Cabinet 5, Drawer 1

Docket No. 92-208-E

STATE OF SOUTH CAROLINA
BEFORE THE
SOUTH CAROLINA PUBLIC SERVICE COMMISSION

In Re:

DUKE POWER COMPANY

DIRECT TESTIMONY OF

PAUL CHERNICK
Resource Insight, Inc.

ON BEHALF OF THE

DEPARTMENT OF CONSUMER AFFAIRS

August 4, 1992

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I. QUALIFICATIONS

Q: Mr. Chernick, please state your name, occupation, and business address.

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

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received an S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an 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.

As a Research Associate at Analysis and Inference and in my current position, I have advised a variety of clients on utility matters. My work has considered, among other things, prospective and retrospective review of supply planning decisions; 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 to this testimony as Attachment 1.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately ninety 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 Maine Public Utilities Commission, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the Vermont Public Service Board, the New Hampshire Public Utilities Commission, the Pennsylvania Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Illinois Commerce Commission, the Minnesota Public Utilities Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. Subjects on which I have testified include (among others) long range energy and demand forecasts, utility supply planning decisions, conservation costs and potential effectiveness, conservation program design, and ratemaking for utility production investments and conservation programs.

Q: Have you testified previously before this Commission?

A: Yes. I testified on conservation program adequacy and cost recovery in Duke's last rate case (Docket No. 91-216-E) and on SCE&G's DSM programs in the Cope certificate case (Docket 91-606-E).

Q: Have you authored any publications on utility planning and ratemaking issues?

A: Yes. I have authored a number of publications on rate design, cost allocations, power plant cost recovery, conservation program design and cost-benefit analysis, and other ratemaking issues. These publications are listed 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 rate for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to the Conservation Law Foundation's (CLF's) conservation design projects in Jamaica and Zimbabwe; 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 Florida environmental groups on review of utility DSM programs and proposed power plants; and to several parties on determining avoided costs and incorporating externalities in utility planning and resource acquisition. I 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. I also assisted the South Carolina Consumer Advocate in review, negotiations, and comments on the Commission's least-cost planning procedures (Order No. 91-885, Docket No. 87-223-E, October 21, 1991, hereinafter referred to as "the Procedures").

Q: **On whose behalf are you testifying?**

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

II. INTRODUCTION

Q: What is the purpose of your testimony?

A: My testimony reviews the adequacy of Duke's 1992 Integrated Resource Plan (IRP), concentrating on the treatment of demand-side management (DSM). Citations in this testimony are to the IRP, and its Exhibits and Appendices, except as noted. Citations to "IR" are to the Company's responses to discovery.

Q: Please summarize your testimony.

A: It is important to note that the current IRP represents a major improvement in Duke's treatment of DSM. Duke has increased the number of DSM programs that it offers; increased its emphasis on energy efficiency, as opposed to load shifting and load building; and increased its reliance on the total resource cost test. Unfortunately, the Company has still not put DSM on an equal footing with supply, is not fully committing to the objective of reducing resource costs, and has not developed a coherent and comprehensive approach to DSM. As a result, there are a large number of deficiencies in Duke's DSM plan and approach. These deficiencies reduce the amount of cost-effective DSM Duke can acquire, increase the cost of that DSM, increase the need for supply resources, and increase the total cost of Duke's resource plan to ratepayers and the state as a whole.

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

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

- The resource planning process will not minimize total resource costs to the extent feasible, as required by the Commission's Procedures.
- The evaluation of DSM understates avoided cost.
- Duke's existing and proposed programs are incomplete and inadequate.
- Duke does not emphasize the acquisition of lost-opportunity resources, as required by the Commission's Procedures.
- Duke's approach to acquiring DSM is piecemeal, resulting in lower effectiveness and higher costs than would a more comprehensive and coordinated approach.
- Many programs "cream-skim" by capturing only a portion of the available savings.
- The incentive structures for many of Duke's programs are not well suited to the market segments they address.
- Some Duke programs are intended to increase loads, which will tend to increase costs. These programs have not been shown to be cost-effective.
- Duke over-emphasizes pilot programs and unnecessarily delays full scale implementation, resulting in additional lost opportunities and increasing the amount of capacity required in the short term.

Q: Do you have any other introductory comments?

A: Yes. As discussed throughout my testimony, Duke's documentation of its DSM programs has been incomplete and contradictory. Duke has not provided summaries of important input and output data. The program descriptions provided in the IRP were obsolete at the time they were filed. These and similar problems have complicated my review of Duke's DSM portfolio and limit the extent of the Commission's oversight of Duke IRP.

Q: How have you organized your testimony?

A: I present the remainder of my testimony in six more sections. Section III discusses problems in Duke's screening process for DSM programs, while Section IV explains the under-estimation of the avoided costs used in that process. Section V describes the errors and omissions in Duke's portfolio of DSM programs, and in the design of individual programs. Section VI discusses inadequacies in Duke's integration of demand resources with supply resources, particularly in the timing of DSM programs and supply additions. Section VII contains some brief comments on cost recovery. Finally, Section VIII provides my conclusions and recommendations.

III. ERRORS IN DUKE'S SCREENING OF DSM

Q: Briefly describe the Company's demand-side planning process.

A: The Company relies on multiple tests including the Total Resource Cost (TRC) test and evaluates DSM options in a four-step process. These four steps are:

1. Initial review of DSM options and programs (excluding interruptible options) through DSManager. Duke says that this analysis relies on marginal energy costs and avoided capacity cost estimates and calculates the four tests, Total Resource Cost (TRC), Utility Cost (UC), Participant, and Ratepayer Impact Measure (RIM) tests (Appendices, p. 38).

2. Single Option Analysis. At this stage of the planning process, Duke evaluated each option separately and calculated the RIM test for each option in order to develop a ranking for use in the Cumulative Option Analysis.

3. Cumulative Option Analysis. At this stage, the Company evaluated the DSM portfolio using production costing models, adding in one program option at a time in the order developed in the Single Option Analysis. With some exceptions, this analysis produced benefit-cost ratios for all four tests for each new option.

4. Optimization. For this stage of the analysis, the Company selected four alternative DSM portfolios, developed optimal supply plans for each, and selected among the supply-demand scenarios based on present worth revenue requirements (PWRR).

Q: What should be the basis for DSM screening?

A: The Company should design and select DSM programs to procure as much cost-effective DSM as feasible. Therefore, in screening supply resources and DSM measures and programs, the utility should rely primarily on the TRC, as required by the Commission's Procedures.[1] Only the TRC test will consistently

[1] The Company was a party to the development of the Procedures, and agreed to the language presented to the Commission.

reflect the true value of efficiency programs. Any measure that passes the TRC screening -- i.e., is cheaper than supply -- is worth pursuing. Least-cost planning requires that the utility attempt to realize the potential of all such measures, since failing to do so would unnecessarily lead to higher total costs.

Primary reliance on the TRC does not mean that other tests and factors should be ignored.

Q: **What role should the other three tests play in the DSM planning process?**

A: The UC test differs from the TRC in that it excludes costs that participants bear and includes incentives paid to the participants. Since the costs that flow through utility rates are not all the costs of DSM, utility cost should not be used to determine whether actions are cost-effective. However, the utility test has both general and specific roles in fine-tuning program design.

In a general sense, the utility cost test is useful in identifying program designs that minimize revenue requirements. All other things (especially total benefits) being equal, lower utility costs are usually preferable to higher costs. Programs should be designed to minimize the Company's share of program costs, so long as customer contributions do not significantly decrease the program's TRC benefits, by discouraging participation and raising overhead costs per installation, or impair the program's equity by limiting the number of customers financially able to participate.

The RIM test is not very meaningful on a measure-by-measure or program-by-program basis. It is a measure of equity, of the effect on other customers of the operation of a particular utility DSM program or measure. Individual measures and programs cannot really be considered equitable or inequitable in isolation. Rather, the effects of DSM on equity between and within classes, and on the pattern of rates and bills over time, should be evaluated for the DSM portfolio as a whole. If there are equity problems, they can be addressed by changing cost recovery patterns, by increasing the penetration of programs to groups that would otherwise face higher bills, and possibly by changing the timing of particular programs.[2]

The Participant test can be useful in gauging the need for, and possible effects of, utility financial incentives to customers designed to overcome market barriers to efficiency investment. However, it should be only part of a broader analysis of the acceptability of the program to the

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[2]The use of the RIM as a test of the DSM portfolio as a whole rather than as a test of each individual DSM option is consistent with the North Carolina Stipulation B-3: "The rate impact measure test . . . should not be used to screen resources, but should be used only <u>after</u> integration of resources to estimate the existence and size of any adverse impacts." In the South Carolina review collaborative, Duke refused to make the same commitment that it previously made in North Carolina, and insisted on the right to screen with any of the four California tests.

participants, considering the characteristics of the market segment. Acceptability may be measured by payback period, years to positive cash flow, or other computations that reflect the market barriers for the particular market segment.

Q: Does Duke adopt the TRC test as the primary basis for screening?

A: No. Duke has previously agreed to the primary reliance on the TRC, and has stated that it does rely primarily on the TRC, but now appears resistant to this standard. The Company interprets primary reliance on the TRC means use of the test as "sole indicator for the selection of a program" (Testimony of W. Reinke, p. 13; also testimony of D. Denton, p. 20). The Company instead claims to have a balanced approach based on consideration of multiple tests. As stated in the testimony of D. Denton (p. 20),

> . . . Duke believes that the use of any one test is inappropriate and the current rules do not allow reliance on one test. . . . Duke uses all tests and evaluates the trade-offs between the tests. Duke believes this balanced approach is appropriate.

The Company does not document its "balanced approach;" it does not specify how tradeoffs between the tests are assessed and decisions made. Instead, the Company simply asks the Commission to believe that the Company is making the appropriate tradeoffs.

In addition, Duke does not fully apply the Total Resource Cost test. As discussed in the next section, Duke excludes any value for environmental effects and otherwise understates avoided costs. Duke ignores completely the effect of electric DSM on consumption of non-electric energy or water. This policy may result in measures that increase fossil energy use, when an alternative measure might have reduced both electric and fossil use.[3]

Q: Is DSM screening based on the TRC test consistent with the Commission rules?

A: Yes. Not only is primary reliance on the TRC test consistent with the Commission least-cost planning rules, it is a requirement. The utility must justify any deviation from least cost planning:

> . . . <u>The utility shall propose an IRP which minimizes total resource costs to the extent feasible</u>, giving due regard to other appropriate criteria such as system reliability, customer acceptance and rate impacts (subsection B(7))
>
> . . . The utility must justify the use of a specific test or tests employed as part of the basis for adoption of a specific resource. . . (subsection B(6a))

(emphasis added).

Q: Does the Company make appropriate tradeoffs in its DSM planning process?

A: No. Duke's planning process is deficient in at least the following respects:

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[3]Given Duke's very limited efforts to screen measures or programs to date, this error may not have made any difference in the 1992 plan. Duke has not committed to correcting this error in the future, when it could be more important.

- Duke simply did not screen certain existing programs, under the TRC or any other test.
- Duke has not applied the Total Resource Cost (TRC) test as the primary basis for DSM program selection. Duke uses the Utility Cost test in its final screening of the portfolio.
- Duke has not limited its use of the RIM to a test of the equity effects of the portfolio as a whole, as required by the Procedures. In particular, the Company relies on the RIM test to rank options for consideration in the Cumulative Option Analysis.
- Duke relies on benefit-cost ratios rather than net benefits to rank programs.
- Duke did not design programs or set incentive levels to maximize TRC benefits to the extent feasible.

Q: What programs were not evaluated in the IRP?

A: The Company did not screen several existing residential programs, including those for Add-On Heat Pump, New Residences Insulation,[4] Central Air Conditioning/ Heat Pump, Refrigerator/Freezer, and Insulation Loan.[5] The first two programs promote the choice of electric over fossil heat, and

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[4]This program is also referred to as the MAX program. It appears to be a combination of marketing efforts and the discounts in Rates RS and RE. Despite the references to "Insulation" and "New Residences," the program covers heat pumps and other measures, and appears to be applicable to some existing buildings.

[5]It is not clear whether Duke considers the existing Off-Peak Water Heating and Interruptible Service programs to be equivalent to the potential new programs.

will tend to increase Duke's costs. It is particularly important that Duke demonstrate that these programs are economically justified before it continues its promotional programs. While some existing programs, such as the <u>Air Conditioning and Heat Pump</u> program, are almost certain to be cost-effective, despite problems discussed below, they should also be subject to screening and improvement.

Q: Mr. Jenkins (p. 13) asserts that these programs were "previously screened." Does this resolve your concerns?

A: No. Duke has not provided these screening results in the IRP, in the discovery process, or in Mr. Jenkins testimony. Mr. Jenkins does not specify the time frame in which this "previous" screening occurred, but it is likely to have been prior to the issuance of the Procedures and to have considered only the RIM test. The avoided costs used are also likely to have been different than those Duke now uses. Hence, the "screening" is of no value for this proceeding.

Q: Of those programs Company did screen, were the selection decisions consistent with the objective of minimizing the TRC?

