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PUBLIC UTILITY COMMISSION
OF OHIO

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CITY OF CINCINNATI

Resource Insight, Inc.
April 12, 1993

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I. IDENTIFICATION 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: On whose behalf are you testifying?

A: I am testifying on behalf of the City of Cincinnati.

Q: Summarize your professional education and experience.

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

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and since August 1990 in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached as Exhibit ___ PLC-1.

Q: Have you testified previously in utility proceedings?

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

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

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

II. INTRODUCTION

Q: What is the purpose of this testimony?

A: In this testimony, I review the demand management (DM) planning process, DM programs, and avoided costs of (Cincinnati Gas & Electric) CG&E.[1]

Q: What perspective do you take in this testimony?

A: The purpose of Integrated Resource Planning (IRP) is to minimize costs to ratepayers by selecting a least-cost mix of resources, including demand-side resources. Under IRP, a utility has a general obligation to identify and implement all DM options that cost less than supply.

Q: Please summarize your findings regarding CG&E's DM planning.

A: CG&E's DM strategy will not achieve the fundamental least-cost planning objective of minimizing total costs, for several reasons. CG&E has not attempted to acquire all cost-effective DM resources, its DM portfolio design has not been sufficiently guided by the Total Resource Cost (TRC) test, and has understated the benefits of DM through errors in screening and avoided-cost determinations.

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

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[1] Though my testimony discusses CG&E's entire DSM portfolio, I pay particular attention to the Company's C/I programs. City of Cincinnati witness Hamilton addresses Residential programs, and witness Morgan discusses programs for low-income customers.

- CG&E's DM planning arbitrarily rejects cost-effective DM options. Thus, CG&E forgoes DM savings that would be less expensive than supply resources.

- CG&E has adopted planning guidelines that sacrifice least-cost objectives in order to satisfy what the Company terms "load shape objectives."

- Numerous errors in CG&E's economic screening understate the benefits of DM resources.

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

- The Company's avoided costs are improperly calculated, and as a result, they underestimate the benefits of DM. CG&E's understates the avoided costs of peaking generation capacity, transmission and distribution capacity, line losses, environmental compliance costs, and dispatch energy costs. CG&E ignores completely the additional costs of baseload capacity and environmental externalities. CG&E treats one of the important benefits of DM, risk reduction, as if it were a cost of DM.

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

A: CG&E's planning strategy has resulted in a collection of piecemeal DM programs that inefficiently acquire relatively small savings.

Many of the neglected savings are in market-driven, or lost-opportunity, sectors. The Company may be able to acquire some of this neglected potential in the future at a higher cost than if it were acquired today. The remainder will not be cost-effective to acquire later, and the Company will be forced to substitute more expensive supply for these lost savings. In either case, CG&E will have failed to acquire all cost-effective savings at the lowest feasible cost.

Q: **What do you conclude regarding additional DM savings available for acquisition by CG&E?**

A: I have estimated the levels of efficiency savings that could reasonably be expected if CG&E corrected the flaws in its DM planning and developed comprehensive programs as aggressive as those developed by leading utilities. By the year 2000, I estimate CG&E could increase its total energy savings from cost-effective <u>efficiency</u> programs (i.e., exclusive of load management) by 1,788 GWh, and 365 MW, over the level it currently projects.

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

A: No. My estimates are intended to give the Commission a sense of the magnitude of savings CG&E is likely to attain if it adopts comprehensive acquisition strategies. The magnitude of CG&E's DM savings can only be determined through program design and implementation.

Q: **How long would it take CG&E to develop a DM plan capable of achieving such a level of savings?**

A: Program design details might be most effectively and efficiently developed through a full collaborative process, in which CG&E would fund and work with experts reporting to the non-utility parties. As is clear from the City's testimony, CG&E has much to learn about the design and screening of DM programs; the collaborative would assist CG&E in reorganizing its thinking about DM. A comprehensive DM plan could be collaboratively developed within approximately 9 months.

Q: Based on these findings and conclusions, what are your recommendations with regard to CG&E's integrated resource planning?

A: CG&E should revise its planning process to develop a truly integrated resource plan, identifying and incorporating all cost-effective DM resources, designing programs to address all market segments, designing programs to eliminate market barriers, and screening resource options including all costs and benefits.

Q: What documents have you reviewed in preparing this testimony?

A: I have reviewed CG&E's <u>1992 Electric Long-Term Forecasting Report</u> (ELTFR), with special emphasis on Volume 1, which addresses demand forecasting and planning and Volume 2, also known as the <u>Short-Term Implementation Plan</u> (STIP), which describes the programs the Company expects to implement over the next four years. I have also reviewed answers to interrogatories, Commission orders and other documents relevant to this case.

III. DEMAND MANAGEMENT IN LEAST-COST INTEGRATED RESOURCE PLANNING

A. Objective of Least-cost Planning

Q: What is least-cost integrated resource planning?

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

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

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

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

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

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

A: No. Least-cost planning is not solely concerned with finding the lowest-cost option to meet new load. A new resource is needed in the least-cost plan if it can substitute for a more expensive resource, whether or not the displaced resource already exists or is considered to be a committed project or transaction.

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

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

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

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

CG&E's goal should be to efficiently acquire <u>all</u> DM available at a lower cost than the supply it avoids.

B. Integrating DM Resources in Least-cost Plans

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

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

- comprehensively invest in customer efficiency opportunities;
- distinctly target lost-opportunity resources;
- adopt program designs that overcome market barriers to customer investments in efficiency; and
- properly screen DM options using full avoided costs.

1. Comprehensiveness

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

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

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

> customer's efficiency markup by squarely addressing the factors that contribute to it.[2]

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

Q: Please define the concept of DM market segments.

A: Opportunities to improve energy efficiency in each customer sector -- residential, commercial, and industrial -- arise in different circumstances. The barriers to efficiency investments also vary with market setting. Program development should therefore start by addressing distinct DM market segments. Market segments are differentiated by the context in which customers make energy-efficiency decisions; each customer decision is a potential point of market intervention.

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

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

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

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

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

A: A DM delivery strategy that addresses not just one end-use or measure, but the entire range of a market segment's efficiency potential, can thoroughly mine each customer's DM resources, and can do so with a minimum of overhead costs to the utility. Utility programs that treat only isolated parts of a customer's efficiency potential must revisit customers many times over to tap all available cost-effective efficiency savings. In addition, installing a moderately efficient measure (or a small bundle of measures) may preclude the installation of the highest-efficiency measure (or more expansive bundle of measures). In the end, less of the efficiency resource would be recovered, and at higher costs, than if the utility extracted all the efficiency potential one customer at a time.[3]

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

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

Nor is it essential that one program cover all end-uses for a particular customer group. Comprehensiveness should

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

be judged by how completely a utility's <u>full portfolio</u> of programs covers relevant measures, end-uses, and DM market segments. For example, utilities may use several programs to cover residential efficiency potential. They target weatherization retrofits, new construction, and appliance replacement separately because of the different structure and timing of the decisions involved.[4]

Just as this Commission stated that it "would expect Centerior to design and implement all feasible cost-effective DM measures beyond those provided in the stipulation" (Case No. 92-708-EL-FOR and 92-1123-EL-ECP, November 1992), it should expect CG&E to design and implement all feasible cost-effective DM measures.

2. Lost-opportunity resources

Q: **What are lost-opportunity resources?**

A: Lost opportunities can be defined as those resources that, "because of physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop these resources or to hold them for future use." (Northwest Power Planning Council, 1986, Volume 1, Glossary-6). On the demand-side, lost-opportunity resource programs pursue efficiency savings that otherwise might be lost because of economic or physical barriers to their later acquisition.

Q: **Where are lost-opportunity resources usually found?**

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

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

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

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

A: The two dominant factors that determine whether a DM option is a lost opportunity measure are (1) the feasibility or cost premium of installing it later, and (2) the service life of the building or equipment involved. In new construction and renovation, when walls are being built or replaced, the cost of designing for daylighting is much less than it would be in existing space. In replacement, the difference in cost between buying an efficient motor or refrigerator and buying an inefficient unit is small compared to the cost of discarding a working inefficient unit and installing an efficient one. In the process of efficiency retrofit, if a lighting fixture is open to install an efficient ballast, the incremental labor cost of adding a reflector and delamping is much lower than it would be in a second operation.

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

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

1. Lost-opportunity resources represent extremely cost-effective savings whose acquisition cannot be post-

poned.[5] To claim these savings, actions must be taken at the time of construction or at the time of equipment replacement. For example, not only is energy efficiency most cost-effectively pursued in new construction, but the consequences of decisions taken in new construction can last, in some cases, for as long as 80 years.

2. A large fraction of load growth results from decisions to add new facilities or expand existing facilities.[6] These decisions create lost-opportunity resources.

3. Lost-opportunity resources most readily adapt to a utility's changing needs. Their benefits tend to mirror growth in demand, since rapid demand growth tends to correspond to construction booms and facility expansion. Unlike other options available to utilities, the acquisition of lost-opportunity resources will parallel the utility's resource needs.

3. Overcoming market barriers

Q. **What are some of the market barriers to customer investment in energy efficiency?**

A. Limited access to capital, institutional impediments, split incentives (e.g., between landlord and tenant), information costs, risk perception, and inconvenience are all factors that keep customers from investing their own time and money in efficiency improvements. Market barriers lead customers to act as if they have a very high discount rate, or as if they priced conservation well above its cost to the utility; this phenomenon can be thought of as either a "payback gap" between the customers and the utility, or as a customer

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[5]In addition, market barriers to customer investment in lost-opportunity resources are among the most pervasive and powerful, including limited time and information, risk aversion, equipment availability, and split incentives. Program strategies for overcoming these barriers are addressed in Section III.B.3 and in the testimony of Mr. Hamilton.

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

"markup" on the societal cost of the measures.[7] The pervasive market barriers underlying the payback gap lead customers to reject substitutes for supply which, if analyzed according to utility investment criteria, would appear highly cost-effective.

Utilities can accelerate investment in cost-effective demand-side measures by designing programs to reduce or eliminate these barriers.

Q. Why does the existence of the market barriers create an opportunity for utilities to invest in customer efficiency improvements?

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

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

- Utility price signals are much weaker as a tool for stimulating investment changes than most analyses assume.
- A vast amount of economical efficiency potential remains for utilities to tap as demand-side resources.

Q: How can DM programs overcome market barriers?

A: Utilities with the most successful DM programs are finding that certain simple strategies allow them to overcome market barriers. These strategies include offering high incentive levels and using direct installation where appropriate.

Q: How should customer incentive levels be set?

A: In general, incentives should be set as high as necessary to maximize the number of participants and to maximize the

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[7] See Plunkett and Chernick (1988), for a detailed exploration of the payback gap.

number and efficiency level of measures installed per participant. Utility experience leads to the inescapable conclusion that, for most DM market segments, maximum cost-effective savings will only be captured if utilities pay for essentially the full incremental costs of efficiency measures. This finding is one of the major lessons learned from utility experience.

Q: **Might such an aggressive approach offer customers higher incentives than the minimum necessary to induce them to participate?**

A: It is certainly possible that high penetration could be achieved in some customer segments, or efficiency measures, with less than full utility funding. A utility will not be able to determine the "optimal" incentive until it learns what works at higher levels. Past utility experience supports the conclusion that setting incentives too low entails more risk than paying too much.

It is important to remember that increasing the fraction of measure costs paid for by the utility will not raise the total costs of the <u>measure</u>, as long as higher incentives lead to additional savings. Provided that uneconomical measures are eliminated at the screening stage of program planning and the diagnostic stage of implementation, increasing utility funding of measure costs is almost certain to increase customer participation, measure penetration, and hence net benefits.

If incentives are set higher than necessary, the worst that will happen is that the utility will pay a larger share of measure costs than with lower incentives: the total measure cost will remain the same. On the other hand, it is likely that higher utility incentives, even full funding, will reduce the total cost of DM programs. The fixed costs of marketing and administering programs will be spread over more savings with full utility funding of measure costs. This will tend to increase the net benefits of the program under the total resource cost test, and may even reduce the utility's cost per kWh saved.[8]

Q: What other program design elements overcome market barriers and yield high levels of savings?

A: In addition to high incentives, a utility can adopt several other program design elements to eliminate market barriers and increase the benefits it obtains from its programs. These program design elements include:

- <u>Offer direct installation of measures for residential and small C/I customers</u>. Residential and small C/I customers face many barriers to investment in energy efficiency. They have limited time and personnel resources. They are often unwilling to spend money on an investment that is not central to the revenue-generating side of their business. They are not knowledgeable about efficiency measures and their implementation. They may have limited bargaining power with contractors. They are unwilling to take risks with unfamiliar technologies.

  Direct installation programs are a highly effective means of eliminating these market barriers. If a utility installs the measures directly for customers, the hassle and risk are minimized. In general, the easier a utility makes it for customers to participate and choose cost-effective measures, the more cost-effective savings it will acquire.[9]

- <u>Target program delivery strategies and marketing approaches according to the decision-makers and types of investments involved</u>. Depending on the program, utilities should direct program incentives to utility customers, equipment dealers, architects, engineers, or building developers. Different marketing and delivery mechanisms are needed to influence investment decisions in new construction, remodeling/renovation,

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[8] As CG&E recognizes in the STIP (pp. 29 and 40), increasing rebates may improve the TRC result. This improvement occurs due to reduce overhead costs.

[9] Furthermore, direct installation programs yield higher savings than their customer-implementation counterparts: without direct installation programs, customers will tend to cream skim, i.e., install only the cheapest or simplest measures. This reduces the level of savings a utility can achieve.

replacement, and retrofit. Trade allies are especially important in improving the efficiency of in-stock equipment and appliances.

- Personal marketing is critical. The prime marketing mechanism for all programs should be personal contacts between utility field representatives and target audiences. These audiences might be residential customers, large customers, equipment and appliance dealers, HVAC contractors, architects, engineers or developers. Through personal contacts, the utility should strive to develop a regular working relationship with the target audience (e.g., for C/I customers, periodic contacts, with the same staff person contacting a particular individual each time). Experience of many utilities, including several side-by-side experiments, shows that personal contact consistently results in higher participation rates than reliance on direct mail, bill stuffers, and other traditional mass-marketing approaches.[10]

- Avoid paying for "naturally-occurring" savings by maintaining high minimum efficiency thresholds. The higher the minimum efficiency criteria utilities set for program eligibility, the more net savings each program dollar buys. This is the best solution for avoiding free riders.

