is this accurate?

A: No. The most speculative estimates of load reductions are those made before program implementation. Increased data obtained through M&E reduces the speculation and replaces it with actual results.

Q: Would reliance on pre-implementation estimates of lost revenues create perverse incentives?

A: Yes. Suppose the utility is assured of receiving compensation for a fixed amount of lost revenues per installation, say 400 kWh. Suppose further that the utility can skew installations toward larger and smaller customers and can affect installation effectiveness. If the utility minimizes the installations' size and effectiveness, it can save just 200 kWh per installation. If lost revenues are worth 5¢/kWh, paying the utility 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 the utility 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, utilities that do a worse-than-projected job of delivering DSM savings would be rewarded; over-achievers would be punished.

Q: How should utilities compute their 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 utilities hope to recover lost demand revenues, they will need M&E programs capable of producing credible estimates of billing demand reductions.

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 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. Utilities which request lost revenue recovery, but have not filed a rate case within the last three years, should be expected to rebut a presumption that marginal demand-related T&D has been avoided.

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 ECR mechanism.

As noted above, lost revenues should be computed net of the effects of any promotional programs, and net of the promotional effects of conservation or load management 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 DSM 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. Depending on the recovery mechanism selected, and on the timing of program implementation, collection may start slightly prior to the program or significantly after. The Commission may reasonably require that the utility actually start implementation, and demonstrate a rate on installation, prior to the recovery of any lost revenues. To avoid the need for refunds, the Commission may wish to initially allow relatively low levels of lost-revenue recovery, corresponding to the lower end of the range of uncertainty in program effects.[24]

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[24]This treatment would result in additional recovery through the reconciliation process.

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 the utility can report results, and on the speed with which the parties can review them.[25]

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

## IV. Incentives

### A. Purpose and scope of incentives

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

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

Q: Why are incentives necessary?

A: DSM investment by utilities tends to be impeded by organizational inertia, vested interests, and risk aversion. These issues are discussed in some detail in Section V.A.1 of Attachment 2.

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

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

Q: What are the implications of the basic rationale for DSM 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.[26]

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 DSM is reduced for the same saving.

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 Pennsylvania's larger utilities, with net income in the

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[26]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.

hundreds of millions of dollars, 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 DSM capability-building period. They should be phased out once DSM is a routine portion of utility planning and operations, institutional barriers have been overcome, and the Commission, customers, and other parties can evaluate utility DSM 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 DSM 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 DSM, since those changes will be critical to long-run DSM savings for ratepayers and DSM 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 DSM 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. I understand that such disallowances are authorized by the performance ratemaking provisions of 65 P.S. § 523.

B. 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.[27] Much lower incentives (e.g., a 0.1% equity increment) are probably too small to have much effect.[28] 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 on equity for an 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

[27]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 5/16/90 (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).

[28]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.

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.[29] The TRC measures the contribution of a DSM measure or program to achieving a least-cost resource mix. Only an incentive based on the TRC provides directions to the utility consistent with the objective of least-cost planning. CEEP's proposal to base incentives on the utility cost test would ignore participant costs and benefits; this could result in higher utility incentives for options that actually increased the costs of energy services, but shifted more of the costs to program

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[29]The terms "Total Resource Cost test" and "Societal Test" are often used interchangeably; I use the term "TRC" here to refer to any test that includes all identified costs and benefits, regardless of who pays or receives them. The TRC equals the difference between total benefits (avoided costs, including non-electric costs avoided by participants) and total DSM costs (utility and participant expenditures, including capital and O&M). Philadelphia Electric advocates the use of the TRC for the incentive computation.

participants. The CEEP proposal would encourage inefficient and counterproductive utility actions.

Q: Are the avoided costs due to DSM worth the same as avoided costs for qualifying facilities?

A: The avoided costs due to a kWh or kW of DSM differ from (and are greater than) avoided costs for qualifying facilities, in terms of:

> **Load shape and avoided energy costs:** DSM tends to provide a larger fraction of its energy in high-load hours than low-load hours (even within a rating period), since the equipment whose efficiency is improved (by definition) operates more in the high-load hours. Hence, the average kWh saved by DSM is more valuable than the average kWh provided by a QF.
>
> **Load factor and demand costs:** DSM tends to provide more peak demand per kWh than does baseload supply, so each $/kW of demand-related costs is worth more in ¢/kWh for DSM than for QFs.
>
> **Losses:** DSM avoids losses, while supply does not.
>
> **Transmission and distribution costs:** DSM (especially efficiency) avoids T&D, while supply does not.
>
> **Environmental costs:** DSM has little if any adverse environmental effects; most supply sources have some. This makes DSM more valuable in terms of reducing the utility's direct costs of compliance, and in terms of reducing the cost to Pennsylvania as a whole.

Avoided costs should include off-system transactions; all PJM utilities have avoided capacity costs at least by about 1994, and perhaps sooner, as opportunities arise for sales to other pool members. Avoided costs should also include potential cost reductions from mothballing capacity and from avoiding reactivation and life extensions.

While cost-recovery guidelines should not prescribe an avoided-cost methodology, which would be beyond the scope of this proceeding, I recommend that the Commission list the cost components utilities should consider in developing their avoided cost estimates and program designs. The Commission should also put the utilities on notice that failure to pursue cost-effective DSM, whether due to failure to use the TRC, improperly estimated avoided costs, or other errors, may result in cost disallowances and other penalties.