A: No. A quick look at the IRP, in particular the Cumulative Option Analysis, would give the impression that the Company <u>has</u> relied primarily on the TRC test. In the Cumulative Option Analysis, the Company did not exclude any cost-effective options just because they failed the RIM test. Duke rejected only the Standby Generator-Capacity Improvement option; it failed the TRC. According to the testimony of W.

Reinke (p. 14), "[a]ll cost-effective DSM options that were identified were pursued in the 1992 IRP."

Upon closer review, it becomes apparent that Duke's DSM planning process does not seek to maximize net benefits. First, contrary to the testimony of W. Reinke, the Company does reject options that apparently pass the TRC. Second, the Company accepted for implementation DSM options that did not pass the TRC test, namely the Residential Load Control -- Water Heating and Off-Peak Water Heating -- Submetered programs.

Q: **What apparently cost-effective DSM options did the Company reject?**

A: The Company rejected the High Scenario cases of the non-residential high-efficiency lighting and industrial motor programs. For the motors program, Duke includes in the IRP a program paying $6/horsepower (hp) rebate for efficient motors, which it describes as resulting in 3 improved motors per participant and achieving a 20% penetration, while rejecting a $25/hp rebate described as achieving 4 motors/participant and 80% penetration.[6] For the lighting program, Duke's program descriptions are difficult to compare, since the Low Scenario is laid out as six sub-programs (new and existing; electric heat, fossil heat, and OPT rate) with

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[6]Like many of Duke's programs, these descriptions of these options are vague and inadequate. The "80% penetration" case is actually projected to reach only about twice as many customers as the "20% penetration" case; the "penetration" values appear to exclude free riders.

savings stated per customer, while the High Scenario is laid out as three sub-programs (new and existing are merged) with savings stated per kW of load reduction.[7] However, it appears that the two scenarios vary in incentive (about $200/kW in the Low Scenario, $500/kW in the High) and in total effect on load (742 MW of savings by 2006 in the Low case, 1,302 MW in the High).

The higher incentives that would be offered under these programs would have a substantial effect on projected DSM savings by encouraging far greater participation and proportionally less free-ridership. The High Scenario industrial motors and efficient lighting programs would increase by 150% the total projected MWh savings for the DSM portfolio by the year 2006 (Appendix, pp. 208-209).

Q: **What was Duke's rationale for rejecting the higher savings from the High Scenarios?**

A: These options were rejected on the basis of a single test: the present worth of revenue requirements (PWRR), which is another name for the utility cost test (UCT). The Company has not provided the UCT results for the individual High Scenario cases (Exhibit 9-8), but asserts that their inclusion increases utility costs.[8]

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[7]The High Scenario lighting is analyzed as only one program in Exhibit 9-7.

[8]As noted below, the increase in utility costs in the high scenarios (if it occurs) is at least partially a result of Duke's inadequate program design.

Q: Would these expanded programs reduce total costs to ratepayers, if the Company's program evaluation assumptions are correct?

A: Yes. Both of the High programs pass the TRC test, by ratio of 3.55 for the lighting and 4.01 for the motors (Exhibit 9-8). However, the TRC tests provided in the IRP do not properly test the economics of these options. Since Duke has the choice of running the programs at low or high levels, it should evaluate the cost-effectiveness of the program expansions on an incremental basis.

In the case of the High Scenario motors program, the Company's program evaluation assumptions virtually ensure that program expansion will be cost-effective. The additional installations in the High scenario would have the same cost and kW and kWh savings as in the Low case, but none of these incremental participants would be free-riders and no additional Marketing and Customer Planning expenditures would be required.[9] Given that the Low case passes the TRC test, the incremental installations under the High case would certainly be cost-effective. In fact, the B:C ratio for the expanded program should be higher than for the Low program.

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[9]The Company's analysis of the motors program recognizes that low customer incentive levels fully capture the free-riders, and that higher incentives reduce the share of incentives and savings due to free riders. The Company also reflects the economies in marketing and overheads for more intense programs. These examples of sophisticated understanding of some aspects of DSM program design and economics suggest that Duke is well positioned to expand its programs rapidly and efficiently, if it makes a commitment to do so.

Duke reports a marginally lower B:C ratio, 4.01 for the High case versus 4.06 for the Low case, but this reduction may result from the fact that the High case was screened later in the Cumulative Analysis. In any case, it is clear that the incremental B:C ratio must also be very close to 4.

The situation is a little more complicated for the lighting program, due to Duke's different handling of the Low and High cases. Table 1 estimates the overall B:C ratio of the Low program, by assuming that the benefits of each sub-program are proportional to the peak reduction.[10] I weight the C:B ratio for each subprogram by the relative benefit of the subprogram, and estimate a total B:C ratio of 3.74. Duke reports that the High program has a B:C ratio of 3.55; arithmetically, the increment must then have a B:C ratio of about 3.3.

Hence, expansion of both programs would appear to offer substantial reductions in the costs to serve Duke's customers. It is unreasonable for the Company to settle on low participation rates (only 20% in the case of the motors program) and high free-ridership without a compelling justification and without exploring alternatives. The Company should not reject outright aggressive lighting and motors programs that would increase the portfolio's conservation

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[10]Actually, the avoided capacity and energy benefits per summer peak kW will vary slightly. Table 1 weights the C:B ratios by the "Capacity" values in Appendix VI-5, which appear to be the summer peak reductions, not capacity reductions.

potential by 150%, simply because these programs fail the PWRR/UC test.

Q: Should Duke be attempting to minimize the Utility Cost Test?

A: This should not be Duke's sole or primary concern. The Procedures properly mandate a central focus on reduction of total costs, including customer costs. The out-of-hand rejection of programs in integration, based on the UC test (or PWRR), negates the effects of Duke's use of the TRC earlier in the process, and is inconsistent with the Procedures.

The Company's objective should not be to minimize the PWRR, but rather to minimize PWRR for a given level of benefits. In any case, as discussed below, Duke did not consistently act to minimize PWRR.

Q: How should the Company have used the results of the UC test in this case?

A: Duke should have quantified the utility cost effects of each of the program enhancements, and clearly identified what level of utility cost would be unacceptable, and why. Duke should examine total bill and energy cost effects for each year, and for each alternative. Duke has not done any of these things.

Assuming that the enhanced programs, as designed, contribute to an excessive utility cost (however that may be defined), Duke should have examined a number of options, including:

1. Analyzing the cost-effectiveness of High Scenario case lighting and motors options individually, rather than considering all lighting options and the motors program in a single analysis.

2. Concentrating resources on the more cost-effective lost opportunity programs in new construction, renovation, and expansion.

3. Eliminating other programs that increase both utility costs and total resource costs.

4. Redesigning the programs and restructuring the customer incentives to provide adequate incentives without paying more than the cost of efficiency.

5. Reviewing the validity of the assumptions used in the economic evaluation of the programs.

Q: What did the Company's analysis miss in analyzing the lighting program as a single program, rather than as multiple programs?

A: Once a utility detects a particular type of cost or equity problem in its DSM portfolio, it should attempt to identify the programs and measures that contribute to the problem. Duke has not explained how it determined that the total utility cost was too high, or how it determined that the high-case motors and lighting programs were responsible for the problem. Indeed, the discussion on page 120 suggests that these two programs were never considered seriously, but were only included so that "various alternative plans could be developed."

Even if Duke had some valid reason for scaling back the lighting and motors programs, the various parts of the programs should have been analyzed separately. Installation of efficient lighting in new construction deserves particular attention because it is a highly cost-effective lost opportunity resource. If the opportunity is missed, the resource will be much more costly to acquire later. DSM in new construction is much less costly than retrofits to existing buildings and is thus much more cost-effective.[11] According to the Cumulative Option Results, the TRC benefit cost ratios for the Low new construction programs range from 10 to 18, while the ratios for retrofits were only between 2.4 and 3.6. It makes no sense to screen out aggressive programs for both new construction and retrofits without a separate evaluation of each.

Q: What other changes might Duke make to its DSM portfolio, to reduce the PWRR without such adverse effects on savings and TRC benefits?

A: While the Company used the UC test as its rationale for rejecting aggressive lighting and motors programs, the Company has not in other respects selected its DSM portfolios to minimize PWRR. There are other changes the Company did not make that could increase the net benefits of its DSM portfolio as well as reduce the PWRR:

1. Suspension of load-building programs, which generally increase PWRR. In particular, the promotion of heat pumps through the Residential Add-On Heat Pump and Insulation-New Residences programs have been included in all of the alternative resource plans. Duke has not even tested the effects of these programs on PWRR. Duke projects that these programs will promote sales growth.[12]

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[11]For these reasons, the Commission's Procedures require special priority for lost opportunity resources.

[12]While Duke suggests that the heat pumps will reduce summer peak and energy requirements, due to increased efficiency, this is unlikely, as discussed below.

2. Suspension of the uneconomic Residential Load Control -- Water Heating and Off-Peak Water Heating -- Submetered programs, which fail the RIM, TRC and UC/PWRR tests. Duke should not be pursuing these unequivocally wasteful programs.[13]

Q: In what ways can the programs be redesigned to lower their adverse effect on the PWRR?

A: The programs, including the incentive structure, can be redesigned to improve participation with lower customer incentives. The customer incentive should be structured so that (1) the participant will prefer the most efficient, cost-effective investment, and (2) the Company does not pay more than it has to to encourage participation. Many of the Company's proposed incentives fail on both counts.

Duke's High Case motor program assumes that achieving an 80% penetration rate would require an incentive of $25/hp, which is larger than the incremental cost of the measures the Company expected to be implemented under the program. This is unlikely for a well-designed program. The Company should have considered other ways to improve participation, including a restructuring of the incentive payment to vary with the size of the motor. The incremental cost of efficiency depends on the size of the motor. A constant payment per hp therefore

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[13]Duke has suggested that the non-cost-effective programs might someday be redesigned to be cost-effective. The fact that a general approach may be beneficial at some point in the future is not a justification for pursuing the approach today, when it is not cost-effective. These programs should at least be closed to new participants until they can be redesigned to be cost-effective.

could overpay for some efficiency improvements, underpay for others.

Duke should also have considered an intermediate incentive payment. The Company rejected the High Case $25/hp, 80% penetration option, in favor of the Low Case $6/hp, 20% penetration option, without even evaluating the $12/hp, 50% penetration incentive described on pages 180 and 181 of Appendix 6. The Company should also have considered an incentive equal to (but not exceeding) incremental cost.

Finally, if Duke thought that this market was a difficult one to reach without massive incentives, it should have explored other ways to increase program participation, including improved marketing and dealer incentives.[14]

Q: **How might revision of program evaluation assumptions resolve the Company's concern about the PWRR effects of the High Scenario programs?**

A: Two types of re-evaluation may be helpful. First, as discussed in more detail in the next section, the Company's estimates of avoided capacity and energy costs understate the benefits of all of its efficiency programs.

Second, Duke does not provide detailed documentation of its program-specific cost and effectiveness assumptions, nor any supporting evidence for its conclusions regarding the participation achievable at different incentive levels. In

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[14]This market is likely to be relatively easy to reach, given the maturity of the technology and the large size and sophistication of many of the customers.

response to discovery, the Company states only that ". . . incentive levels for all options are established by the option work teams based on their judgment and experience (IR 2-22f)." Given the importance of Duke's assumptions with regard to these two programs, the Commission should expect a more detailed discussion of the experience and plans of other utilities for similar programs, along with an analysis of the groups of customers to be served in each program, and the most cost-effective means of increasing penetration for each group.

In particular, Duke should have examined whether some of the difference in the utility cost test was due to the difference in timing of the Low and High Cases of the lighting program. The Low case starts its savings in 1993; the High case assumes a two-year delay to 1995. Thus, two years of savings are lost due to an arbitrary difference in the program assumptions.

Q: Were there other instances where the Company may have excluded cost-effective options?

A: Duke reviewed and excluded alternative DSM options at various stages of the planning process. The screening of these multiple cases is largely undocumented and unreviewable. The IRP identifies several additional cases: two types of incentives for the <u>Residential Controlled Off-Peak Water Heating</u> programs; different start dates for <u>Interruptible Service Additions</u>; alternative incentive payment levels for <u>Standby Generation - Capacity Improvement</u>; and different incremental (export) capacities for Standby Generator with Backfeed. While the decisions involving these programs are unlikely to be as crucial as the decision to forego aggressive lighting efficiency and industrial motors programs, Duke's failure to explain its decision process is of concern.

Q: What was the basis for selection among these multiple cases?

A: The selection process is largely undocumented. The Company does not specify the tests used or factors considered, results of tests, basis for selection, and reason for rejection. In the case of the DSManager analysis,[15] the Company states only that it selected the most "effective" case, that is, the case "that is judged to best meet the option criteria and produce the best combination of results in DSManager. No one test result is used to determine the most effective case." (IR 2-19f). Duke would not even provide a summary of results for each option (IR 2-19b).

In the Single Option Analysis, the Company calculated only the RIM test for screening multiple cases. The Company relied also on some unspecified "engineering judgment," which also took into account rate impacts (IRP, p. 111)

Q: Please explain why it is inappropriate to use the RIM test to rank options.