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

- Keep the mechanics of program participation as simple as possible for the customer. The more complex

[10]For example, NYSEG offered energy audits to two carefully-matched groups of commercial/industrial customers. One group was personally contacted, the other group received a phone call to identify the key decision-maker followed by a direct-mail solicitation to this person. Participation rates averaged 37% for the personal contact group and 9% for the phone/mail group. Xenergy, Inc., Final Report, Commercial Audit Pilot, Burlington, Mass. Likewise, Niagara Mohawk Power Corp. conducted a similar experiment with lighting rebates. Response to the personal solicitation was substantially higher (21%) than it was to the mail solicitation (3%). (Clinton and Goett 1989)

programs appear to customers, the lower participation will be. Make it easy for customers to participate, particularly by minimizing complex calculations and paperwork. For example, a customer requesting payment should not have to list details on individual measures. Programs should minimize application and verification paperwork.

- <u>Provide the right amount of technical assistance to customers free of charge</u>. Energy audits should serve as the point of entry to utility efficiency programs and should therefore be marketed aggressively. The sophistication of technical support should vary according to the size and complexity of customers. To maximize participation and savings in new construction programs, utilities must also provide computerized analysis and pay for outside design assistance.

4. Screening DM Options

Q: **How should utilities screen DM resources?**

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

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

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

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

Q: What are the different screening steps required to develop a DM plan?

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

- measure screening,[11]
- measure enhancement and design,
- program screening,
- program specification,
- resource allocation, and
- project screening.

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

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

This measure-screening process will avoid mistakenly assuming that a DM measure would be cost-effective merely because the package or program in which it might be included would be cost-effective. Such an assumption could lead to uneconomic investments -- i.e., individual measures with costs exceeding their incremental benefits. Measure screening should also exclude administrative and overhead costs except those incrementally caused by inclusion of the measure. Measures that may not be cost-effective individually if required to support program delivery costs may be economic when combined in a program whose fixed delivery costs can then be distributed over numerous measures.[12]

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

In addition to higher levels of intensity (e.g., thicker insulation), a utility will need to screen other improvements and enhancements, such as combining measuring (e.g., installing daylighting and automatic dimmers in

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

addition to high-efficiency lighting) and lowering thresholds (lower hours use, smaller motors).[13]

Once a utility has identified the set of cost-effective measures and selected the optimal level of measure enhancement, it can move on to program screening. The savings include the effects of the mix of measures likely to be installed, which will often be fewer than all eligible measures.[14]

<u>Program screening</u> takes into account the costs of fielding the programs and reflects specific marketing approaches, customer incentive structures, and delivery mechanisms. The total cost of the program includes the direct costs of the assumed mix of measures,[15] plus all joint costs omitted from the screening of measures: marketing, administration, setting up visits, traveling to the customer, and initial site audits. Program screening is the first step in the process in which free riders and free drivers are relevant.

Some programs may change significantly over time, as the program changes the market, produces a better-educated professional community, encourages code changes, and so on. Program costs may fall over time, as effectiveness rises.

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

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

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

If possible, program screening should reflect conditions over the life of the program, not just in the first year.

Full program specification is necessary only for those programs that pass the screening. Specification includes determining such factors as delivery mechanisms, marketing mechanisms, cost shares between the utility and participants, and the structure of participant co-payments. Some of these specifications may also be necessary earlier, when conceptualizing the program (e.g., is this a mail-in or door-to-door lighting program?), estimating response rates (lower utility cost shares will result in lower penetrations), and estimating costs (low utility cost shares may require greater marketing efforts and hence higher social costs). As was true for all other design decisions, the objective is to maximize net social benefits. Whatever produces the greatest spread between total savings and total costs should be selected.

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

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

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

Q: How should CG&E compare the costs and benefits of DM options over time?

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

C. The Potential for DM in Least-cost Plans

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

A: These utilities are identifying and pursuing electricity savings that are significant fractions of their projected demand growth. These sizable savings are associated with major financial commitments: aggregate DM expenditures represent a few percent of total utility revenues. The efficiency resources these utilities are buying compare favorably to new utility supply -- all the more so when the costs of environmental externalities are included in the costs of new supply. Finally, the long-range DM plans of these leading utilities aim at achieving all cost-effective DM savings from utility customers, over time.

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

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

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

A: More so than their peers, these utilities have designed DM plans that meet the integrated resource planning objectives described above.[16] Accordingly, the energy and capacity savings of these utilities indicate the level of savings that can be expected by a utility that implements comprehensive DM programs in all major DM market segments. Moreover, these efforts should be considered representative of what a utility dedicated to maximizing the amount of cost-effective DM savings can achieve.

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

A: The DM plans of these leading utilities are generally designed to achieve all cost-effective DM savings from utility customers over time, although some of these utilities have been slow to ramp up programs for certain market segments. These DM portfolios are all expected to pass the TRC test.

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

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

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

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

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

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

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

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

A: Exhibit ___ PLC-3 also provides a rough indication of how much DM costs per unit of energy savings acquired. Annualized DM costs are estimated by amortizing DM budgets over an estimated average measure life of 15 years. Dividing the annual cost by cumulative annual energy savings produces the cost of conserved electricity, which ranges from 1.4¢/kWh to 5.8¢/kWh. On average, electricity savings cost 3.6¢/kWh saved.[17]

Q: How do CG&E's DM programs compare to those of the leading utilities?

A: Exhibit ___ PLC-4 calculated the percentage of each class's energy use that CG&E plans to meet with DM. CG&E's plans peak about the year 2000 at 3.2% of commercial energy, 0.6% of residential energy, and virtually no industrial savings, for a system-wide energy reduction of 1%. Some of the leading utilities are planning to save about as much <u>every year</u> as CG&E is planning to save over its entire planning horizon.

Q: Has CG&E estimated the potential for demand-side savings in its service territory?

A: No. CG&E has never performed any studies of the technical potential of <u>any</u> DM programs or technologies. (DR City 2-42) The Company has conducted studies of its residential and commercial customers' efficiency, but it has not used these studies to study the potential for cost-effective efficiency improvements. (DR City 2-15)

Furthermore, the Company does not appear to have determined the maximum achievable savings for the DM programs proposed in the ELTFR, or for the other programs considered in the ICF report.

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

IV. PROBLEMS IN CG&E'S DM PLANNING PROCESS

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

A: No. It is clear from CG&E's description of its planning objectives that the Company does not have the explicit goal of producing a least-cost plan. The Company's "long-term planning objective is to develop a dynamic integrated resource planning process and implement the plan that represents the greatest value for the Company's ratepayers and shareholders." (ELTFR, p. 1-3) CG&E does not identify what constitutes "value" to either shareholders or ratepayers.

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

A: The Company's failure to adopt and prioritize basic least-cost principles leads to severe shortcomings in its DM planning. CG&E has not properly screened DM options for cost-effectiveness, nor designed programs to overcome market barriers. It has instead arbitrary selected programs, measures, incentives, and program structures. CG&E appears to have been distracted by a number of inappropriate considerations, including load shape objectives, the results of the rate impact measure (RIM) for programs and concerns about cost recovery.

Partly as a result of its poor screening, CG&E's DM programs are limited and unambitious. CG&E is neglecting many cost-effective DM resources, thus unnecessarily imposing high costs on customers. Consequently, the ELTFR cannot be considered an integrated least-cost plan.

I concur with the Staff assessment of CG&E's DM portfolio: "the Company's conservative [DM] strategy has resulted in minimal development and introduction of new programs... CG&E should submit the results of cost/benefit analyses of an expanded list of potential DSM programs." (Staff Report of Investigation, 92-1464-EL-AIR, p. 144)

In the words of the Commission, CG&E should "design and implement all feasible cost-effective DSM" (Cases 92-708-EL-FOR and 92-1123-EL-ECP, Centerior, Order Summary, p. 18), move to "aggressive implementation of DSM" and "should already have begun implementation of all DSM programs determined to be cost-effective." (Case 92-790-EL-ECP, American Electric Power, p. 28) These statements are equally true for CG&E.

A. Flaws in CG&E's DM Screening

1. Arbitrary Rejection of Cost-effective DM

Q: Please describe the process through which CG&E selected the DM program it is proposing in the STIP.

A: As agreed to in a 1989 Stipulation with Armco, PUCO staff, and the Office of Consumer Counsel, CG&E set up a working group with these three parties, in order to evaluate and develop DM programs. The working group commissioned a report on DM options from ICF, Inc. This report, produced in 1990, identified 10 C/I programs that were cost-effective under the TRC.

Q: Was it reasonable for CG&E to rely on a 1990 ICF report to identify potential cost-effective programs for a June 1992 ELTFR?

A: The ICF report has several flaws. It is relatively old, as it was published in December of 1990. It is outdated in several regards: avoided costs have changed and the costs of both DM equipment and baseline inefficient equipment have changed. Furthermore, because utilities have gained additional experience with DM, there are now many more sources of information on utility programs available than when ICF wrote the report.

Even for its vintage, the ICF report represents only a partial analysis of DM opportunities, omitting, for example:

- consideration of alternative efficiency levels (e.g., air conditioning SEERs),

- several standard DM measures (e.g., occupancy sensors, daylighting, energy management systems, chillers, commercial and industrial refrigeration), and
- programs addressing many lost opportunities (e.g., commercial new construction, residential new construction, industrial process expansion).[18]

Q: **Did CG&E implement all of the DM programs that the ICF report found cost-effective?**

A: No. CG&E only implemented four of these programs.[19]

Q: **How did CG&E select which of ICF's cost-effective options to implement?**

A: The selection does not appear to have been based on <u>any</u> economic analysis. Instead, CG&E determined via "group consensus" which programs would be considered for further evaluation by the Company. (DR CCUR 1-5)

Q: **Did CG&E give any explanation of the way in which this "group consensus" decision was made?**

A: Yes. In a teleconference on March 22, 1993, a CG&E representative explained that the Company tried to select options that would have the greatest effect on summer peak. But CG&E did not even apply this rule consistently to the DM options available. For example, it selected lighting rebates for T8 lamps, but rejected delamping and efficient lighting fixtures, which have the same load shape as T8 lamps, and probably a much larger total effect on peak.[20]

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[18]Commercial Program 4, "building envelope," would be directed at new commercial construction, but would only promote ceiling insulation, ignoring such more-important opportunities as window treatment, cooling equipment efficiency, HVAC system design and sizing, and lighting systems. This idiosyncratic selection of a generally irrelevant measure is unexplained.

[19] The Company also implemented one C/I program not found cost-effective under the TRC (thermal storage), and several informational and pilot programs not screened in ICF's report.

[20]The neglect of reflectors may have resulted from CG&E's reluctance to engage in cost-effective DM prior to resolution of cost-recovery issues.

Q: Is CG&E's emphasis on summer peak reductions consistent with least-cost planning principles?

A: No. CG&E equates its vague goal of providing "the greatest value" to its shareholders and ratepayers with using DM to "improve its overall system load shape." (ELTFR, pp. 1-2; 2-1 to 2-3). In this context, "improving" system load shape means increasing load factor. Thus, the Company's guiding DM principle is defined in terms of shaping load instead of minimizing cost.

CG&E was so fixated on reducing peak load that it treats reduction of energy use as an afterthought.

> The goal [of the T-8 lighting program] is to achieve a system peak reduction of 25 mw by 1995. This supports the load shape objective of peak clipping. A <u>residual benefit</u> of the program will be support for the load shape objective of strategic conservation, in that a reduction in energy consumption accompanies the decrease in on-peak demand resulting form lighting retrofits." (STIP p. 25, emphasis added)

While CG&E asserts that "the load shape objective <u>must be</u> the reduction of peak load during the summer weekday" (ELTFR p. 2-3, emphasis added), least-cost planning requires that the objective must be reducing total costs, regardless of the effect on load shape.[21]

2. Accounting for DM Benefits Over Time

Q: Does CG&E properly compare for the benefits and costs of DM options?

A: No. It appears that both the ICF report and the Company's own analysis only account for measure benefits incurred during the 20-year analysis period. For example, the Commercial Lighting Rebate program assumes a 15-year measure life, and the program will be offered through 2001. (ELTFR, p. 2-68) A measure installed in 2001 would have benefits

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[21]CG&E's load shape objective is also inconsistent with its allocation of avoidable capacity costs equally to the twelve monthly peaks (DR Staff 19(d)).

through 2015. CG&E's analysis period ends in 2011. CG&E appears to have ignored all program benefits in the years 2012-2015. In the March 22 teleconference, the Company agreed that it had truncated benefits. This error biases cost-effectiveness screening against DM, because it undervalues DM benefits.

3. Screening programs with the RIM test

Q: **Did the Company calculate RIM test ratios for individual DM options?**

A: Yes. Both the ICF report and the ELTFR calculated RIM ratios for individual DM options. These two reports also calculate TRC ratios.[22]

The TRC equals the difference between total benefits (avoided costs, including non-electric costs avoided by participants) and total DM costs (utility and participant expenditures, including capital and O&M).[23] The TRC includes all identified costs and benefits, regardless of who pays or receives them.

The RIM, as CG&E appears to use it, is a rough estimate of the effect of a DM option on average system rates over the life of the option, or some other lengthy analysis period. The RIM is not a cost-effectiveness test.

Q: **Is it appropriate to calculate the RIM for a DM measure or program?**

A: No. The RIM should not be used in program design for at least four reasons:

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

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[22] The Company also calculated ratios for the Participant's test and the Utility test.

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

- the RIM attempts to measure only the effect on rates, not on bills;
- the standard RIM does not accurately measure rate impacts; and
- the ELTFR does not indicate that CG&E conducts any comparable analysis of the rate impacts of supply resources.

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

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

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

A: DM that passes the TRC test will almost always reduce the present value of total revenue requirements, average utility bills, and total costs of energy services, including the costs paid directly by participants.[24] Thus, even if rates rise, energy consumption will fall by a larger percentage, resulting in a net decrease in bills.

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

A: The ratepayer impacts of the DM portfolio should be examined carefully to flag any equity problems or disruptive rate impacts. The standard RIM test, however, is not a very meaningful test of equity or rate changes.[25] It looks at

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

[25]Indeed, the standard references on DM cost-benefit tests specify more complex analyses of rate effects. The California Standard Practice Manual for Economic Evaluation of DM Programs specifies a number of different rate impact tests that should be performed, including determination of the annual effect on customers' bills, rather than rates, by class (pages 17-23). Even the EPRI Technical Assessment Guide recommends that rate impacts be

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

The DM option that most conclusively fails the RIM test can increase the equity of the portfolio. Suppose the failing option is a residential lighting program, the only program that might be under consideration for small customers without electric heat, hot water, or central air conditioning. These small customers are likely to bear a portion of the costs of programs directed to the other members of the class; without the lighting program, the distribution of costs and benefits would be inequitable.[26] The lighting program would increase the equity of the DM offerings, while reducing total revenue requirements and bills, even though it would slightly increase residential rates.

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

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evaluated in the context of overall system rate levels, rather than as a stand-alone computation (p. 1-19).

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

groups that would otherwise face higher bills, and possibly by changing the timing of particular programs. DM should not be rejected simply because it fails CG&E's RIM test.