Q: Should avoided capacity costs be included for measures with lives of less than 10 years?

A: Yes. As I discussed above in connection with lost revenues, all avoided costs should be included in all analyses. Delaying the need for a 1994 purchase to 1996, or allowing additional sales from 1997 to 2000, are real benefits that should be included in the computation of measure and program cost-effectiveness and incentives.

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.

C. 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:

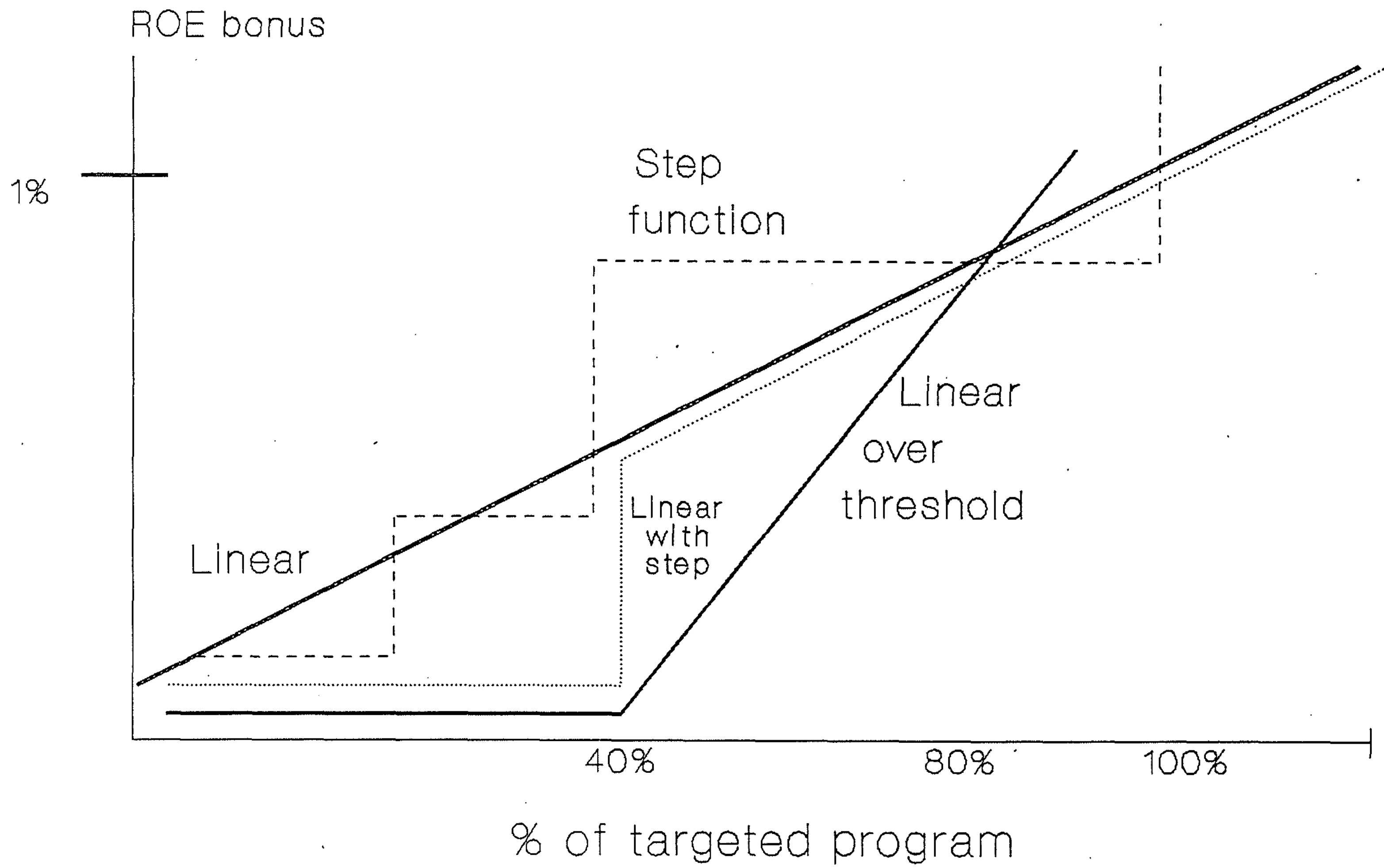
- linear,
- step function,
- linear above a step, and
- linear from zero above a threshold.

These relationships are illustrated in Figure 1. The four examples are constructed so that the incentive would be the same for 80% of the target.

The linear form has been requested by Penn Power and PECo, among others. It has been implemented by the New York Public Service Commission for most of its utilities and in various forms in other jurisdictions.

The step function approach has been used by the Wisconsin PSC. There are 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,

# Figure 1
## Comparison of Incentive Structures



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 is used by the New York PSC for Consolidated Edison and Orange and Rockland, and has been proposed by CEEP, with two steps: to 15% of net benefits at 75% of the target level and to 20% at the target level. This approach 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. The Massachusetts DPU uses this approach for electric and gas utilities.[30] Similar approaches include one in place in Rhode Island and one approved in Vermont. California incentives include both a threshold and penalties below the threshold. 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 DSM 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.