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[15] The documentation is contradictory: According to the IRP (Appendices, p. 38), the Company excluded cases based on the DSManager analysis. But, according to IR 2-19, no cases were excluded at this stage of the analysis.

A: The Company's reliance on the RIM test to rank options for the Cumulative Option Analysis may result in a suboptimal selection of DSM programs. The order in which options are analyzed affects the estimate of their cost-effectiveness.[16] In particular, in the case of competing resources, like the high efficiency A/C versus the A/C load control programs, one program makes the other less cost-effective. Under the RIM test, the load control programs tend to receive a higher ranking than the energy efficiency programs. If the order were reversed in the Cumulative Option Analysis, the cost-effectiveness of the energy-efficiency programs may increase and that of load control programs decrease.

Q: You have stated that the Company's use of benefit-cost ratios rather than net benefits may promote cream-skimming. Please explain.

A: A DSM option is cost-effective if has positive net present value (NPV) or if its benefit-cost ratio (BCR) exceeds unity. Anything that passes the NPV also passes BCR. However, NPV and BCR produce a different ordering of actions.

Consider the following options for DSM treatments in retrofitting residential electric space heating. Two options have been identified for infiltration control: Option 1 is

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[16] Exhibit 9-7 (p. 119) lists options in the order their RIM-based ranking from the Single Options Analysis, and provides the RIM tests from the cumulative analysis. Note that the relative RIM tests appear to be very different for some options, implying that the estimated benefits of the programs depend significantly on the order in which they are analyzed in the cumulative analysis.

a low-cost weatherstripping package, while Option 2 is a comprehensive program driven by blower-door identification of bypasses.

Table 2: Infiltration Control Example

	Cost	Benefit	NPV	BCR
Option 1	$100	$300	$200	3.0
Option 2	$900	$1500	$600	1.7
Difference	$800	$1200	$400	1.5

If the objective is to minimize total resource costs, it is better to spend $900 to save $1500 than spend $100 to save $300, even though the benefit-cost ratio of the former is lower (1.7 versus 3.0). Option 1 has a greater benefit-cost ratio, but selecting that option would lose the opportunity to save another $400 and would thus not result in the highest achievable net program value. Option 2 has a higher present value than Option 1 and hence is preferable.

Among those competing mutually-exclusive DSM decisions that pass TRC test, the one delivering the maximum net benefit should be selected. The objective of least-cost planning, as specified in the Commission's Procedures, is to minimize total resource costs; this goal can only be achieved by selecting actions that maximize the difference between the DSM benefits and costs. As a result, DSM screening should not seek to maximize the benefit-cost ratio of the DSM portfolio or individual programs or measures.

Q: How should the TRC test be used in the development of program design?

A: Duke currently screens DSM at the program level only.[17] In the design of DSM programs, the determination of measures to be included in programs, of efficiency levels, and of participation targets should be based on the TRC test. The Company should be designing programs to include all measures with incremental costs below incremental TRC benefits. Measures should also be screened for different efficiency levels; if the incremental TRC benefits of the higher efficiency level exceed the TRC costs of achieving the higher level, program designs should be changed to achieve or encourage the higher level. The cost-effectiveness of programs and measures as a function of usage level and other relevant factors should be determined, so that each DSM option can be made available only for those applications for which they are cost-effective.[18]

Duke's failure to screen measures and efficiency levels means that neither Duke nor the Commission can determine

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[17]Mr. Jenkins (p. 15) notes that Duke "considers measures," but admits that Duke only screens the cost-effectiveness of an individual measure if the measure is in a single-measure program. Single-measure programs are generally inefficient, as discussed in Section V below.

[18]For example, a ground-source heat pump may be cost-effective for a very large residential customer, and for many commercial customers, but not for average sized homes.

whether the Chiller program would produce higher net benefits if certain sizes or types of chillers (e.g., reciprocating or screw compressors) were excluded, if additional measures (e.g., cooling tower efficiency improvements, variable speed drives) were added, or if some incentives were increased or decreased.[19] Each program is presented to the Commission on a take-it-or-leave-it basis.

[19]In a few cases, as described above, Duke describes alternative program-wide incentives and participation rates, but not alternative groups of measures or efficiency levels. Some of the programs for which the detailed results would be most interesting, such as the Insulation Loan and MAX programs, have not been screened at all.

IV. DUKE'S UNDERESTIMATION OF AVOIDED COSTS

Q: Please summarize your evaluation of the Company's DSM avoided cost modeling.

A: In principle, Duke's modeling has some features that are superior to standard utility practice. In particular, Duke reflects the energy benefits associated with the load shape of each DSM program, rather than assuming that all DSM has a flat load shape. The Company also models explicitly the reliability benefits of each DSM option, taking into account the effect of each program's load shape as well as the constraints on the operation of load management and interruptible options. However, the use of sophisticated modeling does not eliminate the need for avoided cost estimates.

In practice, the Company's avoided cost modeling produces apparently anomalous results and has deficiencies which result in the underestimate of avoided costs.

Q: In response to the concern that the IRP lacks simplified avoided cost estimates for use in the DSM planning process, and that the avoided cost modeling is flawed and inadequately documented, Duke contends that the Consumer Advocate does not recognize the value of the Company's more rigorous modeling techniques (testimony of W. Reinke, pp. 14-15; testimony of F. A. Jenkins, p. 15-16). Are you proposing that the use of production costing models be abandoned?

A: No. The Company misunderstands the Consumer Advocate's concern. For final program screening, production costing models are a valuable tool. It is the Consumer Advocate's position that Duke's detailed modeling should be corrected and better documented, not discarded. However, at earlier stages of screening, utilities generally find production costing models too cumbersome to use in exploring numerous combinations of measures, efficiency levels, applicability rules, and delivery mechanisms. Avoided cost estimates are needed to facilitate measure screening, to assist program designers in understanding the features of programs that are most valuable, and to allow for the screening of custom DSM projects. They are also needed to guide DSM bidders (to the extent bidding is used in the future). Furthermore, they are useful as a test of the plausibility of the Company's more complex modeling of DSM option cost-effectiveness. For example, Duke should be able to provide a table of avoided energy costs (in ¢/kWh) by measure, and then explain why the differences in avoided costs are consistent with the differences between measure load shapes.

Q: The Company claims that for preliminary screening in DSManager, it did rely on production costing models rather than simplified avoided cost estimates (testimony of F. A. Jenkins, p. 15-16). Have you been able to review this analysis?

A: No. The Company was unable to provide the marginal cost estimates used in that analysis (IR 2-19g).

Q: What apparently anomalous results have you identified?

A: For some of the efficiency programs, the PROMOD estimates of production cost savings swing wildly in certain years with no obvious pattern. For example, the production cost savings for the Residential W/H Blanket program fall from $3200K in 2002 to $246K in 2005 and then swing up to $7,803K in 2004 (IR 1-20, Attachment 1-27). The decline in 2003 may be attributable to the installation of a baseload coal plant in that year. However, there are large swings in the production cost estimates in other years as well. Even more odd is the prediction by PROMOD that the High Efficiency Unitary Equipment Air Conditioning Program, will actually raise system production cost savings in some years (IR 1-20, Attachment 1-27).

The Company should provide an explanation of these results if the PROMOD analysis is to be relied upon for program screening.

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

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

- The modeling overstates the benefits of interruptible options by neglecting some effects of payback;

- The analysis does not credit energy efficiency options with avoided reserve requirements;
- The Company credits DSM with avoiding capacity only in 1996 and after, rather than starting in 1995, the scheduled date of the first capacity addition;[20]
- The analysis ignores possible benefits of deferring baseload plants;
- It neglects the possibility of avoidable life extensions and replacements of existing capacity;
- It ignores opportunities for additional or continuing off-system sales of capacity and energy (IR 2-18);
- The analysis understates avoided T&D costs;
- It omits avoided losses and distribution costs on the customer side of the meter (IR 2-7);
- In estimating kW and kWh reductions due to DSM, the Company incorrectly applies average line losses, rather than marginal losses;
- The analysis apparently neglects certain costs of compliance with the Clean Air Act Amendments;
- It neglects environmental externalities; and
- It omits the risk mitigation advantages of DSM.

Q: Please explain how the Company models interruptible options?

A: In the Cumulative Option Analysis, the Company uses the production costing models ENPRO and PROMOD to estimate DSM program benefits. ENPRO is used to model interruptible programs with payback (i.e., where the interrupted load is later recaptured by the customer), taking into account the constraints on interruption of customers, payback, and

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[20]There is also the possibility that DSM will have capacity value before 1995. The Company's surplus capacity before 1995 may have market value. If so, freeing up capacity for off-system sales is another positive benefit of DSM.

customer load at the time of interruption.[21] ENPRO estimates the extent to which interruptible programs can flatten system load, and calculates monthly demand reductions and payback.

Duke has not used the ENPRO results to adjust the daily load shapes input to PROMOD. Instead, the ENPRO peak reductions are modelled as an emergency generator with equivalent monthly capability. This emergency capacity is lower than Duke's primary measure of avoided capacity, the Maximum Net Dependable Capability (MNDC), which is measured in terms of less-reliable combustion turbine capacity.

Q: **Do ENPRO and PROMOD accurately model interruptible programs?**

A: Not necessarily. A generator is not an accurate proxy for an interruptible program with payback. The emergency generator has the capacity to provide power in all of the hours it is available for dispatch, analogous to the interruptible option in all of the hours it is available for interruption. However, when the generator is not dispatched, it produces nothing. On the other hand, when the control is lifted, the interruptible customer increases its load above its baseline use (e.g., takes its "payback"). Ignoring payback would cause PROMOD to overstate both reliability and energy benefits of an interruptible program.

Q: **Has the Company corrected for this problem?**

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[21]Duke uses "interruptible" to refer to all load management programs, with the possible exception of residential controlled off-peak water heating, which Exhibit 6-5 labels "load-shifting."

A: It is unclear. In the case of production cost impacts, there is conflicting information. On the one hand, Company has described an external adjustment to reduce production cost benefits in the case of interruptible options with payback (Letter from W.L. Porter to R.E. Lark, 6/2/92). On the other hand, in response to a request for documentation of this adjustment, the Company stated that the energy benefits of interruptible options were derived directly from PROMOD runs, with no adjustment for payback (IR 2-13, IR 2-15).

In determining reliability benefits, the Company made no correction to the estimate of MNDC to account for payback. Duke asserts that it will not lift load controls unless there is sufficient capacity, and therefore payback will not reduce system reliability (testimony of W. Reinke, p. 18). This explanation does not account for a number of factors. First, there are contractual constraints on the total hours of interruption. Second, as more load is shifted, longer interruptions will be required to prevent payback from contributing to the need for capacity; longer interruptions will reduce the magnitude of the interruption available at any hour. Third, increasing off-peak load will reduce reliability by reducing the available peak period capacity of the Company's pumped hydro capacity.

Q: Have you identified any other problems specific to the modeling of interruptible options?

A: Yes. Duke's model inputs do not adequately reflect the constraints and limitations of the load control. In particular, Duke assumes no payback for Interruptible Service customers (IR 1-18a). The Company provides the following explanation for modeling assumption:

> Duke assumes payback is related to end-uses that are weather responsive or have storage functions. Since production and process loads are the predominate loads contracted in the Interruptible Service program, it is assumed that customers interrupt their loads for the needed period of time, then resume operations as normal (IR 2-16)

This assumption appears to be simplistic. Customers with fixed production targets will need to accelerate production after the interruption. Customers who have deferred operations will need to resume the deferred operations, in addition to the normal activities at the end of the interruption. Even if <u>activities</u> return only to normal levels, the simultaneous start-up of all interrupted equipment may mean that <u>load</u> increases immediately after the interruption ends.

Q: You stated previously that at least in principle the Company's model explicitly models the reliability benefits of the DSM option. What evidence have you identified that indicates that the Company's analysis is not crediting DSM with avoided reserve requirements?

A: A DSM program with the same load shape as the system's should be credited with more than its peak reduction to reflect avoided reserve requirements. The Company uses a minimum planning reserve margin of 20% (Vol II, p. 147), and is actually planning a reserve margin of about 24% in the 1990s (Exhibit 11-6). Thus, each kW of Duke's average load requires about 1.2-1.24 kW of capacity; each kW of average-shaped load removed through DSM should receive credit for avoiding 1.2-1.24 kW of MNDC. Yet Duke's estimates of MNDC benefit are <u>below</u> the summer peak reduction for all efficiency programs (for which we have documentation), as shown in Table 3.

Q: **Is there a plausible explanation for this result?**

A: Not entirely. The reliability benefits of a given DSM option are a function of its load shape. A DSM option that avoids load with a shape flatter (sharper) than the system load shape will contribute more (less) than its peak load reduction plus the target reserve margin. A DSM measure that avoids load only on the summer peak is not as valuable as a CT that operates many times during the year; a DSM measure that reduces load in every hour would have greater reliability contribution than the CT, which cannot operate in every hour.