B. DM Efforts and Cost Recovery

Q: In what way do cost recovery considerations affect CG&E's DM planning?

A: CG&E writes that the cost recovery and performance incentives associated with program implementation influences its assessment of DM programs and that "provisions made, or not made, by the Commission regarding these issues directly influence the composition, reliability, and performance of both this and future integrated resource plans," and "if demand-side activity does not prove to be as profitable to the shareholders, resources will be diverted to more profitable activities." (ELTFR p. 2-16) Thus, CG&E appears to be limiting DM activity until favorable cost recovery is assured.

CG&E appears to be placing the cart before the horse. CG&E should demonstrate its understanding and willingness to pursue integrated resource planning, propose a resource portfolio including all cost-effective DM, and then request cost recovery and incentives to support that effort.

Q: Could an aggressive, comprehensive DM portfolio <u>increase</u> CG&E's rate of return?

A: Yes. If the Company wants to provide its shareholders with greater profits, it should improve its DM programs. The Commission has already once criticized CG&E for its poor programs, and taken its DM efforts into account when setting the rate of return. In 1992, the Commission wrote, "one would expect a utility as capacity-tight as CG&E to be a statewide leader in DSM initiatives. Instead, evidence of record demonstrates that the Company's management has failed to focus its attention on this area and provide a sufficient number of quality programs for its customers. This too argues for our adoption of the low point of the rate of return range." (PUCO order in case 91-410-EL-AIR, p. 90)

Furthermore, the Commission has written, in its order in Case No. 89-1001-EL-AIR, and reiterated, in its order in Case 92-1204-EL-AAM et al., that "in future rate cases, one of the criteria for determining the appropriate return on equity will be the applicant's efforts in pursuing demand-side management initiatives." The Commission added in its recent order that it "urges the Company to move forward with aggressive implementation of all cost-effective DM." (Case 92-1204-EL-AAM et al., 12/30/92, p. 5) Most utilities with advanced DM programs receive favorable cost recovery and shareholder incentives.

C. Estimating Program Participation

Q: How does the Company estimate program participation?

A: CG&E estimates program participation according to the Lawrence-Lawton diffusion estimation method, developed by Synergic Resources Corporation. (ELTFR, p. 2-73)

Q: Please describe the Lawrence-Lawton diffusion estimation method.

A: The method uses payback acceptance curves to derive customer participation rates. Derived from case studies reported in the trade press, these curves relate customer acceptance of DM measures to the payback periods for these measures. The Company then uses the curves to estimate long-run market share based on the payback associated with the measure adopted.

Q: Is this an appropriate way to estimate program participation?

A: No. The Company's reliance on payback acceptance curves to estimate participation rates has two fundamental problems, both of which have been noted by the method's developers, Synergic Resources Corporation (SRC). SRC acknowledges that the data used to derive the curves

> shows "revealed" preferences, i.e., the decision makers reports in Energy User News form a biased sample of those who have already installed the DM technology using unknown measurement criteria (perhaps other than payback).[27]

Although SRC believes that data compiled from its own surveys of utility customers around the country confirm the validity of basing the curves on data from Energy User News, it also notes that

> the larger question of whether payback is indeed an adequate representation of market acceptance and long-run share remains to be addressed. An enhancement such a multi-attribute model in which payback is just one of the attributes is being developed at SRC to address this issue.

Thus, even if the data used to develop the payback acceptance curves are valid, the basic approach to estimating market share using customer payback is fundamentally inadequate. As SRC acknowledges, DM participation and penetration rates depend on the ability of program design to overcome such non-economic factors as customer uncertainty about the DM measure's performance, hassles associated with program participation, split incentives, and lack of information about DM technology, suppliers, and contractors.

In other words, the curve does not account for non-economic barriers to customer efficiency investment, or for comprehensive program designs' ability to overcome these barriers and maximize customer participation. The curves may therefore overstate penetration rate for naive program design, and understate penetration for properly structured programs. At any rate, the focus on payback misdirects CG&E's attention towards rebate size and away from program

[27] Synergic Resources Corporation, "Payback Acceptance Characteristics," Working Paper Draft, SRC Report 7540-R2.

design considerations such as directing the incentive to the right party and making participation easy for the customer.

D. CG&E's Commercial/Industrial Programs

1. Overview

Q: **What DM programs does CG&E offer its commercial and industrial customers?**

A: The STIP lists the demand-side programs that the Company has proposed. Mr. Hamilton will discuss the residential programs. The commercial and industrial (C/I) programs are:

- <u>curtailable/interruptible rate program</u>, which offers incentives to large C/I customers who agree to reduce usage upon notification by the Company;
- <u>thermal storage program</u>, which offers customers a cash incentive and technical assistance for installing thermal energy storage, so as to shift cooling demand off-peak;
- <u>high efficiency lighting rebate program</u>, which offers a rebate for the retrofitting of existing fluorescent lamps with T8 lamps and electronic ballasts, and informational services about T8 lamps;

and three educational programs,

- <u>lighting technical assistance</u>, which produces educational materials and events that promote efficient lighting;
- <u>small C/I energy audit</u>, which educates small C/I customers on ways to reduce their energy bills, and
- <u>C/I load management rider</u>, which advertises the load management rate, a rate that favors off-peak demand.[28]

Q: **Which of these programs are end-use efficiency programs?**

A: Only three programs are end-use <u>efficiency</u> programs -- the lighting rebate program, the lighting technical assistance program, and the small C/I audit program. These programs

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[28]CG&E also screened a Gas Cooling program, which failed the TRC (response to PUCO Staff interrogatory #81). For some reason, CG&E models Gas Cooling as increasing electricity use.

seek to increase the efficiency of customers' electricity use. None of the other programs improves end-use efficiency. The Thermal Storage program is a load shifting program. The curtailable/interruptible rate and C/I load management rider programs are marketing programs designed to market the Company's rates.[29]

Q: **How would you characterize CG&E's demand-side efforts in the commercial/industrial sector?**

A: CG&E's demand-side efforts in the commercial and industrial sectors are woefully inadequate. Apart from educational programs, the only end-use efficiency program which the Company has chosen to implement in these sectors is the High Efficiency Lighting Rebate program which offers customers financial incentives to install T8 fluorescent lamps with electronic ballasts. Though there are many cost-effective DM programs and end-use efficiency measures available to CG&E, the Company has chosen to make use of just one. CG&E has ignored almost the complete range of market segments and cost-effective applicable technologies.

The only market segment addressed by CG&E's High Efficiency Lighting Rebate program is medium and large commercial and industrial firms' purchases of fluorescent tubes and ballasts.

Q: **What are the consequences of the limitations of CG&E's portfolio?**

A: First and most important, by failing to address all market segments and by failing to offer its customers a wide range of technologies and measures, CG&E fails to capture a significant amount of cost-effective demand-side resources.

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[29] In its Order in case No. 92-1304-EL-AAM et al., the Commission agreed with Staff's finding that "interruptible rates have been a standard practice for Ohio utilities and have historically been justified based on cost-of-service considerations," and that cost-based tariff programs should be distinguished from DSM programs. (p. 4)

As a result, customers' needs for electric service must be met by more costly supply-side resources.

Second, the fact that a significant portion of these lost resources are in lost-opportunity market segments (e.g., new commercial construction, industrial plant expansion, and commercial and industrial equipment replacement) means that these potential demand-side resources are lost for a very long time (i.e., the useful lives of the buildings and equipment).

2. Neglected Market Segments

Q: Which market segments should CG&E's C/I programs be addressing which are presently not being addressed?

A: Most importantly the CG&E IRP should address the following lost-opportunity sectors with measures other than lighting:[30]

- new commercial construction,
- commercial renovation and remodelling,
- commercial equipment replacement,
- new industrial construction and plant expansion,
- industrial process overhaul, and
- industrial equipment replacement.

I discuss these markets in greater detail in Section V, below. In addition, the Company should address discretionary savings opportunities from the following markets:

- small commercial retrofits,
- government/institutional retrofits,
- large commercial retrofits,
- small industrial retrofits, and
- large industrial retrofits.

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[30] This is not to suggest that the CG&E lighting program as currently designed is adequate to address these market sectors.

Q: Does the Company provide any explanation for its lack of a new commercial construction program?

A: Yes. The Company assumes "that more efficient technologies will be adopted naturally in the building design." (STIP p. 68) CG&E said that this assumption is based on "informal observations of market trends over time." (City DR 1-19)

Q: Do you agree that "natural" market forces obviate the need for a new construction program?

A: No. Although it is true that "natural" market forces have continually improved the energy efficiency of new commercial construction, such "natural" improvements in standard practice have never included all the cost-effective energy efficiency available. The many utility programs that target C/I new construction routinely obtain savings of 25% beyond standard practice and modern building codes (such as those based on ASHRAE Standard 90.1).

CG&E should not be truncating its DM portfolio and foregoing lost-opportunity resources on the basis of "informal observations," any more than it would rely on informal observations to decide if new generation facilities are needed.

Q: Does the High Efficiency Lighting Rebate program adequately address lighting in the range of C/I markets you described above?

A: It does, but only sporadically, not in a systematic way. This program's deficiencies include:

- The measures offered are too limited: the program only offers a rebate for one technology, T8 lamps with electronic ballasts.
- The program's $20 rebate approximates the incremental cost of the measure, and thus would be appropriate for securing savings from market-driven opportunities. The fact that the rebate is close to the incremental cost

of the measure is a coincidence.[31] The program is not likely, however, to obtain much savings from this market segment. The program specifically excludes new construction projects. It is not clear if renovations would be eligible; the Company offers pre-installation inspections (STIP p. 25), which may preclude renovation customers from participating. At any rate, they do not appear to be targeted.

- For retrofit customers, the rebate may be too low. Because this financial incentive does not cover the full cost of the measure, cost will be a barrier for some customers. Furthermore, the program does not address non-financial barriers to participation. In particular, the program is not likely to attract many small C/I customers, because it does not directly install the lighting measures.

- The program is not likely to enlist many participants from government/non-profit customers, because the rebate does not address non-financial barriers to program participation.

Q: What non-financial barriers are you referring to?

A: Several characteristics of small commercial, small industrial, and government/institutional customers prevent significant levels of participation unless they are addressed in program design. For small commercial and industrial firms, these problems include a lack of access to capital for investment in energy efficiency opportunities, a lack of engineering capability to evaluate energy efficiency options, and a lack of in-house staff to implement and/or supervise installation of energy efficiency measures. These non-financial barriers account for the greater success of direct installation programs over rebate programs. Full cost direct installation programs do not require customers to have the financial and technical resources necessary to necessary to participate in rebate programs.

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[31] To set the rebate level, CG&E first obtained information about the rebate levels of four other utilities, and then picked the lowest of the four rebates, which ranged from $20 to $45. (follow-up response to City of Cincinnati interrogatory #20, first set)

The principal barriers to participation in rebate programs by government/institutional customers relate to decision-making and budget processes. Facility management staff in government buildings tend to have less authority and to be less technically sophisticated than their private sector counterparts. Public sector facility management staff is generally less able to initiate decision-making regarding facility investments. Secondly, the process of allocating funds for facility investments is usually tied to a political budget making process and a budgetary cycle of one year or greater. Thus, there is an inability to allocate customer funds to invest in energy efficiency with the relative ease of private sector customers. Further, the financial savings which result from investments in energy efficiency are often not matched to the budget which provided the funds for investment. This prevents funds allocated for energy efficiency from being viewed as cost-effective investments.

Q: Has CG&E considered or evaluated programs designed to address the needs of small commercial, industrial, or government/institutional customers?

A: Apparently not. The Company provided no evidence in its responses to discovery questions that indicate that it has evaluated any direct installation.

3. Neglected Technologies and Measures

Q: Which technologies do the Company's C/I DM programs fail to address with financial incentives?

A: Omitted technologies are extensive and significant. As discussed previously, there are no efficiency measures approved for financial incentives which address anything other than a single lighting measure.

Q: **Please identify the technologies omitted from CG&E's current program offerings.**

A: Omitted technologies or measures which would be expected to be cost-effective depending upon site specific conditions include:

- building envelope measures such as window film and additional insulation;
- domestic hot water measures such as tank insulation, pipe insulation, faucet aerators, and point-of-use water heating;
- HVAC efficiency measures including efficient air conditioning systems, economizer controls (e.g.,free cooling, enthalpy controls), programmed controls (e.g., optimized start/stop), or conditioned air distribution system conversion (e.g., to a variable-air-volume system); and
- industrial measures such as efficient compressors, efficient motors, adjustable speed drives, process heat, electrotechnologies, and motive power applications (i.e., fans, pumps, and piping systems).

CG&E's High Efficiency Lighting Rebate program fails to qualify a number of lighting measures including:

- lamps other than the T8 type,
- lighting controls such as occupancy sensors and continuous dimming (ballasts for daylighting control), or
- reflector retrofits (with delamping).

Q: **What is the effect of all of these missing technologies or measures with respect to program savings impacts?**

A: Obviously, most achievable cost-effective savings are ignored, or even lost forever.

Q: **Are CG&E's proposed programs consistent with your reading of the technical terminology in its 1989 Stipulation?**

A: No. The stipulated agreement reads "[t]he parties have agreed to a cooperative process to achieve the goal of evaluating and developing an aggressive portfolio of feasible and cost-effective Demand-Side Management (DM) programs, including conservation and load management, for all customer classes." (Stipulation, as cited in summary of PUCO order in case 89-569-EL-FOR, 10/3/89) As discussed above, CG&E's current programs can in no way be considered "aggressive," nor do they include all feasible and cost-effective savings.

Q: **Do other Ohio utilities offer their C/I customers a greater range of DM options?**

A: Yes. For example, Columbus Southern Power's proposed DM programs, while they are not on a par with collaboratively-designed programs, would offer its customers many more opportunities for reducing costs. Commercial customers may receive measures that address lighting, HVAC, refrigeration, electric water heating, space cooling/heating, and building envelope. Industrial customers may receive measures that address motors (disaggregated into six different size classes) lighting, electrolytics, and process heating.

V. MODEL COMMERCIAL/INDUSTRIAL PROGRAMS

Q: **What types of C/I programs should CG&E attempt to include in its IRP?**

A: The types of generic C/I programs through which CG&E should be able to maximize the savings from its commercial and industrial customers include:

Commercial New Construction - CG&E would fund or provide technical assistance and full incremental cost financial incentives for energy-efficient measures representing efficiency levels beyond standard construction practice. In addition to working with architects to address overall building design, the program would provide incentives for a comprehensive range of measures covering lighting, HVAC, motors and drives, water heating, building envelope, and refrigeration. The program would offer a custom track for large projects and a prescriptive track, offering a menu of measures and incentives, for smaller projects. CG&E would attempt to identify potential program participants as early in the design process as possible and would publicize the program to builders, realtors, architects, engineers, equipment vendors and suppliers, and building trade associations.