Q: Should incentives be reduced if the utility spends more than projected?

A: No. This outcome, suggested by CEEP on page 20, would provide exactly the wrong incentives.

Q: Should incentives be offered for non-cost-effective programs?

A: Not in general. Utilities usually invest in non-cost-effective programs because they are mandated by regulators for social reasons. These programs may be justified by

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[30]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.

equity and other considerations, but are not driven by least-cost resource planning. Ratepayer support for these programs may contribute to the common good, but I see no reason for ratepayers (most of whom cannot receive the benefits) to reward utilities for delivering the essentially philanthropic services for which the ratepayers are already bearing the direct costs.

Utilities generally will assist in providing DSM services to low-income customers, especially on a small scale; incentives are not necessary for this purpose.[31] Incentives are no more appropriate for non-cost-effective DSM programs than for other social programs operated through the utilities, such as CrimeWatch, or programs that train utility staff to recognize and report child abuse or elders in need of service.[32]

Q: If incentives are given for approved non-cost-effective programs, should they be based on the costs of the programs?

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[31]Utilities may see the provision of DSM services to low-income households, for example, as a way to reduce bad debt and generate good will at the same time.

[32]Many low-income DSM programs have not been cost-effective because they were really two related programs: housing enhancement and DSM. These programs frequently repair broken windows, patch leaky roofs, and make other expensive structural repairs without which DSM investments would be pointless. In these situations, it may be possible to isolate the costs and effectiveness of the DSM investment <u>per se</u> and grant incentives for those investments along with other DSM. The structural improvements are socially valuable for preventing homelessness and other problems, but cannot be meaningfully compared to utility avoided costs.

A: The incentive should not be based on cost, since that simply encourages the utility to spend money. The incentive should be based on energy and demand savings, gross resource savings, or a modified net benefit computation. For example, if a socially desirable program were expected to have a benefit/cost ratio of 0.80, the incentive might be structured to given the utility a share of a modified net benefit, such as 5% of

(1.25 * benefits) - costs.

This formula would give the utility no incentive if benefits equalled 80% of costs; but if the utility could increase the benefits or decrease the costs, it would receive an incentive. The larger the benefits, and the lower the costs, the higher the utility's incentive. This structure would encourage the utility to be both effective and efficient in delivering the services. Paying incentives as a fraction of costs would encourage the utility to be inefficient, and provide no bonus for effectiveness.

## V. Cost Recovery Mechanism

Q: Do you have any comments on CEEP'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 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 the utility overstates its sales, it will have an opportunity to make up the undercollection. If the utility's sales are underestimated, the overcollection will be returned to the ratepayers.

Q: Do you have any concerns about the details of the mechanism CEEP has suggested?

A: Yes. I disagree with the CEEP proposal in three areas. First, CEEP suggests that interest for the EEA, like that for the ECR, be computed on overcollections but not on undercollections. This limitation works in the desired direction for the ECR. Since utilities that allow fuel costs to rise are not compensated for the time lag between expenditure and recovery, cost control is encouraged. The same limitation works in the wrong direction for DSM, discouraging utilities from incurring additional DSM costs by pursuing additional DSM beyond projected levels.[33] While ratepayers are rarely better off paying more than expected for fuel, they are often better off paying for more DSM than previously expected. Interest should be allowed for both overcollections and undercollections.

Second, I recommend that the EEA 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.[34] Separately identifying any of these costs as a line item on bills would attract attention, mostly negative. DSM costs should neither be singled out nor preferentially sheltered from public scrutiny. Bill stuffers could certainly describe the magnitude of the DSM portfolio, with projections of the number of participants, the costs, and the savings.

Third, I believe that the CEEP proposal that the EEA be effective on April 1 for all utilities may be too rigid.

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[33]The same disincentive would operate whenever the EEA happened to be undercollecting DSM costs.

[34]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.

For each utility, the EEA should be implemented on the least disruptive date, such as when seasonal rate changes take effect. Since rates are changing at that time, the effect of the EEA on bills will not obscure consumption trends and price signals. For some utilities, the effective date of the ECR may be the best choice, but this is not necessarily true for all utilities.

Q: CEEP (p. 12) proposes that the EEA be allocated to rate classes in proportion to their revenues. Do you agree?

A: No. DSM costs usually should be collected primarily from the classes receiving the DSM 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 DSM 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.

Secondarily, the direct costs of DSM resources might be allocated in proportion to energy and peak demand usage, as would supply resources.[35] This approach is problematic for most utilities, except those with embedded costs well below marginal costs, where a reduction in any class's load will help to hold down rate increases for all classes. For the more common case, in which embedded costs are above or close to marginal costs, allocating DSM costs as resources will tend to create tensions between classes. 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).[36] No such tension arises if each class pays for its own programs.

The CEEP proposal to allocate costs in proportion to existing revenues would allocate a substantial amount of DSM costs to customer-related costs, such as meters, services, and the minimum distribution system. None of these costs affects or is affected by DSM expenditures. This allocation is unfair to classes such as residential and streetlighting customers, with larger-than-average portions of customer-related costs.

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[35]It is more difficult to justify this approach for lost revenues, which are directly associated with savings for a particular class.