The low MNDCs Duke reports for some DSM programs (e.g., <u>Unitary Equipment</u>) may be attributable to their narrow focus on summer peak reduction. However, the water heater wrap program reduces loads throughout the year, with substantially higher kW and kWh savings in non-summer seasons (Appendices, p. 152), and has a load factor of 129%. By comparison, the forecasted system summer load factor is only about 60% (Duke 1992 Forecast, p. 20). This program should have MNDC savings much greater than its summer peak reduction. Yet Duke estimates that the water heater wrap MNDC value is only 79% of its summer peak reduction.

Q: The Company asserts that the use of 1996 as the start date for DSM capacity credits is consistent with the Base Supply Plan which specifies 1996 as the first year of deferrable capacity (testimony of W. Reinke, p. 15). Does the Base Supply Plan justify the assumption that no capacity can be deferred until 1996?

A: No. According to the Company's own analysis, the base case plan was an unrealistic assessment of the Company's capacity needs.[22] The Company's <u>actual</u> supply plan schedules the Lincoln Combustion Turbine Station units for 1995 (Executive Summary, Exhibit ES 11-6; testimony of W. Reinke, p. 15). The Company states explicitly that DSM can defer the installation of these units:

> the states of operation will remain flexible to accommodate changes in resource needs. (Note 7 to Exh. ES 11-6)

Q: The Company contends that its peaker method reflects the benefits of deferring baseload plants (testimony of W. Reinke, p. 16). Is this assertion correct?

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[22] In addition, the Base Case plan does not appear to provide sufficient capacity in 1995. The Base Case has 296 MW level generation and 405 MW less DSM in 1995 than does the IRP. Thus, the 19,917 MW equivalent capacity in the IRP would be only 19,216 MW in the Base Case. The resulting reserve margin of 19.1% is below Duke's 20% target.

A: No. The Company's method estimates the value of DSM in backing out new peaking units and variable costs, assuming a coal plant addition in 2003. What the Company's methodology does not examine is the possibly greater savings to the utility if DSM can be used to delay a coal plant.

Q: How can DSM delay a baseload plant?

A: In principle, the utility installs baseload plant instead of a peaking unit when the NPV of the system operating costs that the baseload unit would displace over its lifetime exceeds its operating costs plus the additional capital costs. The installation of a coal unit in a given year may be economic in the absence additional DSM. However, when new programs are added to the resource plan, the decline in load growth may reduce the production cost savings of the coal plant so that it is no longer economic in that year.[23] In the case of Duke's proposed IRP, the proposed DSM options will be sufficient to defer the coal plant addition from 2003 to 2006.

The Company's load-building and peak-shifting programs can require an increase in the need for baseload capacity. Failure to reflect the cost of this baseload capacity will overstate the benefits of these peak-shifting or load-building programs. Conversely, efficiency programs will

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[23]In other words, the additional costs of the coal plant may be higher than marginal system operating costs after the coal plant is added. The best use of additional DSM is then to avoid the coal plant, not to further reduce system energy production.

reduce the need for baseload capacity; their benefits will be understated by ignoring the value of baseload plant deferral.

Q: You criticize the Company's analysis for neglecting the possibility of avoidable life extensions and replacements of existing capacity. Does load growth contribute to the need for plant replacements and life extensions?

A: Yes. In fact, the Company states that because no baseload additions are planned, load growth may require life extensions or replacements of existing plant to maintain a reliable and economic supply (testimony of J. Hendricks).

Q: Has the Company studied whether DSM can defer or eliminate life extensions and plant replacements?

A: No. The Company merely assumes that these are unavoidable,[24] and in response to the Consumer Advocate's concern, states only that it would be inappropriate to accept or assume that lower load growth through DSM could eliminate or defer these expenditures (testimony of W. Reinke, p. 17). Least cost planning requires the Company to consider whether load reductions through DSM can maintain the system reliability, but at lower cost.

Q: What deficiencies have you identified in the Company's avoided T&D estimates?

A: The Company understates the effect of DSM on T&D requirements, first, by understating the avoided cost of T&D

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[24]The Company does agree that the DSM avoided cost modeling reflects no plant retirements (testimony of W. Reinke, p. 16), and thus assumes that replacements are committed.

per kW of load, and second, by using the MNDC to adjust the kW savings of DSM downward without justification.

Q: Why do you think the Company's estimates are too low?

A: The Company estimates a total avoided T&D cost per kW of only \$19.94 (in real levelized 1991\$). According to the Company's workpapers (IR 1-22), this estimate reflects only the bulk transmission (\$9.07/kW-yr) and bulk distribution (\$10.87/kW-yr) portions of the system.

The marginal demand-related costs of transmission and distribution capacity can be quite high; when considered together, they often exceed avoided generating capacity costs per kw of load reduction. Reductions in customer loads will tend to reduce loading on the company's transmission, subtransmission, primary distribution, and secondary distribution circuits. Such reduced loading will translate into cost savings, since Duke will be able to postpone or avoid investments to expand or upgrade existing or planned transmission and distribution circuitry. Reduced loading may also enable Duke to install smaller, less expensive equipment to serve new loads.

Utility estimates for the value of avoided transmission and subtransmission capacity costs per coincident peak kW (at run in the range of \$20-30/kW-yr (in real levelized 1991\$). 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-$150/kW-yr (in real levelized 1991$). (All values are stated at the generation voltage level.)

Q: **You state that in the avoided T&D capacity estimates the company has incorrectly used the MNDC T&D to adjust the kW savings of DSM downward. Please explain.**

A: The Company determines the total T&D capacity credit for a program based on the program's MNDC, rather than on its peak kW reduction. The MNDC reflects the program's effect on the system's reliability-based need for generation capacity; it seems to be unrelated to the need for T&D. In the case of energy efficiency programs, which have MNDC's below their projected peak kW reduction, the application of the MNDC further reduces the T&D capacity benefits estimated for DSM.

The Company does not explain why the MNDC is relevant to calculations of avoided T&D, but rather asserts without support that the MNDC is needed to reflect the ability of DSM to defer T&D expenditures (testimony of W. Reinke, p. 16). That value of deferral is already reflected (although not adequately) in the Company's calculation of the avoided T&D capacity cost per kW (IR 1-22). The Company provides no explanation for making any adjustment to the program's peak kW savings before calculating the program's total T&D credits.

Q: **The Company claims that it does use marginal losses in its avoided cost modeling. What evidence do you have that it does not?**

A: The analysis provided in IR Attachment 1-23 appears to be a calculation of average losses, based on total kWh sales divided total kWh delivered.

Q: What is the distinction between average and marginal losses for purposes of DSM screening?

A: Average losses are the total line losses incurred during a rating period, divided by the total energy sold. This measure is the loss factor commonly reported in aggregate energy sales tabulations. Marginal losses, on the other hand, equal the difference between total losses at a higher, pre-DSM load level, and total losses at a lower, post-DSM level. What is important for valuing DSM 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: You state that the avoided cost analysis apparently neglects certain costs of compliance with Clean Air Act Amendments. According to the Company, however, preliminary compliance plans have been included in the IRP analysis (Testimony of J. Hendricks, pp. 4-6, 9-11; testimony of W. Reinke, p 17). Does this testimony answer your criticism of Duke's avoided cost modeling?

A: No. The Company agrees that CAAA compliance costs should be taken into account in the assessment of resource options. However, it is significant that the Company never actually states that compliance costs were reflected in its avoided cost modeling of DSM options, as opposed to some other analysis. If they had been, the Company could easily have documented their inclusion by specifying all changes made to plant characteristics and operating costs. But the Company declined to provide any such documentation, including PROMOD inputs (IR 1-2), the preliminary CAAA compliance plan (IR 2-6) and analyses of the costs and benefits of control options (IR 2-5). Given the lack of documentation, the Commission should place no reliance on any assertion that the Company's DSM avoided cost estimates reflect costs of compliance with the CAAA.

It is certain that the Company did not reflect the value of sulfur allowances in its avoided cost modeling. The Company has not even developed a value for allowances because the allowance market is only in the "development stage (testimony of J. Hendricks, p. 10)." In addition, the Company views allowances only as an alternative to supply-side control technologies to be considered in developing a compliance plan. What the Company overlooks is that even given implementation of the final compliance plan, allowances should still figure into the calculation of DSM benefits. Reductions in sulfur emissions due to DSM will free up allowances for sale in the allowance trading market.

Q: **The Company contends that it is taking externalities into account in the integration process by including the cost of environmental compliance in the cost of future supply-side**

technologies (Testimony of J. Hendricks, pp. 11-12). Do you agree?

A: No. Even with more stringent environmental controls on emissions, there will still be externalities associated with electric production.

V. DEFICIENCIES IN DUKE'S DSM PORTFOLIO

Q: What shortcomings have you identified in Duke's DSM portfolio?

A: I have identified several omissions and deficiencies in the Company's DSM portfolio. A large part of my description of Duke's shortcomings is similar to my critique of Duke's programs in Docket 91-216-E, because many aspects of the Company's programs have not changed since then. The most salient shortcomings of Duke's current DSM portfolio are:

1. Duke fails to target DSM market sectors comprehensively. The Company omits essential sectors, end-uses, and measures.

2. Duke's existing programs inadequately address market barriers. Duke does not sufficiently target trade allies, and Duke's incentives are not well structured. The indexed incentives, loans, and rate discounts that Duke uses to promote its programs send the customer weak or inappropriate messages.

3. Several of the Company's conservation program designs are deficient in that they can be expected to result in "cream-skimming". There is reason to believe that some of the Company's programs may actually <u>reduce</u> the availability of cost-effective conservation resources.

4. Certain of the programs Duke touts as conservation programs may actually lead to load building.

5. Duke's pilots are poorly designed, and most often they are not even necessary. Ratepayers would be better served through full-scale programs. Duke's demand-side plans, and its pilots in particular, are not well integrated with Duke's supply planning.

A. Omissions in Duke's DSM Programs

Q: In what ways are Duke's programs not comprehensive?

A: Duke's DSM portfolio has a number of gaps in its coverage of the market for efficiency. The Company ignores DSM resources that can provide significant sources of savings. Duke's omissions can be found at every level of its DSM portfolio, including DSM market segments, end-uses, and measures.

Q: What do you mean by a "DSM market segment?"

A: A DSM market segment is a portion of the potential for improved efficiency that requires a distinct marketing and delivery approach. For example, large industrial customers, small commercial customers, and residential customers are unlikely to be successfully reached through a single program. Similarly, new construction, routine equipment replacement, and retrofit generally require programs with different incentive levels, program structures, technical assistance, and other features.

Q: Does Duke have programs that target lost opportunities?

A: Yes. The <u>Residential MAX Package</u>, <u>Refrigerator and Freezer</u>, <u>Heat Pump and Central Air Conditioning</u>, <u>Motors</u>, and <u>Chillers and Unitary Equipment for Air Conditioning</u> programs target portions of lost opportunities in the residential new construction, residential equipment replacement, and non-residential equipment replacement market segments. They do not always do so very well. For example, the MAX Package is inadequate because it fails to pursue many of the cost-effective opportunities present in residential new construction projects which participate in the program, and uses an inappropriate type of incentive.[25] I elaborate on the shortcomings of the MAX Package and the Heat Pump/Central Air programs in the next section.

Q: Which lost-opportunity segments has Duke neglected?

A: Duke has ignored two lost-opportunity segments altogether, and has not even proposed pilots in these areas. First, Duke forgoes the most important lost-opportunity resource, non-residential new construction and renovation. Duke does not have a program targeting this large source of cost-effective energy and capacity savings. This failure has load-growth consequences that will last for over 40 years.

Second, Duke does not pursue any savings from industrial process changes in new factories, plant expansion, or refurbishment.

[25]The MAX package allows for insulation and window efficiencies lower than those selected by Potomac Electric Power (PEPCo) for its cooler service territory. Given the higher cooling loads, cost-effective efficiency levels may be much higher in Duke's territory.

Q: Does the existence of programs for non-residential motors and some cooling equipment reduce the need for a new non-residential construction program?

A: No. The new construction market segment is substantially different from the replacement of existing equipment. New construction also provides opportunities for a much wider range of efficiency improvements than are available in the replacement of individual systems. The type of HVAC system, the type of heating and cooling distribution, the sizing of ducts and pipes, the orientation of the building, the design of windows (size, location, light and heat transmittal), the inclusion of thermal mass, internal air flow can be altered to reduce energy usage when the building is being built, but rarely thereafter. Hence, the new construction program should be designed to encourage architects and engineers to find better total system solutions, and to encourage owners to install them, as well as to encourage installation of efficient hardware. New construction also usually involves very short lead times, requiring mechanisms for rapid identification of new projects and prompt intervention in planning and acquisition decisions.

Q: What price do Duke's ratepayers pay as a result of the neglect of these lost-opportunity resources?

A: By omitting these resources from its IRP, Duke is denying its ratepayers significant cost-effective energy and capacity savings. It will be far more expensive, and in some cases, impossible, for Duke to reap savings from these resources once the window of opportunity (e.g., the construction process or the equipment purchase) has closed.

Q: Is Duke pursuing all cost-effective savings from discretionary DSM market segments?