Specialized program components would be developed for renovation and remodelling projects.

Industrial Facility Expansion/Process Overhaul - CG&E would co-fund technical assistance and pay full incremental cost for energy-efficient measures that exceed standard industry practice. The program would cover all lost-opportunity measures including lighting, HVAC, motors and drives, water heating, building envelope, refrigeration and industrial processes. CG&E would develop contacts with plant managers and trade allies to identify potential program participants as early in the design process as possible.

C/I Equipment Replacement - When existing equipment is replaced or new equipment is added, CG&E would use rebates and funding of feasibility studies to encourage customers to purchase energy-efficient equipment. Rebates would cover the full incremental cost of cost-effective efficiency upgrades. Feasibility studies would be co-funded with the customer. Most measures covered would be in lighting, HVAC, motors, water heating, building envelope, and refrigeration. Trade allies (vendors, suppliers, and contractors) would be critical to the success of this program, and may receive some incentive directly

Customers replacing HVAC equipment would be encouraged to combine HVAC equipment replacement with comprehensive retrofit package, to reduce HVAC equipment size.

Small C/I Comprehensive Retrofit - With customer approval, CG&E contractors would identify and install all cost-effective electrical-efficiency measures, principally lighting, at no charge to the customer. The scope of work would be determined by a site survey.

Large Commercial and Industrial Comprehensive Retrofit - CG&E would conduct a walk-through survey of the facility to identify potentially cost-effective retrofit efficiency measures. CG&E would co-fund feasibility studies and the measures, to the extent necessary for the customer to realize a one-year payback on its investment.

Measures would be installed by the customer or its contractors. CG&E would review project proposals, approve the proposed installations, and inspect completed work. CG&E would maintain an on-going relationship with facility personnel in order to provide continuing technical assistance to the customer's energy- and facilities-management staff.

Government and Institutional Not-for-Profit Comprehensive Retrofit - CG&E would evaluate the cost-effectiveness of retrofit measures for these customers, provide contractor services for the project, specify measures, and install them at no charge to the customer.

Q: Are you suggesting that the least-cost plan for CG&E would include these C/I efficiency exactly as you describe them?

A: No. I am proposing a framework for capturing C/I efficiency resources. CG&E should develop a conceptual program design for each market segment, and then subject the programs to proper cost-effectiveness testing. For each program, CG&E should first screen individual measures for cost-effectiveness, and then add administrative and delivery costs and to screen the full program. All cost-effective programs should be implemented. The most effective programs designs for CG&E may differ somewhat from the structure I outlined above, but should be equally comprehensive.

Q: Would these programs put least-cost planning principles into practice?

A: These programs would comprehensively cover C/I market segments, and are structured so as to secure the greatest participation by eligible customers and penetration of cost-effective measures. Program strategies combine marketing, technical assistance, measure delivery, and financial incentives.

VI. ADDITIONAL SAVINGS ATTAINABLE WITH COMPREHENSIVE PROGRAMS

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

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

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

A: A precise answer to this question will have to wait until CG&E gains experience with comprehensive programs of the scope described above. Nevertheless, it is possible to extrapolate in general terms from the plans of utilities with third-generation DM programs: comprehensive, well-funded, appropriately directed programs, covering all market segments. I used the data presented in Section III.C to derive a rough estimate of the additional DM resources that CG&E might acquire if it follows the lead of utilities with aggressive and comprehensive plans.[32]

Q: How much additional energy might CG&E save?

A: As shown in Exhibit ___ PLC-5, the plans of utilities with comprehensive DM plans suggest that CG&E might acquire an 1,135 GWh of cost-effective efficiency savings (including losses) by 2000, in addition to the DM savings CG&E projects, for a total savings of 1,386 GWh. This total represents approximately 6% of year 2000 energy sales. By comparison, the ELTFR includes only enough DM displace 1% of CG&E's energy requirements in the year 2000. The associated additional peak savings are 231 MW, or roughly twice as much as CG&E is currently pursuing.

DM programs reflecting average practice of the third-generation utilities in Exhibit ___ PLC-5 would defer the

[32]This estimate should not be construed as representing the highest level of conservation achievable by CG&E.

need for about four of the six planned Woodsdale units. In 2002, DM would allow CG&E to defer the first new coal plant. Hence, these programs would have significant effects on CG&E's supply planning, as well as on fuel costs, T&D costs, and environmental compliance.

Q: How did you estimate energy savings potential shown in Exhibit ___ PLC-5?

A: First, I estimated the new energy savings from DM that might be achieved in each year. For each class, I computed annual additional energy savings as a percentage of projected annual sales. I based these percentages on the plans of the utilities with the most comprehensive DM portfolios, by class.

I multiplied these annual percentages by CG&E's projected average annual sales, for each year. I added the annual figures to obtain a cumulative savings figure. To determine the savings CG&E could secure <u>in addition</u> to what it already projects, I subtracted CG&E's projected savings from Exhibit ___ PLC-4.

Second, to project peak demand savings generated by intensifying CG&E's DM portfolio, I applied CG&E's system load factor to my estimate of potential additional energy savings, and computed sensitivity cases for load factors 15% higher and lower than CG&E's system average. The total potential peak savings from all of CG&E's DM programs are the sum of these additional peak savings and CG&E's projection of peak savings.

Q: How should the Commission use these savings computations?

A: My computations are intended to assist the Commission in determining the scale of DM resource acquisition that is likely to be cost-effective for CG&E. Once a comprehensive, state-of-the-art DM portfolio is developed for CG&E, the savings from that portfolio will replace these rough estimates.

VII. AVOIDED COSTS

A. Role of Avoided Cost

Q: **Why are CG&E's avoided cost estimates important?**

A: Avoided costs are used to determine the cost-effectiveness of DM. The magnitude of avoided costs will determine the amount of DM that is found to pass the TRC. CG&E's initial screening of DM options occurred in the 1990 ICF report. The survivors were screened again in DSManager using avoided costs from a PROMOD run based on the 1991 ELTFR, and then in the PROVIEW/PROSCREEN package (ELTFR p. 2-130).

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

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

- CG&E understates generation capacity cost.
- The analysis understates avoided T&D costs.
- It understates avoided demand and energy losses.
- The analysis neglects costs of compliance with the Clean Air Act Amendments.
- It omits environmental externalities.
- It gives DM no credit for risk mitigation.

B. Development of Avoided Costs for DM

Q: How should CG&E estimate the supply costs avoided by DM?

A: CG&E should capture the avoidable costs of

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

1. Generating Capacity

Q: How should CG&E estimate the generating capacity costs avoidable by DM?

A: The avoidable generating costs are the difference between (1) the least-cost supply plan without the DM and (2) the least-cost supply plan with the DM. The DM should be assumed to have a realistic load shape (generally, similar to overall system load), and the amount of DM should be comparable to the capacity of avoidable supply. The portion of the avoided capacity cost that is comparable to the cost of peaking capacity (generally combustion turbines (CTs)) should be assumed to be related to demand or reliability, while the excess should be assumed to be related to energy load.

2. Variable Generation Energy Costs

Q: **How should CG&E estimate the variable generation energy costs avoided by DM?**

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

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

3. Transmission and Distribution Capacity

Q: **How should CG&E estimate avoidable transmission and distribution capacity for DM?**

A: In general, it is not possible to directly compute the difference in T&D investment for the base and DM cases, due to the lack of system planning models comparable to the system models used in generation planning. Hence, it is usually necessary to estimate T&D costs from historical (and perhaps projected) relationships between investments and loads, and between O&M and loads.

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

4. Line Losses

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

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

5. Environmental Compliance Costs

Q: **How should CG&E include the costs of environmental compliance?**

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

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

6. Externalities

Q: **How should externalities be incorporated into utility planning?**

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

7. Risk Mitigation

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

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

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

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

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

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

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

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

A: Participation in market-driven lost-opportunity programs (in new construction and renovation programs, equipment additions, and replacement programs) varies directly with service area load growth. Thus, a utility committed to pursuing lost opportunities will automatically synchronize its new resource acquisitions with swings in resource needs.

In addition, the savings produced by previous efficiency investments will also tend to track load. For example, increasing industrial output in existing facilities will raise electricity use. If those facilities use high-efficiency motors, the increase in electricity use will be less than with standard motors. The same is true for commercial and residential customers; for example, thermal efficiency improvements in building construction and HVAC equipment (e.g., insulation, chiller efficiency) will reduce the effect of weather on load. In extreme weather conditions, these measures provide additional resources, while supplies are essentially fixed. Indeed, under extreme summer conditions, thermal power plants tend to produce less power and transmission lines are able to carry less power.

Drought and ice also reduce supply but usually leave DM unaffected, or even enhance DM effects.

Compared to supply, efficiency resources therefore reduce the uncertainty surrounding the rate and magnitude of future load growth, thereby reducing over- and under-building. DM also reduces the magnitude of cost swings due to fuel prices, construction costs and schedules, operating costs, and power plant availability.

Q: **Have the risk-mitigating advantages of energy-efficiency resources been quantified in other jurisdictions?**

A: Vermont Public Service Board (VPSB Docket 5270) increases base-case avoided costs, including transmission and distribution, by 11.1% (or equivalently, decreases DM costs by 10%) to reflect the expected risk-reduction benefits of DM. The Northwest Power Planning Council (1991, pp. 930-931) considered the "added advantages" of energy efficiency, including "the ability to track local growth" and the tendency of "savings [to] increase as the weather becomes more severe." Based on the risk analyses and other studies,[33] NPPC increased the avoided costs for energy-efficiency programs by 30% to account for these planning benefits.

Ontario Hydro (1989, 1991, 1992) applies a 10% avoided-cost premium to preferred options, including DM, to reflect "long-term availability and price stability" for fuel.

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

C. CG&E's Avoided Costs

Q: **Did CG&E correctly estimate avoided costs for the purposes of DM analyses?**

A: No. CG&E's understates several aspects of avoided costs, including peaking and baseload generation capacity, transmission and distribution capacity, energy dispatch, environmental compliance, line losses, risk, and externalities.

1. Generation Capacity Cost

Q: **What avoidable generation capacity is reflected in CG&E's avoided costs?**

A: CG&E uses a demand-related generation capacity cost of $46.76/kW-yr in real-levelized 1991$.

Q: **What problems have you identified in CG&E's approach to estimating avoided production cost?**

A: CG&E's approach to estimating avoided production cost has the following deficiencies:

- demand-related capacity costs are understated due to a computational error;
- CG&E does not appear to reflect the derating of CTs during its summer peak;
- no reserve margin is included;
- capacity costs are divided over the 12 months in a manner which apparently precludes reflection of the full cost; and
- CG&E does not treat the higher capacity cost of coal plants as avoidable.

Q: **How are the demand-related capacity costs understated?**

A: As shown in DR Staff-19, CG&E restates the ratemaking costs of a CT on a real-levelized basis.[34] The real-levelized cost is a value in the base year (in this case, stated in $/kW-yr) that, when escalated over the life of the plant, will have the same present value as the stream of annual ratemaking costs. This approach is appropriate and useful. Unfortunately, CG&E miscalculates the real-levelized CT capacity cost.

Exhibit ___ PLC-6 demonstrates that CG&E's real-levelized CT capacity cost of $45.86/kW-yr produces a present value of $576/kW over the 25-year life of the CT. The present value of the actual stream of annual ratemaking costs (levelized at $77.90/kW-yr) is $633/kW, 11.5% higher than the capacity cost CG&E used in screening DM. The error appears to arise from inadvertently discounting the costs by one year too many in the levelization process. Exhibit ___ PLC-6 also shows that a real-levelized capacity value of $51.13/kW-yr would produce the correct present value. Hence, the demand-related capacity cost used in screening DM should be increased to $52.03/kW-yr in 1992$, escalating at 5.4%.

In addition, CG&E appears to have forgotten to include the overhead costs, including payroll taxes, benefits, and management (administrative and general) costs. These costs generally represent about 40% of O&M, plus some small fraction of plant.

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[34]The CT used in this computation is not a unit of the type planned by CG&E, but a hypothetical 80 MW unit from the EPRI Technical Assessment Guide (TAG). The CG&E unit may be more expensive than the hypothetical unit; CG&E does not provide the costs of its supply options.

Q: Why doesn't CG&E include any reserve margin in avoided costs?

A: CG&E argues that

> At the early stages of DSM program development and implementation no reserve margin credit is warranted. This is due to the fact that the actual DSM program performance is unknown. In the early years of DSM program implementation, the need to carry a higher reserve margin to cover DSM uncertainty may be justified. Later, after actual experience is gained, reserve margin credits may be applied to DSM program with known and documented impacts. This process is similar to that used to arrive at the general 20 percent reserve margin required to maintain reliability on an electric system. Actual experience over many years on many system played a major role in making this general reserve margin determination.
>
> Reserve margin is to cover both uncertainties in generating capability availability and load level uncertainty. The former may be due to maintenance, forced outages or unit derations. The latter may be caused by load fluctuations due to any number of factors including: extreme weather, economic conditions, or DSM performance. (DR OCC 1-14)

Q: Is this argument valid?

A: No. DM avoids all of the "uncertainties in generating capability availability" listed by CG&E -- "maintenance, forced outages [and] unit derations" -- and also avoids uncertainties in construction schedule, project completion, and unit longevity.[35] Corresponding uncertainties for DM are quite minor on a system level, since the risks are so heavily diversified: a 100-MW generating unit may fail within minutes, while corresponding simultaneous failures in 100 MW of efficiency DM are difficult to imagine.

As discussed below, DM also reduces the risk of load fluctuations due to "extreme weather [and] economic

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[35]Most of these factors are more important as risks (random outcomes from a well-known distribution), rather than uncertainties (unknown probability distributions).

conditions." Hence, DM avoids five of the six risk factors CG&E lists, plus at least three more. CG&E's last risk factor is "DSM performance," which is only uncertain until the DM is installed and has operated long enough to reduce CG&E's load data. CG&E seems to be assuming that it will install reserves for loads that DM avoided years earlier. The maximum sensible response to CG&E's concern would be to exclude a reserve margin for the first year of DM measure operation.[36]

Even that accommodation to CG&E's concerns would not be necessary, if CG&E actually developed aggressive DM programs. The diversity of the programs, and CG&E's resulting capability to adjust program delivery, would reduce DM performance risks. In addition, CG&E's increased sophistication with DM program delivery, and knowledge of other utilities' results, would give CG&E greater confidence in its projections of DM savings.

CG&E has created a Catch-22 for DM. Since DM is new to CG&E and untried in Southwest Ohio, CG&E discounts DM's value. The lower imputed value results in less DM appearing to be cost effective and developed (and even some apparently cost-effective DM is not pursued). Since CG&E is not rapidly developing its DM resources, DM remains new and unfamiliar.