[36]This approach can also raise the bills of customers who are unable to participate in any programs that would reduce their bills by a similar amount.

Q: Does your answer imply that DSM is not a system planning resource?

A: Not at all. DSM has benefits at two levels: the system and the participant. The system's cost of service declines as a result of DSM, and the participant's bill also declines. In many cases, the participant benefit will exceed the system benefit. Hence, the participant's class is better situated to pay for the DSM than is the rest of the system.

The system benefits are quite real, and should be used in determining whether particular DSM measures and programs are cost-effective. However, the participant benefits are also quite real, and should be considered in determining the allocation of DSM costs between classes.

VI. Review of Utility Programs and Cost Recovery Requests

A. Procedure

Q: How should 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. Notice or copies of filings should be served on all participants in the utility's previous rate case, the utility's previous DSM proceeding, and anyone registered with the Commission to receive such notice.

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.

For the schedule proposed by CEEP, with the EEA effective as of April 1, the review of program design and cost recovery should start the preceding fall. The CEEP suggestion that the programs be filed with the Commission by February 1, and the EEA computation be filed March 1, would not provide an opportunity for sufficient review.

As a practical matter, the Commission and the parties cannot effectively review six different DSM plans simultaneously, particularly on a short schedule.[37] The list on page 26 of the CEEP proposal of items that must be covered in the preapproval process only hints at the complexity of the process.[38] Hence, either the filings should be staggered or a significant amount of time should be allowed for review, especially in the first few years of the program. If all six programs are to be approved with EEAs effective April 1, the DSM programs should be filed with the May 1 resource plan, and the draft EEA should be filed soon thereafter.

B. Standards

Q: What should the utility be required to demonstrate to be eligible for EEA cost recovery?

A: To be eligible for EEA cost recovery, the utility will need to demonstrate that its energy efficiency programs are prudent and that they represent a significant level of

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[37]If PennElec and MetEd have different programs, there would be seven reviews.

[38]As discussed elsewhere, I do not agree with CEEP's view that costs and savings per installation should be fixed for cost recovery purposes prior to implementation and evaluation. I also believe that CEEP overemphasizes the importance of controlling utility spending on DSM. Nonetheless, the approval of the DSM portfolio will require approval of the design of each program, including incentive levels, delivery mechanisms, and measures to be included; approval of avoided-cost estimates (which are themselves quite complex); and review of estimates of costs, savings and participation rates, to determine whether each program and each measure within the program is likely to be cost-effective, as well as to determine whether some rejected programs and measures should have been included.

effort.[39] A "significant level" might initially be defined as spending at least 1% of gross revenues and having a reasonable expectation of reducing energy use (e.g., sales growth) by 0.25% annually.

To be eligible for lost-revenue recovery, the utility will need to demonstrate that its programs are prudent and significant, and that monitoring and evaluation is adequate to support the recovery claimed. In addition, the utility will need to determine the magnitude of the various offsets to lost revenues, as discussed in Section III, or demonstrate that those are de minimis.

To be eligible for incentives, the utility will need to demonstrate that its programs are aggressive, state-of-the-art, and a high effort level. Since New England utilities are spending about 5% of annual revenues on DSM, a high level of effort for Pennsylvania would probably require at least 2% of annual revenues. This should be a guideline rather than a requirement, since the Commission should base incentives on achievements, not expenditures. Annual energy savings should be at least 0.5% of sales.

The Commission might also allow for deferral of costs and lost revenues to allow utilities to recover costs during ramp-up periods when they may not be ready to file comprehensive programs.

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[39]As discussed above, I do not believe that any other type of program cost should be recoverable through the EEA.

Q: What do you mean by a "prudent" DSM plan?

A: The definition of prudent DSM 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 DSM cost recovery.

A: 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 may be collaboratively managed, or selected by the Commission (as for management audits).

## VII. Summary of Recommendations

Q: Please summarize your recommendations.

A: My principal recommendations include:

- Appropriate DSM activity should receive the easiest, most rewarding, and least painful regulatory treatment of any resource acquisition option.
- The Commission should establish cost recovery mechanisms and procedures that can handle very large and rapidly expanding DSM programs.
- The cost recovery mechanism should be flexible enough to allow the capture of all lost-opportunity DSM resources without penalty to the utility.
- Special DSM ratemaking treatment should be regarded as temporary.
- Each utility should be allowed to combine projections, deferrals, and/or interim adjustments to collect its DSM costs, subject to Commission approval. The Commission should select a recovery mechanism that is practical for the specific situation of the individual utility and other interested parties.
- Special cost recovery procedures are justified only for energy efficiency programs.
- Utilities should be encouraged to accelerate their DSM programs when opportunities arise. The Commission should not establish an <u>a priori</u> spending cap that would limit the utility's ability to manage its DSM program.
- The Commission should establish a preference for amortization of DSM costs over the full life of the installed measures, as opposed to expensing the costs in a single year.
- Cost-recovery patterns for DSM may be altered to maintain rate continuity, avoid rate shock, and improve utility cash flow at critical times.
- The interest credit for capitalized DSM costs should mirror the treatment of capitalized supply costs as closely as possible.
- It serves the utility's ratepayers' interests for the utility to <u>maximize</u> lost revenues by maximizing the

scope of cost-effective DSM programs. Hence, cost recovery for lost revenues should not encourage utilities to minimize lost revenues.