A: No. Duke's IRP lacks programs for several discretionary (i.e., non-lost-opportunity) market segments. Missing discretionary market segments include:

- comprehensive multi-family residential retrofit;
- comprehensive residential direct-installation retrofit, including air conditioning (tune-up and duct sealing) and lighting measures for general usage single-family customers, water heating measures for customers with electric hot water, and audit and space heating measures for electric heating customers;
- direct installation program for low-income customers;[26]
- small commercial direct installation program;
- non-residential prescriptive rebates; and

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[26]Part of the water heater pilot consists of volunteers wrapping water heaters for low income and other special needs customers.

- non-residential custom design and rebate service.

In addition, other programs are proposed for pilots, sometimes with excessive delays in implementation, especially for non-residential lighting retrofit.

Q: **Do Duke's programs comprehensively cover the DSM market segments they address?**

A: No. There are large gaps within Duke's existing and proposed programs. Examples of missing end-uses and measures include:

- Duke's piecemeal conservation programs for non-residential equipment replacement cover chillers, unitary HVAC equipment, and motors, but fail to capture some other important lost opportunities. There is no program to encourage the selection of high-efficiency replacement compressors, fans, pumps, and other long-lived equipment.

- Although Duke offers a residential refrigerator and freezer program, it misses lost opportunities that arise in other routine residential equipment and appliance purchases, including customer-driven purchases of room air conditioners, and water heater purchases driven by plumbers.

- Duke's MAX program for residential new construction is missing numerous measures and overlooks entire end-uses as well. It offers water heating load control, but neglects other measures for hot water heating, including flow restrictors and measures to reduce standby losses; it also fails to include incentives for solar and heat-pump water heating. The MAX package includes an efficient heat pump and higher-than average levels of insulation, but it does not offer a comprehensive bundle of thermal envelope measures. It omits window measures such as low-E windows, shading, and solar gain; it does not set infiltration limits; and it does not seek to achieve the highest cost-effective level of insulation, air tightness, water-heater efficiency, air conditioner and heat pump efficiency. Finally, the MAX package does not address the lighting end-use at all.

- The residential water heating program misses measures to reduce standby losses (pipe wrap, thermostat setback) and measures to reduce usage (low-flow showerhead, flow restrictors). This program is discussed further below.

Q: Does Duke recognize the importance of comprehensive program design?

A: Yes. Mr. Jenkins (p. 15) asserts that Duke attempts to "ensure that a comprehensive set of options covering all markets and end-uses is evaluated." Unfortunately, Mr. Jenkins suggests that Duke's evaluation of a single additional end use (room air conditioners) will make its offerings comprehensive. He does not even recognize the need to address all measures within an end-use category.

B. Cream Skimming in Duke Programs

Q: What is cream-skimming?

A: Cream-skimming is the acquisition of easily available inexpensive conservation resources in a manner that renders otherwise cost-effective resources non-cost-effective or more difficult to obtain.

Q: When can cream-skimming occur?

A: Cream-skimming occurs in either of the following circumstances:

(1) A program neglects measures that would be cost-effective if implemented at the same time as other planned measures. In this type of cream-skimming, the administrative, diagnostic, delivery, and other overhead and joint costs make later implementation of the neglected measures more expensive and less cost-effective. For example, if a utility is wrapping a water heater, it could install water heater measures (low-flow showerheads, faucet aerators) and compact fluorescent bulbs in the same visit. The increase in costs for installing those measures in the initial visit is small compared to the cost of returning for a second installation.

(2) A program captures a small amount of inexpensive savings but at the same time renders a larger amount of otherwise cost-effective savings less cost-effective and more difficult, or even impossible, to obtain. Thus, the utility forgoes otherwise cost-effective conservation. For example, if a utility installs insulation with an R-value lower than the most efficient cost-effective level (e.g., R-30 instead of R-38), the

incremental savings from the more efficient insulation will no longer be cost-effective.

Cream-skimming typically improves a program's benefit/cost ratio at the expense of lowering the program's total savings. However, the benefit/cost ratio may also be decreased by cream-skimming, since overhead and joint costs are supported by smaller savings.

Q: Which of Duke's programs show evidence of cream-skimming?

A: Some examples include the MAX Package, Insulation - Existing Market, and Air Conditioner Load Control programs. A related problem occurs in the structure of the Chiller and Unitary Equipment programs.

Q: How is Duke likely to be cream-skimming in the Residential MAX Package?

A: The Residential MAX Package, Duke's residential new construction program, consists of higher than average levels of insulation, a heat pump with a minimum seasonal energy efficiency ratio (SEER) of 11, and pre-wiring for Duke's load control/off-peak water heating program. This program cream-skims in both of the ways discussed above.

First, the company does not attempt to obtain all cost-effective measures from residential new construction. The program ignores many sources of savings, including but not limited to: compact fluorescent lighting, high thermal performance glazing (e.g., reflective glass), high efficiency water heaters, and low-flow showerheads and faucet aerators.

Second, the program sets too low an eligibility threshold for insulation efficiency. The "higher-than-average" level of insulation does not appear to represent the least-cost level, and may not even represent standard practice. For example, wall insulation of R-19 may have a zero or negative net installation cost, compared to the R-12 Duke specifies, since the use of 2x6 framing on 24" centers uses less labor than traditional 2x4 framing on 16" centers. In addition, Duke's standards for electric heat (R-30 ceilings, R-12 walls, and R-19 floors) are virtually the same as the South Carolina Code requirements for all houses (R-30 for most ceilings, R-13 walls, and R-19 floors).

Q: What signs of cream-skimming approaches are evident in the <u>Residential Insulation - Existing Market</u> program?

A: The <u>Residential Insulation - Existing Market</u> program encourages the upgrades of insulation levels in the residential market by making low interest loans available to the customer. Like the <u>Residential Max Package</u> program, this program ignores cost-effective measures such as other thermal integrity improvements (including window upgrades), high efficiency lighting, and water heating measures.

This program is not structured to encourage maximum cost-effective levels of insulation. It cream-skims by setting a cap on its low-interest loans. The caps artificially limit the extent of each participant's retrofit and the amount of cost-effective savings Duke can obtain. The cap can prevent some participants from installing the most efficient (highest R-value) cost-effective insulation.

Q: Does the <u>Residential Air Conditioner Load Control</u> program show signs of cream-skimming?

A: Yes. The program may be cream-skimming by reducing the Company's ability to capture a block of otherwise cost-effective efficiency improvements. In other words, by implementing inexpensive load control, Duke may be losing cost-effective opportunities to install high-efficiency equipment. Because load control equipment shifts loads off-peak, peak savings attributable to the installation of more efficient equipment may be reduced and the cost-effectiveness of such efficiency improvements may be impaired. The fact that a load control program can produce some savings inexpensively does not mean it would be a part of a least-cost integrated resource plan. To determine if the load control is cost-effective, Duke should compare control to conservation and to combinations of control and conservation.[27]

Q: What deficiencies have you identified in the <u>Residential Water Heater Wrap</u> pilot?

A: This program is a classic example of cream skimming, because it omits numerous measures that could be installed at the same time as the water heater wraps. These include water heating measures, such as

- measures to reduce standby losses, including pipe wraps and aquastat resets;
- measures to reduce usage of hot water, including low-flow shower heads and faucet aerators;
- solar and heat-pump water heating, if cost effective.

Duke also neglects measures addressing other electric end uses, including:

- comprehensive HVAC and building shell audit;
- installation of compact fluorescent lamps;
- cleaning of air conditioner and refrigerator coils;

[27]Similar possibility of cream-skimming arises in Duke's water heater control programs. A combination of reduced standby losses, from water heater and pipe wraps; reduced usage from faucet aerators, and low-flow showerheads; and increased water-heating efficiency from solar or heat pumps may provide hot water at lower total costs than does load control. Duke has not compared these alternatives.

- repair of air conditioner ductwork;
- HVAC tune-up;
- reduction of cold water use in homes with water pumps; and
- provision of information on appliance replacement programs.

Duke could spread the cost of contacting a customer, arranging for a home visit, travel time, and monitoring and evaluation over a large number of measures, reducing the costs and increasing the acceptability to customers. Piecemeal single-measure programs are usually wasteful of the efforts of the Company and its customers, producing lower savings at higher costs than comprehensive programs.[28]

Q: **What related problem occurs in the structure of the Chiller and Unitary Equipment programs?**

A: The load on cooling equipment depends on the amount of heat generated in the cooled space; in commercial buildings, much of that heat is generated by lighting systems. The capacity of the cooling equipment should be matched to the load, since

[28]Duke has indicated in Mr. Porter's letter of 4/3/92 to the PSC it will reconsider program design to include the bundling of DSM options, at least in the water heater wrap program, but only if the unbundled wrap-only program passes unspecified evaluation requirements. This approach is backwards, since the single-measure program is the least likely one to be cost-effective.

excessive capacity will reduce efficiency and/or comfort levels. Before aging cooling equipment is replaced, Duke should encourage customers to reduce their lighting loads, which will reduce the size and cost of the new efficient cooling system. If the lighting retrofit takes place after the cooling system replacement, the new equipment will be unnecessarily expensive and will generally operate less efficiently than it should.

Once again, Duke's failure to structure comprehensive programs increases costs and decreases effectiveness. In addition, Duke's unnecessary delay in implementing a non-residential lighting program prevents the efficient sizing of equipment being installed under the **Chiller** and **Unitary Equipment** programs.

Q: Given the potential for cream-skimming in Duke's programs, is it likely that these programs would be part of a truly least-cost plan?

A: No. The cream-skimming potential in these programs suggests that some or all of them would be modified or eliminated in a least-cost plan.

C. Duke Programs That Do Not Address Market Barriers

Q: Do Duke's existing DSM programs adequately address market barriers?

A: No. Duke's existing programs will not be able to squeeze all of the cost-effective savings from the DSM market segments they target, because Company's programs do not adequately address market barriers. In particular, Duke lacks a mechanism for targeting trade allies, and Duke's incentives are not structured so as to maximize savings.

1. Insufficient Attention to Trade Allies

Q: Why is it important to target trade allies?

A: When existing equipment breaks, it usually needs to be replaced immediately. High efficiency equipment often needs to be special-ordered, and special ordering can take days or even weeks. In order to ensure that customers are able to replace their failed equipment with a high-efficiency model, Duke must work with trade allies to ensure that they have sufficient stocks of high efficiency equipment. By offering incentives to dealers, Duke can raise the efficiency of in-stock equipment.

Q: Does Duke currently offer any incentives to trade allies?

A: No. Neither Duke's Freezer and Refrigerator program, Chillers and Unitary Equipment for Air Conditioning program, nor its Heat Pump and Central Air Conditioning program offer incentives to trade allies, or take any other steps to ensure that dealers have sufficient stocks of high-efficiency equipment.

2. Errors in Duke's Incentive Structures

Q: **Will the incentives in Duke's programs maximize DSM benefits?**

A: No. Duke's incentives exhibit several weaknesses. The incentive schedules for equipment and appliance replacement do not encourage the customer to buy the highest-efficiency equipment. The loan offered in the Residential Insulation program does not address the market barriers residential customers face. The conservation rate discounts send contradictory message to Duke's customers.

a. Inappropriate Incentive Schedules

Q: **In which programs does Duke offer inappropriate incentive structures?**

A: Duke uses inappropriate incentive structures in the Residential Heat Pump and Central Air Conditioner program, and in the motors program.

Q: **What are the problems with the incentives in Duke's motors program?**

A: As described in Section III, Duke examines two incentives for efficient motors. The program selected for pilot operation, and projected to be in full scale operation by 1994, applies a $6 incentive per horsepower (hp) for selection of efficient motors.[29] An alternative design applies a $25/hp incentive. In each case, the same incentive applies for new and replacement motors, and for all sizes and types of motors. These rebate structures are poorly matched to the actual structure of motor efficiency costs, which vary with the type and size of the motor.

Table 4 shows the cost of standard and efficient motors for the two most common types of motors: totally enclosed fan-cooled (TEFC) and open drip proof (ODP). Efficiency is usually more expensive, as measured in $/hp, for small motors than for large motors, although costs of efficiency rise again over 100 hp. Efficiency also costs more for the TEFC motors than the ODP motors. In new applications, the $6/hp incentive would cover the entire incremental cost of efficient ODP motors of 30-200 hp, but would cover less than half of the cost of motors under 5 hp. The $25/hp incentive would be more than incremental cost (up to 6 times

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[29]Unlike heat pumps, motors of a given size and type are generally available in only two efficiency levels: standard and high-efficiency.

incremental cost) for almost all new applications, but much less than incremental cost for 1 hp motors. Duke would pay far too much for some motors, and not enough for others.

The situation is more complex for existing motors, depending on how close they are to failing and whether they can be rewound. If a relatively new existing motor is replaced with an efficient unit, the costs vary from $31/hp to $315/hp; again, the most expensive increments are for small TEFC motors. If the motor would have to be replaced soon, the incremental cost would be between the new and replacement values in Table 4. When motors over about 50 hp burn out, they are often rewound, rather than replaced. Since the cost of rewinding a motor is less than the cost of a new standard motor,[30] the incremental cost of efficiency (in $/hp) is higher than shown for "new motors" in Table 4, but less than early replacement.