Q: **Please describe the problem with CG&E's computation of monthly capacity costs.**

A: CG&E states that it allocates the capacity costs equally to the 12 months (DR Staff 19(d)). Thus, CG&E appears to have simply divided the annual cost by 12. In order to be credited with a kW of load reduction, a DM measure would have to save 1 kW on each of the twelve monthly peaks.

[36]By CG&E's reasoning, CG&E should plan for extra reserve margin requirement any time a new unit is to be added, to reflect the uncertainty in this untried unit's performance.

In fact, CG&E's actual loads, which drive the addition of capacity, are not constant in every month. The system peak is about 21% higher than the average monthly peak (DR City 3-40, Exhibit). Thus, CG&E's summer peak grows by 1.21 kW for each kW of average monthly peak. If CG&E wishes to allocate costs equally to each month, it should increase the value per kW by 21%; including a 17% reserve margin, each kW of monthly peak load reduction should be credited with avoiding 1.42 kW of generating capacity.[37]

Q: Why should CG&E treat the higher capacity cost of coal plants as avoidable?

A: CG&E's supply plan projects the installation of coal plants in 2002 and 2006; all load growth from 2002-2012 would be met by these coal plants. These units are much more expensive than the CTs used to determine the demand-related avoidable capacity cost. The additional costs of the coal plant are incurred to meet long hours of demand and to reduce fuel costs, and are thus driven by energy use, rather than peak demands. The excess cost of the coal plant over the CT should thus be included in avoidable energy costs.[38]

Q: Why does CG&E exclude these costs?

A: CG&E asserts that the extra capital costs of the coal plants are offset by their fuel savings (ELTFR p. 2-134, fn 1).[39]

Q: Is this argument valid?

A: No. CG&E does not support this assertion with any analysis. Since baseload plants are usually justified based on their lifetime fuel savings, not first-year savings, it would be

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[37]As noted below, line losses should be added to this value.

[38]Utilities often assume that capacity costs must be demand-related. This is only true for the costs of peaking capacity; other capacity costs may be driven by energy requirements.

[39]CG&E also assumes that DM can defer CTs, but not the coal plants (ELTFR, p. 3-44). This assumption may be driven by a desire or perceived need to build additional steam plants, for institutional reasons.

surprising if the fuel savings in the early years of the coal plants' lives equalled the extra capacity costs of the coal plants. The CG&E approach could result in a situation in which

- gas and oil prices are projected to rise and reliance on those fuels is projected to increase;
- coal plants are added to avoid the high future gas and oil costs;
- the additional coal plants keep the percentage of gas and oil low;
- DM is credited with avoiding only the low capital costs of CT and a low-cost fuel mix primarily composed of coal; and
- CG&E rejects DM that is more expensive than its erroneously-estimated avoided costs, but builds still more expensive coal plants.

Indeed, this pattern appears to be visible in CG&E's own planning. CG&E reports that new coal plants are less expensive than new CTs only if the CTs would have operated at a capacity factor of more than 25% (ELTFR p. 2-10). Yet the Woodsdale CTs are expected to operate at capacity factors below 3% (DR Staff-85); the new CTs are reported (ELTFR pp. 2-10 and 2-11) to have higher variable costs than Woodsdale, and hence would operate even less. The coal plant would cost about $200/kW-yr more than sum of CT capacity and avoided fuel computed by CG&E.

As a result of its erroneous treatment of baseload plant costs, CG&E reports that "The Company's avoided costs are determined by: energy costs based largely on barge delivered coal burned in efficient existing generating units and marginal capacity costs based on gas turbines and DSM options" (ELTFR 3-13).[40] CG&E obviously cannot continue to supply power with this set of costs in the longer term.

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[40]The reference to avoiding DM options is difficult to understand.

These avoided costs would preclude the development of DM that was less expensive than CG&E's avoidable coal plants.

To avoid this error, CG&E should explicitly model the extra capital costs of the avoidable coal plants, and include those costs in avoided energy costs.

2. Variable Energy Costs

Q: **Has CG&E properly computed avoided variable energy costs?**

A: CG&E's documentation of its avoided variable energy costs is quite sparse; even the values of the avoided costs used in the PROSCREEN screening have not been provided (DR Staff-19(h); DR City 3-5). As discussed below, the variable energy costs do not include all compliance costs. In addition, it appears that the DSManager runs used marginal energy costs averaged over the hours in each rating period, rather than weighted by sales or DM savings in each hour (DR OCC 1-15). This error understates the value of most DM options.

3. T&D Capacity Cost

Q: **Has CG&E included T&D costs in its DM screening analysis?**

A: Yes, to a very limited extent. CG&E includes \$16.98/kW in real-levelized 1991\$ for transmission (DR Staff-9, Attachment 3), of which \$3.50/kW is O&M and the remaining \$13.48/kW is capital recovery.[41] In the March 22 teleconference, CG&E staff indicated that this value was intended to include distribution costs as well as transmission. It appears that the costs are understated in several ways:

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[41]DR Staff-57 indicates that this value should be \$16.98 in 1992\$. Since CG&E provides no documentation for the \$173/kW capital costs or the O&M underlying its calculations, I cannot determine whether the transmission costs in either of these responses is stated in the correct year's dollars.

- Some costs appear to have been improperly excluded. CG&E indicates that it omitted "blankets, road work, etc." (Staff DR9, Attachment 3) It is not clear why costs incurred under blanket authorizations should be assumed to be unrelated to load. "Road work" presumably refers to relocation of lines to accommodate roadway construction; these costs vary with the amount of transmission in service, and are thus related to load, if not to load growth. CG&E does not provide any explanation of what was omitted under the "etc." category.

- The "computation of plant additions" (DR City 3-11, Attachment 1) used in calculating the avoided transmission cost has several problems:

  - The response provides a time series of costs, without any indication of how those are computed.

  - The data in the response appear to be inconsistent with historical data from the FERC Form 1 and with budgets from DR City 3-29. The costs are far too small to represent total transmission and distribution investment.

  - The analysis covers 1986-96, but omits costs from 1989.

  - Costs are discounted at 11.3% to 1991 present value terms. Discounting has no legitimate role in this computation. The costs should have been stated in real (or constant) dollars, using an inflation rate of about 5%.

  - Even with all of these errors, dividing CG&E's computed $237,752,885 present value of investment from 1986-1996 (excluding 1988) by load growth from 1986-1996 (1037 MW, from DR City 3-11) yields a cost of $230/kW (1991$), not the $173/kW (1991$ or 1992$) CG&E used.

- CG&E's computation of transmission cost repeats the same error discussed above in relation to generation capacity. In order to produce the same present value as the nominally-levelized 15% carrying charge, CG&E would need a real-levelized charge of $14.95/kW-yr for capital, plus the $3.50/kW-yr in O&M, for a total cost of $18.45/kW-yr.

- The cost of capital used in computing the levelized transmission cost is 10.92%, rather than the 11.3% or 11.5% used elsewhere in the ELTFR; this appears to result in an additional understatement of a few percent.

CG&E's transmission value falls below the range of transmission costs commonly reported by other utilities, as reported in Exhibit ___ PLC-7. The value is far too low to reflect any significant fraction of load-related distribution costs. Hence, CG&E has effectively omitted distribution from its avoided-cost analysis.

Q: Why should transmission and distribution capacity be treated as avoidable?

A: Transmission and much of the distribution system (substations, feeders, primary and secondary networks) provide bulk services, driven entirely by demand growth.[42] Some portions of local primary laterals and secondary equipment is used by only a few customers, but the sizing of this equipment is determined by load levels for new construction, when older equipment reaches the end of its life and is replaced, and when load growth requires that additional equipment be added. DM can also help extend the life of existing equipment by reducing the frequency and magnitude of heavy loadings.

Q: By ignoring distribution capacity costs, how much could CG&E be understating avoided costs?

A: The marginal demand-related costs of distribution capacity can be quite high, often exceeding avoided generating capacity costs per kW of load reduction. Reductions in customer loads will tend to reduce loading on the company's transmission, sub-transmission, primary distribution, and secondary distribution circuits. Such reduced loading will translate into cost savings, since CG&E will be able to postpone or avoid investments to expand or upgrade existing or planned transmission and distribution circuitry. Reduced

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[42] See DR City 3-26, Attachment 1, for CG&E's summary of its guidelines for adding distribution capacity.

loading can also enable CG&E to install smaller, less expensive equipment to serve new loads.

Utility estimates for the value of avoided transmission and sub-transmission capacity costs per coincident peak kW fall in the range of $20-30/kW-yr. Utilities that include all load-related distribution costs (e.g., substations, feeders, laterals, transformers, and secondary lines) as being avoidable find that the costs range from $50-$150/kW-yr.[43] Exhibit ___ PLC-7 provides a survey of several utilities' estimates of load-related T&D costs; my own analyses of utility cost data generally result in costs in the same range. While load patterns and details of T&D practices vary between utilities, the similarities in overall load characteristics, the national market for T&D technology, and the limited number of suppliers suggest that CG&E's T&D costs will be comparable to those in Exhibit ___ PLC-7.

4. Losses

Q: What loss factors has CG&E used in its avoided cost analysis?

A: CG&E reports energy loss factors of 8.55% for commercial and residential customers, and 3.83% for industrial customers (DR City 3-42).[44] The same response indicates that peak demand losses are not "available." I assume that this means that CG&E treated peak losses as being zero.

In the various versions of Form IRP-4 in the ELTFR, reports that in PROSCREEN it used "billing seasonal [loss] factors," without providing values; and that in DSManager it

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

[44]It is not clear whether these factors are expressed as a fraction of sales or a fraction of generator output.

used "Annual Loss factors" of 7.085% for commercial and residential, and 3.17% for industrial programs.

Q: Are these values appropriate for screening DM?

A: No. CG&E's approach understates avoided costs for the following reasons:

- CG&E incorrectly applies average losses, rather than marginal losses (DR City 3-14; DR OCC 1-10);
- CG&E's analysis fails to recognize that marginal losses vary between and within rating periods, as load level varies;
- CG&E ignores all line losses at peak load, and hence understates demand-related costs of generation and transmission;[45] and
- In applying a lower loss factor to industrial DM, the analysis ignores avoided losses on the customer side of the meter.[46]

Q: How do losses vary with load level?

A: Variable losses as a percentage of load or of generation increase roughly linearly with load, as explained in Exhibit ___ PLC-8, and hence by time period. Losses at peak are roughly equal to average annual energy losses divided by system load factor; for CG&E, this would be about 8.5% ÷ 60% = 14%. Marginal losses (the losses on the marginal kWh delivered) are roughly twice as large as average losses at any given load level.

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

A: Average losses are the total line losses incurred during a rating period, divided by the total energy sold. This measure is the loss factor commonly reported in aggregate energy sales tabulations. Marginal losses, on the other

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[45] If CG&E had included any distribution costs, those would have been understated as well.

[46] CG&E may have similarly ignored losses on the customer's side of the meter for commercial customers served at primary.

hand, equal the difference between total losses at a higher, pre-DM load level, and total losses at a lower, post-DM level. What is important for valuing DM savings is that percentage losses tend to increase linearly with load level. Thus, marginal losses will always exceed average losses at any given load level.

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

A: As explained in Exhibit ___ PLC-8, total variable losses are proportional to the square of load. As load increases, the average losses (losses divided by load) rise linearly. Marginal losses (the derivative of losses with respect to load) also increase linearly, and are approximately twice average variable losses.

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

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

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

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

5. Environmental Compliance Costs

Q: **Did CG&E include environmental compliance costs in screening DM?**

A: CG&E did not include environmental compliance costs in its DSManager screening for the ELTFR, nor for the 1990 ICF screening, which eliminated many DM options. Low-sulfur fuel costs and sulfur allowances were included in the PROSCREEN screening.

No compliance costs have been included for NO_x, air toxics, or CO_2.

Q: **To what extent can DM reduce CG&E's air emissions?**

A: For coal-fired systems, marginal emissions tend to run in the range of 2,000-2,200 lbs/MWH CO_2, 12-50 lbs/MWH SO_2 (assuming the marginal unit is not scrubbed), and 3-20 lbs/MWH NO_x.

Q: **What are CG&E's SO_2 allowance costs?**

A: CG&E will be required, under the CAAA, to hold emissions allowances for every ton of SO_2 it emits. CG&E is planning to reduce emissions on its own system by enhancing scrubber efficiency at East Bend 2 and switching to low-sulfur coal at Conesville 4, Miami Fort 5-7, Beckjord 5 & 6, and possibly Beckjord 1-4 and Stuart 1-4, at costs of up to about $200/ton in 1991$ (ELTFR, Volume III, Appendix 1, p. V.16). Every additional ton of SO_2 that CG&E plants emit annually will force CG&E to buy one more allowance, or sell one less allowance.

Q: **What are the potential additional direct costs to CG&E of emissions of NO_x?**

A: CG&E is required to install low-NO_x burners on its fossil facilities under Title IV of the CAAA, and it may be subject to additional costly controls, depending on the NO_x reductions required by the State Implementation Plan (SIP) to comply with Title I of the CAAA. The Cincinnati area is a moderate non-attainment area for ozone under Title I. The

NO_x reduction requirements will depend on the results of the airshed modelling to determine the relative effectiveness of NO_x and VOC emissions to reducing ozone levels in this area.

The results of the airshed modelling will affect both the Best Achievable Control Technology (BACT) requirements for new facilities and the Reasonably Available Control Technology (RACT) requirements for retrofitting existing facilities. If selective catalytic reduction (SCR) is required to reduce emissions from new turbines to 9 ppm, the incremental cost would be on the order of $3,000-$10,000/ton NO_x (Cleaver-Brooks, 1992). For new coal plants selective non-catalytic reduction (SNCR) or SCR would typically cost $3,000-$8,000 per ton. For retrofits, typical RACT requirements include measures costing up to $2,000/ton, or more depending on the jurisdiction. Average costs for RACT NO_x measures required by the Texas Air Control Board, which exceed $2,000/ton for utility boilers and $5,000/ton for industrial boilers. Although Ohio's <u>average</u> RACT costs may be lower than those of Texas, because of its higher air quality, <u>marginal</u> RACT costs in Ohio are likely to be in the same range as average Texas costs.

These costs are avoidable by reducing usage of plants and by reducing the number of new plants that must be built.

Q: **What are the potential additional direct costs to CG&E of emissions of particulates and toxics?**

A: CG&E may be subject to additional controls of particulates and airborne toxics under Title III of the CAAA. This title addresses control of emissions of 189 toxic pollutants from stationary sources, several of which are emitted by coal combustion.[47] Utilities are not immediately covered by the provisions of this title, but utilities may be subject to future controls, particularly as they contribute to

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

degradation of the Great Lakes' water quality and the accumulation of mercury.