- All lost revenues from eligible and prudent efficiency programs should be recoverable; lost revenue recovery should not be:

  - subject to arbitrary and declining caps,
  - limited in duration,
  - limited to utilities with short-term generation capacity needs,
  - limited to energy production costs, or
  - limited to measures that produce on-peak savings or reduce rates.

- DSM programs for new loads create lost revenues, which should be recoverable.

- Lost revenue recovery should not be reduced because of load growth.

- If the Commission wishes to impose earnings limits on utilities, those limits should function regardless of whether the utility is engaged in a vigorous DSM effort.

- 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 (which should be recognized even in the absence of DSM), and net of the promotional effects of conservation or load management programs.

- Inadequate or counterproductive utility action on DSM 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, without arbitrary exclusions.

- 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.

- Incentives should not be reduced if program activity exceeds projections.

- Utilities should not receive incentives for investing in non-cost-effective programs mandated by regulators for social reasons. Cost-effective DSM programs linked to related social programs should be eligible for incentives.

- DSM cost collection should be reconciled.

- Interest should be allowed for both over- and under-collections.

- The EEA should not appear as a separate item on the customer bills.

- For each utility, the EEA should be implemented on the least disruptive date.

- DSM costs should be collected primarily from the classes receiving the DSM services.

- Cost recovery proposals should be subject to public review.

- To be eligible for EEA cost recovery, the utility should be required to demonstrate that its energy efficiency programs are prudent and that they represent a significant level of effort.

- To be eligible for lost-revenue recovery, the utility should be required to demonstrate that its programs are prudent and significant, 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 are aggressive, represent the state of the art, and comprise a high 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 DSM portfolio is prudent. The monitoring and evaluation function is a very important part of the overall DSM effort.

Q: Does this conclude your testimony?

A: Yes.

## Table 1: Demand and Energy Savings, as Percent of Peak and Sales, and DSM Expenditures as Percent of Revenues

| | Peak savings (MW) [1] | Peak load (MW) [2] | Peak savings as % of peak [3] | Total energy savings (GWh) [4] | Total projected sales (GWh) [5] | Energy savings as % of sales [6] | Avg. annual DSM expenditures (1991$) [7] | 1991 Revenues (1,000,000 1991$) [8] | DSM expenditures as % of 1991 revenues (1991$) [9] |
|---|---|---|---|---|---|---|---|---|---|
| BECo (growth 1990-94 inclusive) | | | | | | | | | |
| Res.: | 8 | 734 | 1.1% | 73 | 3,709 | 2.0% | $6,342,960 | | 0.5% |
| C/I: | 109 | 2,159 | 5.0% | 454 | 10,145 | 4.5% | $38,137,008 | | 3.0% |
| Total: | 117 | 2,893 | 4.0% | 527 | 13,854 | 3.8% | $44,479,968 | $1,271 | 3.5% |
| Annual | | | 0.81% | | | 0.76% | | | |
| Eastern Utilities (growth 1991-95 inclusive) | | | | | | | | | |
| Res.: | 7 | NA | | 37 | 1,627 | 2.3% | $3,690,340 | | 1.4% |
| C/I: | 73 | NA | | 198 | 2,924 | 6.8% | $11,638,816 | | 4.4% |
| Total: | 80 | 869 | 9.2% | 236 | 4,622 | 5.1% | $15,329,156 | $264 | 5.8% |
| Annual | | | 1.84% | | | 1.02% | | | |
| NEES (growth 1991-1995 inclusive) | | | | | | | | | |
| Res.: | NA | | | 222 | 8,208 | 2.7% | | | |
| C/I: | NA | | | 757 | 14,487 | 5.2% | | | |
| Total: | 340 | 4,581 | 7.4% | 1,120 | 25,070 | 4.5% | $80,405,260 | $1,711 | 4.7% |
| Annual | | | 1.48% | | | 0.89% | | | |
| New York State Electric and Gas (growth in 1991-2008 inclusive) | | | | | | | | | |
| Res.: | NA | | | 912 | NA | | | | |
| C/I: | NA | | | 1,867 | NA | | | | |
| Total: | 846 | 4,470 | 18.9% | 2,794 | 22,170 | 12.6% | $81,582,263 | $1,218 | 6.7% |
| Annual | | | 1.05% | | | 0.70% | | | |
| Northeast Utilities (growth 1992-2000 inclusive) | | | | | | | | | |
| Res.: | 77 | NA | | 556 | 10,890 | 5.1% | | | |
| C/I: | 743 | NA | | 2,895 | 18,983 | 15.2% | | | |
| Total: | 819 | 5,543 | 14.8% | 3,460 | 30,180 | 11.5% | | | |
| Annual | | | 1.64% | | | 1.27% | | | |
| United Illuminating (growth 1992-2010 inclusive) | | | | | | | | | |
| Res.: | 48 | NA | | 47 | 2,259 | 2.1% | | | |
| C/I: | 262 | NA | | 776 | 5,021 | 15.4% | | | |
| Total: | 310 | 1,554 | 19.9% | 827 | 7,347 | 11.3% | | | |
| Annual | | | 1.05% | | | 0.59% | | | |
| Wisconsin Electric (growth 1991-2000 inclusive) | | | | | | | | | |
| Res.: | 77 | NA | | 291 | 6,808 | 4.3% | | | |
| C/I: | 211 | NA | | 739 | 19,358 | 3.8% | | | |
| Total: | 288 | 5,140 | 5.6% | 1030 | 29,902 | 3.4% | | | |
| Annual | | | 0.56% | | | 0.34% | | | |
| Average of annual figures | | | 1.2% | | | 0.8% | | | 5.2% |