In order to maximize efficiency savings, without grossly overpaying for efficiency, Duke should adopt a rebate structure that mimics the costs of efficiency for differing sizes of motors. Incentives based on the incremental cost of efficiency would differ with the size of the motor, the motor

[30]Rewinding reduces the efficiency of the original motor.

type, and whether the motor is for a new application or for a replacement.

Q: **What are the problems with the heat pump and central air conditioner programs' incentive structure?**

A: These programs offer incentives that are indexed to the equipment's efficiency. The rebate is $75 per ton for a heat pump for SEER 11, $65/ton for an air conditioner with SEER 11, and an additional $25 per ton for each SEER point above 11. These rebates do not provide consistent incentives for the purchase of the highest-efficiency equipment available.

Since the Federal law now requires that SEERs be at least 10, the average purchase will have a SEER of about 10.5. Duke's incentive schedule provides the customer with a big "reward" ($75) for the first 0.5 SEER incremental improvement, or $150/SEER-ton, but only $25/SEER-ton for each subsequent SEER. This "front loading" is lopsided, and has three inappropriate effects.

First, the incentive structure will encourage cream skimming. While cost structures vary from one market area to another, and will vary over time, improving heat pump or air conditioner efficiency from SEER 10 to SEER 11 costs roughly as much as increasing from SEER 11 to SEER 12, or from SEER 12 to SEER 13. Paying $65-$75/ton for the first small increment and only $25/ton thereafter will encourage customers (and other purchasers of HVAC equipment, such as builders) to select SEER 11 equipment, rather than better equipment.[31]

Second, while the incentives are adequate to encourage purchase of SEER 11 equipment by many purchasers for larger units, they are too small to have much effect on purchaser behavior, above SEER 11 and for smaller equipment:

- The incremental cost of SEER 11 over SEER 10 is about $200-400 for 4-ton units, for which Duke would pay $300, or 75-150%. This incentive will encourage most purchasers to select the efficient unit.
- The cost of the SEER 10-11 increment is about $200-300 for 2-ton units, of which Duke would pay $150, or only 50-75%. This incentive may be sufficient for many purchasers, but it is unlikely to attract speculative developers, who are necessarily very sensitive to first costs.
- Increasing efficiency from SEER 11 to SEER 12 costs about $250-350 for a 4-ton unit, of which Duke would pay $100, or 30-40%.
- The SEER 11-12 increment costs roughly $200-300 for a 2-ton unit, of which Duke would pay only $50, or 15-25%.

The results for the SEER 12-13 increment would be similar to the SEER 11-12 improvement.

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[31]The participants paid for SEER 11 equipment (only slightly above standard) will tend to have a higher percentage of free riders than would occur if Duke encouraged more efficient equipment.

Third, Duke's $/ton incentive structure provides an incentive for oversizing equipment. Since efficiency improvements are more expensive (per ton) for small heat pumps and air conditioners than for large units, Duke's incentive structure will encourage the oversizing of equipment. Oversized HVAC equipment tends to operate less efficiently, due to inherent cycling inefficiencies and reduced comfort for a given temperature.

Duke should restructure the incentive schedule such that the customer is encouraged to buy the equipment with the highest cost-effective efficiency level, and not encouraged to select oversized equipment. This incentive structure should pay about the same percentage of incremental cost across equipment sizes. Incentives as a percentage of incremental cost should be constant or increase as efficiency rises.

b. Loans

Q: Does Duke offer any incentives in the form of low-interest loans to customers?

A: Yes. The Residential Insulation Loan program offers loans up to $2,500 to customers who install insulation in existing homes.

Q: Is this loan likely to be an effective means of maximizing the savings Duke can obtain from residential insulation?

A: No. Customers in the residential retrofit market segment face many market barriers to energy efficiency investments. Prominent among these barriers are a high customer discount rate, an aversion to dealing with contractors, the effort and difficulty of obtaining dependable information on technologies and providers, and lack of time. These barriers are most effectively overcome through direct installation programs, which install measures for the customer with a minimum of difficulty and with little risk with respect to cost or performance. A loan program does not overcome enough barriers to encourage most customers to participate in most programs.

The residential insulation program should be converted from the current reliance on low interest loans towards Duke arrangement of direct installation through private contractors, with significant Duke financial contribution.

c. Ineffectual Rate Discounts

Q: Does Duke offer rate discounts to its DSM programs' participants?

A: Yes. The residential insulation loan and residential MAX programs offer the customer lower rates as an incentive to participate (Rate RE, Category 2; Rate RS, Categories 2, 3, and 4).

Q: Are rate discounts likely to be the most economical way for Duke to capture savings from residential retrofits and new construction?

A: No. To qualify for the rate discounts, a new construction customer must first install a number of measures (insulation, efficient equipment heat pump, and load control pre-wiring) and then apply for the rate discount. This system requires the customer (or the developer) to pay the up-front cost of the measures. For a customer building a new home, and especially for speculative developers, every dollar of efficiency cost must usually compete with other uses (more space, better finishes). The developer either give up the features that make the home more saleable, or must finance any additional cost until the home sells (which is unpredictable), put more of his financial eggs in one basket, and hope that the selling price of the home covers the additional cost.

Duke should replace the rate discount with direct services, training, and up-front cash incentives to builders and customers, sufficient to overcome the market barrier to the efficiency investment. This approach will be more effective in overcoming the market barrier of high up-front customer outlays.

Q: **What message do rate discounts send to the customer?**

A: These rates are price signals that would normally encourage customers to increase their energy use. This would result in customers on conservation rates "taking back" a portion of the savings of the conservation programs. Such "take back" decreases these programs' effects on load growth and may reduce the cost-effectiveness of the programs.

Q: **How does this price signal fit within the least-cost planning process?**

A: It fits poorly. A conservation program simultaneously offering conservation measures and lower tail-block rates operates at cross purposes with itself. The price signal poses the risk that Duke will spend money on conservation programs only to have the programs' effects "taken back" by the customers. Duke should not offer lower rates as an incentive in its conservation programs.

D. Potential for Load Building

Q: Do any of Duke's conservation programs have the potential to build load, rather than decrease it?

A: Yes. The residential heat pump sales component of the MAX program encourages the adoption of heat pumps. This program increases winter load and total energy usage. While Duke asserts that the MAX heat pumps decrease summer load, this assertion is based on the assumption that the air conditioner that otherwise would have been installed in 1991-2000 would have an SEER of only 9.5; manufacture of such air conditioners has been illegal since January 1, 1992.[32] Duke assumes that the Max home heat pumps will be SEER 12. While this is unlikely, given the weak incentives Duke provides for efficient heat pumps (especially over SEER 11), if Duke achieves SEER 12 for heat pumps, it will probably also achieve at least SEER 12 for air conditioners, since the incentives for efficient air conditioners and heat pumps are essentially identical. Hence, Duke should not claim any cooling efficiency credit for the heat pump promotion.

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[32]Duke has asserted that the 9.5 SEER assumption was appropriate for an analysis conducted in 1991, since the low-efficiency air conditioner was still legal then. However, since Duke knew that the Federal efficiency standard was coming into effect, it should have used realistic efficiency assumptions.

The Dual Fuel Heat Pump program is explicitly a load-building program. Duke's analysis assumes an even less likely efficiency for the competing central air conditioner: SEER 7.5. Since the dual fuel heat pump is most likely to be installed as a replacement for a failed air conditioner, the alternative is a SEER 10+ air conditioner. With an appropriately structured air conditioner efficiency program, there would be no difference in the SEER of the heat pump and air conditioner.

Q: Is Duke marketing heat pumps to customers who currently heat with fossil fuels?

A: Yes. The Dual Fuel Heat Pump program is only available to customers who currently have fossil heat; Duke will not provide the incentive to customers who wish to reduce their energy bills and their impact on Duke's peak by converting from a standard heat pump to one with fossil back-up. It is also clear from Duke's documentation that the Max program is intended to encourage selection of heat pumps over fossil heating.

Q: Will load-building programs foster least-cost energy service?

A: Not generally. Electric end-uses requiring promotion are unlikely to be either cost-effective or energy-efficient. For example, Duke is promoting electricity use for heating.

In most residential applications, fossil fuels are more cost-effective and fuel-efficient than electricity for heating. Even though electric heating results in higher customer heating costs, the emphasis on first costs in construction markets makes electric heating attractive to builders because of its lower first costs. It is to be expected that more fossil fuel will be used to generate electricity for providing heat at the end-use than the customer would have used to generate heat directly from fossil fuel. The Company has not screened its load-building programs; if it did so, they would be likely to fail the TRC and other tests.

The Dual Fuel Heat Pump program has a special cost-effectiveness problem when applied to gas-heated homes. On mildly cold days, it would shift relatively inexpensive gas to electricity;[33] expensive on-peak energy on the coldest days would still be served by the gas utility. The participant may receive a substantially lower gas bill because of the inability of the gas company to set its prices according to system load or outside temperature. Since the real savings to South Carolina are small but the bill savings are high,

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[33]Some of the heating electricity will be off-peak, but some will be on Duke's daily, weekly, and monthly peak hours, especially in shoulder months, contributing to LOLP and the need for capacity, and sometimes using high-cost fuels.

the Dual Fuel Heat Pump program may successfully encourage customers to make wasteful investments and use a mix of energy sources that is far from least-cost.

Q: Has Duke limited its promotion of the Dual Fuel Heat Pump to customers with oil heat?

A: No. In Docket 91-216-E, Mr. Denton asserted that "Duke's dual fuel heat pump program targets existing oil heated homes that currently have inefficient air conditioning systems" (Tr. vol. 6 at 128). Nothing in Duke's documentation supports this assertion. The program description does not limit the applicability to oil-heated homes, nor does it require any test of current air conditioner efficiency. The marketing materials supplied in discovery address all fossil heating systems (IR 2-34). Duke does not even know what fraction of its Dual Fuel Heat Pump participants use gas heat (IR 2-28d). In the "collaborative" review process, Duke refused to limit the program in the manner Mr. Denton had previously claimed it was limited.

Q. How could stimulating heating sales affect Duke's costs?

A. Duke's extra heating sales will increase loads at times that contribute to Duke's capacity need, which is determined by peak loads throughout the year. Even loads outside the daily peak hour can reduce the capacity benefits of storage hydro and pumped storage, since the same amount of water will produce less capacity over a longer high-load period, and increase loss of load probability. In addition, even totally off-peak load growth can necessitate tomorrow's baseload generating expansion; eventually, sustained growth in electric energy use will surpass the capability of Duke's current baseload capacity. Sales that do not change the total <u>amount</u> of generating capacity needed may increase the fraction of future capacity that is expensive baseload generation.

Even in the short run, greater sales lead to greater costs for fuel, O&M, and environmental compliance. Unless there are clear benefits to offset these costs, the sales should not be encouraged.

Q. **Do you suggest that under no circumstances should Duke promote growth in electric energy use, off-peak or otherwise?**

A. No. The Company should encourage such sales increases or shifts only if they are cost-effective. Duke needs to consider the costs and effects of such load building carefully and consistently. To begin with, the cost of <u>operating</u> today's coal plants does not represent the total long-term cost of serving such load. Such costs include the extra capital costs of new baseload facilities, the effects of increased load factor on reserve requirements, changes in transmission and distribution investments, and costs associated with mitigating the environmental damage from burning coal.

Programs promoting sales growth may be advisable if they can be shown to be cost-effective. This is easier for programs with only temporary effects. The Idaho PUC recognized this relationship in requiring utilities to phase out load-building rates.[34] Duke's heat pump promotions will have long-term effects.

Q: **Does Duke's promotion of heat pumps appropriately encourage inter-fuel competition?**

A: No. The Commission should encourage alternative fuels to compete on the basis of cost and quality of service, not on marketing advantages and market imperfections. Duke should reduce the cost of electric heating, by increasing the efficiency of equipments and buildings, and by demonstrating more efficient technologies, such as ground-coupled heat pumps. If Duke can then demonstrate that the resulting electric heating system is less expensive than oil heat, over

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[34]See "Load-Building Rate Discounts Must Anticipate Energy Shortages," Public Utilities Fortnightly, July 6, 1989, p. 47, citing Re "Quid Pro Quo" Demanded for Special Electric Rate Contracts, Case No. IPC-E-89-5, Order No. 22489, May 24, 1989.

the life of the equipment, it should be encouraged to promote efficient electric heating for new construction where gas is not available and for existing oil-heated buildings. If Duke can demonstrate that efficient electric systems are less expensive than comparable gas systems, on a life-cycle basis, Duke should be encouraged to promote electric heat throughout its service territory. The gas companies and oil dealers should simultaneously be promoting efficiency in the use of their own products. The result of this efficiency competition would be the selection of the lowest-cost mix of heating fuels for South Carolina.

Duke's marketing approach builds on some important initial advantages for electric heat, exploits market barriers, and may result in the installation of uneconomical heating systems. It is relatively easy to convince developers, or cash-short customers building their own homes, to select electricity over gas, which requires additional capital for a separate hook-up, interior piping, and sometimes a line extension. The market barrier to least-cost energy selection posed by limited capital is exacerbated by Duke's provision of financing for heat pumps.

E. Inappropriate Use of Pilot Programs

Q: What pilot programs is Duke implementing or proposing?