Some air toxics are removed from flue gas from particulate controls, such as electrostatic precipitators. Since the very smallest particulates, which are hardest to capture in particulate controls, are usually the most hazardous, control on the order of 99.9% efficiency may be required, probably with fabric filters. In addition, while emissions of some toxics can be reduced through the use of high efficiency particulate control, other toxics cannot. In particular for coal plants, gaseous mercury and chlorine are not well controlled by particulate controls, and must be addressed through more expensive flue gas treatment measures.

Q: **What are the potential additional direct costs to CG&E of emissions of CO_2?**

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

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

A: No.

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

A: Including these costs would serve to increase CG&E's avoided cost, increasing the amount of cost-effective DM. The amount by which these costs would increase CG&E's avoided cost depends on the resources avoided by additional DM, but could easily be several mills. The proposed Federal energy tax would add a few mills to CG&E's avoided energy costs.

6. Externalities

Q: Please define "externalities."

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

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

Q: Has CG&E included externality values in its avoided costs?

A: Though the Company was directed by the Commission to consider whether DM programs that fail the TRC test would pass the test if externalities were taken into account, it did not perform this calculation (ELTFR p. 1-94). CG&E explains that it "has not analyzed unregulated environmental impacts because it is uncertain there are impacts, and if they exist, they are unquantifiable and not properly addressable in this proceeding." (ELTFR 1-98)

CG&E also argues that

- "analysis of externalities and their inclusion in the analyses in the ELTFR is not necessarily the least expensive way to improve the environment. There may be less expensive ways to reduce environmental impacts." (ELTFR 1-96 to 1-97)

- "Such consideration and assessment of costs for unregulated environmental externalities may not be consonant with the concept of least cost planning." (ELTFR 1-97)

- "[I]t is not equitable for environmental externalities to be applied to only one segment -- the regulated electric utilities -- while non-regulated suppliers of electricity and all other energy suppliers are not required to conduct these analyses." (ELTFR 1-96)

- "[T]he environmental standards which [sic] govern virtually all of the pollutants identified [by the Commission] are set . . . at levels that are protective of human health and the environment. Meeting these standards means that there should be no unacceptable impact on the environment from emissions. Thus, in CG&E's view, environmental impacts are already internalized in the planning process." (ELTFR 1-95)

Q: **Do you agree with CG&E that it is uncertain whether unregulated emissions have environmental impacts?**

A: No. In fact, most common pollutants, including those routinely emitted by utility operations, do not have known threshold values. There appear to be effects below regulated levels for several pollutants, including SO_2, ozone and lead. Indeed, the U.S. EPA criteria documents used in setting the NAAQSs suggest that there is no established threshold for the effects of most of the six criteria pollutants.[48] For example, the U.S. EPA criteria document for ozone states:

> Recent health effects studies show that single ozone exposure for several hours induces pulmonary effects at concentrations

[48]The six criteria pollutants are sulfur dioxide, nitrogen oxides, particulate matter, ozone, carbon monoxide, and lead.

well below the current ambient standard. (U.S. EPA, 1989)

Further, for pollutants whose effects have been intensively studied over a long period, the level of exposure at which effects have been demonstrated continues to fall, as data accumulates and research methods improve (U.S. Department of Health and Human Services, 1991; Freeman and Krupnick, 1992). For example, the federal action level for lead in children's blood, in micrograms per deciliter, was revised downward twice since 1989, when it was 25: first, to 15, and recently to 10 (Rowe, 1991). The NAAQSs for SO_2 and lead are currently under review.

The General Accounting Office of the U.S. Congress recently criticized the U.S. EPA for inadequate regulation of chemicals that might cause birth or developmental defects.[49] The GAO also found that 60% of chemical regulations the agency reviewed are not based in any way on reproductive effects.[50] According to the GAO, the EPA's response to this criticism was that the law did not require that reproductive and developmental effects be reflected in the setting of allowable exposure levels. Even if the primary health effects had thresholds below the levels of current regulations, reproductive effects, the combined or synergistic effects of exposure to multiple pollutants, ecosystem degradation, visibility impairment, and other non-health effects may have lower thresholds.

In addition, while exposure to a pollutant in one medium, such as air, may be low, total exposure through all pathways of inhalation and ingestion may cause health problems. For example, mercury emissions accumulate in the

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[49]"Science Scope," Science, October 25, 1991.

[50]"Reproductive Toxicity: Regs Slow to Change," Science, October 4, 1991.

sediments of waterways and make their way up the food chain to humans, and inhalation of lead emissions can aggravate already elevated blood lead levels.

Q: Do you agree with CG&E that environmental impacts are unquantifiable?

A: No. It is true that external costs are not known with certainty, but this is neither an unusual aspect of inputs to utility decisions nor a bar to rational decision-making.

Uncertainty pervades utility planning, in load forecasts, in other determinants of need (completion rate of proposed projects, performance and life of existing resources), in forecasts of the direct costs of supply resources (fuel prices, availability, construction and operating costs, and operating life), and in projections of the direct costs of demand resources (measure costs, overhead costs, average savings, penetration and participation rates). Load forecasts of 7% annual growth have been followed by actual load growth below 3%; forecasts of 2% growth have turned out to be 5%; positive growth forecasts have been followed by negative growth. Plants that were expected to be built in five years for $500 million have taken fifteen years and cost $7 billion. Oil prices that were expected to reach $100/bbl by the early 1990s have been closer to $20/bbl. Utility planners live with these uncertainties, by using the best estimates available.

Fuel costs are not set to zero because they are uncertain; neither should external costs be set to zero when a positive value is likely, even if that value must be estimated with a degree of uncertainty.

Five states (Massachusetts, New York, Wisconsin, California, Nevada) have estimated externality values and required utilities to include those values for externalities in their new resource selection. The Bonneville Power Administration also monetizes some externalities. Several other states are in the process of monetizing externalities for resource planning.

CG&E has also overlooked the virtual certainty that added CG&E NO_x emissions will increase Clean Air Act compliance costs for its service territory. The CAAA establish a cap on regional ozone levels. Any additional emissions must be offset by additional controls on CG&E, industrial sources, or transportation sources, at the marginal cost of control.

In Southwestern Ohio, new pollution control requirements are principally governed by CAAA requirements, as discussed above. Based on the control requirements discussed above, external NO_x costs are likely to be at least $2,000/ton for the Cincinnati area, and may be significantly understated.

Q: Is CG&E correct that "analysis of externalities and their inclusion in the analyses in the ELTFR is not necessarily the least expensive way to improve the environment"?

A: No. The cost per ton of emission reduction from considering externalities in the ELTFR may be very small. It is difficult to believe that alternative controls are available at a lower cost than the costs of CG&E's potential analyses. The cost of the resources CG&E might cost-effectively select as a result of that analysis will vary with the marginal cost of control through other sources; since CG&E has not determined those marginal costs of control, it cannot know how much additional (or different) demand and supply resources will be cost-effective.

Q: Is consideration and assessment of costs for unregulated environmental externalities consistent with the concept of least cost planning?

A: Yes. Externalities are costs. Minimizing costs requires the utility to minimize the total of all costs, including externalities.

Q: Is it "inequitable" for environmental externalities to be applied to CG&E, but not to other suppliers of electricity and all energy suppliers?

A: CG&E's concern with equity seems to be misplaced. The Cincinnati area will be better off if CG&E includes the environmental effects of its electric operations. Neither shareholders nor any group of ratepayers is treated "inequitably" by reflection of these costs.[51] CG&E should include externalities in evaluating gas resource options, as well, eliminating most of the problems of applying externalities for one energy source and not its major substitute.

It is not clear whether "unregulated suppliers of electricity" refers to non-utility generators (NUGs) or to municipal utilities. Since the selection of NUG power supply by CG&E and other Ohio utilities can reflect the same externality values used in all other resource decisions, I do not see why NUGs should be a matter of any concern. If CG&E believes that municipal utilities receive some major benefit at CG&E's expense, it should propose regulatory or legislative solutions, rather than delaying the analysis of externalities.

Q: How would including externalities affect CG&E's avoided cost?

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

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[51] I assume that shareholders will continue to have a reasonable opportunity to earn a fair return on all prudent investments.

Q: Would the public interest be served by CG&E including externalities in its IRP?

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

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

In new-resource selection, valuing externalities allows utilities to select resources with the least total social costs, by finding the external costs associated with competing resources and adding those costs to the resources' direct costs. Decisions that are informed by these external costs are better than those that are not, even if they cause some individual customers to experience greater costs in the short term.[52]

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

Q: How would these values affect avoided costs?

A: Looking only at air emissions of NO_x and CO_2, the environmental costs might be on the order of 1-3 cents/kWh, depending on the avoided unit. Including other air

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

emissions such as mercury, and water and land impacts would further increase the avoided cost.

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

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

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

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

The public utility commissions of California, Massachusetts, Nevada, New York, New Jersey, and Wisconsin require their utilities to assign specific dollar values to externalities; this practice is known as "monetizing" externalities. Of these six states, all but New Jersey estimate externality values based on the costs of regulations.[53] The Bonneville Power Administration also monetizes externalities with damage costs.

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

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[53]New Jersey uses the damage cost method.

The state of Vermont imposes an externality adder on avoided costs, for comparing DM costs to the avoided costs of supply.[54]

7. Risk Mitigation

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

A: No. Curiously enough, instead of assigning DM a credit for its risk mitigation properties, CG&E finds that "DM activity, in general, may decrease the reliability of CG&E system." (ELTFR p. 2-14) The Company explains that the decrease in reliability is due to the fact that "there is no guarantee that the programs will perform as modelled," and that "only after some experience has been gained with a program can accurate reliability estimates be made."

Q: Do you agree with CG&E's assessment of the reliability risks of DM?

A: No. I disagree with CG&E on two counts. First, CG&E suggests that not enough "experience has been gained" in order to reliably project the savings of a DM program. This is incorrect. At least a dozen utilities throughout the country are currently implementing aggressive DM programs to cover all types of customers and end-uses. These utilities have compiled considerable experience with their programs. CG&E is wrong to suggest that there does not exist adequate experience with DM programs. There is some uncertainty as to the level of savings any particular program design will achieve in any given year, but this risk can be mitigated by diversity of programs and by adaptation of programs over time. As noted above in Section VII.C.1, with reference to reserve margins, CG&E's failure to design, assess and

[54] Vermont is currently revising its externality policy.

implement aggressive DM programs creates much of the uncertainty about which CG&E complains.[55]

Second, as discussed in Section VII.B.7, I disagree with CG&E's overall premise that DM increases risks.

Q: Does CG&E discuss the "risks" of DM elsewhere?

A: Yes. The SO_2 Working Group Report (ELTFR Volume III) includes a discussion of the risks of compliance measures. Appendix 1, pp. VI.4-VI.9, reports CG&E's subjective and undocumented assessments of DM risks, including poor scores (1 to 3 out of a possible 10 points) for several "Want" items. The following list of those items includes a summary of the explanation of the score from Appendix 6 of ELTFR Volume III, along with my assessment of the validity of the concern.

1. **Short Lead Time.** The long assumed lead time reflects " time for increased customer participation in order to realize a noticeable benefit." If CG&E were more aggressive in implementing DM, savings would be noticeable within a year or two.

4. **CG&E Experience Base.** DM is derated because CG&E has not "had successful experience" with it; this is due to CG&E's inertia, not any flaw in DM.

5. **Current State-of-the-Art (Mature Level).** CG&E claims that DM is not "prevalent throughout the industry" and has "little or no demonstrated maturity in the industry." While DM hardware and delivery continue to improve, CG&E's vague complaints are ill-founded.

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[55]CG&E emphasizes the importance of evaluating experience with DM programs (ELTFR, p. 2-15), but has made no effort to evaluate its own programs. CG&E reports that many of its existing programs have been in effect for years, but that little data has been collected for evaluation purposes (DR City 2-5(d)). CG&E also suggests that it needs operating experience with a DM program in order to decide whether to implement it (ELTFR, p. 2-15); thus, programs cannot be implemented because CG&E has no experience with them, and CG&E has no experience because it will not implement the programs.

7. **Easy to Retrofit.** "Since . . . the [DM] option requires installing a lot of equipment, there is a greater risk associated with implementing [this] option." CG&E has this point backwards; diversity decreases risk.

8. **Minimizes Risk of Cost Overruns.** DM "options have a lot of uncertainty associated with implementing them even though they are currently being used in California." CG&E does not define or document the "uncertainty," but major cost overruns are unlikely, given the rapid feedback, short lead times, and small increments. CG&E's claim that DM is "being used" only in California indicates a sad lack of familiarity with the topic.[56]

10. **Minimizes Risk of Not Obtaining Full Cost Recovery.** "The [DM] option was scored the lowest since there's a lot of uncertainty associated with this option. There is nothing sure about cost recover [sic], and if allowed, there probably would not be a full cost recovery." No basis is provided for this statement, which is inconsistent with experience nationally; utilities often request and receive preferred ratemaking treatment for major DM efforts. CG&E also asserts that supply options, such as scrubbers, do not receive full cost recovery, but does not reflect DM benefits in avoiding unrecoverable future supply costs.

In addition, DM received a mediocre score for "Want #20" (Minimizes Financial Risk), when it is likely to reduce CG&E's financing requirements and risks, and was rated as having potentially serious risks of

Can't Obtain Necessary Supplies (low probability, high consequence). Given the rapidity with which the result would be apparent, the consequences are likely to be minor.

Customer Acceptance Never Materializes (medium probability, high consequence): This outcome has a

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[56]Whoever wrote and reviewed this Volume of the ELTFR appears to have been unfamiliar and uncomfortable with DM. In preparing this analysis, CG&E does not appear to have consulted its own DM staff.

very low probability, given experience of other utilities. Given the rapidity with which the result would be apparent, the consequences are likely to be minor.

Can't Fully Recover Costs (medium probability, high consequence). Again, CG&E's analysis is dominated by a fear of massive DM cost disallowances. This outcome has not occurred elsewhere for DM, but has been common nationally (and locally) for major supply options.

In the compliance analysis, as elsewhere, the ELTFR displays a consistent and unwarranted bias against DM.

VIII. SUMMARY OF RECOMMENDATIONS

Q: Please summarize your recommendations.

A: My recommendations for CG&E's DM planning and screening are:

- CG&E should evaluate all potential DM measures, without arbitrary pre-screening.
- CG&E should design programs to maximize TRC benefits, not to achieve load shape objectives.
- Screening should compare the present value of all costs and benefits of DM, without arbitrarily limiting the duration of benefits.
- CG&E should plan to implement all cost-effective DM options, placing a priority on the acquisition of lost opportunities.
- CG&E's DM portfolio should be comprehensive in covering market segments, end uses, and measures, using effective program designs, with sufficient incentives, targeted to appropriate decision-makers.
- CG&E should be acquiring much more efficiency than it has proposed.
- In particular, CG&E should expand the number and breadth of the programs it offers to commercial and industrial customers.