*Notes to Table 1:*

| | |
|---|---|
| *[1]:* | *Energy (and peak) savings are for the final year of the interval indicated.* |
| *[2]:* | *Total sales (and peak) figures are for the final year of the interval indicated, and are pre–DSM forecasts; that is, they do not take into account reductions due to DSM.* |
| *[3]:* | *[1]/[2]* |
| *[4]:* | *[1] minus the savings (or peak) of the year preceding the first year of the specified interval.* |
| *[5]:* | *[2] minus the sales (or peak) of the year preceding the first year of the specified interval. For example, BECo's projected sales growth equals 1994 sales minus 1989 sales.* |
| *[6]:* | *[4]/[5]* |
| *[9]:* | *[7]/[8]* |

*Sources:*

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

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

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

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

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

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

*WEPCo figures from "Supplemental Information to Advance Plan 6", filed March 1 1991.*

*Revenues from Public Utilities Reports, Inc., "The P.U.R. Analysis of Investor–Owned Electric and Gas Utilities." 1991.*

## Table 2: Example of Real–Levelized and Nominally–Levelized Costs

| | |
|---|---|
| Inflation | 5.0% |
| Discount Rate | 11.0% |
| Real Discount Rate | 5.7% |

| Year | | Real-levelized Real $ [1] | Real-levelized Infl $ [2] | Nominal-levelized '92–'16 Infl $ [3] | Nominal-levelized '94–'18 Infl $ [4] | |
|---|---|---|---|---|---|---|
| 1992 | 0 | 5 | 5.00 | 7.43 | | |
| 1993 | 1 | 5 | 5.25 | 7.43 | | |
| 1994 | 2 | 5 | 5.51 | 7.43 | 8.19 | |
| 1995 | 3 | 5 | 5.79 | 7.43 | 8.19 | |
| 1996 | 4 | 5 | 6.08 | 7.43 | 8.19 | |
| 1997 | 5 | 5 | 6.38 | 7.43 | 8.19 | |
| 1998 | 6 | 5 | 6.70 | 7.43 | 8.19 | |
| 1999 | 7 | 5 | 7.04 | 7.43 | 8.19 | |
| 2000 | 8 | 5 | 7.39 | 7.43 | 8.19 | |
| 2001 | 9 | 5 | 7.76 | 7.43 | 8.19 | |
| 2002 | 10 | 5 | 8.14 | 7.43 | 8.19 | |
| 2003 | 11 | 5 | 8.55 | 7.43 | 8.19 | |
| 2004 | 12 | 5 | 8.98 | 7.43 | 8.19 | |
| 2005 | 13 | 5 | 9.43 | 7.43 | 8.19 | |
| 2006 | 14 | 5 | 9.90 | 7.43 | 8.19 | |
| 2007 | 15 | 5 | 10.39 | 7.43 | 8.19 | |
| 2008 | 16 | 5 | 10.91 | 7.43 | 8.19 | |
| 2009 | 17 | 5 | 11.46 | 7.43 | 8.19 | |
| 2010 | 18 | 5 | 12.03 | 7.43 | 8.19 | |
| 2011 | 19 | 5 | 12.63 | 7.43 | 8.19 | |
| 2012 | 20 | 5 | 13.27 | 7.43 | 8.19 | |
| 2013 | 21 | 5 | 13.93 | 7.43 | 8.19 | |
| 2014 | 22 | 5 | 14.63 | 7.43 | 8.19 | |
| 2015 | 23 | 5 | 15.36 | 7.43 | 8.19 | |
| 2016 | 24 | 5 | 16.13 | 7.43 | 8.19 | |
| 2017 | 25 | 5 | 16.93 | 25.16 | 8.19 | |
| 2018 | 26 | 5 | 17.78 | 25.16 | 8.19 | |
| 25 year PV 1992–2016 (a) | | | 62.56 | 62.56 | | (1991 PV $) |
| 25 year PV 1994–2018 (b) | | | 55.98 | | 55.98 | (1991 PV $) |
| [2.b]–[2.a] | | | 6.58 | | | |
| [4.b]–[3.a] | | | | | 6.58 | |

# Table 3: Summary of Cost Recovery Considerations for Utility DSM and Efficiency Programs

| | General | | Cost Recovery Issues | | Lost Revenue Issues | | Incentives | | |
|---|---|---|---|---|---|---|---|---|---|
| Program Type | Extensive Utility Experience? 1 | Results Readily Measurable? 2 | Significant costs? 3 | Special Treatment Necessary? 4 | Revenues Lost? 5 | Special Recovery Justified? 6 | Generally Good for Ratepayers? 7 | Short-term Benefits for Shareholders? 8 | Incentives Required? 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 |