A: Duke is proposing and/or implementing the following six pilot programs:

Residential:

High efficiency ground-coupled Heat Pumps

Water Heater Improved Insulation

High-efficiency lighting

Non-Residential

Cool storage

High efficiency indoor lighting

Air conditioning load control

Q: Is it appropriate for Duke to offer these as pilot programs?

A: No. The Company has not demonstrated that its pilot programs are appropriate to a least-cost Integrated Resource Plan. Pilot programs may be justified to test innovative program designs and build the capability to produce program results. Pilot programs are not necessary for well-established approaches that have been tested elsewhere. Most of the programs Duke is proposing to run as pilots offer technologies that are by now well understood. Numerous other utilities have implemented programs that offer these technologies.

The Company should attempt to pursue new DSM programs as full-scale demonstration programs, rather than limited pilots. Pilots are appropriate for experimental technologies or program designs. However, limited pilot programs are not necessary when similar full-scale programs are already successfully offered by other utilities.

In addition, some of the programs Duke plans to run as pilots are so overwhelmingly cost-effective that delay of the program to allow time for a pilot program is unlikely to increase the net benefit of the program. Any improvement in the program due to the delay would be more than balanced by the cost of delaying the benefits. The non-residential lighting program, especially in new construction, and the residential water heater wrap-up program are excellent examples of this problem.

Q: Are the pilot programs well designed?

A: No. There are three types of problems with the design of the pilots. First, Duke has not clearly identified the issues to be resolved through the pilots, and how the pilots will gather the required data.[35] Second, the pilot programs are

[35] In some cases, the pilots are scheduled to be implemented or completed by now, so some of the future tense in the section might be incorrect. However, Duke has not reported the results of the pilots, so I describe them as if they were still in the planning stage.

generally not well described. Third, those programs that are described are not always designed to provide Duke with information on how to maximize the savings from the markets segments they target.

For example, the water heater wrap program is intended to determine the impact of a "full program" on "distribution infrastructure (i.e., warehousing)" and "manpower requirements and training," and "to determine the impact target marketing has on market acceptance and penetration" (Appendix p. 84). Yet the pilot consists of only 400 wraps (which will not be much of a test of warehousing or manpower), some of which are to be delivered through volunteers (which will obviously not be applicable to a full-scale program). No mass media marketing will be appropriate to this tiny pilot, and no marketing appears to be contemplated in the pilot. The pilot will not answer the questions Duke raised; given the broad experience with water heater wraps by other utilities over the last decade, it is probably unnecessary.

Similarly, the discussion of the motors program (Appendix pp. 97-98) acknowledges the importance of variable speed drives and of the efficiency of the motor-driven devices, but the pilot deal with neither of these. The pilot is intended to "identify the market potential," but the low incentive will not attract all of the potential participants. It is not clear how the pilot is to be structured, what data will be collected, or how it will be analyzed.

The residential high-efficiency lighting pilot is particularly poorly designed.

Q: What deficiencies have you identified in the residential high-efficiency lighting pilot?

A: I have identified the following three deficiencies, based on the description on Appendix pp. 80-81 and the May 5, 1992 program package filing:

- The program offers one kind of compact fluorescent lamp, an Osram 15W to replace a 60W incandescent; yet there are many kinds of compact fluorescent lamps. Duke should offer the customer a variety of bulbs, of different lighting levels and shapes, to replace as many incandescents as possible get with compact fluorescents, and to learn about its customers' preferences.

- The program targets "customers who have a genuine concern about the environment and energy related issues [and] are willing to invest money in high-tech energy saving devices" (program filing, Leaf No. 218) This description suggests that Duke is testing its program on the market that is easiest to penetrate likely to have the highest percentage of free riders. If the purpose of the pilot is to find out what delivery mechanisms work best, it should be directed toward harder-to-reach customers.

- Duke imposes a limit of three bulbs per home; this limit prevents the Company from determining the maximum market potential for this program.

This program illustrates well the poor connection between Duke's concerns and its pilot program designs. The pilot programs may simply delay program implementation, without adding much useful information to Duke's evaluation or program design.

VI. INADEQUATE INTEGRATION OF DEMAND-SIDE AND SUPPLY-SIDE PLANNING

Q: **Are Duke's demand-side plans well integrated with Duke's supply-side planning?**

A: No. Duke's demand-side planning, and its pilots in particular, are not well integrated with Duke's supply planning. While Duke is correct that it is appropriate to "walk before you run," most of its DSM pilots represent only tentative tiptoeing towards integrated planning.

I have already discussed the problems with Duke's slow and partial efforts to capture lost opportunities. Duke is also failing to implement retrofit programs promptly enough to allow it to defer Lincoln.

From Appendix VI-5, the largest of the efficiency programs screened into the IRP is the Low Case non-residential lighting program. This is a very cost-effective program, with which other utilities have a vast amount of experience. Duke should be able to design and implement a good non-residential lighting program by early in 1993, with a high degree of assurance that its actions will be cost-effective. Instead, Appendix p. 76 shows that Duke plans to spend the rest of this year designing the pilot program, and then wait until the spring of 1994 before implementing the pilot. The evaluation would be completed at the end of 1994. No schedule is presented for the ramp-up of the full-scale program, but this presumably would not happen until some time in 1995. Since the first units of Lincoln are scheduled to enter service in 1995, the full-scale program could not affect the timing of Lincoln additions.

Oddly, Duke also shows (Appendix p. 202) the savings from the Low Case non-residential lighting program to start at their full-scale rate in 1993, suggesting implementation two years prior to the timing implied by the pilot schedule.[36] The High Case is scheduled to start in 1995 (if Duke had selected it).

Pilots, where they are justified, should be completed as rapidly as possible to allow for conversion to a subsequent full-scale DSM program in time to contribute to the deferral of Lincoln and subsequent generation. Pilot programs should generally run for months, rather than years.

Q: Are there other problems with Duke's integration of demand and supply resources?

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[36]Similar inconsistencies between Duke's reported pilot schedules and its projected savings occur for other programs. For example, the water heater wrap program in 1992 is to be limited to pilot distribution of 400 blankets, but Duke shows savings of 8,844 MWH in 1992. Since Duke estimates savings of only 407 kWh/blanket, the 8,844 MWH savings would require some 22,000 blankets.

A: Yes. Duke imposes an unnecessarily long time scale for DSM program and measure screening. For example, in the "collaborative" discussions in June 1992, Duke claimed to be unable to screen any of its existing programs or the measures included in some of the existing and proposed programs in time for the Short-term Action Plan (STAP) filing in April 1993, ten months later. Duke asserted that its planning process was too far advanced, and that the screening process required more than a year. Duke should be able to screen additional programs, measures, and levels of efficiency in a matter of a few weeks.

In addition to being implausibly inefficient, Duke's alleged difficulty in screening DSM options is inconsistent with its treatment of supply options. In order to function in today's power market, Duke must be able to screen opportunities for power purchases and sales within days or weeks; in the case of short-term power transactions, the screening must be completed in minutes or hours. Duke is crippling its DSM efforts by precluding timely evaluation of alternatives.

Q: Have you identified any problems in Duke's treatment of supply options?

A: I have not intensively reviewed Duke's screening of supply options, but I have noticed two points worth noting here. First, Duke has not included gas-fired combined cycle power plants in its set of supply options. These are the most common type of new intermediate and baseload capacity in the country; Duke's failure to consider gas combined cycle is particularly odd in light of Duke's decision to screen several candidate technologies that are obsolete (e.g., gas and oil-fired boilers), experimental (fuel cells, pressurized fluidized bed, advanced batteries, advanced nuclear), and poorly suited to the Carolinas (solar central receiver). Duke should include gas combined-cycle options in future supply-side screening.

Second, Duke declined to provide its projections of fuel costs, on the grounds that they are confidential. I have never known any other US utility to make this claim at the system level. Obviously, the PSC cannot meaningfully review Duke's supply-planning decisions without this information. Duke should be required to include fuel price forecasts in its 1993 STAP.

VII. COST RECOVERY

Q: Does your review of Duke's IRP suggest any implications for cost recovery?

A: Yes. First, Duke's failure to screen several programs should make those programs ineligible for cost recovery until the screening is complete and unless that screening indicates that the program is cost-effective. Second, the deficiencies in documentation make any prudence determination impossible; programs may have undocumented deficiencies, and the relationship between the information in the IRP and the programs Duke actually operates are unclear.

Third, Duke's programs are not sufficiently advanced to warrant any incentives. Duke is not an industry leader in the scope of its DSM programs, in its approach to DSM planning, or in the quality of program design. These mediocre efforts do not deserve any reward. Indeed, if Duke's programs are not much improved by the time of its next rate case, I would suggest that the Commission reduce Duke's return on equity to reflect the inefficiency of its DSM operations.

Q: Does Duke's continued load-building efforts have any implications for cost recovery?

A: Yes. Duke's short-run internal marginal cost of electric supply is probably lower than its rates, which are based on the average cost of service, including costs that do not vary much in the short term. Any load building that occurs will result in increased earnings for Duke shareholders, at least until the next rate case. This will occur at the same time that the Company seeks recovery of its conservation expenditures. In short, the Company will be profiting from increased sales and charging customers for conservation expenditures -- activities that may be operating at cross purposes. This increases the importance of screening the load-building programs, and of ensuring that any "found revenues" from load building are subtracted from the lost revenues from efficiency programs.

VIII. CONCLUSIONS AND RECOMMENDATIONS

Q: Please summarize your conclusions on Duke's DSM program in its IRP.

A: Duke's DSM program is too small, too slow, and too poorly organized to meet the Commission's objective of minimizing total resource costs. Duke has

- screened out some programs that appear to be cost-effective, without adequate justification;
- included programs that do not appear to be cost-effective;
- failed to screen other programs at all;
- understated DSM avoided costs;
- failed to prioritize the acquisition of lost-opportunity resources, as required by the Commission's Procedures;
- missed some market segments and many end-uses and measures;
- structured programs and incentives in ways that are unlikely to capture all of the feasible, cost-effective savings;
- selected incentive structures for many programs that are not well suited to the market segments they address;
- separated DSM efforts into too many distinct programs, reducing effectiveness and raising costs;
- continued to pursue load-building programs without adequate evaluation; and
- over-emphasized pilot programs and unnecessarily delayed full scale implementation.

Q: What are your recommendations for the Commission on the Duke DSM program?

A: I recommend that the Commission reject the IRP and order Duke to:

1. immediately suspend its marketing of heat pumps, of the Dual Fuel Heat Pump program, and of the uneconomic Residential Load Control -- Water Heating and Off-Peak Water Heating -- Submetered programs, or file a justification for the programs within 30 days, including all screening results;
2. provide screening results for all existing programs not screened in the IRP process within 90 days;
3. screen all measures included in the New Residences program;
4. screen alternative levels of efficiency (SEERs, wall insulation, ceiling insulation, etc.) for the New Residences, Residential Insulation Loan, Heat Pump/Air Conditioner, Chillers, and Unitary Equipment programs;
5. redesign the Motors, Heat Pump/Air Conditioner, and Non-residential Lighting programs so that incentives for various types and sizes of equipment in new, replacement and retrofit applications reasonably match the incremental cost of the efficiency;

6. design programs to achieve the savings of the high cases of the Motors and Non-residential Lighting programs, or explain why these savings are not beneficial to ratepayers;

7. design comprehensive programs for new non-residential construction and industrial process changes;

8. screen additional measures for the Water Heater Wrap and New Residences programs,

9. redesign its programs to provide as many measures as feasible to each market sector through a single comprehensive program; and

10. provide full documentation of screening assumptions and results (annual peak, MNDC, and energy reduction; annual avoided capacity and energy cost; annual program costs and customer costs), and fuel price assumptions.

Except as otherwise noted, I recommend that the Commission order the Company to comply in the 1993 STAP filing, or to explain in that filing why the changes cannot be made in the available time, and to provide a compliance schedule. All compliance filings should be subject to review and comment by the Parties.

The Commission should remind the Company that cost recovery for the Lincoln peakers, subsequent capacity, and

Clean Air Act compliance costs will depend on a prudence determination, and that costs that could have been avoided through less expensive DSM will not be considered prudent.

Given the multiple problems with Duke's DSM portfolio, with its DSM documentation, and with its approach to DSM planning, I do not believe that the Commission can effectively identify all of the changes that should be made in Duke's DSM resource plan. The Company would profit from extensive input from the Consumer Advocate and PSC Staff in a truly collaborative DSM design process, as opposed to the very limited "collaborative" review process provided for in the Procedures. Other utilities that have engaged in collaborative DSM design have found that the collaborative allowed them to rapidly increase the scope and quality of their DSM portfolio. Other Commissions have encouraged utilities to participate in design collaboratives, to reduce the need for detailed regulatory review of the myriad vital details of DSM program design; if the parties reach consensus, the Commission's review can be much more limited.

In order to participate fully in the design process, the other parties will require consulting resources that they cannot fund from existing sources. In other design collaboratives, the utility has generally funded consultants reporting to one or more of the other parties, on the order of $300,000 systemwide for the first year. This investment, plus Duke's expenditures for its own consultants, is insignificant compared to the several hundred million dollars of potential annual DSM benefits that Duke has identified.