My principal recommendations with regard to the estimation of CG&E's avoided costs for DM include:

- Generation capacity costs should include reserve margin, and be corrected for the computational problems discussed above.
- The full costs of baseload plant additions should be included in avoided costs.
- Generation costs should reflect current and anticipated environmental compliance costs.
- Energy costs should be sufficiently documented, and recognize the likely load shape of DM.
- Full avoidable transmission and distribution capacity costs should be included for all classes.

- Marginal line losses should be included to the end use for all classes; those losses vary with load.

- The substantial risk-reduction benefits of DM should be quantified and recognized.

- The environmental and other external benefits of DM should be quantified and included in avoided costs.

Q: Does this conclude your testimony?

A: Yes.

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Projected Energy Savings from Demand Management by Selected Third Generation Utilities

	Energy savings, last yr of DM prog GWh [1]	Pre-DM energy req'ts, last yr of DM prog GWh [2]	DM as % of energy req'ts last yr of DM prog [3]	Avg annual incr. DM GWh [4]	Avg Annual energy req'ts in prog period GWh [5]	Avg Annual DM as % avg energy req'ts in prog period [6]	Growth in DM GWh [7]	Growth in energy req'ts GWh [8]	New DM as % of new energy req'ts [9]
Boston Edison (1990 - 1994)									
Residential	73	3,709	2.0%	13	3,593	0.4%	66	295	22.4%
Com/Ind	454	10,145	4.5%	91	9,705	0.9%	454	1,205	37.6%
System	527	13,854	3.8%	104	13,298	0.8%	520	1,500	34.6%
Eastern Utilities (1991 - 2000)									
Residential	26	1,875	1.4%	3	1,724	0.2%	26	277	9.4%
Commercial	275	2,599	10.6%	27	2,159	1.3%	275	782	35.2%
Industrial	15	917	1.6%	2	854	0.2%	15	85	17.9%
System	339	5,683	6.0%	34	4,996	0.7%	339	1,220	27.8%
New England Electric (1991 - 2010)									
Residential	555	9,201	6.0%	24	8,549	0.3%	489	1,210	40.4%
Commercial	1,692	12,390	13.7%	74	10,012	0.7%	1,471	4,624	31.8%
Industrial	523	7,546	6.9%	24	6,297	0.4%	483	2,432	19.9%
System	2,956	32,385	9.1%	129	27,812	0.5%	2,586	9,251	28.0%
New York State Electric & Gas (1993 - 2008)									
Residential	530	7,168	7.4%	30	6,225	0.5%	479	1,617	29.6%
Com/Ind	783	4,878	16.1%	39	4,123	1.0%	629	1,487	42.3%
System	1,598	19,773	8.1%	85	17,478	0.5%	1,367	4,513	30.3%

Projected Energy Savings from Demand Management by Selected Third Generation Utilities

	Energy savings, last yr of DM prog GWh [1]	Pre-DM energy req'ts, last yr of DM prog GWh [2]	DM as % of energy req'ts last yr of DM prog [3]	Avg annual incr. DM GWh [4]	Avg Annual energy req'ts in prog period GWh [5]	Avg Annual DM as % avg energy req'ts in prog period [6]	Growth in DM GWh [7]	Growth in energy req'ts GWh [8]	New DM as % of new energy req'ts [9]
Northeast Utilities (1991 - 2000)									
Residential	556	10,890	5.1%	56	10,395	0.5%	556	1,390	40.0%
Commercial	1,987	12,330	16.1%	199	10,585	1.9%	1,987	3,349	59.3%
Industrial	907	6,652	13.6%	91	5,835	1.6%	907	1,205	75.3%
System	3,460	30,756	11.3%	346	27,695	1.2%	3,460	5,857	59.1%
Potomac Electric - Maryland (1992 - 1996)									
Residential	70	5,740	1.2%	14	5,611	0.2%	70	481	14.5%
Commercial	823	9,259	8.9%	165	8,834	1.9%	823	1,099	74.8%
System	892	15,227	5.9%	178	14,652	1.2%	892	1,621	55.0%
United Illuminating (1991 - 2010)									
Residential	47	2,259	2.1%	5	2,040	0.2%	41	432	9.6%
Commercial	519	3,435	15.1%	25	2,838	0.9%	507	1,176	43.1%
Industrial	257	1,586	16.2%	13	1,313	1.0%	251	525	47.8%
System	827	7,284	11.4%	40	6,195	0.6%	803	2,137	37.6%
Sacramento Municipal Utility District (1992 - 2010)									
System	3,418	14,790	23.1%	178	11,877	1.5%	3,378	5,760	58.6%
Pacific Gas & Electric(1993 - 2011)									
System	9,890	106,170	9.3%	521	94,020	0.6%	9,890	25,437	38.9%
Aggregate figures:									
Residential	1,857	33,674	5.5%	144	38,136	0.38%	1,727	5,702	30.3%
Commercial	5,296	40,013	13.2%	490	34,427	1.42%	5,062	11,030	45.9%
Industrial	1,702	16,701	10.2%	129	14,299	0.90%	1,656	4,246	39.0%
Com/Ind	8,234	71,737	11.5%	749	62,554	1.20%	7,801	17,969	43.4%
System	23,907	245,922	9.7%	1,616	218,023	0.74%	23,235	57,296	40.6%

Notes:

General comments:
Aggregate figures are the sum of all available data.
All sales forecasts are pre-DM, i.e., the effects of DM have not yet been netted out.
All growth calculations are inclusive of the first year of the period.
All growth calculations are inclusive of the first year of the period.
For example, growth in sales for the period 1991-2010 inclusive is measured as sales in 2010 minus sales in 1990.

Utility-specific comments:
BECO's DM only includes conservation programs and not load management savings.
EUA totals in main table include losses (and streetlighting).
ie, class numbers are at sales level, total # at generation level, for savings and needs.
Figures assume that all DM given in load forecast is new, i.e., it includes no savings from previous DM efforts.
NEES DM savings by class are at customer level; they do not include include losses. NEES System savings are at generation level, they do include losses.
NEES' system sales is not the sum of residential, commercial and industrial sales because the system figure includes losses, streetlights, and sales for resale.
NEES's DM includes savings from load management.
NYSEG's DM includes savings acquired prior to 1993.
The GWh demand by class is at the customer level (i.e., pre-losses).
The GWh demand for the system includes streetlighting and other misc. uses, and also includes losses.
Total DM savings are the sum of res., C/I, and agricultural DM. Load management has not been netted out.
NU figures are exclusive of load management programs. System sales include sales for resale, streetlighting, and railraod sales. NU's original sales and peak projections include reductions due to DM. In order to obtain a pre-DM forecast, we have added NU's DM savings back into the Company's sales and peak projections. NU system DM includes reduction due to streetlighting.
PEPCo has no industrial DM programs. No load management programs are included.
UI's load and sales projections include reductions due to DM. In order to obtain a pre-DM forecast, we have added UI's DM savings back into the Company's sales and peak projections. System DM savings include savings from streetlighting. UI DM savings are net of load control, interruptible, TOU rates, and cool storage programs, but might include other smaller load control.
SMUD's system energy requirements and DM include transmission and distribution losses.
Load management has not been netted out of the DM savings.
PG&E's load forecast is interpolated for the years 1990-1995.
Load management and building standards are excluded from PG&E's DM savings.

Sources:
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United Illuminating Company, "Report to the Connecticut Siting Council," March 1, 1991, pp. IV-6 - IV-10, IV-48
SMUD, "1991 Load Forecast," April 30 1991, pg. 48.
PG&E DM from "Form R-6.6," page 4, February 5, 1992.
PG&E load forecast from CEC's "Electricity Report," Table 2-4, September 1992.

Exhibit ____PLC-3: Total Demand-Management Spending by Selected Leading Utilities

Demand Management Budget[a]	Average DM Budget as Average Annual of 1990 (1991$)	Percentage savings DM budget	DM Amortized Revenues[b]	Gross GWh[a]	budget[c]	$/kWh[d]
Boston Edison (1990–1994)						
	$223,156,000	$44,631,200	3.9%	520	$22,976,759	$0.044
Eastern Utilities (1991–1995)						
	$69,549,000	$13,909,800	3.1%	235	$7,160,957	$0.030
New England Electric (1991–1995)						
	$421,793,000	$84,358,600	4.6%	750	$43,428,973	$0.058
New York State Electric and Gas (1993–1997)						
	$159,104,679	$31,820,936	3.0%	641	$16,381,857	$0.026
Potomac Electric–Maryland (1992–1996)						
	$124,437,000	$24,887,400	4.8%	892	$12,812,377	$0.014
United Illuminating (1990–1992)						
	$34,899,000	$11,633,000	2.0%	72	$3,593,297	$0.050
Western Massachusetts Electric (1991–1995)						
	$93,141,000	$18,628,200	5.1%	266	$9,590,055	$0.036
Sacramento Municipal Utility District (1993–2000)						
	$488,038,278	$61,004,785	8.9%	1,240	$50,249,770	$0.041
Aggregate	$1,579,218,956	$279,240,920	4.6%	4,544	$162,600,749	$0.036

Notes:

[a] Expenditures and savings are cumulative over the program period. UI data available only for 1990–92.

[b] Utility 1990 ultimate consumer revenues from *PUR Analysis of Investor-Owned Electric and Gas Utilities*, 1991 edition; 1990 figures inflated to 1991, 5 percent inflation assumed. SMUD 1990 revenues from personal communication with D. Estrada of SMUD.

[c] DM budget amortized over 15 years, at a 6 percent real discount rate.

[d] Amortized budget ÷ DM savings × 10^6.

Sources:

Boston Edison, "The Power of Service Excellence," 3/90.

Eastern Utilities Association, "An Overview of Montaup's Residential and Commercial C&LM Programs," February 1991.

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SMUD, "Business Plan for Achieving Energy Efficiency Goals 1992–2000," April 8, 1992, Tables 22, 23, 89–90.

Exhibit____PLC-4
CG&E's Projected DM and Demand Forecast

	Pre-DM Sales				Summary of Cumulative DM Savings				From End of 1992: New DM as Percent of New Electricity Requirements				DM as Percent of Total Electricity Requirements			
	Res. GWh	Com GWh	Ind GWh	System GWh	Res. Energy Savings GWh	Com Energy Savings GWh	Ind Energy Savings GWh	Total Energy Savings GWh	Res	Com	Ind	System	Res	Com	Ind	System
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
1992	6,780	5,260	5,442	19,390	2	5	2	8								
1993	6,834	5,321	5,550	19,611	4	17	4	25	5.53%	18.86%	1.93%	7.39%	0.06%	0.21%	0.04%	0.08%
1994	6,913	5,450	5,645	19,947	9	38	5	51	5.59%	17.17%	1.43%	7.71%	0.14%	0.60%	0.05%	0.22%
1995	6,999	5,567	5,772	20,308	15	71	5	91	6.14%	21.36%	1.01%	8.97%	0.24%	1.18%	0.06%	0.41%
1996	7,102	5,677	5,926	20,710	22	111	5	138	6.29%	25.28%	0.77%	9.79%	0.36%	1.86%	0.06%	0.62%
1997	7,182	5,752	6,062	21,025	28	147	5	181	6.70%	28.87%	0.60%	10.55%	0.47%	2.47%	0.06%	0.82%
1998	7,287	5,856	6,272	21,480	34	173	5	213	6.41%	28.22%	0.45%	9.78%	0.55%	2.87%	0.06%	0.95%
1999	7,379	5,949	6,493	21,914	38	190	5	233	6.13%	26.75%	0.35%	8.90%	0.62%	3.10%	0.06%	1.03%
2000	7,497	6,093	6,780	22,508	41	198	5	245	5.53%	23.17%	0.28%	7.58%	0.65%	3.17%	0.05%	1.05%
2001	7,617	6,211	7,030	23,028	41	203	5	249	4.74%	20.78%	0.23%	6.62%	0.64%	3.18%	0.05%	1.05%
2002	7,717	6,288	7,204	23,396	41	203	5	249	4.24%	19.22%	0.21%	6.01%	0.63%	3.14%	0.05%	1.03%
2003	7,823	6,356	7,350	23,737	41	203	5	249	3.80%	18.03%	0.20%	5.54%	0.62%	3.11%	0.05%	1.01%
2004	7,925	6,419	7,489	24,060	41	203	5	249	3.46%	17.05%	0.18%	5.16%	0.62%	3.08%	0.05%	1.00%
2005	8,026	6,485	7,641	24,398	41	203	5	249	3.18%	16.13%	0.17%	4.81%	0.61%	3.05%	0.05%	0.99%
2006	8,113	6,555	7,785	24,715	41	203	5	249	2.97%	15.25%	0.16%	4.52%	0.60%	3.01%	0.05%	0.97%
2007	8,196	6,624	7,917	25,013	41	203	5	249	2.79%	14.49%	0.15%	4.28%	0.60%	2.98%	0.05%	0.96%
2008	8,273	6,681	8,026	25,268	41	203	5	249	2.65%	13.90%	0.14%	4.10%	0.59%	2.96%	0.05%	0.95%
2009	8,347	6,723	8,121	25,489	41	203	5	249	2.52%	13.50%	0.14%	3.95%	0.59%	2.94%	0.05%	0.94%
2010	8,415	6,755	8,228	25,703	41	203	5	249	2.41%	13.21%	0.13%	3.81%	0.58%	2.92%	0.05%	0.94%
2011	8,487	6,787	8,346	25,931	41	203	5	249	2.31%	12.94%	0.13%	3.68%	0.58%	2.91%	0.04%	0.93%
2012	8,563	6,811	8,444	26,134	41	203	5	249	2.21%	12.74%	0.12%	3.57%	0.58%	2.90%	0.04%	0.92%

Notes:
[1]-[3]: From Form FE1-1B: Page 1-304, 1-305, without losses
[4]: From Form FE1-1B: Page 1-304, 1-305, includes streetlighting, resale & other, without losses
[5]-[8]: Calculated from difference between sales before and after DM from Form FE1-1B: Pages 1-304, 1-305, 3-86, 3-87, without losses. Includes load management.
[9]-[12]: (DM savings - 1992 DM savings)/(Pre-DM sales - 1992 Pre-DM sales)
13]-[16]: (DM savings - 1992 DM savings)/(Pre-DM sales)

Exhibit____PLC-5
Estimate of CG&E's Economically Achievable Efficiency Savings
Based on Collaboratively-Designed Portfolios