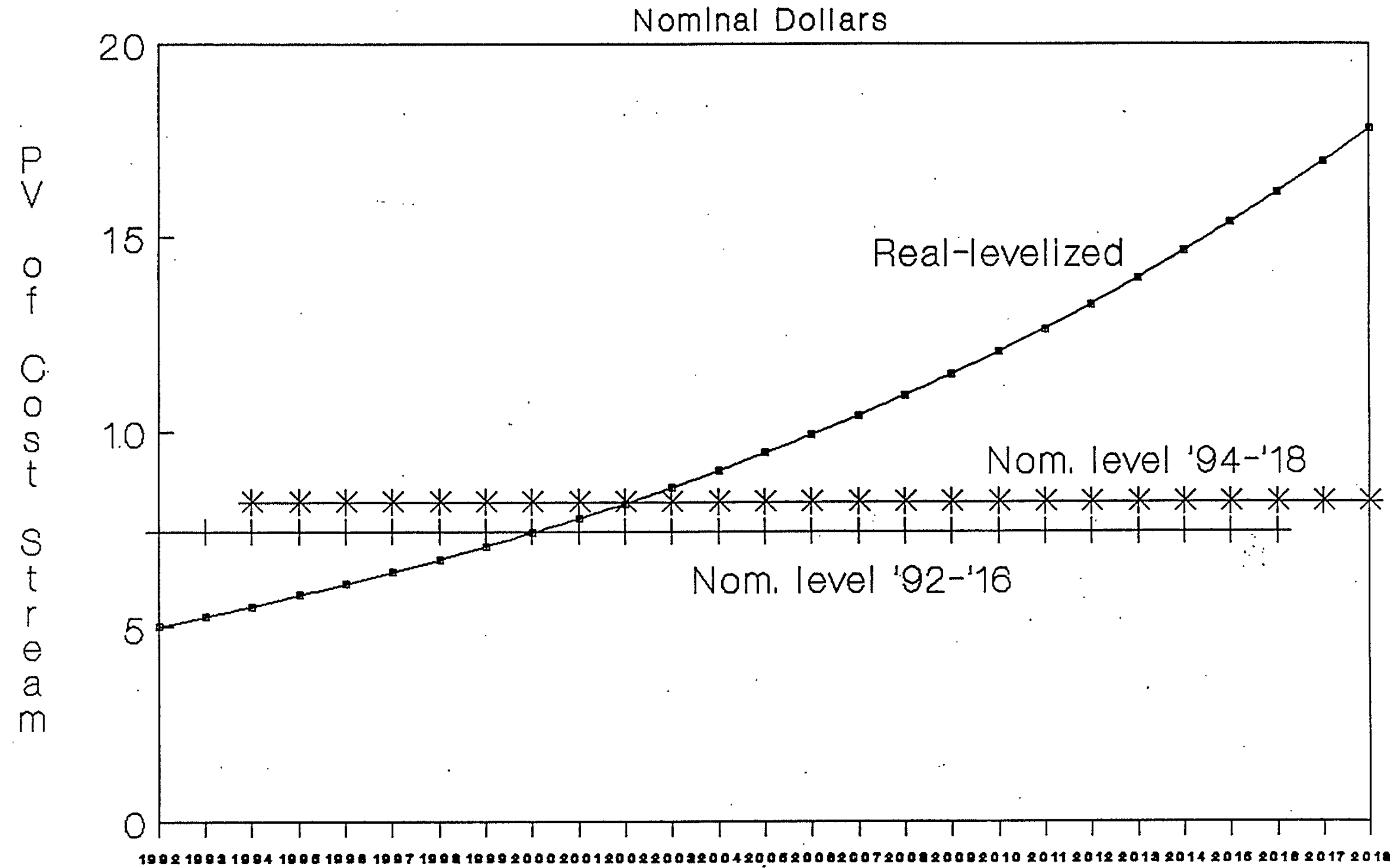
*Notes:*

*[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.*

# Figure 1
## Presentation of Levelized Streams



ATTACHMENT 4

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October 1, 1990

O. Ray Bourland, III
Task Force Chairman
Public Service Commission
of Maryland
American Building, 12th Floor
231 East Baltimore Street
Baltimore, Maryland 21202

**Re: Pepco-Collaborative Cost Recovery Mechanism**

Dear Examiner Bourland:

I have enclosed a document which describes the agreed upon cost recovery mechanism that will be applicable to programs resulting from the Pepco-collaborative process. This document reflects an agreement among all collaborative participants - Pepco, DNR, Staff and People's Counsel.

There are several points which need to be highlighted. While this document is being sent to the Task Force members, all of the Pepco-collaborative participants agree that the cost recovery mechanism described therein is not necessarily transferable to other electric utilities in Maryland. Perhaps more important, however, is that the Staff, DNR and People's Counsel firmly believe that before a utility may adopt a non-traditional cost recovery mechanism, a review of the Company's existing and projected DSM programs is necessary.

Finally, as you are aware, issues surrounding DSM cost recovery are quite complex. The negotiation of this collaborative cost recovery mechanism took place over a few months. It is quite possible that arriving at a "generic" mechanism would be far more difficult. It is hoped that the effort expended in the Pepco-collaborative process will somehow aid the Task Force in defining and accomplishing its goal.