Q: Does this conclude your testimony?

A: Yes.

TABLE 1: COMPUTATION OF INCREMENTAL B:C RATIO FOR HIGH SCENARIO NON–RESIDENTIAL LIGHTING

Subprogram	TRC B:C ratio	TRC C:B ratio	MW savings in 2006	Share of savings	Weighted C:B ratio
LOW SCENARIO					
El Htg – New New	10.82	0.092	86	12%	0.011
El Htg – Existing	2.42	0.413	188	25%	0.105
Fossil – New	11.45	0.087	173	23%	0.020
Fossil – Existing	2.54	0.394	180	24%	0.096
OPT – New	17.77	0.056	21	3%	0.002
OPT – Existing	3.64	0.275	94	13%	0.035
TOTAL			742	100%	0.268
Weighted	3.74	0.268			
HIGH SCENARIO					
El Htg			559		
Fossil			549		
OPT			194		
TOTAL	3.55	0.282	1302		
Increment over LOW SCENARIO	3.33	0.300	560		

TABLE 3: COMPARISON OF ENERGY EFFICIENCY OPTION MNDC TO KW PEAK REDUCTION IN 2006

PROGRAM	MNDC (MW) (a)	SUMMER PEAK KW REDUCTION (b)	ENERGY MWH REDUCTION (c)	MNDC/KW (d)	DSM OPTION LOAD FACTOR (e)
HE UNITARY EQUIP FOR A/C	22.1	33,463	24,463	0.66	0.08
HE CHILLERS FOR A/C	60.7	70,421	171,695	0.86	0.28
NON–RES HE LTG – ELEC HTG – NEW	84.1	86,263	251,345	0.97	0.33
NON–RES HE LTG – ELEC HTG – EXISTING	178.7	188,009	547,805	0.95	0.33
RES HVAC TUNE–UP	33.8	51,174	105,930	0.66	0.24
NON–RES HE LTG – OPT – NEW	19.9	20,945	134,467	0.95	0.73
RES W/H BLANKET	3.7	4,694	53,065	0.79	1.29
NON–RES HE LTG – FOSSIL HTG – NEW	147.6	173,084	737,409	0.85	0.49
NON–RES HE LTG – FOSSIL HTG – EXISTING	150.9	179,680	765,511	0.84	0.49
NON–RES HE LTG – OPT – EXISTING	85.1	93,963	603,233	0.91	0.73
MOTOR SYSTEMS – $6/HP	253.5	267,948	1,563,047	0.95	0.67

Source:
(a) IR 1–20, Attachment 1–27
(b) Appendix VI, pp. 204–205
(c) Appendix VI, pp. 208–209
(d) (a)/(b)
(e) [(c)*1000]/[(b)*8760]

TABLE 4: COST OF MOTOR EFFICIENCY

A	B	C	D	E	F	G	H	I	J
						Incremental Cost per Horsepower			
	Cost of TEFC Motors		Cost of ODP Motors		labor cost for retrofit	New Motors		Early Replacement of Existing Motor	
Horse-power (hp)	Standard Efficiency	High Efficiency	Standard Efficiency	High Efficiency		TEFC	ODP	TEFC	ODP
1	$144	$183	$132	$164	$132	$39	$32	$315	$296
2	$169	$216	$159	$198	$132	$24	$20	$174	$165
3	$178	$251	$144	$184	$132	$24	$13	$128	$105
5	$221	$290	$179	$231	$132	$14	$10	$84	$73
7.5	$301	$389	$240	$327	$132	$12	$12	$69	$61
10	$360	$471	$300	$388	$132	$11	$9	$60	$52
15	$498	$646	$397	$527	$221	$10	$9	$58	$50
20	$615	$787	$497	$647	$221	$9	$8	$50	$43
25	$744	$968	$590	$762	$221	$9	$7	$48	$39
30	$888	$1,147	$688	$874	$221	$9	$6	$46	$37
40	$1,143	$1,499	$869	$1,111	$363	$9	$6	$47	$37
50	$1,405	$1,874	$1,021	$1,278	$363	$9	$5	$45	$33
60	$2,173	$2,663	$1,282	$1,583	$363	$8	$5	$50	$32
75	$2,725	$3,270	$1,608	$1,925	$363	$7	$4	$48	$31
100	$3,398	$4,285	$2,090	$2,494	$856	$9	$4	$51	$34
125	$4,464	$5,957	$2,465	$2,991	$856	$12	$4	$55	$31
150	$5,338	$6,937	$3,209	$3,933	$856	$11	$5	$52	$32
200	$6,267	$8,294	$3,909	$4,949	$856	$10	$5	$46	$29
250	$8,239	$10,398	$4,674	$6,986	$856	$9	$9	$45	$31

Notes: Columns A–F from Nadel, et al, "Energy–Efficient Motor Systems," ACEEE 1991.
G = (C – B) / A
H = (E – D) / A
I = (C + F) / A
J = (E + F) / A

Attachment 1

Resume

of

Paul L. Chernick

PAUL L. CHERNICK

Resource Insight, Inc.
18 Tremont Street, Suite 1000
Boston, Massachusetts 02108

PROFESSIONAL EXPERIENCE

President, Resource Insight, Inc.
August 1986 - present

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

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

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

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

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

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

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

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

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

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

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

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

PROFESSIONAL AFFILIATIONS

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

EDUCATION

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

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

HONORARY SOCIETIES

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

OTHER HONORS

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

Chernick, P., "Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making," forthcoming in 1992.

Chernick, P. and Birner, S., "ESCOs or Utility Programs: Which Are More Likely to Succeed?," The Electricity Journal, Vol. 5, No. 2, March 1992.

Chernick, P. and Schoenberg, J., "Determining the Marginal Value of Greenhouse Gas Emissions," Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II, July 1991.

Chernick, P. and Caverhill, E., "Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs," in Proceedings from the Demand-Side Management and the Global Environment Conference, April 1991.

Caverhill, E. and Chernick, P., "Accounting for Externalities," Public Utilities Fortnightly, Vol. 127, No.5, March 1, 1991.

Chernick, P. and Caverhill, E., "Methods of Valuing Environmental Externalities," The Electricity Journal, Vol. 4, No. 2, March 1991.

Chernick, P. and Caverhill, E., "The Valuation of Environmental Externalities in Energy Conservation Planning," Energy Efficiency and the Environment: Forging the Link. American Council for an Energy-Efficient Economy; Washington: 1991.

Chernick, P. and Caverhill, E., "The Valuation of Environmental Externalities in Utility Regulation," External Environmental Costs of Electric Power: Analysis and Internalization. Springer-Verlag; Berlin: 1991.

Chernick, P., Espenhorst, E., and Goodman, I., "Analysis of Residential Fuel Switching as an Electric Conservation Option," Gas Energy Review, December 1990.

Chernick, P., "Externalities and Your Electric Bill," The Electricity Journal, October 1990, p. 64.

Chernick, P. and Caverhill, E., "Monetizing Externalities in Utility Regulations: The Role of Control Costs," in Proceedings from the NARUC National Conference on Environmental Externalities, October 1990.

Chernick, P. and Caverhill, E., "Monetizing Environmental Externalities in Utility Planning," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P., Espenhorst, E., and Goodman, I., "Analysis of Residential Fuel Switching as an Electric Conservation Option," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P. and Plunkett, J., "A Utility Planner's Checklist for Least-Cost Efficiency Investment," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Ottinger, R., et al., Environmental Costs of Electricity. Oceana; Dobbs Ferry, New York: September 1990.

Plunkett, J., Chernick, P., and Wallach, J., "Demand-Side Bidding: A Viable Least-Cost Resource Strategy," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P. and Caverhill, E., "Incorporating Environmental Externalities in Evaluation of District Heating Options," in Proceedings from the International District Heating and Cooling Association 81st Annual Conference, June 1990.

Chernick, P. and Plunkett, J., "A Utility Planner's Checklist for Least-Cost Efficiency Investment," in Proceedings from the Canadian Electrical Association Demand-Side Management Conference, June 1990.

Chernick, P. and Caverhill, E., "Incorporating Environmental Externalities in Utility Planning," Canadian Electrical Association Demand Side Management Conference, May 1990.

Chernick, P., "Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in Proceedings of the NARUC Second Annual Conference on Least-Cost Planning, September 10-13, 1989.

Chernick, P., "Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in Least Cost Planning and Gas Utilities: Balancing Theories with Realities, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23, 1989.

Plunkett, J. and Chernick, P., "The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal," in Summer Study on Energy Efficiency in Buildings, 1988, American Council for an Energy Efficient Economy, 1988.

Chernick, P., "Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in Proceedings of the 1988 Annual Meeting of the American Solar Energy Society, American Solar Energy Society, Inc., 1988, pp. 553-557.

Chernick, P., "Capital Minimization: Salvation or Suicide?," in I.C. Bupp, ed., The New Electric Power Business, Cambridge Energy Research Associates, 1987, pp. 63-72.

Chernick, P., "The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in Current Issues Challenging the Regulatory Process, Center for Public Utilities, Albuquerque, New Mexico, April, 1987, pp. 36-42.

Chernick, P., "Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in Proceedings of the Fifth NARUC Biennial Regulatory Information Conference, National Regulatory Research Institute, Columbus, Ohio, September, 1986, pp. 547-562.

Bachman, A. and Chernick, P., "Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System," in Proceedings of the Fifth NARUC Biennial Regulatory Information Conference, National Regulatory Research Institute, Columbus, Ohio, September, 1986, pp. 2093-2110.

Eden, P., Fairley, W., Aller, C., Vencill, C., Meyer, M., and Chernick, P., "Forensic Economics and Statistics: An Introduction to the Current State of the Art," The Practical Lawyer, June 1, 1985, pp. 25-36.

Chernick, P., "Power Plant Performance Standards: Some Introductory Principles," Public Utilities Fortnightly, April 18, 1985, pp. 29-33.

Chernick, P., "Opening the Utility Market to Conservation: A Competitive Approach," in Energy Industries in Transition, 1985-2000, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November, 1984, pp. 1133-1145.

Meyer, M., Chernick, P., and Fairley, W., "Insurance Market Assessment of Technological Risks," in Risk Analysis in the Private Sector, pp. 401-416, Plenum Press, New York, 1985.

Chernick, P., "Revenue Stability Target Ratemaking," Public Utilities Fortnightly, February 17, 1983, pp. 35-39.

Chernick, P. and Meyer, M., "Capacity/Energy Classifications and Allocations for Generation and Transmission Plant," in Award Papers in Public Utility Economics and Regulation, Institute for Public Utilities, Michigan State University, 1982.

Chernick, P., Fairley, W., Meyer, M., and Scharff, L., Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December, 1981.

Chernick, P., Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September, 1977.

PRESENTATIONS

American Planning Association 1992 National Planning Conference; May 10, 1992; "Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making."

DSM Advocacy Workshop; April 15, 1992; Session Leader for "Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels.

Energy Planning Workshops; Columbia, S.C.; October 21, 1991; "Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs."

Demand-Side Management and the Global Environment Conference; Washington, D.C., April 22, 1991; "Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs."

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28, 1991; "Least Cost Planning and Gas Utilities."

NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24, 1991; "Least-Cost Planning in a Multi-Fuel Context."

Understanding Massachusetts' New Integrated Resource Management Rules; Needham, Massachusetts, November 9, 1990; "Accounting for Externalities: Why, Which and How?"

National Association of Regulatory Utility Commissioners' National Conference on Environmental Externalities; Jackson Hole, Wyoming, October 1, 1990; "Monetizing Externalities in Utility Regulations: The Role of Control Costs."

New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10, 1990; "Increasing Market Share Through Energy Efficiency."

Lawrence Berkeley Laboratory Training Program for Regulatory Staff; Berkeley, California, February 2, 1990; "Quantifying and Valuing Environmental Externalities."

District of Columbia Natural Gas Seminar; Washington, D.C., May 23, 1989; "Conservation in the Future of Natural Gas Local Distribution Companies".

Massachusetts Natural Gas Council; Newton, Massachusetts, April 3, 1989; "Conservation and Load Management for Natural Gas Utilities".

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22-23, 1989; "Assessment and Valuation of External Environmental Damages."

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30, 1985; "Reviewing Utility Supply Plans".

National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13, 1984; "Power Plant Performance".

National Conference of State Legislatures; Boston, Massachusetts, August 6, 1984; "Utility Rate Shock".

National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20, 1984; "Review and Modification of Regulatory and Rate Making Policy".

Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27, 1983; "Insurance Market Assessment of Technological Risks".

REPORTS (excluding reports incorporated in testimony)

"The Agrea Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

"The Potential Economic Benefits of Regulatory NO_x Valuation for Clean Air Act Oxone Compliance in Massachusetts," March 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports," (with E. Caverhill), January 1991.

"Comments on the 1991-1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities," (with Plunkett, J., et al.), September 1990.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with I.Goodman and E. Espenhorst), Boston Gas Company, December 22, 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with E. Espenhorst), Boston Gas Company, December 22, 1989.

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

    Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

100. South Carolina PSC Docket No. 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20, 1992.

Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.