Total Efficiency Resources, By Sector / Total Efficiency Resources, All Sectors

	Residential Sector			Commercial Sector			Industrial Sector			Total System			
Year [1]	Annual Sales GWh [2]	Percent of Annual Sales Met With New Effic. [3]	Annual Incremental New Effic. GWh [4]	Annual Sales GWh [5]	Percent of Annual Sales Met With New Effic. [6]	Annual Incremental New Effic. GWh [7]	Annual Sales GWh [8]	Percent of Annual Sales Met With New Effic. [9]	Annual Incremental New Effic. GWh [10]	Annual Incremental New Effic. GWh [11]	Cumulative Energy Savings GWh [12]	Cumulative Energy Savings as Percent of Sales [13]	Cumulative New Energy Savings as % of Cum. Sales Growth [14]
1993	6,834	0.38%	26	5,321	1.42%	76	5,550	0.90%	50	152	152	0.8%	68.4%
1994	6,913	0.38%	26	5,450	1.42%	78	5,645	0.90%	51	155	306	1.5%	54.9%
1995	6,999	0.38%	26	5,567	1.42%	79	5,772	0.90%	52	158	464	2.3%	50.5%
1996	7,102	0.38%	27	5,677	1.42%	81	5,926	0.90%	53	161	625	3.0%	47.3%
1997	7,182	0.38%	27	5,752	1.42%	82	6,062	0.90%	55	164	789	3.8%	48.2%
1998	7,287	0.38%	28	5,856	1.42%	83	6,272	0.90%	57	167	956	4.5%	45.7%
1999	7,379	0.38%	28	5,949	1.42%	85	6,493	0.90%	59	171	1,127	5.1%	44.6%
2000	7,497	0.38%	28	6,093	1.42%	87	6,780	0.90%	61	176	1,303	5.8%	41.8%
2001	7,617	0.38%	29	6,211	1.42%	88	7,030	0.90%	63	181	1,484	6.4%	40.8%
2002	7,717	0.38%	29	6,288	1.42%	89	7,204	0.90%	65	184	1,667	7.1%	41.6%
2003	7,823	0.38%	30	6,356	1.42%	90	7,350	0.90%	66	186	1,854	7.8%	42.6%
2004	7,925	0.38%	30	6,419	1.42%	91	7,489	0.90%	68	189	2,042	8.5%	43.7%
2005	8,026	0.38%	30	6,485	1.42%	92	7,641	0.90%	69	191	2,234	9.2%	44.6%
2006	8,113	0.38%	31	6,555	1.42%	93	7,785	0.90%	70	194	2,428	9.8%	45.6%
2007	8,196	0.38%	31	6,624	1.42%	94	7,917	0.90%	71	197	2,625	10.5%	46.7%
2008	8,273	0.38%	31	6,681	1.42%	95	8,026	0.90%	72	199	2,823	11.2%	48.0%
2009	8,347	0.38%	32	6,723	1.42%	96	8,121	0.90%	73	200	3,024	11.9%	49.6%
2010	8,415	0.38%	32	6,755	1.42%	96	8,228	0.90%	74	202	3,226	12.5%	51.1%
2011	8,487	0.38%	32	6,787	1.42%	97	8,346	0.90%	75	204	3,430	13.2%	52.4%
2012	8,563	0.38%	32	6,811	1.42%	97	8,444	0.90%	76	205	3,635	13.9%	53.9%

Notes:
[2] CG&E's pre-efficiency Residential sales
[3] Avg. annual Res. effficiency savings as percent of Res. sales, based on collaboratives.
[4] [2]*[3]
[5] CG&E's pre-efficiency Commercial sales
[6] Avg. annual Com. effficiency savings as percent of Com. sales, based on collaboratives.
[7] [5]*[6]
[8] CG&E's pre-efficiency Industrial sales
[9] Avg. annual Ind. effficiency savings as percent of Ind. sales, based on collaboratives.
[10] [8]*[9]
[11] [4]+[7]+[10]
[12] cumulative sum of [11]
[13] [12]/(Utility's pre-efficiency sales).
[14] [12]/(growth in energy demand from end of 1992)

Exhibit____PLC-5
Estimate of CG&E's Economically Achievable Efficiency Savings
Based on Collaboratively-Designed Portfolios

Additional Efficiency Resources:

	Cumulative Energy Savings With Losses GWh [15]	Total Added Energy Savings GWh [16]	Total Added Peak Savings MW [17]	Sensitivity to Load Factor: Total Added Peak Reduction with Varied Load Factors — With 15% Greater Load Factor MW [18]	With 15% Less Load Factor MW [19]	Total Peak Savings MW [20]
1993	161	144	29	23	40	43
1994	326	280	57	45	78	83
1995	493	406	83	65	113	127
1996	665	527	107	85	147	169
1997	839	655	134	105	182	213
1998	1,017	800	163	129	223	255
1999	1,199	960	196	154	267	296
2000	1,386	1,135	231	182	316	335
2001	1,578	1,322	270	213	368	376
2002	1,774	1,517	309	244	422	415
2003	1,972	1,716	350	276	478	456
2004	2,173	1,916	391	308	534	497
2005	2,376	2,120	432	341	590	538
2006	2,583	2,327	474	374	648	580
2007	2,792	2,536	517	408	706	623
2008	3,003	2,747	560	442	765	666
2009	3,217	2,961	604	476	824	710
2010	3,432	3,176	647	511	884	753
2011	3,649	3,393	692	545	945	798
2012	3,867	3,611	736	581	1,005	842

System Losses: 6.0%
System Load Factor: 56%

[15] [12]/(1-System losses)
[16] [15]-(CG&E total energy DM savings from beginning of 1993, including losses)
[17] [16]*1000/(system load factor*8760)
[18] [16]*1000/((system load factor+15%)*8760)
[19] [16]*1000/((system load factor-15%)*8760)
[20] [17]+CG&E Peak DM savings

Exhibit ____PLC–6:
Correction of CG&E Computation of Real–Levelized Combustion–Turbine Carrying Cost For Capital

Year	Nominally Levelized Cost ($/kW–yr) [1]	CG&E Real–Levelized Cost ($/kW–yr) [2]	Corrected Real–Levelized Cost ($/kW–yr) [3]
1	$77.90	$45.86	$51.13
2	$77.90	$48.33	$53.89
3	$77.90	$50.94	$56.80
4	$77.90	$53.69	$59.87
5	$77.90	$56.59	$63.10
6	$77.90	$59.65	$66.51
7	$77.90	$62.87	$70.10
8	$77.90	$66.26	$73.88
9	$77.90	$69.84	$77.87
10	$77.90	$73.61	$82.08
11	$77.90	$77.59	$86.51
12	$77.90	$81.78	$91.18
13	$77.90	$86.19	$96.11
14	$77.90	$90.85	$101.30
15	$77.90	$95.75	$106.77
16	$77.90	$100.93	$112.53
17	$77.90	$106.38	$118.61
18	$77.90	$112.12	$125.01
19	$77.90	$118.17	$131.76
20	$77.90	$124.56	$138.88
21	$77.90	$131.28	$146.38
22	$77.90	$138.37	$154.28
23	$77.90	$145.84	$162.61
24	$77.90	$153.72	$171.40
25	$77.90	$162.02	$180.65
Present Value @ 11.5%	$633	$568	$633

Notes:

[1]: From DR Staff–19, Attachment 2:
$38,950,400 capital cost
80 MW capacity
$487 /kW
16.0% nominal levelized carrying charge

[2]: From DR Staff–19, Attachment 2:
$46.76 /kW–yr total cost
$0.90 /kW–yr O&M

[3]: [2] * NPV[1] ÷ NPV[2]
Year 1 = 1992

Exhibit ____PLC-7: Transmission and Distribution Costs of Selected Electric Utilities

In 1991 dollars per kW-yr; kilowatts measured as coincident peak at generation

	PEPCo (MD)	BECo	EECo	NEPCo, MECo[a]	Citizens (VT)	Central Vermont	NYSEG	Comm. Ed.	LADWP	Bangor Hydro	BG&E[c]	SMUD
Transmission	$4	$26	NE	$19	$45	$17	$39[b]	$31	$22	$22	$28	$11[d]
Subtransmission	$17				$15				$10			
Primary distribution	$70	$57	$72	$31	$68	$38	$44	$87	$33	$24	$77	$13[e]
Secondary distribution	$92	$52	$110	$31	$6	$11	$24	$58	$42[f]	$17	$19	NE

NE: Not estimated.

Notes

[a] Understated by about 50 percent, due to exclusion of new customers and of what MECo calls "reliability-related" costs.

[b] Understated, should be about $67.

[c] Not all distribution included.

[d] Some projects excluded.

[e] Substations only.

[f] Approximation, due to documentation limits; probably understated.

4 percent inflation assumed throughout.

Sources

PEPCo: Personal communication from E. Mayberry, Potomac Electric Power Company.

BECo: Boston Edison Company, "Marginal Cost Study." 1989.

EECo: Eastern Edison Company, "1987 Marginal Cost-of-Service Study." Submitted in Massachusetts DPU 88-100.

MECo: Massachusetts Electric Company, "Marginal Distribution Cost Study." Submitted in Massachusetts DPU 91-52. New England Power Company, Rate W-10 filing at FERC. July 1990.

Citizens: Citizens Utilities Company, "Marginal Cost Study." November 1990.

Central Vt.: Cater, James C., Testimony in Vermont PSB Docket No. 4634. August 10, 1988. (Central Vermont Public Service)

NYSEG: New York State Electric and Gas Corporation, "Marginal Costs of Demand Related Facilities."

Comm. Ed.: Commonwealth Electric Company, "Long-Run Marginal Cost Study." Submitted in Massachusetts DPU 90-331.

LADWP: Parmesano, H. S., "The Time-Differentiated Marginal Costs of the Los Angeles Department of Water and Power." September 1989.

Bangor Hydro: Bangor Hydro-Electric Company, "Long Run Marginal Cost Study, Docket No. 86-242," March 30, 1988.

BG&E: Baltimore Gas and Electric, "Electric Marginal Cost Study." May 1990.

SMUD: Sacramento Municipal Utility District, "Marginal Cost Study." June 29, 1990.

Derivation of Load-Related Transmission and Distribution Marginal Line Losses

Figure 1 illustrates a simplified transmission or distribution circuit, with a single input and a single output load. For simplicity, only simple direct-current resistance is included; the complications of inductive and capacitive loads, and of alternating current, would not change the basic results. The circuit could be

- the transmission system, where the input is the generator and the output is the secondary winding of the distribution substation transformer;
- the primary distribution system substation, where the input is the distribution substation and the output is the line transformer;
- the secondary distribution system, where the input is the line transformer and the output is the customer's end use; or
- a composite of the above.

From Joule's Law,

$$V = I \times R,$$

where V = the voltage across a load,

I = the current flowing through the load, and

R = the resistance of the load.

To maintain a constant voltage of V_o (which would be 120V for most residential loads) across an output load with resistance R_o hence requires a current

$$I = V_o \div R_o$$

From Ohm's Law,

$$P = V \times R = I^2 \times R,$$

where P = the power consumed in the load.

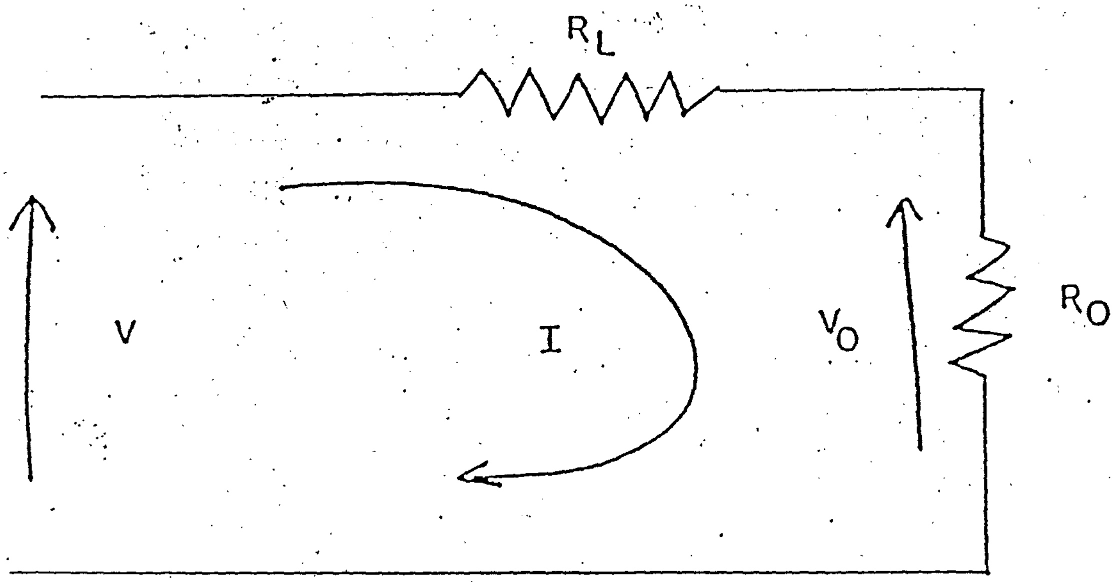

FIGURE 1

Hence, the losses in the circuit can be expressed in terms of the constant R_l, the resistance of the line:

$$Loss = I^2 \times R_l = \{V_o^2 \div R_o^2\} \times R_l$$

The power output at the load is

$$Output = I^2 \times R_o = V_o^2 \div R_o$$

Alternatively,

$$R_o = V_o^2 \div Output$$

The power input to the circuit is

$$Input = Output + Loss = I^2 \times (R_l + R_o)$$

$$= V_o^2 \times (R_l + R_o) \div R_o^2$$

Hence,

$$dR_o/dOutput = -V_o^2 \div Output^2$$

$$= -V_o^2 \div \{V_o^2 \div R_o\}^2$$

$$= -R_o^2 \div V_o^2$$

$$dInput/dR_o = -V_o^2 \div R_o^2 - 2V_o^2 \times R_l \div R_o^3$$

These two derivatives can be combined as

$$dInput/dOutput = dInput/dR_o \times dR_o/dOutput$$

$$= \{-V_o^2 \div R_o^2 - 2V_o^2 \times R_l \div R_o^3\} \times \{-R_o^2 \div V_o^2\}$$

$$= 1 + 2 \times \{[V_o^2 \div R_o^2] \times R_l\} \times (R_o \div V_o^2)$$

$$= 1 + 2 \times Loss \div Output = 1 + 2L_o$$

$$= 1 + 2 \times Loss \div \{Input - Loss\}$$

$$= \{Input + Loss\} \div \{Input - Loss\}$$

$$= \{1 + L_i\} \div \{1 - L_i\} > 1 + 2L_i$$

where L_o = Loss ÷ Output = average losses as a fraction of output

L_i = Loss ÷ Input = average losses as a fraction of input

Hence, marginal losses as a fraction of output are twice as large as the average ratio of losses to output, and an even larger multiple of the average ratio of losses to input.