If you have any questions concerning this matter, feel free to contact any of the collaborative participants.

Very truly yours,

Paul S. Buckley

Paul S. Buckley
Assistant People's Counsel

PSB\mcm

Enclosure

cc: Task Force Service List

POTOMAC ELECTRIC POWER COMPANY

Proposed Collaborative Demand Side Cost Recovery
Maryland

## General Description

Demand side program cost resulting from the collaborative process will be recovered by the implementation of a Demand Side Rider (DSM rider) which will be developed annually based on a projection of conservation program costs, sales, lost revenues and when applicable, estimated savings. Such amounts will be directly assigned to the Maryland jurisdiction. Amounts deferred (unamortized balance) shall have a capital cost recovery factor (CCRF) applied to the unamortized balance. The rider will be a new tariff which will be initially applied to all customers expressed as cents per kilowatt-hour and will include the effects of gross receipts tax. The changes resulting from the application of the rider will be included in the base rates reflected on the customers' bills. The rider will be applied each year when the rate of return on rate base, as adjusted for the estimated effects of the DSM programs, shown in the last quarterly earnings report does not exceed the Commission authorized return on rate base (Earnings Test). If the rider is not applicable in any given year all program costs will be deferred until such time as the rider is applicable. Program costs are to be amortized over five years. The rider will include 5% of estimated savings when the Company's performance exceeds the program goals set by the collaborative by 10%. Each rider will include adjustment from the prior year for variances from estimates for program costs, CCRF and, if applicable, shared savings incentives to reflect dollar for dollar recovery. It is expected that all amounts and computations shall be established during the collaborative process.

Definitions:

Program Cost - This will include all advertising, administration, marketing and rebates paid to customers applicable to the pilot and full scale demand side measure.

Lost Revenue - Lost revenue will be the anticipated reduction to base revenues in a calendar year which have not been reflected in base rate proceedings and which are the direct result of the implementation of the demand side measure. Lost revenues will be based on the same estimates used to determine projected program benefits.

Capital Cost Recovery Factor (CCRF) - The last allowed rate of return in a base rate proceeding.

Estimated Savings - The estimated savings are the estimated present value of the benefits of the program less the estimated present value of the program cost (determined consistent with the All Rate payers test unless mutually agreed otherwise by the collaborative process) expressed as a percent of program costs. This factor is applied to the current year program cost to determine the current year estimated savings.

__Incentive__ - When the Company's performance in a given year exceeds goals set by the collaborative by 10% the next applicable DSM rider will include 5% of that year's estimated savings.

__Earnings Test__ - The earnings test shall be calculated annually by adjusting the last available quarterly filing with the Maryland Public Service Commission by the amount of incremental DSM rider cost not reflected in the filing. The column currently titled "Maryland Adjusted" will be the basis of the computation of the Earnings Test. The adjustment for the DSM rider will include the following factors.

- The estimated unamortized balance of program cost
- Estimated lost revenue
- Estimated amortization of program cost
- Estimated incentive
- Effects of income taxes
- Estimated increase in the CCRF

If the resulting return is equal to or less than the last allowed rate of return, the rider will be applicable to future sales. If the result exceeds the last allowed rate of return the rider will not be applicable.

__Adjustment__ - The Company will maintain records such that the rider can be reconciled to actual results. Variances from actual results for program cost, CCRF, sales and if applicable, incentive amounts will be adjusted in the next applicable rider.

__Amortization Period__ - The amortization period will be five years for all program cost. If during the amortization period the rider becomes inapplicable due to the Earnings Test the amortization will be extended to reflect the period of time during which the rider was not in effect.

__Other__

- The components of the DSM rider will not be included in base rate proceeding.

- Current rate treatment of the following programs is not affected. Future programs may also be included in this category based on the collaborative process.

  1. Kilowatchers Club
  2. Curtailable load programs
  3. Time of Use rate program
  4. 100% Kilowatcher
  5. Small curtailable load

Docket No. I-900005

**COMMONWEALTH OF PENNSYLVANIA**
**PUBLIC UTILITY COMMISSION**

INVESTIGATION INTO
DEMAND SIDE MANAGEMENT BY
ELECTRIC UTILITIES:
UNIFORM COST RECOVERY MECHANISM

SUPPLEMENTAL DIRECT TESTIMONY OF

**PAUL L. CHERNICK**

ON BEHALF OF THE

PENNSYLVANIA ENERGY OFFICE

Resource Insight, Inc.
May 15, 1992

SUPPLEMENTAL DIRECT TESTIMONY OF

PAUL L. CHERNICK

Q: Mr. Chernick, do you wish to supplement your direct testimony filed on January 10, 1992?

A: I would like to provide the revised final versions of the reports that I attached to my direct testimony. Both of these documents are from a series of reports my firm is writing for the Pennsylvania Energy Office which we call *From Here to Efficiency: Securing Demand Management Resources*. Attachment 2 (Revised) is the entire Volume III of the series entitled *Cost Recovery: Reconciling Utility and Ratepayer Interests*. Attachment 3 (Revised) is a section on economic screening tests from Volume IV entitled *Screening Demand Management Options*.

Q. Are these the only matters that you would like to address at this time?

A. Yes.

Attachment 2 (Revised)